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Portfolio Optimization of Electricity and Natural Gas Supply of Vertically Integrated Electric Utility

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ΔΗΛΩΣΗ ΓΡΑΦΟΝΤΑ

Ο υπογράφων Ευσταθίου Δημήτριος-Χρήστος βεβαιώνω ότι το έργο που εκπονήθηκε και παρουσιάζεται στην υποβαλλόμενη διπλωματική εργασία είναι αποκλειστικά ατομικό δικό μου. Όποιες πληροφορίες και υλικό που περιέχονται έχουν αντληθεί από άλλες πηγές, έχουν καταλλήλως αναφερθεί στην παρούσα διπλωματική εργασία. Επιπλέον, τελώ εν γνώσει ότι σε περίπτωση διαπίστωσης ότι δεν συντρέχουν όσα βεβαιώνονται από μέρους μου, μου αφαιρείται ανά πάσα στιγμή αμέσως ο τίτλος.

Ευσταθίου Δημήτριος-Χρήστος

Ευχαριστίες

Πρώτα απ’ όλα θα ήθελα να εκφράσω την εγκάρδια εκτίμηση και τις ευχαριστίες μου στον επιβλέποντα μου Επίκουρο Καθηγητή Αθανάσιο Δαγούμα, για την διαφωτιστική καθοδήγηση, τη συνεχή έμπνευση, την αδιάκοπη στήριξη, και ευγενική εποπτεία που οδήγησε στην επιτυχή ολοκλήρωση αυτής της μεταπτυχιακής εργασίας. Οι εποικοδομητικές συζητήσεις και η συνεργασία κατά τη διάρκεια όλης αυτής της προσπάθειας, σε συνδυασμό με τις συμβουλές, τις προτάσεις και την συνεχή βοήθειά του, ήταν καθοριστικής σημασίας για την επίτευξη αυτού του έργου.

Θα ήθελα επίσης να εκφράσω τις ειλικρινείς μου ευχαριστίες στους συνεπιβλέποντες μου Αναπληρωτή Καθηγητή Ιωάννη Παραβάντη και Επίκουρο Καθηγητή Μιχαήλ Πολέμη που δέχτηκαν να είναι μέλη τις τριμελής επιτροπής αξιολόγησης αλλά και για την εποικοδομητική κριτική τους που βοήθησαν στην επιτυχή ολοκλήρωση αυτού του έργου.

Δεν υπάρχουν λέξεις για να εκφράσω τις ευχαριστίες μου προς την οικογένεια μου για την αληθινή πίστη σε μένα, την άνευ όρων υποστήριξη και ενθάρρυνση όχι μόνο για την επίτευξη αυτού του αποτελέσματος αλλά και για όλες τις ευκαιρίες που είχα μέχρι τώρα.

Abstract

This thesis introduces a Non-Linear Programming (NLP) model that comprises of two separate models/parts. The model is resolved in the General Algebraic Modeling System (GAMS) environment using the IPOPT solver. The first part of the model is a Dynamic Economic Dispatch (DED) model that simulates the day-ahead electricity market calculating the optimal scheduling between energy producers while the second part is an econometric model that calculates the optimal retail electricity and natural gas prices offered to price responsive customers. The integrated model is applied in a vertically integrated company operating a gas-fired power plant. Three different CO_2 emission prices are examined in the first part of the model in order to calculate their impact on the company's profits from its wholesale activities. Also, in the second part of the model three different scenarios are examined calculating the impact that various levels of i) energy (electricity and gas) demand and ii) customers' demand elasticity, have on the company's financial performance. The integrated model is designed to calculate the optimal retail prices offered by the company to its customers in order to maximize the company's profits. Also, the model determines the optimal power scheduling between day-ahead and spot markets. First results indicate that energy prices offered to customers are constant during the 24-hour period. These constant values are calculated by the retailer in order to maximize its profits when implementing retail prices at their maximum allowed level. Results also highlight the important link between CO_2 prices and the company's profitability. The company's total profits are €17.3 m on average for a range of possible scenarios while its revenues and costs are €143.4 m and €126.2 m respectively. This integrated model constitutes a pivotal study and a tool for companies operating in both wholesale and retail electricity and natural gas sectors. Further research on customers' behavior would provide useful information and inputs to expand this model and implement bundle pricing and other strategies to attract customers and maximize profits.

Περίληψη

Η εργασία αυτή παρουσιάζει ένα μη γραμμικό μοντέλο προγραμματισμού το οποίο αποτελείτε από δύο μέρη. Το μοντέλο επιλύθηκε στο περιβάλλον GAMS (General Algebraic Modeling System) χρησιμοποιώντας τον IPOPT solver. Το πρώτο μέρος αποτελεί ένα Dynamic Economic Dispatch (DED) μοντέλο το οποίο προσομοιάζει την αγορά ηλεκτρικής ενέργειας της επόμενης ημέρας υπολογίζοντας το βέλτιστο προγραμματισμό παραγωγής μεταξύ των μονάδων που συμμετέχουν στη διαδικασία παραγωγής ηλεκτρικής ενέργειας. Το δεύτερο μέρος του μοντέλου αποτελεί ένα οικονομετρικό μοντέλο το οποίο υπολογίζει τη βέλτιστη τιμή πώλησης ηλεκτρικής ενέργειας και φυσικού αερίου στη λιανική αγορά σε καταναλωτές οι οποίοι ανταποκρίνονται σε αλλαγές τις τιμής. Το μοντέλο που παρουσιάζει αυτή η εργασία εφαρμόζεται σε μια καθετοποιημένη εταιρεία η οποία παράγει ηλεκτρική ενέργεια από μια μονάδα η οποία χρησιμοποιεί ως καύσιμο φυσικό αέριο και δραστηριοποιείται στη λιανική αγορά ηλεκτρικής ενέργειας και φυσικού αερίου. Με σκοπό τον υπολογισμό της επίδρασης της τιμής του διοξειδίου του άνθρακα (CO_2) στο κέρδος που παρουσιάζει η εταιρεία από τις δραστηριότητες της στην χονδρική αγορά, εφαρμόζονται τρία σενάρια στο πρώτο μέρος του μοντέλου εξετάζοντας διαφορετικές τιμές CO_2. Ομοίως, στο δεύτερο μέρος του μοντέλου εφαρμόζονται τρία διαφορετικά σενάρια τα οποία εξετάζουν την επίδραση που έχουν διαφορετικές τιμές i) της συνολικής ζήτησης ηλεκτρικής ενέργειας και φυσικού αερίου αλλά και ii) της ελαστικότητας ζήτησης των καταναλωτών, στην απόδοση της εταιρείας. Το ενοποιημένο μοντέλο υπολογίζει την βέλτιστη τιμή πώλησης ηλεκτρικής ενέργειας και φυσικού αερίου στους τελικούς καταναλωτές αλλά και το βέλτιστο προγραμματισμό για την αγορά ηλεκτρικής ενέργειας μεταξύ των αγορών της επόμενης ημέρας και ενδοημερήσιας, με σκοπό η επιχείρηση να μεγιστοποιήσει τα κέρδη της. Τα πρώτα αποτελέσματα δείχνουν πως οι τιμές πώλησης παραμένουν σταθερές καθ' όλη τη διάρκεια του 24ώρου. Οι σταθερές αυτές τιμές καθορίζονται από την εταιρεία ώστε να μεγιστοποιήσουν τα κέρδη της όταν αυτές τεθούν στο μέγιστο επιτρεπτό όριο. Ακόμη, τα αποτελέσματα αναδεικνύουν τη σύνδεση μεταξύ του συνολικού κέρδους της εταιρείας και της τιμής του διοξειδίου του άνθρακα. Η εταιρεία εμφανίζει συνολικά κέρδη της τάξης των €17.3 εκατ. κατά μέσο όρο για τα πιθανά σενάρια τα οποία εξετάστηκαν. Τα αντίστοιχα έσοδα είναι της τάξης των €143.4 εκατ. ενώ τα συνολικά κόστη είναι €126.2 εκατ. Το ενοποιημένο μοντέλο που παρουσιάζεται αποτελεί μια βασική μελέτη και ένα εργαλείο για εταιρείες οι οποίες δραστηριοποιούνται τόσο στη χονδρική όσο και στη λιανική αγορά της ηλεκτρικής ενέργειας αλλά και του φυσικού αερίου. Περαιτέρω ανάλυση της συμπεριφοράς των καταναλωτών μπορεί να παρέχει χρήσιμες πληροφορίες για την επέκταση του μοντέλου αλλά και την εφαρμογή διαφορετικών στρατηγικών τιμολόγησης με σκοπό την προσέλκυση νέων πελατών και τη μεγιστοποίηση του κέρδους.

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Equations

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ANN	Artificial Neural Network
CCGT	Combined Cycle Gas Turbines
CCHP	Combined Cooling, Heating and Power
CCPP	Combined Cycle Power Plant
CEGB	Central Electricity Generating Company
DA	Day-ahead
DED	Dynamic Economic Dispatch
DRP	Demand Response Program
EdF	Électricité de France
EE	Energy Efficiency
EEX	European Energy Exchange
ETS	Emissions Trading System
EU	European Union
GHG	Greenhouse Gas
HHI	Herfindahl-Hirschman Index
HRSG	Heat Recovery Steam Generator
ICA	Imperialistic Competitive Algorithm
IEA	International Energy Agency
IGU	International Gas Union
ISO	Independent System Operator
ITO	Independent Transmission System Operator
kW	kilowatt
LNG	Liquefied Natural Gas
m	millions
MS	Member State
MW	Megawatt
NBP	National Balancing Point (UK)
NWE	North-West Europe
O&M	Operational and Maintenance
PPC	Public Power Corporation
RES	Renewable Energy Sources
RSI	Residual Supply Index
RTP	Real-time Price
tCO_2	(Metric) tons of Carbon Dioxide
tCO_2e	(Metric) tons of Carbon Dioxide equivalent
TOP	Take-or-pay
TOU	Time-of-use
TTF	Title Transfer Facility
UC	Unit Commitment

Chapter 1 – Introduction

The aim of this study is to present an optimization model, maximizing profits of a vertically integrated company operating in both gas and electricity sector. The company under examination, owns and operates a gas-fired power plant, participates in wholesale electricity market, where it sells the electricity generated from the power plant, and retail electricity market, where it buys electricity from the day-ahead and/or spot market and sells it to its customers. Also, the company participates in natural gas market, buying gas from the wholesale market and selling it to its customers. Company's goal is to maximize profits from all its activities, having both the role of a producer and a retailer. By presenting some major issues faced by market players, such as gas and electricity price fluctuations contributing to energy companies' shrinking profits, this chapter concludes presenting the need for energy companies to participate in both electricity and gas markets simultaneously in order to hedge their risks and increase their profits. Optimizing their activities will assist market players to increase their profits and improve their performance. Consequently, by presenting an overview of both electricity and natural gas markets in EU countries this chapter concludes with the need for optimization and more specifically optimization models.

1.1 Energy Market Liberalization

Power generation and supply industry in the early 1900's was mainly monopolized and in the hands of the state in almost every European country. The end of WW2 led to the merging of the far-flung companies that have existed so far and to the creation of large vertically integrated companies of a national interest enjoying a monopoly privilege[1]. Vertically integrated, state owned companies in both the electricity and gas sector, used to have the role of the producer, retailer and transmission system operator. Typical examples in the electricity sector were CEGB (Central Electricity Generating Company) in England and Wales, Enel in Italy, EdF in France and PPC in Greece. As a result, the European energy markets contained large state-owned electricity and gas utilities and were characterized by significant government subsidies and very high sunk costs. These markets were not sufficiently interconnected and as a result there was a high degree of inefficiency. Customers' were not benefited from this market structure as there was no competition resulting to relatively high energy prices. Therefore, there was a need for a regulatory policy that would focus on market development and harmonization of rules in the EU Member States (MSs). According to Fafaliou and Polemis (2010), "*The low productivity of the industry along with high degree of borrowing by the state-owned energy companies, have gradually led governments to*

[1] See: Harris, C. (2008). Electricity Markets: Pricing, Structures and Economics 1st Edition. Chichester: Wiley.

pursue strategies focusing at the opening of the electricity markets"[2]. In the early 1970's, the first step towards energy market liberalization was made by partially opening the generation sector to new entrants aiming to replace the vertically integrated utilities with competitive markets in order to reduce costs and increase market efficiency. The next steps were made in the 1990's with the beginning of competitive electricity markets, specifically in England and the growth of the first pool model in Scandinavia[1]. Market liberalization continued with swift changes with the proliferation of power exchanges across Europe. In order to allow competition to flourish, it was necessary to restructure the national monopolies into an unbundled form, introduce network codes for third party access and privatization of incumbent energy companies. This was materialized at the end of the 19th century with the first energy package from the European Commission.

It is undisputed that networks are considered to be natural monopolies. Consequently, they have to be highly regulated in order to avoid any abuse of power by the company operating the network. As energy transmission and distribution networks are also considered natural monopolies, power generation and supply activities have to be completely separated from network operation. Both of these activities are highly dependent in the use of the power grid and therefore common ownership and operation of these raise conflicts of interest. For example, the power network owner may raise some entry barriers towards new entrants or charge them excessively to extract more profit. Regulation codes and the three Energy Packages implemented by the EU, focused on the unbundling process of these networks while also integrating EU countries' energy framework. Europe's first collective effort was to create a common framework and establish common goals for the EU (Article 194 of the Treaty of the Functioning of the European Union[3]-Lisbon Treaty 2007). As a result, energy was upgraded as one of EU's main policy issues. The first goal of Article 194 was to ensure the functioning of the (internal) energy market such as competition issues, liberalization of the market, energy transport and third party access. Apart from the aforementioned reasons, political and environmental issues were also responsible for market liberalization and the unbundling process. However, as both *Fafaliou and Polemis* (2010) and *Karan and Kazdalgi* (2011)[4] highlight, there were also strategic goals, because the energy sector plays a strategic role in economic growth.

In 1992-1994, prior to Lisbon Treaty, EU introduced the first energy package (Directives 96/92/EC[5] and 98/30/EC[6]) aiming to increase competition in production, ensure that new power producers will be able to use the transmission and distribution networks without any barriers from the previously vertically integrated companies (Third Party Access) while also creating the appropriate market conditions for competition in retail. The first package introduced the functional and accounting separation between production, transportation and distribution activities. The next step was to ensure a competitive environment in the supply market and give consumers the ability to choose freely their supplier. Consequently, in the early 2000's, the second energy package was

[2] Fafaliou, I. and Polemis, M. (2010). Trends in the European electricity markets: the case of Greece. International Journal of Economics and Business Research, 2(5), p.369.
[3] Treaty of the Functioning of the European Union: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:12012E/TXT&from=EN
[4] Karan, M. and Kazdağli, H. (2011). The Development of Energy Markets in Europe. Financial Aspects in Energy, pp.11-32.
[5] European Parliament Directive 96/92/EC: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:31996L0092&from=EN
[6] European Parliament Directive 98/30/EC: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:31998L0030&from=EN

implemented (Directives 2003/54/EC[7] and 2003/55/EC[8]). The second package restricted the control that vertically integrated companies had at the time. However, incumbent companies perceived the business environment they are called upon to compete and reorganized their structure in order to make sure they will survive in this fast changing environment. This package forced companies to completely separate their activities from a legal perspective (legal separation). Finally, the third energy package was implemented in 2009 aiming for a fully effective, fair and transparent energy market, guarantee a non-discriminatory network access, build a single EU gas and electricity market in order to keep the prices as low as possible and increase security of supply. The third package consists of two Directives (2009/72/EC[9] and 2009/73/EC[10]) and three Regulations (715/2009[11], 714/2009[12] and 713/2009[13]). This package forced market players of the EU countries to completely unbundle their activities. Companies owning transmission and/or distribution systems while also performing other activities in the energy market had to use one of the unbundling models presented in the third energy package: Ownership Unbundling, Independent System Operator (ISO) and Independent Transmission System Operator (ITO). Therefore, electricity and gas transmission and distribution activities would be completely separated from production and supply activities. This unbundling process encourages new entrants in both markets. However, these new market players may offer extremely low prices in order to establish themselves in the energy market and increase their market share. This aggressive pricing strategy influences other participants, who are also lowering their prices and reduce their overall profits. This could have a negative effect in their cash-flows and threaten their viability.

Overall, EU aims to strengthen the energy market integration between the EU countries and its neighbours (Energy Community countries). Market integration will deliver several benefits to countries and market participants such as enhanced economic efficiency, security of supply and free competition. Market integration will have huge impact on market prices by allowing the lowest cost producer to serve the demand in neighboring countries. Given the aforementioned, it becomes apparent that both electricity and gas industries experienced significant changes the last decades. Many European Directives' and Regulations' goal was to integrate EU countries' markets and improve their performance, nevertheless this is a humongous process and is still a work in progess.

1.2 Penetration of RES

European Union also target's to establish an ecological and sustainable energy market by setting mid and long-term targets for the implementation of renewable energy sources (RES), increase in energy efficiency (EE) and the reduction of greenhouse gases (GHG). In 2007, EU introduced the "Europe 2020 Climate & Energy Package"[14] which focuses on renewables, energy

[7] European Parliament Directive 2003/54/EC: http://eur-lex.europa.eu/resource.html?uri=cellar:caeb5f68-61fd-4ea8-b3b5-00e692b1013c.0004.02/DOC_1&format=PDF
[8] European Parliament Directive 2003/55/EC: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32003L0055&from=EN
[9] European Parliament Directive 2009/72/EC: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=EN
[10] European Parliament Directive 2009/73/EC: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0073&from=EN
[11] European Parliament Regulation 715/2009: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0715&from=EN
[12] European Parliament Regulation 714/2009: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0714&from=en
[13] European Parliament Regulation713/2009: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0713&from=EN
[14] See: https://ec.europa.eu/clima/policies/strategies/2020_en

efficiency and emissions and gives an overall view of the targets the EU should achieve by 2020. The package is a set of binding legislation and sets three key targets (European Commission):

- 20% cut in greenhouse gas emissions compared 1990 levels;
- 20% of EU energy from renewables;
- 20% improvement in energy efficiency.

In 2014, the EU leaders adopted the "2030 Climate and Energy Framework"[15] which builds on the 2020 climate and energy program and is in line with the long-term targets set in the "Roadmap for moving to a competitive low carbon economy in 2050"[16]. The 2030 framework sets three key targets (European Commission):

- 40% cut in greenhouse gas emissions compared to 1990 levels;
- at least 27% share of renewable energy consumption;
- at least 27% energy savings compared with the business-as-usual scenario.

EU has also set a target for 2050, to reduce greenhouse emissions by at least 80% below 1990 levels through domestic reductions alone. These strategies ensure an affordable energy for all consumers, increase the security of supply by reducing energy imports while also boost Europe's economy by developing clean energy technologies. These targets, helped to almost double the share of renewables in gross energy consumption, as it can be seen in Figure 1.

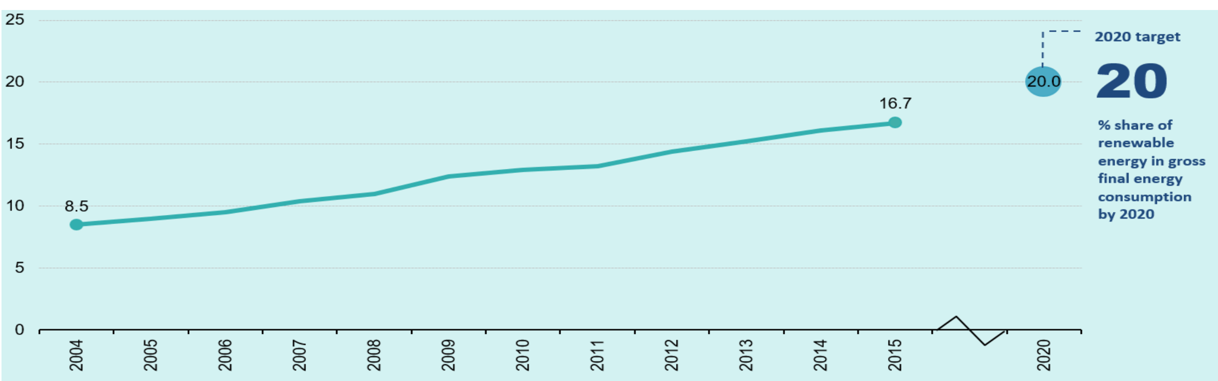

Figure 1 Share of renewable energy in gross final energy consumption, EU-28, 2004-2015

Source: Eurostat[17].

Energy markets responded positively to these targets imposed be EU and the share of final energy consumption that comes from renewable energy sources increased from 8.5% in 2004 to 16.7% in 2015. In a more recent example, solar and wind electricity generation increased by 5% between 2015 and 2016. As projections demonstrate, the share RESs in the global energy mix will increase further and almost half of Europe's electricity supply in 2040 will come from renewables[18]. These projections also indicate, that wind energy may become the first source of electricity by 2030[19]. According to Bloomberg's New Energy Outlook 2017, by 2040 $10.2 trillion

[15] See: https://ec.europa.eu/clima/policies/strategies/2030_en
[16] See: https://ec.europa.eu/clima/policies/strategies/2050_en
[17] See: http://ec.europa.eu/eurostat/statistics-explained/index.php/Europe_2020_indicators_-_climate_change_and_energy
[18] New Energy Outlook 2017, Bloomberg
[19] World Energy Outlook 2017, IEA

will be invested in new power generation worldwide, the 72% of which will go to renewables resulting in 34% share in electricity generation coming from RES[20].

Despite all that, MSs are not on the same page regarding their targets and progress. It becomes apparent that, even within the EU, there is a huge gap between Member States. Figure 2 illustrates the share of RES by country in their final energy consumption, in 2015, compared to their 2020 targets. For example Sweden with 55% share of RES in 2015, has already achieved its target for 2020 (50% share of RES), while the UK having achieved 8% share is far from its goal.

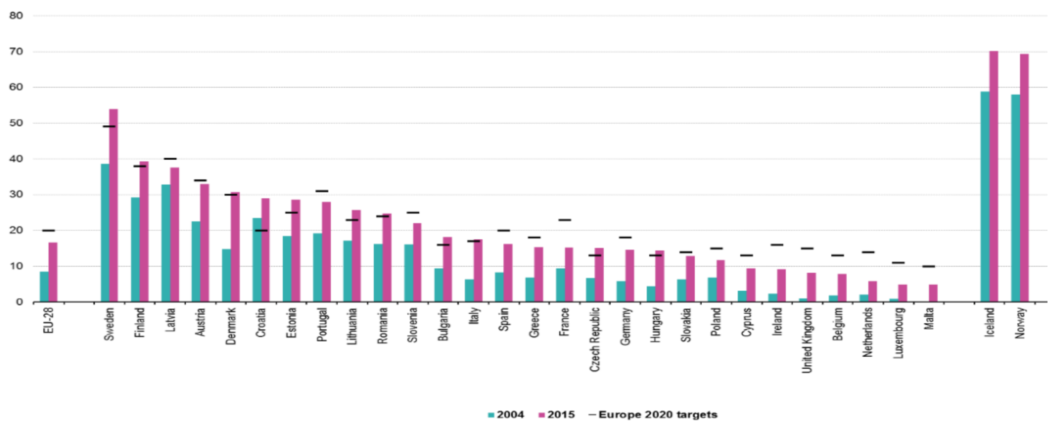

Figure 2 Renewable energy share in gross final energy consumption by country and their target for 2020 (2015)

Source: Eurostat[21].

Penetration of RESs imposes some major challenges to electricity markets. Due to their variability in electricity generation, RESs impose the need for flexible power plants with fast ramp-up capacities. Solar plants are linked with the sunset effect (duck curve), where peak demand occurs at the time solar power is no longer available, usually late in the afternoon. On the contrary "wind output is de-linked from the demand evolution" according to *Koltsaklis et al (2017)*[22] and as a result creates lower needs for flexible units compared to photovoltaics. Nevertheless, wind power is still dependent on wind availability. Consequently, penetration of RESs increases the need for flexible power plants that can ramp-up fast. Such plants are hydro power plants and combined cycle gas turbines (CCGT) having a ramping capacity of 12 MW/minute.

1.3 Electricity Markets

1.3.1 Wholesale Electricity Markets

Increasing electricity production from RES, was among other factors the reason for the downward trend of wholesale electricity prices in several European markets in 2016. Figure 3 presents the evolution of day-ahead (DA) electricity wholesale prices where the average price declined in almost every market. In 2016, gas and coal prices declined and this had an impact on wholesale electricity prices as well, pushing them further down. The effect of RES in wholesale

[20] New Energy Outlook. (2017). New Energy Finance. Bloomberg

[21] See footnote 15

[22] Koltsaklis, N., Dagoumas, A. and Panapakidis, I. (2017). Impact of the penetration of renewables on flexibility needs. Energy Policy, 109, pp.360-369

prices can be seen in the Nordic+Baltic region where the observed increase in prices (16%) in 2016 was due to a decrease in wind and solar generation (5%). Consequently, it is evident that a higher share of RES pushes down wholesale electricity prices while also facing the risk of having extremely high prices or price surges at times of scarcity.

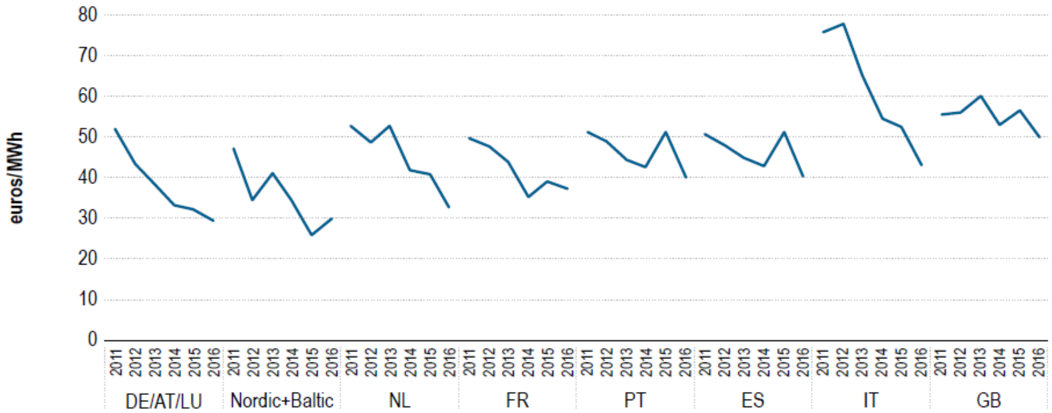

Figure 3 Evolution of DA electricity prices in different European power exchanges (2011-2016)

Source: Acer MMR Electricity Wholesale Market 2016, ENTSO-E, PLATTS (2017) and ACER calculations.

Another effect of the penetration of RES was believed to be an increase in price volatility[23]. Due to this trend, an increase in lower price periods would reduce the load from conventional generation plants and as a result their revenues. These periods happen when the production from RES is high compared to demand. Electricity producers would compensate these revenues at times of high electricity price periods or price spikes that might take place at times of shortages. These price spikes would be crucial for the conventional plants in order to compensate the reduced load factors and to cover at least a share of their costs. However, these expectations were not materialized as the frequency of price spikes decreased for the period 2009 to 2015. Based on Figure 4, it becomes evident that the frequency of price spikes in 2014 and 2015 was significantly lower than in 2009. On the contrary, in 2016, price spikes more than tripled compared to 2015. These spikes occurred in MSs with the tightest adequacy margins, such as GB, France and Belgium[24].

[23] See the summary report "How wind variability could change the shape of British and Irish electricity markets" at http://www.poyry.com/sites/default/files/impactofintermittencygbandi-july2009-energy.pdf.
[24] See Figure 7 of ENTSO-E's "Winter outlook report 2016/2017 and summer review 2016"

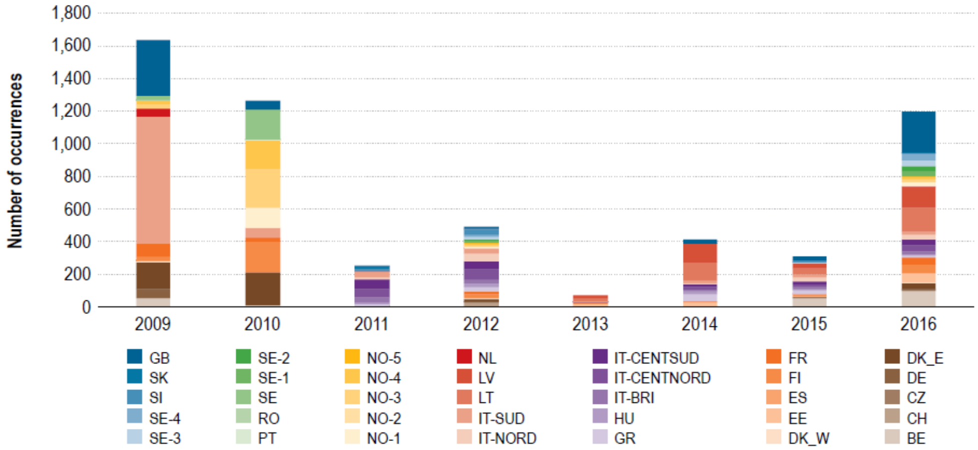

Figure 4 Frequency of price spikes in main wholesale DA markets in Europe (2009-2015)

Source: ACER MMR Electricity Wholesale Market 2016, ENTSO-E, Platts (2017) and ACER calculations.

On the one hand the increase in low price periods (see Figure 5) and on the other hand the decrease in the frequency of high price periods are correlated with the surge of RESs in electricity production. However, several other factors such as an increasing overcapacity and the successful market integration of many European day ahead (DA) markets have contributed to shrinking prices and reduced volatility[25].

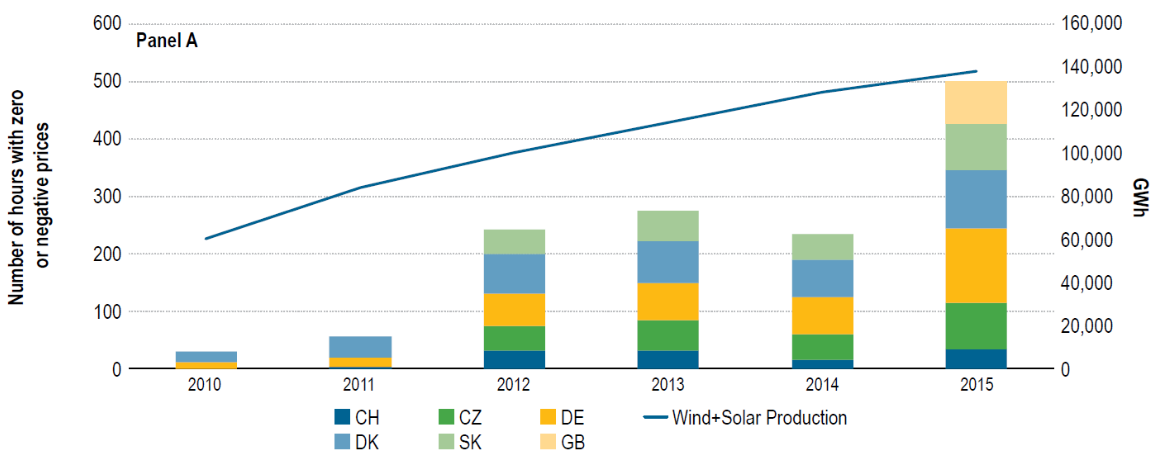

Figure 5 Frequency of zero or negative wholesale prices and the quantity of electricity produced from RES (2010-2015)

Source: ACER MMR Electricity Wholesale Market 2015.

Role of Natural Gas in Electricity Production

The role of each fuel in the electricity production mix in EU for the period 1990-2015 is illustrated in Figure 6. It becomes evident that the role of gas fired power plants is diminishing

[25] ACER Market Monitor Report Electricity Wholesale Market 2015

while the use of RES in energy production is surging. From 1990 and up until 2007, the use of natural gas was increasing rapidly, but after 2008 its role started to decline. The last 2 years, electricity production from gas-fired power plants is ramping up. Despite the fact that in 2016 electricity production from gas was at the same level as in the early 2000's, the role of these plants is extremely important for the aforementioned reasons.

Subsequently, given the fact that RES are substituting conventional plants, the financial viability of conventional electricity generation has been affected by low wholesale prices in combination with the decline of high price periods. Most significantly, the competitiveness and even the survival of gas-fired generation plants has been put to the test as the combination of cheap coal and low carbon prices affected them the past years. The future viability of gas-fired plants will be challenging as they will be acting more as flexible generation plants and provide stability to the system. Despite the fact that the importance of gas-fired power generation is increasing, European climate policies and the cost reduction of renewables will push these type of power plants in a more balancing role rather than a baseload role by the mid-2020s[26].

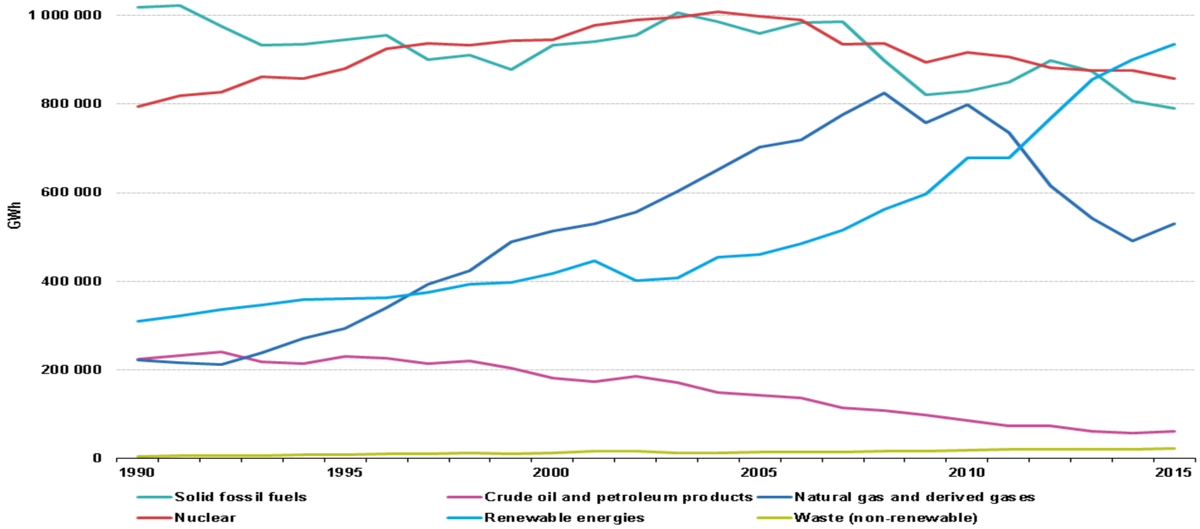

Figure 6 Gross electricity production by fuel, GWh, EU-28, 1990-2015

Source: Eurostat[27]

According to ACER, clean spark and clean dark spreads can assess the impact of declining electricity prices on gas and coal power plants respectively as "*they represent the theoretical gross margin of one MWh produced with each… technology*"[28]. Figure 7 presents the correlation between ETS and spreads.

[26] According to IEA World Energy Outlook 2017
[27] http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_and_heat_statistics
[28] Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015. (2016). ACER

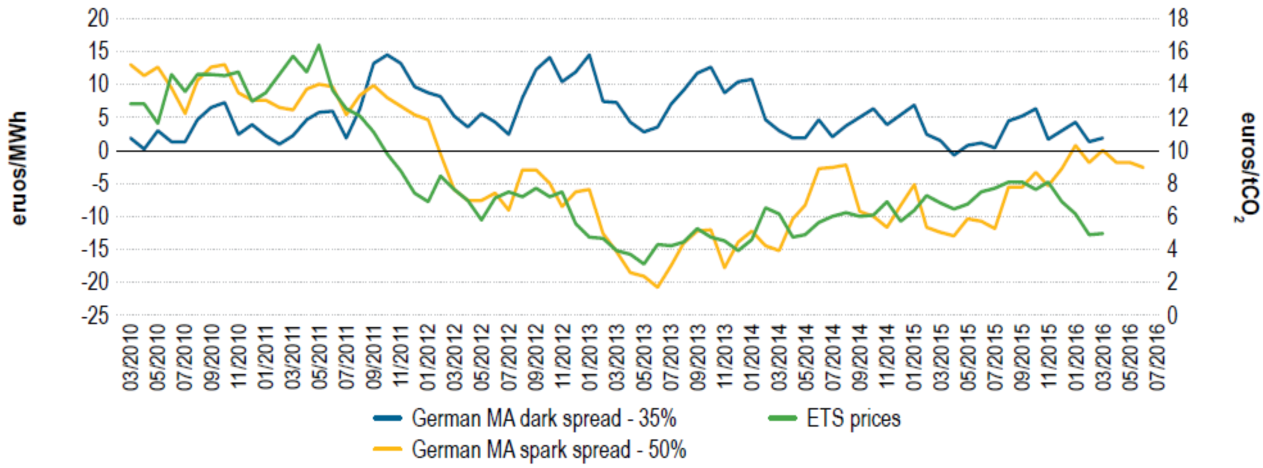

Figure 7 Evolution of month-ahead clean sparks and clean dark spreads and ETS prices in Germany 2010-2015

Source: ACER Electricity MMR 2015

The overall profits of these power plants depend on gas and coal prices but also on the CO2 prices (Emissions Trading System - ETS prices). As illustrated in Figure 7, gas power plants profits increase when ETS prices rise and decrease when ETS prices drop as well. The reason for this correlation is that coal power plants pollute 2.5 times more than gas plants[29].

1.3.2 Retail Electricity Markets

From the retail side and the downstream activity, electricity prices follow a different pattern. The last decade, average retail electricity prices in Europe increased by 26.4% for households and 5.8% for industrial consumers. The upward trend of household electricity prices observed the last ten years has changed and in 2016 prices have fallen for the first time. On the contrary, industrial consumers benefited for the third consecutive year of decreasing prices. Figure 8 demonstrates the average final electricity price for both households and industrial consumes from 2008 up until 2016. Despite the overall decline in final electricity prices in EU in 2016, in some MSs, retail household prices increased compared to 2015 for as much as 15.8% (Norway), while in others, retail prices decreased[30] for almost 20% (Slovenia). It is evident that, the development of electricity prices is different in each MS and as a result, retail electricity prices differ across the EU, where in some countries prices may be three times higher compared to other countries. For instance, in 2016 across the EU, the highest final electricity price in nominal terms for household consumers was in Denmark (30.86 €c/kWh) which was more than triple compared to prices in Bulgaria[31] (9.6 €c/kWh)[32].

[29] See: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/641983/Fuelmixdisclosurewebpage2017.pdf
[30] Eurostat and ACER MMR Electricity and Gas Retail Markets 2016 data
[31] It is worth mentioning that a nuclear power plant operates in Bulgaria and may drive electricity prices
[32] Prices are derived from Eurostat

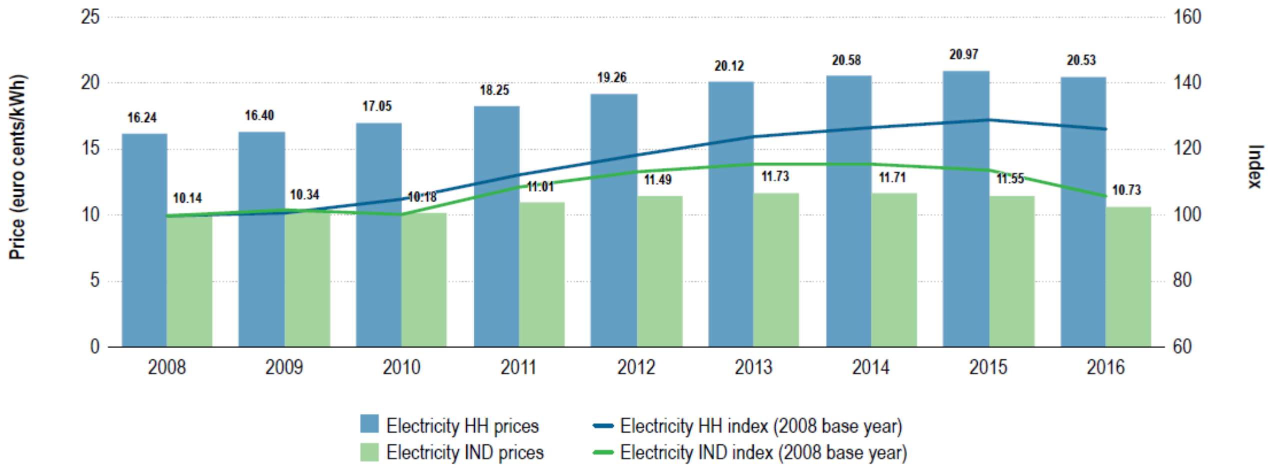

Figure 8 Final electricity prices for household and industrial consumers in EU MSs and Norway (2008-2016)

Source: ACER MMR Retail Electricity and Gas Markets 2016.

The price discrepancies between European countries mentioned above are caused by a different composition of the final electricity bill. The final electricity price consists of the energy component, regulated transmission and distribution charges, VAT, levies and other taxes such as RES charges. For instance, the energy component in Malta accounted for 78%, while in Denmark for only 13%[33]. Another example could be Norway, where the share of distribution costs was the highest and almost double compared to other EU MSs. Similar differences can be found all over Europe, where every country follows its own pricing methodology. Nevertheless, the decline of the energy component observed in the final price is the most important evidence that the last few years the retail electricity sector is facing many challenges and serious viability issues. Despite the fact that the final electricity price for household consumers increased, with 2016 being the exception, the share of the energy component as a percentage in the final price declined steadily for the last five years. This is mainly due to the decrease of wholesale electricity prices. This decline in the energy component was compensated by an increase in absolute terms of network costs, VAT and other taxes. Figure 9 presents the share of each component on the weighted average final electricity price in EU capital cities during the period 2012-2016. The energy component decreased for more than 5% in 5 years, leaving suppliers with little room for competition and thus reducing their profit margins. For example, in England, ten years after the liberalization of energy markets and the new era of fierce competition, profits of retail energy supply activities were less than 1.5% of sales[34]. Figure 9 also shows that between 2012 and 2016 the share of RESs charges more than doubled assisting their viability and supporting the financing of new projects.

[33] See: ACER MMR Retail Electricity and Gas Markets 2016

[34] See: Eakin and Faruqui (2000).

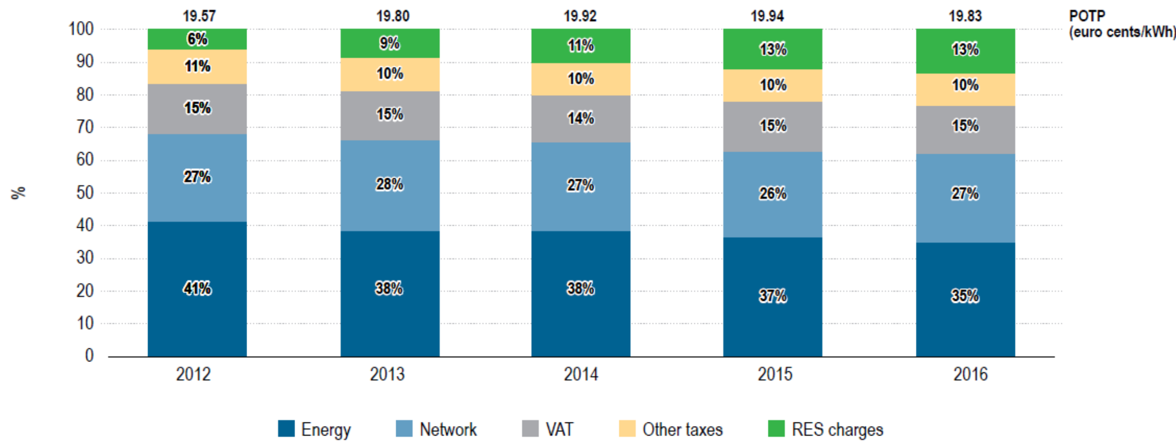

Figure 9 Weighted average post-taxes electricity price breakdown for households in EU capital cities and Oslo (2012-2016)

Source: ACER MMR 2016 Retail Electricity and Gas Markets 2016.

1.3.3 Need for Optimization in the Electricity Sector

Therefore, based on the aforementioned, it should be clear by now that the effort electricity markets are making in order to meet the decarbonisation targets while also ensuring affordability and security of supply, has resulted in facing many new challenges. Other concerns are supply disruptions, additional costs enforced by climate action plans from national or European policies, technological advancements and many more[35]. Nevertheless, suppliers carry a substantial risks in their every-day activities with little margins to compensate them. Given the fact that generation businesses can endure poor cash flows better than the retail sector, due to their high fixed marginal costs of electricity production[36], generation businesses present an opportunity for retailers for a liquidity hedge tool. Generators and suppliers have a similar risk due to the competitiveness of energy markets, but for the latter, competition is more intense. As already mentioned above, profit margins of suppliers are shrinking over the years. Despite the fact that these two business risks are not offsetting each other, the diversification of their portfolio presents a hedging tool for a modern company in order to survive and become more competitive by increasing their market share, their revenues or their profits. Therefore, there are many firms in the electricity sector that have the role of the producer and retailer. Typical examples in Europe are EdF in the UK and France, Vattenfall in Denmark and Germany and PPC in Greece. Companies involved in both of these activities need to find an equilibrium, on a real time basis, between their upstream and downstream portfolios resulting in exposing them to price and quantity risks[37]. In order to maximize profits, revenues or even market share in multiple activities, electricity companies need a portfolio optimization tool. By doing so, they have an instrument, a scientific tool, that presents to them the optimal solution in order to help decision makers take an investment decision, identify the optimal output, price, and expected returns and also determine the production level of their generating power plants. Overall, portfolio optimization finds the optimum mix that makes the utmost of the diversification between these two activities.

[35] See: Retail Electricity Pricing and Rate Design in Evolving Markets.
[36] See: Electricity Markets: Pricing, Structures and Economics by Chris Harris
[37] According to Boroumand and Zachmann (2011)

1.4 Natural Gas Markets

1.4.1 Natural Gas Demand and Production

Gas demand in EU increased in 2016, for the second consecutive year, by 7% compared to 2015. The main reason for this, is an increase in gas consumption of gas-fired power plants, as mentioned above, which contributed to 60% of this increase. The fact that gas fired power plants will have a more balancing role could influence total gas consumption by reducing it and consequently reducing gas prices, according to ACER Gas Market Monitoring Report 2016. Nevertheless, forecasts suggest that there will be an increase in global gas consumption due to rapid withdrawal of coal plants[38], the competitiveness of gas relative to other fuels, CO2 pricing, technological developments and an increase of gas use in land and maritime transportation. According to World Energy Outlook 2017 and the New Policies Scenario "(Global) *Natural gas use rises by 45% to 2040; with more limited room to expand in the power sector, industrial demand becomes the largest area for growth*"[39], but the overall demand in EU will be reduced in 2040 by approximately 1% compared to 2016.

Domestic gas production is steadily declining for the last 12 years[40] and could drop below 20% by 2030[41]. Consequently, natural gas imports for EU countries increased in 2016 with Russia being the main supplier with 34% share. Europe's physical gas supply is based on bilateral contracts between buyers and some of the main suppliers, such as Gazprom and Sonatrach, where in these contracts gas prices are mainly linked to oil product prices. However, these long-term bilateral contracts are being phased out and EU's gas markets are moving towards a gas hub model and gas-to-gas competition. In Europe, the North West (NWE) gas markets are leading the way with well-established gas hubs, such as NBP in the UK and TTF in Netherlands, and more than 90% share of gas-to-gas pricing mechanisms, while other regions, such as Central Europe, follow closely with approximately 58% share. On the contrary, Mediterranean price formation is mainly based on oil-priced contracts. It becomes obvious that, between MSs, there are differences in their preferred pricing methodology but overall, according to the International Gas Union (IGU), in Europe, gas-to-gas competition "*remains the largest share, standing at 66%*" with oil linked contracts, predominantly pipeline imports and followed by LNG, at 30%[42]. As a result, the regulatory framework and business strategies have to be redefined in many MSs in order to adapt to the new and modern gas price mechanisms.

1.4.2 Wholesale Gas Markets

The last 4 years, international gas prices declined steadily mainly due to falling oil prices and the shale boom in the US. In 2015 international gas prices fluctuated. They declined during the first three quarters and afterwards they saw an upturn. Decreased gas demand in combination with the increased storage levels[43] and lower oil prices was the reason behind declining gas prices.

[38] Many countries announced the imminent phase-out of coal-fired power plants

[39] World Energy Outlook 2017, IEA

[40] Derived from data analysis from Eurostat

[41] See: http://www.eurogas.org/uploads/media/Eurogas_Workshop_Long-Term_Outlook_for_gas_to_2035_221013.pdf

[42] See: International Gas Union – Wholesale Gas Price Survey 2017.

[43] According to ACER Gas MMR 2016, 40% of Europe's underground gas storage capacity remained unused and as a result it can be concluded that there is an overcapacity in storage facilities that affect market prices

As for the last quarter, the main reason was an increase in gas consumption by gas-fired power plants as a result of the coal price surge, and an increase in Asian and US gas prices. Consequently, the last quarter of 2016, prices of oil-linked contracts were lower than hub prices. Figure 10 presents the evolution of international wholesale gas prices for the period 2010-2017. Following the aforementioned, wholesale gas prices in Europe fluctuated in accordance with internal production, storage levels, demand, and oil prices. Over the period 2005-2013, wholesale gas prices in Europe increased largely due to the increased gas demand and prices in China[44]

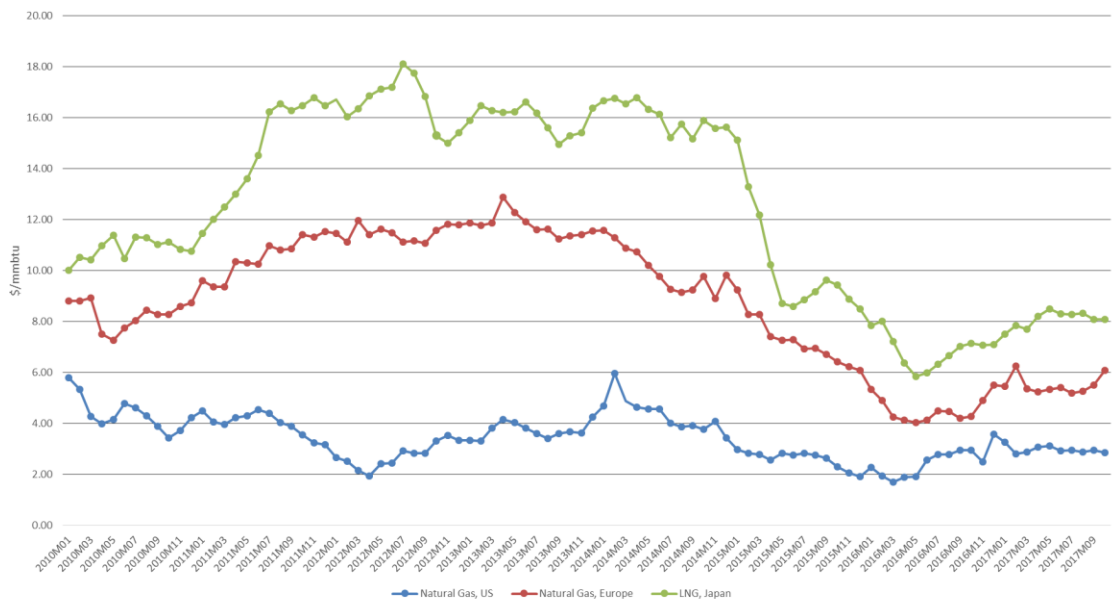

Figure 10 Evolution of international wholesale prices (2010 – Sept. 2017) in $/MMBtu

Source: The World Bank data.

New pipelines and/or strengthening and upgrading programs of the existing gas network throughout Europe improved the interconnectivity between MSs and third countries and contributed also to the decline in gas prices in Europe. Nevertheless, there are still many gaps and bottlenecks primarily in South-South East Europe, Central-East Europe and Baltic regions. Consequently, gas prices could be higher in these regions and might have an impact in neighbour markets. However, the effort made to achieve price convergence between EU gas hubs and gas markets may not be very effective given that new infrastructure is required in many regions due to bottlenecks. These investment costs will be recovered through tariffs resulting in different final prices between MSs. For example, in the NWE region, wholesale gas hubs prices are lower and they present a higher degree of price convergence compared to other hubs. This is due to the fact that NWE markets are sufficiently interconnected, with greater liquidity and higher available cross-border capacity between MSs. Gas hub prices in the other regions of the EU are varying, mainly due to interconnection gaps and bottlenecks between MSs.

In order to compare the performance of gas markets across MSs, our focus should be on market health. Market health is evaluated in order to measure the competitiveness, resilience and

[44] According to IGU

diversity of supply and it is calculated using three indexes. These indexes are: a) the diversity of supply, b) the Residual Supply Index (RSI) and c) market concentration on the supply side[45]. Security of supply (diversity of supply) is measured in order to measure import dependency and consequently the political influence of other countries. According to ACER, the minimum acceptable limit for each MS is at least three suppliers. RSI index determines the capacity capabilities of all suppliers without the largest one while the minimum acceptable level is 110%. The last index is market concentration on the supply side and is measured by the Herfindahl-Hirschman Index (HHI)[46]. According to Acer Gas Target Model (AGTM), this index should be lower than 2000. Large market share or a small amount of suppliers results into higher market concentration and consequently higher HHI. Figure 11 presents an overview of these metrics for EU's MSs in 2016.

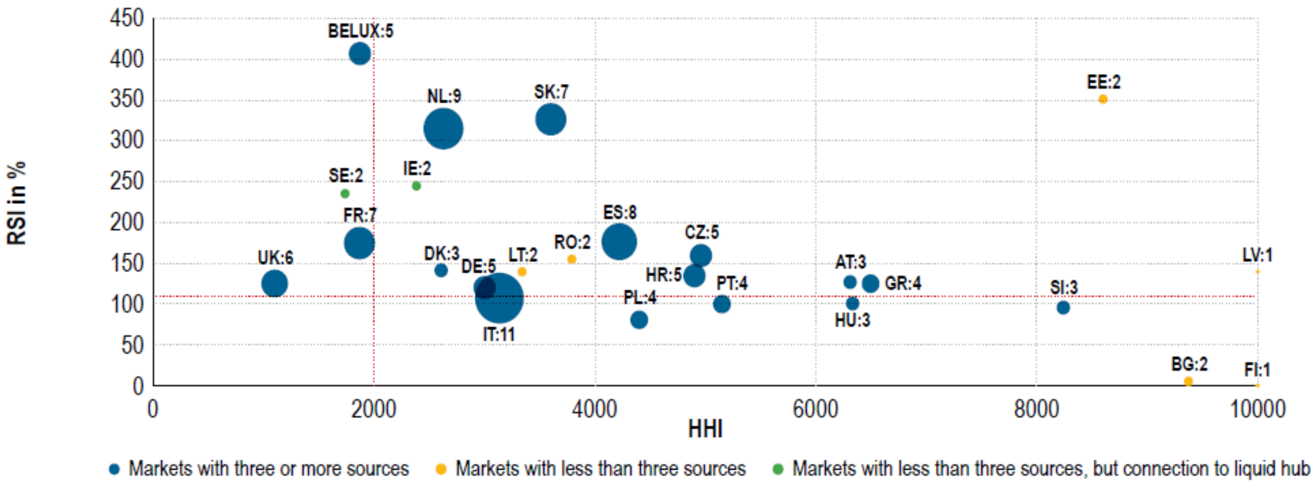

Figure 11 Market health indexes of EU MSs in 2016

Source: ACER GAS MMR 2016, based in ENTSOG and Eurostat data.

It becomes obvious that the most challenging indicator is the diversification of supply, as many MSs have three or fewer different sources. Figure 11 reveals that smaller countries perform poorly - Bulgaria, Latvia - while those MSs that have gas hubs or are sufficiently interconnected to large hubs, like Ireland and Denmark, and those that have LNG facilities - Greece, Lithuania - perform better and have lower HHI values. Additionally, countries that have LNG facilities have a higher RSI index. As it is also shown in Figure 11, almost half of MSs have more than three suppliers and RSI larger than 110%. In these MSs, although their HHI index may not be above the 2000 threshold, the main supplier is considered to be exposed to market competition and as a result is not capable to manipulate the market by setting prices at a monopolistic level. However, MSs that do not achieve the RSI threshold and those with less than 3 suppliers - Bulgaria, Finland - depend almost entirely by these suppliers and consequently they (suppliers) can set the price at their desired level.

[45] According to Acer Gas Target Model (AGTM)

[46] It is calculated as the sum of squared market shares for each firm supplying gas at the import level

Adding to all of the aforementioned, market liquidity is one of the most crucial indicators that reveal the efficiency of gas wholesale markets. Liquid spot and forward markets present a crucial hedging tool for the market participants. NBP in the UK and TTF in Netherlands are the most developed spot and forward gas hubs in terms of performance in the EU with the French, Austrian and German hubs following. Other MSs don't have a functional hub or energy exchange, such as Greece and Ireland. All in all, year by year EU gas wholesale markets are improving and gas prices are converging and correlating.

One of the most important aspects for a supplier is the average source costs. These costs are calculated by ACER and take into account both long-term oil-indexed contracts and hub prices[47]. In 2016, in many markets, gas source costs continued to decrease by more than 20% compared to 2015. The reason behind this is the decline of oil prices affecting the oil-linked contracts, and also gas hub prices as those are interconnected. In 2016, MSs that traditionally have oil-linked contracts had the lowest sourcing prices, in contrast to what was happening in previous years where these MSs had substantially higher costs compared to MSs supplied via hubs. Therefore, oil prices are affecting the source costs of a supplier and as a result his profitability. All of the above, illustrate the uncertainty and the risks a gas supplier is facing.

1.4.3 Retail Gas Markets

From the retail perspective and the downstream activities, retail energy prices vary considerably across the EU. In 2016, average household gas prices increased by 8.9%. This is the first year of declining prices (8.4% decline compared to the previous year[48]). On the contrary, gas prices for industrial consumers decreased compared to 2008. This is the third consecutive year of declining industrial prices, with 20.1% decrease compared to 2015. Figure 12 presents the household and electricity final gas prices for MSs for the period 2008-2016. However, across Europe there are large differences in final retail prices between MSs, notably in Sweden, where nominal household gas prices in 2016 were more than three times higher than the prices paid by Romanian consumers. Between 2016 and the previous year, final household prices declined for most of the MSs as they decreased by 9% on average. Final gas prices increased slightly for only 4 MSs, while it remained unchanged for the last 4 states.

[47] See ACER Gas MMR 2016

[48] According to Eurostat and ACER Retail Electricity and Gas MMR 2016

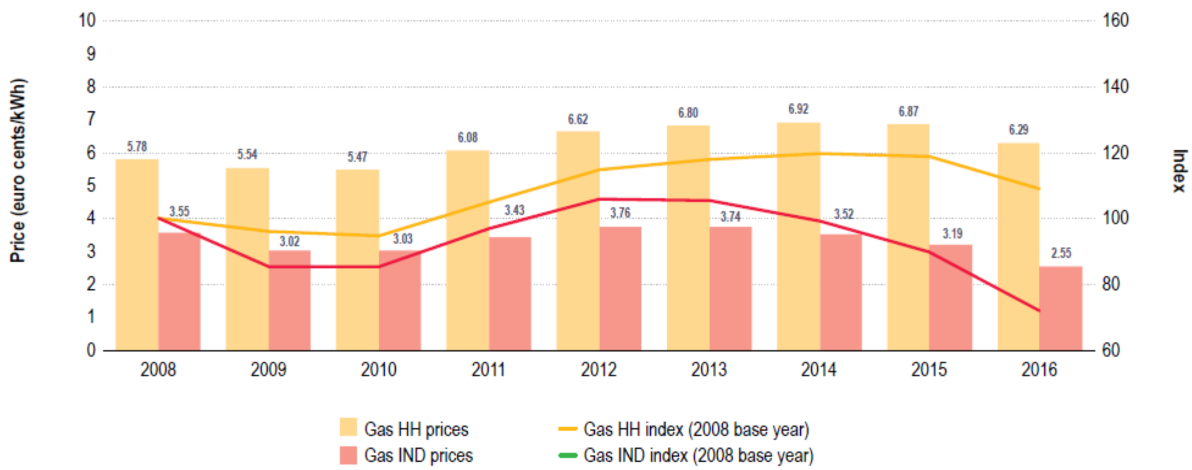

Figure 12: Final gas prices for household and industrial consumers in MSs and the index change (2008-2016)

Source: ACER Retail Electricity and Gas MMR 2016, based on Eurostat.

Similar to the electricity sector, each MS presents a different composition of the final gas bill. For instance, in Greece the energy component considered to be 78% while in Finland accounted for only 27%. Similarly, the share of network costs in Lithuania are almost double to what a Danish consumer is paying. As mentioned above for the electricity sector, the important part for the electricity bill is the energy component because all the other components are regulated. The reason final household prices decreased between 2012 and 2016, is due to the decrease of the energy component accounted for 50% of the final gas price in 2016. This decline is the result of a well-functioning wholesale market resulting to lower gas wholesale prices. Figure 13 illustrates the share of each component on the weighted average final electricity price in EU capital cities during the period 2012-2016.

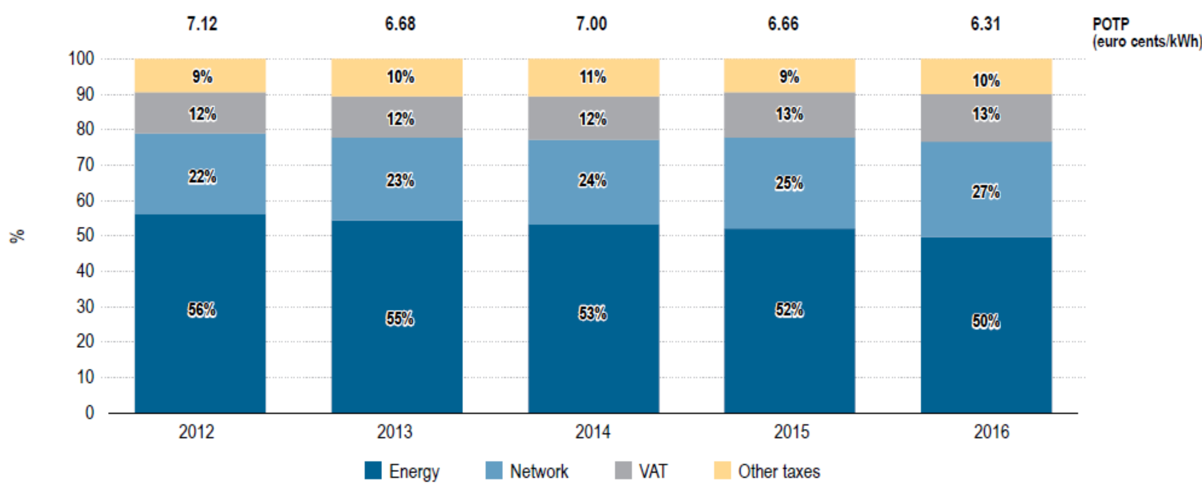

Figure 13 Weighted average post-taxes gas price breakdown for households in EU capital cities and Oslo (2012-2016)

Source: ACER Retail Electricity and Gas MMR 2016.

It is worth noting that ACER performed a survey questioning shippers and traders about the barriers in gas wholesale market[49]. Some of these barriers are high cost of transmission tariffs, insufficient harmonization across the EU and lack of market transparency.

1.4.4 Need for Optimization in the Gas Sector

Up to this point it has been proven that electricity generators and suppliers need a diversification of their activities and hence the need to optimize their activities in order to achieve their goals. The same applies for companies participating in gas markets as they are facing many challenges, as it has already been highlighted. Other concerns that have not been mentioned but are equally important are the possibility of gas supply disruptions, such as the explosion in Baumgarten gas hub in December 2017, a possible crisis between EU and key suppliers, namely Russia, future costs and tariffs due to CO_2 emissions, high transmission tariffs due to gas transmission network expansion, future geopolitical uncertainties and extreme weather conditions that could result in excessive variances in demand and prices. Consequently, gas market players, need a way to hedge these risks and uncertainties, and increase their profits. In order to address these problems, minimize their risks and increase their profit margins, many gas companies are operating in both wholesale and retail gas markets. In order to maximize their profits from both of these activities, gas companies need an optimization tool.

1.4.5 Interdependence of Gas and Electricity Markets

From the abovementioned analysis becomes evident that electricity and gas markets are highly interdependent. This connection is more apparent for gas fired power plants which are major gas consumers. For example, if natural gas prices are relatively high compared to other fossil fuels, the electricity market will then use power plants that use coal or oil and as a result will increase the final electricity price. Another example as presented by Shahidehpour et al (2005), is the connection between electricity and gas demand which peak simultaneously in severe weather conditions resulting in increased energy prices. As a consequence, generation cost of gas fired power plants would be higher and therefore final electricity prices would be affected in the same way.

1.5 Need for Optimization of Multiple Activities

The energy landscape has shifted in recent years. Customers are directly involved in energy generation, a surge of distributed energy generation installations, new European and national policies, consumers' changing behavior and their new needs, such as cheap energy, fierce competition between energy companies in order to keep their customers and decarbonisation policies are some of the reasons that have led to the reconstruction of the energy sector. While these may constitute major obstacles for an energy company, they also present some opportunities. Modern markets require multiple activities in order to be able to avoid all these risks and the fierce competition between companies but also to develop new market positions in order to have a competitive advantage against others. Companies need to have a portfolio with multiple activities. For example, big oil companies are investing in renewables and other new and promising

[49] See ACER Gas MMR 2016

technologies. For this reason, recently in Europe, but many years before in the USA[50], many companies operating only in electricity sector attempted to engage in gas sector as well. Integrating these two activities will increase the diversification of the company's portfolio, increase its profit margins and provide a tool to hedge risks giving also the opportunity to arbitrage between two markets. Examples of companies operating in both sectors are Engie in France, Enel in Italy, E.ON in the UK and many more. A possible next step is to sell gas and electricity as a mixed bundle[51]. This is a highly used marketing and pricing strategy offering products or services as one or combined. Companies are using this technique in other sectors such as paid TV and internet. Recently many businesses are offering utilities and telecommunication bundling their services in order to reduce cost and increase profits.

This new business model creates a new need. The need for co-optimization, where generation and retail activities are simultaneous optimized within one formulation, so that the company maximizes its overall profits. With co-optimization, profits from one activity may be sacrificed in order to maximize overall profits from all activities.

Despite the benefits from risk reduction, combining gas and electricity and selling them together offers many more advantages to the companies but also to the customers. Companies may benefit from marketing efficiencies, common technical expertise, economies of scope and a reduction of processing costs. On the other hand, customers may benefit from these dollar savings through lower energy prices, from the convenience of one stop shop and lower search costs for their desired product. The luxury of buying from one retailer with a single transaction gives the illusion of added value and this may benefit retailers[52]. Consequently both companies and customers are benefited from gas and electricity sold together as a bundle product.

The remainder of this thesis is organized as follows. Chapter 2 - Literature Review presents an overview of the relevant literature. Chapter 3 – Model Description describes the proposed model while Chapter 4 describes the numerical results of the model. Chapter 5 presents the conclusions.

[50] See Granier and Podesta (2010)
[51] Mixed bundle: offering two products separately with two distinctive prices and as one product with one price
[52] Eakin and Faraqui (2000)

Chapter 2 - Literature Review

Portfolio optimization has been implemented in many activities and in recent years in the energy sector it used in order to find the optimum energy mix for a country or a company, the optimal generation scheduling of a power plant in order to maximize profits, the optimal mix of suppliers and many more. Due to the price volatility of energy markets and risks involved, *Luth* (2006) focused on a midterm power portfolio optimization with risk management and Monte Carlo simulations for a load serving entity in order to maximize profits. *Yusta et al* (2005) calculated the optimal electric power and energy selling prices that maximize profits of an energy service provider in the Spanish electricity market. Their model is an economic and technical model which takes into account several factors such as customers' demand elasticity and the company's pricing strategy.

Some focus on risk management. *Liu, Wu and Ni* (2006) present some techniques, such as hedging and portfolio optimization, for risk management in the electricity markets. In their next work, *Liu and Wu* (2007) demonstrate that energy trading among multiple markets (spot and contract markets, futures, swaps and options) is an effective way for risk management for generation companies. Their model help a generation company design the optimal trading portfolio depending on its objective. *Hatami et al* (2009) proposed a model in order to determine the optimal sale price of electricity for a retailer and his procurement policy while maximizing his profits. In their model, the retailer can use the spot market, forward contracts, call options or self-production to obtain the electricity required to supply his customers. *Boroumand and Zachmann* (2012) demonstrate that physical hedging supported by forward contracts and spot transactions is an efficient approach to risk management in decentralized electricity markets. Given the fact that electricity retailers are facing uncertainties about the quantity of electricity consumed by their customers during the day, *Boroumand et al* (2015), demonstrate the superior efficiency of intra-day hedging portfolios managing price and quantity risks compared to daily, weekly and yearly hedging. *Gabriel et al* (2002) analyzed several strategies to determine future loads (forward positions) for an electricity retailer using Monte Carlo simulations and probability distributions for consumers' load and spot market prices. Despite the uncertainty of consumers' demand, a retailer faces the uncertainty of high pool prices and the risk that clients might change their provider if electricity is expensive. *Gabriel et al* (2006) propose a stochastic optimization model guiding retailers setting contracts quantities and prices with suppliers and consumers in order to maximize their profits and protect themselves from settlement risks. *Carrión et al* (2007) proposed a stochastic programming methodology to determine the optimal price a retailer should offer to his clients and the forward contracts he should sign in order to maximize profits. *Charwand et al* (2014) assume that an electricity retailer manages different types of contracts and defines final prices imposed to customers. While rival retailers compete to attain the largest market share, their study proposes a model that aims at offering the optimal prices to customers while maximizing retailers' profits.

Doostizadeh and Ghasemi (2012) focused on real time pricing (RTP) methodology of a retailer. First they identified the main barriers of RTP and then they proposed a model that would help retail energy providers offer optimal day-ahead (DA) hourly prices to consumers. This model aims to maximize retailer's profits while it takes into account consumers' response to electricity prices, consumers' benefits and distribution network constraints. *Jia and Tong* (2012) propose a two stage optimization model where the electricity retailer optimizes DA prices and then residential customers adjust their demand in respond to retail prices. In order to portray customers' behavior who participate in different DR programs, *Yousefi et al* (2011) proposed a model that can depict the hourly changes in customer's demand corresponding to the customer's demand function and the price elasticity of demand as well as the hourly changes in electricity prices. This model helps retailers offer DA RTP to its customers by comprehending customers' behavior to RTP programs and by improving retailers' forecasts about customer's response to DR programs in the future. *Sekizaki et al* (2016) propose a model that formulates selling electricity prices (TOU prices) offered by a retailer over one day, consumers' response to selling prices and distribution network constraints with the objective to maximize retailer's profits. Their results show that the characteristics of each type of consumer plays a crucial role for the response to selling prices. *Salies* (2013) address the feasibility and effectiveness of RTP when consumers are unwilling or unable to decrease their electricity consumption. Results showed that producers tend to charge inefficient prices to customers using RTP discriminating them against consumers who do not participate in such a program. *Lijesen* (2006) in his study examines the real-time price elasticity of electricity. His results showed a very low degree of price elasticity even for consumers active in the spot market. On the contrary, *Allcott* (2011) in his study showed that consumers are price elastic to hourly RTP and they reduced their consumption during peak hours, but did not increase during off-peak hours. *Polemis and Dagoumas (2013)* tried to depict the relationship between electricity demand and economic growth in Greece. Using cointegration techniques and the error correction model they quantified long and short-run elasticities. *Dagoumas and Polemis* (2017) examine the linkage between demand response and the wholesale power market. In their study they describe a model that estimates the income and price elasticities of demand by simulating the day-ahead (DA) electricity market in combination with an econometric model. This model, also estimates the retailer's profitability with demand responsive consumers. Customers who participate in demand response programs have different energy consumption habits and different load profiles.

Traders have to make the appropriate decisions about buying energy for their customers either from electricity pools or bilateral contracts. However, forecasting customers' behavior is a difficult task for retailers. Tackling this problem of uncertainty, *Algarvio et al* (2014) present an optimization model helping a retailer to optimally select its customers while maximizing profits. However, while retailers try to increase their revenues they attract a large number of clients with similar consumption profiles imposing a risk to retailers. In order to minimize that risk, *Algarvio et al* (2017) try to define retailers' optimal portfolio of end-use customers by optimizing the risk–return output. They consider retailers who buy electricity from the DA and spot market and sign bilateral (forward) contracts with consumers. Their focus is on maximizing the return while also minimizing the risk associated with consumers who have similar consumption profiles. This can be achieved by differentiating between consumers or attracting customers with different consumption patterns through different tariffs or incentives. By doing so, retailers keep a more stable portfolio of customers to the risk-return ratio.

Dagoumas, Koltsaklis and Panapakidis (2017) focused on cross-border trading. They studied the risk retailers are facing participating in cross-border electricity trade as a consequence of the uncertainty of price forecasting. Their model integrates the Unit Commitment (UC) problem with artificial neural network (ANN) that provides electricity price forecasting of a neighboring power system. This model estimates also the traders' profits and risk.

Others focus on the optimization of a power plant maximizing its profits. *Valdés, Durán and Rovira* (2003) proposed an optimization model of a CCGT power plant using a genetic algorithm. They considered two different objectives, one that minimizes production costs per unit of output and one that maximizes the annual cash flow. By comparing the results they find the best optimization strategy for a power plant. They extended their research by optimizing a heat recovery steam generator (HRSG). *Li et al* (2006) proposed an optimization model, based on a genetic algorithm, for a natural gas combined cycle power plant including the absorption of CO_2. *Chabar et al* (2010) presented a model that determines the optimal dispatch strategy of a thermal power plant. In their model they take into account fuel agreements, such as take-or-pay (ToP), opportunities of sales and purchases in the spot market and operational characteristics. *Kragelund et al* (2012) focus on the dynamic modeling of an electricity power plant, which is able to use three different fuels, and electricity price. The objective of this model is to maximize profits over 24 hours of operation using Pontryagin's maximum principle. *Kittithreerapronchai et al* (2010) develop a model that optimizes the electricity generation schedule of a gas-fired generation company and the delivery terms and quantities of natural gas. Their model shows that the company can gain greater profits by accessing the spot market and adapting its production to natural gas and electricity actual spot prices rather than using only the expected prices. *Dueñas et al* (2013) developed a model for a company owning a gas-fired power plant that optimizes gas purchases, pipeline contracts and the operation of the power plant under the uncertainty of the electricity demand due to increased generation from renewables. Others focus on minimizing generation costs. *Ahmadi and Dincer* (2011) optimized the operating parameters of a combined cycle power plant (CCPP) by minimizing total costs using a generic algorithm. A power utility needs to minimize generation costs and so demand has to be optimally distributed among company's generating units. *Mohammadi-ivatloo et al* (2012) focus on this and they propose an imperialist competitive algorithm (ICA) to schedule the generating units minimizing total costs, while also taking into consideration operating constraints and load demand.

Others focus on bidding strategies. Some use mathematical programming methods. *Ruiz and Conejo* (2009) consider a power producer who trades electric energy in an electricity pool. Their research provides a method to determine the optimal biding strategy for a producer in a pool based market while maximizing profits using a mixed-integer linear program. *Sen, Yu and Genc* (2006) propose a model for scheduling and hedging in wholesale electricity market using forward and spot market.

Others study both the upstream and downstream activities, like a company having a power plant and also participated in retail markets. *Dehnavi and Abdi* (2016) combine both the upstream and downstream activities in their model. They proposed a model that on the one hand schedules generation units (Dynamic Economic Dispatch) in order to minimize fuel costs and on the other hand DRPs (Demand Response Programs) determines the optimal TOU (time of use) prices. Using this model they achieved greater costumers' benefits and lower fuel costs.

Shifting to natural gas markets. *Vespucci et al* (2006) develop an optimization model that assists gas retail companies maximize their profits taking into consideration the type and consumption behavior of consumers and maximum and minimum consumption in order to avoid penalties. The model is optimized as a non-linear programming (NLP) mixed integer model and it is resolved in the General Algebraic Modeling System (GAMS) environment. In their next work *Maggioni et al* (2007) they extended their previous work but also introduced a stochasticity due to the influence of temperature on gas consumption. Using a mean reverting process and Monte Carlo scenario simulation they model the influence of temperature on consumption. The model is extended in *Allevi et al* (2007) where in their model they take also into account price limits imposed by law as well as retailer's policies and targets. *Maggioni et al* (2010) extend the previous model and in their model also consider the influence of oil prices on monthly gas purchase and sell prices.

Finally, *Jirutitijaroen et al* (2013) focused on a natural gas power plant operating in both electricity and gas markets. Using a stochastic programming model they formulated a problem where the energy company can determine the quantities of natural gas to be procured and the optimal trading strategy in the electricity and gas spot market while maximizing its profits. In their study, *Tookanlou et al* (2014) determine the optimal hourly prices for both natural gas and electricity for a combined cooling, heating and power (CCHP) system with gas turbine. Using a particle swarm optimization algorithm based on a bi-level programming approach they determine the optimal energy prices for a 52 weeks period and with four different day types.

Bunn et al (1997) study the possible opportunities that a dominant electricity generator can take advantage by participating in both the electricity and gas markets. This company can increase earnings by increasing electricity prices, profits from selling gas and spot market's volatility.

Granier and Podesta (2010) studied the electricity and gas sector from a different point of view. They proved that selling electricity and gas products as a bundle may trigger a merger wave of energy firms.

To my knowledge, a gap can be observed in the literature concerning the co-optimization of gas and electricity generation and supply. This thesis will try to address these gaps while also contributing to the preceding literature. The objective of this study is to model a company with a gas-fired power plant, while also it is engaged in electricity and gas retail activities. The goal of the company is to maximize its profits while also ensuring the supply of its customers. A possible extension of this study could be the co-optimization of the aforementioned company while also offers energy services. These services focus on providing energy saving projects, risk management tools enhancements that increase the energy efficiency of buildings and many more features.

Chapter 3 – Model Description

3.1 Problem Description

The model proposed on this thesis focuses on profit maximization of a vertically integrated company. The model constitutes a Non-Linear Programming (NLP) model that is resolved in the General Algebraic Modeling System (GAMS) environment using the IPOPT solver. The entity under examination fully owns and operates a gas-fired power plant and participates in deregulated wholesale and retail gas and electricity markets. This company acquires natural gas from the wholesale market of an energy exchange where participants are engaging in hourly trading. The company can sell natural gas to its retail customers with hourly real-time prices (RTP) and/or supply its power plant with gas in order to generate electricity. The company sell the electricity produced from its power plant to the wholesale market. In order to supply its customers with electricity, the company, can buy electricity from the day-ahead market and/or from the spot market, depending on market prices. The company can sell electricity to its retail customers with hourly RTPs.

The proposed model determines the dispatch of the company's power plant, the optimal mix of power bought from the day-ahead and spot market and the optimal selling prices of electricity and gas in order to maximize the company's profits. Figure 14 depicts the decision process of the company and the overall flow of both gas and electricity.

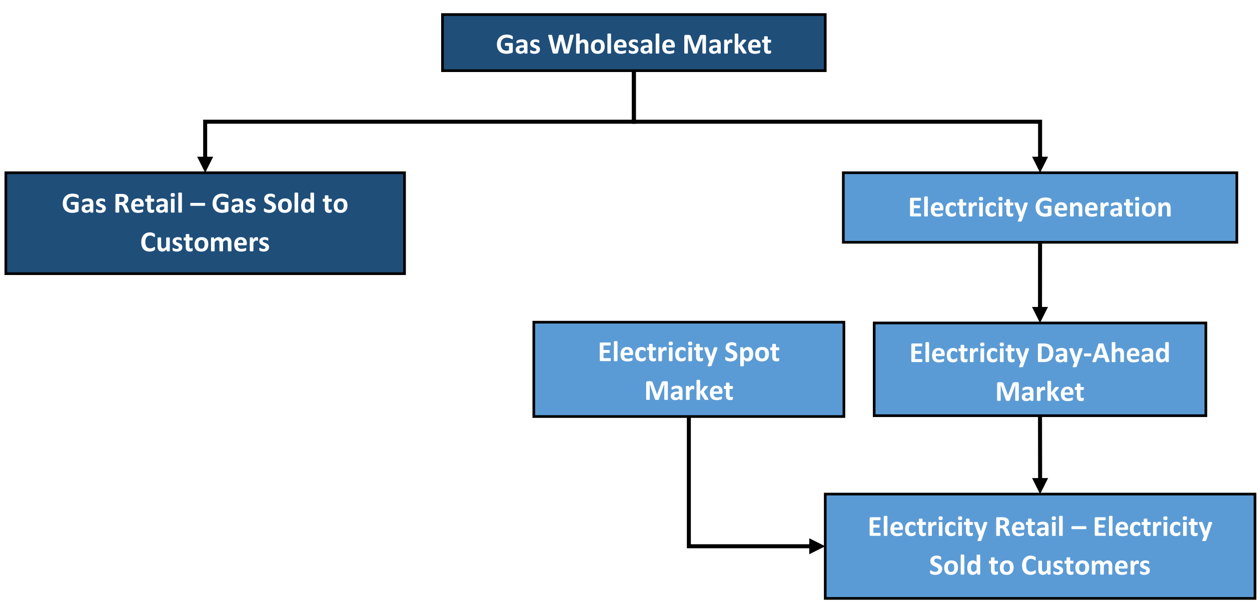

Figure 14 Market Representation

3.2 Nomenclature

Sets

h	24 hour period
w	scenarios
R	Retailers

Parameters

$PWhole_h$	Wholesale Electricity Price (€/MWh)
PCO2	Shadow Price of CO_2 (€/kgCO_{2eq})
$WholesaleCons_h$	Hourly Electricity Consumption of Wholesale Market (MWh)
Cost	Variable cost per hour for the retailer under examination (€/MWh)
CO2Cost	Emissions cost per hour for the retailer under examination (€/MWh)
$GASPRICE_h$	Day-Ahead/Wholesale Gas Price (€/kWh)
$IntraDayPrice_h$	Intra-Day Spot Market Electricity Price (€/kWh)
$GasElasticity_{w,h}$	Hourly Gas Price Elasticity
$ElElasticity_{w,h}$	Hourly Electricity Price Elasticity
$ES_{w,h}$	Total Electricity Supplied (Power Plant + Spot Market) (kWh)
$TotCost_w$	Company's Total Cost from all its activities (€)
$HourlyELCons_{w,h}$	Hourly Electricity Consumption of day d-1 (kWh)
$HourlyGasCons_{w,h}$	Hourly Gas Consumption of day d-1 (kWh)
$Prob_w$	Probability of Scenario w

Variables

REVWhole	Revenues from the wholesale market (€)
PROFWhole	Profits from the wholesale market (€)
CPP_w	Power Plant Production Cost (Variable Cost) (€)
$TCCO2_w$	Cost of CO2 Emissions (€)
$P_{w,h}$	Production of Retailer R (MW)
$TotProdCost_w$	Total Production Cost (€)
OF	Total Wholesale market cost (€)
$SEP_{w,h}$	Selling Electricity Price (€/kWh)
$SGP_{w,h}$	Selling Gas Price in Euros (€/kWh)
REV_w	Total Revenues (€)
$PROF_w$	Total Profits (€)
TotalElDemand	Total Electricity demand (kWh)
$GasDemand_{w,h}$	Gas Demand by retail customers and power plant consumption (kWh)
$ELCOST_w$	Cost of Electricity bought from Day-Ahead Market (€)
$TOTGASCOST_w$	Total Gas Cost (€)
$PSM_{w.h}$	Power bought from the Spot Market (kWh)
$PDA_{w,h}$	Power bought from the Day ahead market (kWh)
CSM_w	Spot Market Cost (€)
$RETAILGASDEMAND_{w,h}$	Demand for Gas by a retail customer (kWh)
$RetailElectricityDemand_{w,h}$	Demand for Electricity by a retail customer (kWh)
Z	Objective Function - The expected profits from all scenarios (€)

3.3 Model Description

In this section the profit maximization model is presented. The objective of the proposed model is to maximize the company's profits from all its activities. The company under examination owns and operates a 300 MW combined cycle gas-fired (NGCC) power plant with an efficiency rate of 55% and participates in both the wholesale and retail electricity and natural gas markets. The model consists of two separate parts. The first part depicts the wholesale market and determines the optimal dispatch of all power plants operating in the market in order to minimize total costs while satisfying customers demand. The second part depicts the retail market determining the optimal selling electricity and gas prices and determine the optimal involvement of spot and day-ahead market in order to maximize the company's profits while satisfying customers demand.

For a detailed and comprehensive presentation of the model formulation please also refer to Annex – Model formulation.

3.3.1 Electricity Generation and Wholesale Market (First Part)

The first part of the model is a Dynamic Economic Dispatch (DED) model that represents the wholesale market, independently, minimizing total production cost of all stakeholders taking into consideration power plants' expenses (O&M, fuel and emission costs) and estimates[1] of total market demand and wholesale prices (Day-Ahead and Spot market prices). The first part is modelled as a non-linear programming (NLP) using the IPOPT solver and subject to economic and technical constraints.

Total electricity generation from power plants must be equal to demand of the wholesale market. The company under examination cannot predict the total wholesale electricity volume and the system's marginal price (SMP) ex-ante. In fact, the company makes forecasts for these indicators. Figure 15 depicts the estimated hourly electricity consumption of the wholesale market (WholesaleCons) while Figure 16 depicts the estimated hourly wholesale marginal prices (PWhole).

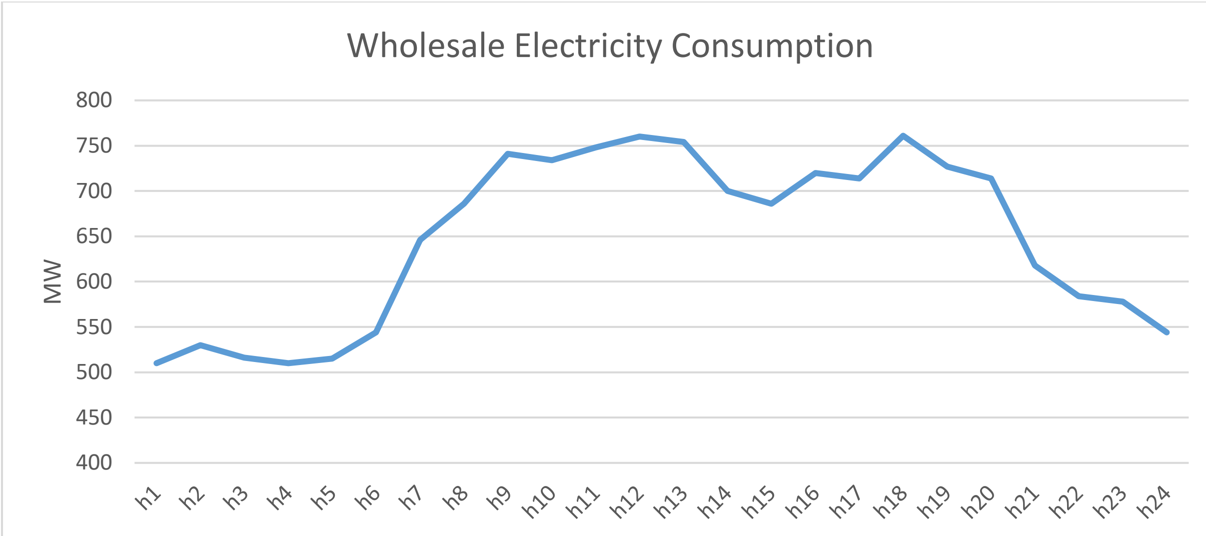

Figure 15 Wholesale Electricity Consumption of day d-1, MW[53]

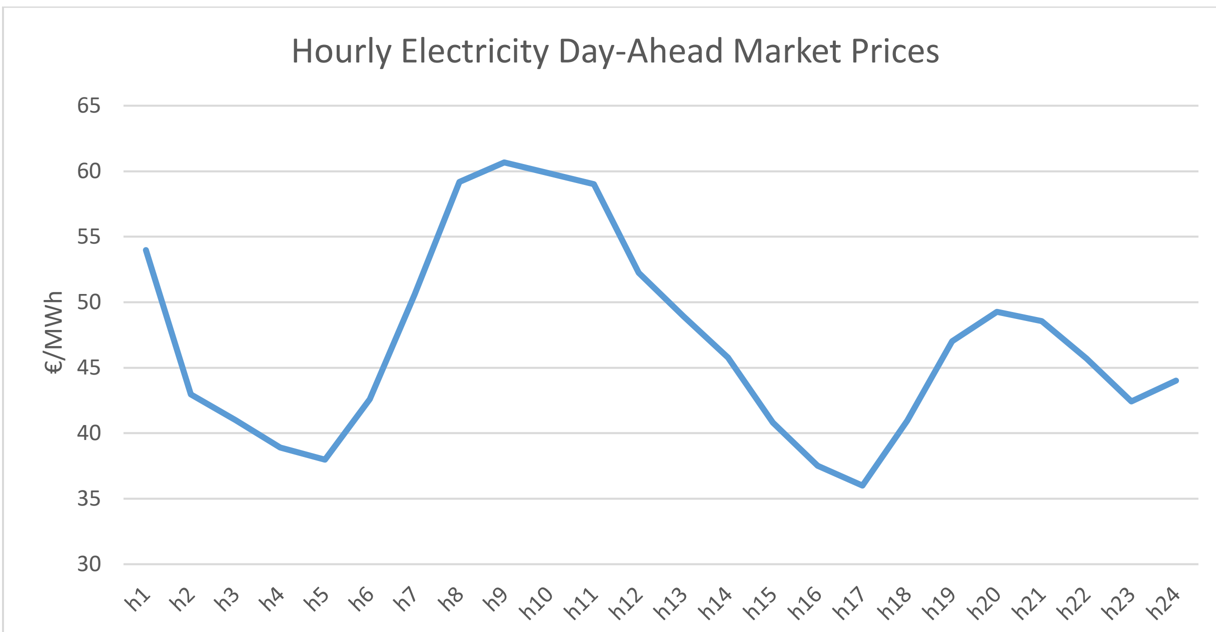

Figure 16 Electricity Wholesale Market Prices[54]

Electricity production of each power plant depends on its technical characteristics and operational expenses as illustrated in Table 1. The sixth generating unit (R6) is the unit of the company examined in this model. The first three columns (a, b and c) represent the cost coefficients for the thermal power plants while the next three (d, e and f) represent the emission coefficients. These coefficients are used for the calculation of production and emission costs respectively. Power plants have to operate between minimum and maximum capacity in order to be able to work

[53] Data derived from Soroudi (2017).

[54] Data derived from Epexspot, Day-Ahead Auction for the French market (April 15, 2019). These data can be accessed from Epexspot website at: https://www.epexspot.com/en/market-data/dayaheadauction/auction-table/2019-04-15/FR

properly. Also, power plants have a specific rump up and rump down capacity. Therefore, multiple technical constraint have been implemented in this model in order to properly represent the operation procedure of power plant units.

Table 1 Technical Characteristics of Power Plants[55]

Company	a (€/MW²)	b (€/MW)	c (€)	d (kg/MW²)	e (Kg/MW)	f (kg)	P min (MW)	P max (MW)	RUP (MW)	RDN (MW)
R1	0.158	12.14	80.1	1.1	-5	3	28	195	40	40
R2	0.143	13.85	74.7	2.3	-4.24	6.06	90	183	30	30
R3	0.135	12.5	90	1.1	-2.15	5.69	68	162	30	30
R4	0.151	13.44	72	1.1	-3.99	5.2	76	256	45	45
R5	0.142	13.65	85.5	1.4	-3.01	4.5	19	94	10	10
R6	0.130	12.14	75	1.0	-3.9	3.2	20	290	50	50

Total variable production cost of each power plant is given by Equation 1. The first term of the equation describes the fixed operational and maintenance (O&M) costs of NGCC power plants while the next term illustrates the variable O&M costs. [56] Following the methodology presented by IEA (2016), fixed O&M costs for a 300MW power plant equals to 8,220 per day. The last three terms describe fuel costs of a gas-fired power plant[57].

$$CPP_R = 10 * Capacity(kW - annum) + \sum_h 3.1 * P(h) + a * P^2(h) + b * P(h) + c$$

Equation 1 Power Plants' Variable Cost

Where a, b, c are the fuel coefficients of the power plant[58].

Total emissions cost for each power plant is depicted in Equation 2. The first component (PCO2) is the CO_2 price while the last three components illustrate the emission coefficients of the power plants. In this model three different CO_2 prices are used for the analysis. In order to capture the

[55] Data derived from: Power System Optimization Modeling in GAMS (Soroudi, 2017).

[56] Fixed O&M costs for Natural Gas Combined Cycle (NGCC) power plants amounts for 10 €/kW – annum while variable O&M costs amount for 3.1 €/MWh. Data derived from: Capital Cost Estimates for Utility Scale Electricity Generating Plants, (EIA) 2016.

[57] The methodology for the calculation of fuel costs is derived from Soroudi (2017).

[58] Soroudi, A. (2017). Power system optimization modeling in GAMS.

full cost of emissions to society, the shadow price[59] of carbon (52 €/tnCO_2e[60]) is used for the calculation of the total emission cost.[61] The second price used is the European allowances auction primary market price from European Energy Exchange (EEX) (24.07 €/tnCO2e)[62] while the last price used is the average market price of 2018 (15.56 €/tnCO2e)[63].

$$TCCO2_R = PCO2 * \sum_h d * P^2(h) + e * P(h) + f$$

Equation 2 Power Plants' Emission Costs

Where c, d and f are the emission coefficients of the power plant[64].

Company's revenues from its electricity wholesale activities are derived by multiplying electricity wholesale price (PWhole) by the company's hourly electricity generation (P(R6)) as calculated by the model.

3.3.2 Retail Market (Second Part)

The second part of the model is an econometric model that simulates the retail market, independently, maximizing the company's profits. This is modelled as a non-linear programming (NLP) using the IPOPT solver and subject to economic and technical constraints. The model calculates optimal selling electricity and gas prices and the optimal power mix from spot and day-ahead power.

3.3.2.1 Objective Function

Many models presented in the literature are trying to simulate consumers' behavior concerning their energy consumption. Due to the difficulty to predict their consumption profile for different real time or very short-term prices, this thesis introduces three different scenarios (w) in order to simulate different possible future developments and analyse different outcomes. Consequently, as can be seen in the table above, almost all parameters and variables are functions of scenario w.

---

[59] Shadow price is used to either reflect the actual market value of a commodity or to quantify the value of a commodity without a market price. In this case the shadow price is used to reflect the actual value of carbon emissions in order to achieve the climate objectives set by the EU, as estimated for the High-Level Commission on Carbon Prices, led by Joseph Stiglitz and Nicholas Stern.

[60] The mean value of high and low shadow prices of 2018 is adopted in this model (Guidance note on shadow price of carbon in economic analysis, The World Bank, 2017).

[61] For more information about shadow prices of carbon please refer to: Guidance note on shadow price of carbon in economic analysis (The World Bank, 2017), Methodology for the economic assessment of EBRD projects with high greenhouse gas emissions (EBRD, 2019) and Report of the High-Level Commission on Carbon Prices (Carbon Pricing Leadership Coalition, 2017).

[62] Auction primary market prices for April 8, 2019. Data can be accessed via the EEX platform at: https://www.eex.com/en/market-data/environmental-markets/auction-market/european-emission-allowances-auction#!/2019/04/08

[63] Data can be accessed via the EEX platform at: https://www.eex.com/en/market-data/environmental-markets/auction-market/european-emission-allowances-auction/european-emission-allowances-auction-download

[64] Soroudi, A. (2017). Power system optimization modeling in GAMS.

The objective function is given by Equation 3 and calculates the sum of profits in each scenario w multiplied by its probability. By multiplying these the model calculates the expected profits of the company. Scenario probability is calculated dividing the total number of scenarios. The maximization of the objective function leads to the determination of the hourly retail electricity and gas prices offered by the company to its customers. The scheduling period is considered to be 24 hours assuming a step of 1 hour. Results are driven by gas and electricity wholesale and spot market prices and customers' demand. Customers are responsive to electricity and gas prices offered from the company. The company has to meet the energy demand of its customers and thus, electricity bought from the day-ahead and spot market has to be equal to total electricity demand of their customers.

$$z = \sum_{w} Profits(w) * prob(w)$$

Equation 3 Objective Function - Expected Profits

Total profits are presented by Equation 4. They are determined by the difference between total revenues and costs from the company's retail and wholesale activities. Total revenues are derived from electricity and gas sales, while total costs are derived from natural gas purchase agreements, day-ahead and/or spot electricity purchase agreements, CO_2 emission and power plant's production costs.

$$Profits\ (w) = \sum_h (Revenues(w) - Costs(w))$$

Equation 4 Profits

Equation 5 presents the entity's Revenues from its retail and wholesale activities[65]. The first and second condition refers to profits from electricity and gas sales while the third condition refers to profits acquired through the company's wholesale market activities (first part of the model).

$$Revenues\ (w) = \sum_h [\overbrace{(SEP(w,h) * TotalElDemand(w,h))}^{\text{Profits Retail (Electricity)}} + \overbrace{(SGP(w,h) * GASDEMAND(w,h))}^{\text{Retail Profits (Gas)}} + \underbrace{(P(R',w,h) * PWhole(w,h))]}_{\text{Wholesale Profits (Electricity)}}$$

Equation 5 Revenues

Equation 6 present the company's total Costs. The first condition refers to electricity production costs (fixed O&M costs, variable O&M costs and fuel costs) while the second condition refers to

[65] Revenues from wholesale activities are calculated by the first part of the model as described above

CO_2 costs from electricity production[66]. The third condition refers to wholesale gas market costs. The fourth condition refers to electricity wholesale market costs (electricity bought from day-ahead market using the wholesale prices). Finally, the last condition refers to electricity spot market costs (electricity bought form the spot market using spot market prices). These costs and revenues are discussed with more detail in the next section

$$Costs_{R6}(w) = \overbrace{CPP_{R6} + TCCO2_{R6}}^{\text{Electricity Production Cost}} + \overbrace{\sum_h \left[\left(GASDEMAND(w,h) * GASPRICE(h) \right) \right]}^{\text{Wholesale Gas Cost}} + \sum_h \left[\overbrace{\left(PDA(w,h) * PWhole(w,h) \right)}^{\text{Day-Ahead Electricity Cost}} + \underbrace{\left(PSM(w,h) * IntradayPrice(h) \right)}_{\text{Spot Market Electricity Cost}} \right]$$

Equation 6 Total Costs

3.3.2.2 Gas Wholesale Market

The company under examination purchases its gas needs from the wholesale market. The company's total gas cost is depicted by Equation 7. GASPRICE represents the wholesale gas prices at which the company purchases gas as illustrated in Figure 17. GASDEMAND represents the company's total gas needs as depicted by Equation 8.

$$TOTGASCOST(w) = \sum_h GASPRICE(h) * GASDEMAND(w,h)$$

Equation 7 Total Gas Cost

[66] These costs are calculated by the first part of the model as described above

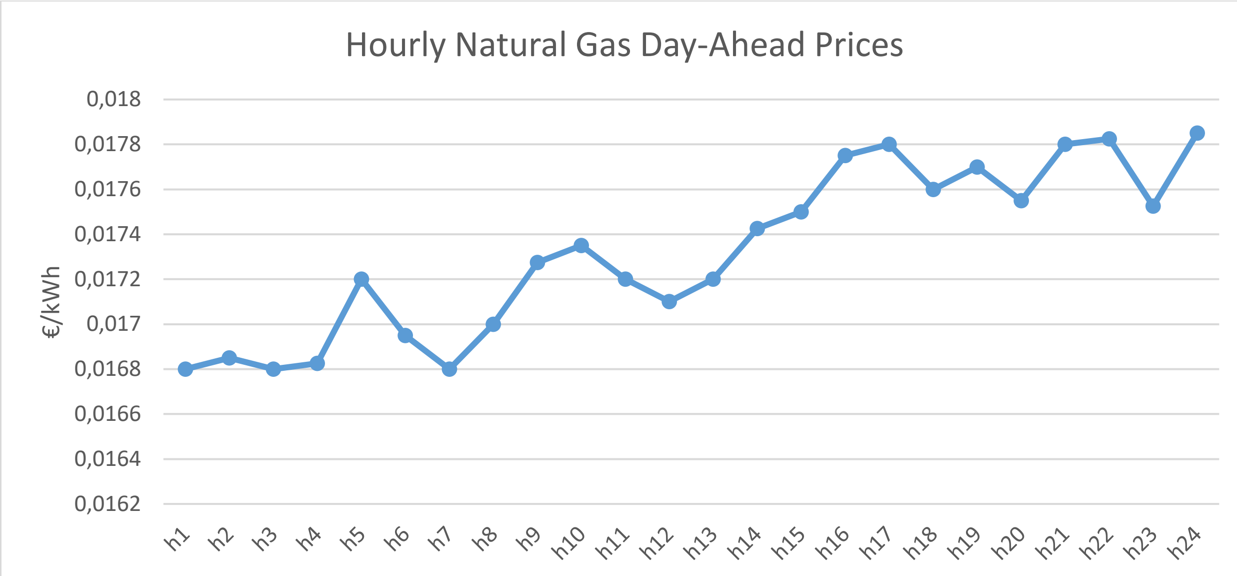

Figure 17 Day-Ahead Natural Gas Hourly Prices[67]

The company's total gas needs consist of its customer's gas demand and the company's power plant consumption in order to generate electricity. The company is considered to have 6,000 gas customers. RETAILGASDEMAND represents customer's final gas demand while the second term of Equation 8 represents the power plant's gas consumption[68].

$$GASDEMAND(w,h) = 6000 * RETAILGASDEMAND(w,h) + 1.82 * P(R6,w,h)$$

Equation 8 Total Gas Demand

3.3.2.3 Gas Retail Market

The company under examination offers natural gas to its customers on prices based on a demand function. The demand function applied for natural gas is the following:

$$RETAILGASDEMAND(w,h) = HourlyGasCons(w,h) - GasElasticity(w,h) * SGP(w,h)$$

Equation 9 Retail Gas Demand Function

Demand for gas is a function of scenario (w) and time (h). SGP represents the final hourly gas price offered to consumers and is different for each scenario w. The hourly gas price calculated by the model refers to the competitive part of gas prices (energy price excluding taxes, transmission & distribution tariffs and other levies). HourlyGasCons represents the customer's gas consumption of the previous day (d-1) as recorded by smart meters. Three different consumption patterns are implemented in this model. Figure 18 illustrates the different residential hourly natural gas consumption patterns for a 24-hour period. Elasticity represent the hourly gas price elasticity.

[67] Data derived from EEX platform (currently operates under PEGAS platform) for Gaspool market for September 27th 2017.

[68] The efficiency rate of the power plant is considered to be 55%. Consequently, in order to generate 1 kWh of electricity the power plant needs 1.82 kWh of gas.

Literature suggests that short-run price elasticity for residential natural gas consumption varies between -0.05 and -0.95[69]. In order to capture the whole range of elasticities suggested by the literature three different values of gas price elasticity are used in this model and are presented in Table 2.

Company's revenues from its gas retail activities are derived by multiplying natural gas retail prices (SGP) by the final retail gas demand of a customer (GASDEMAND) and by the total number of customers

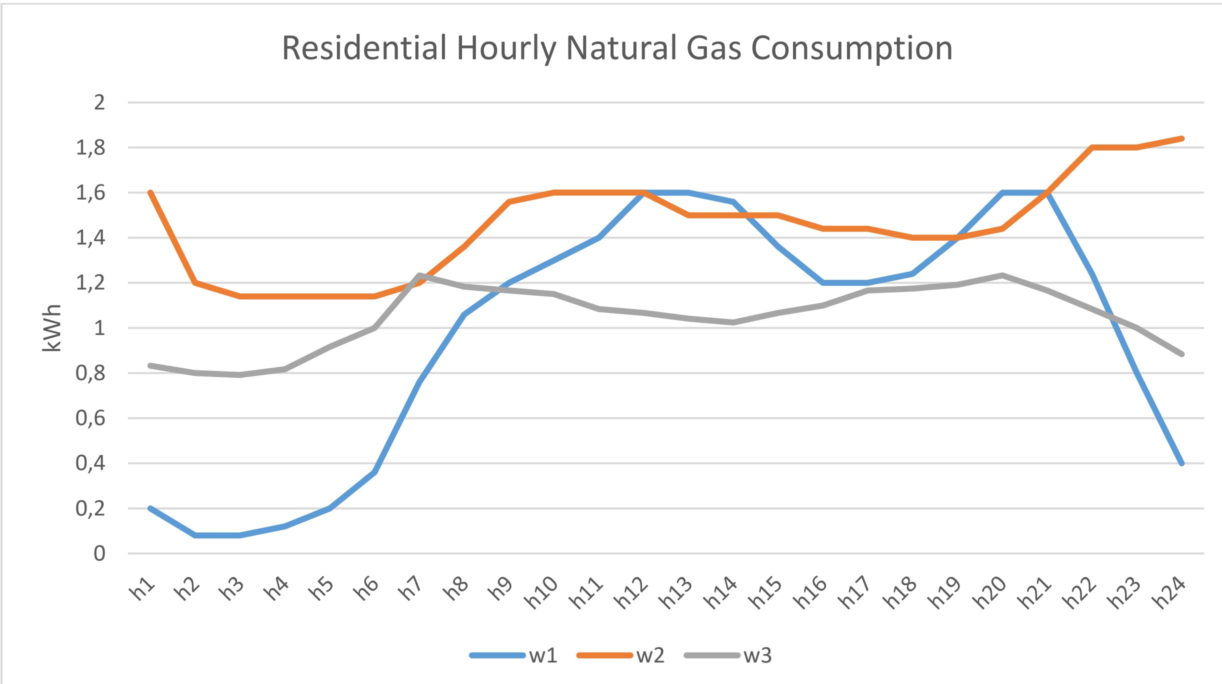

Figure 18 Residential Hourly Natural Gas Consumption

Table 2 Short-run natural gas price elasticity[70]

	h1	h2	h3	h4	h5	h6	h7	h8	h9	h10	h11	h12	h13	h14	h15	h16	h17	h18	h19	h20	h21	h22	h23	h24
w1	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
w2	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053
w3	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

A restriction in retail prices has been implemented in this model. Retail gas prices are restricted between a minimum of $0 {}^{€}/_{kWh}$ and a maximum price of $0.03 {}^{€}/_{kWh}$.[71] These constraints were introduced in order for the company to be able to offer competitive prices.

[69] Rehdanz (2006), Al-Sahlawi (1989), Labandeira, Labeaga and Lopez-Otero (2016) and Berkhout, Ferrer-i-Carbonell and Muskens (2004)

[70] Elasticities presented in this table are in absolute values

[71] These prices refer to the competitive part of gas price as tariffs, levies and taxes are not included in this model.

3.3.2.4 Electricity Spot and Retail Market

The company is able to purchase electricity either from the day-ahead market or from the spot market. In order to maximize profits, depending on intraday-spot and day-ahead prices, the model chooses the optimal mix of power bought from these markets. Therefore, in this model, an option has been implemented allowing the company to purchase electricity from the least expensive market. However, in order to minimize the company's exposure to price surges during the day (intraday prices), the retailer buys at least 50% of its electricity needs from the day-ahead market. The amount of electricity bought from the day-ahead market and the spot market must be equal to the total demand of its customers. Intraday prices implemented in this model are depicted in Figure 19.

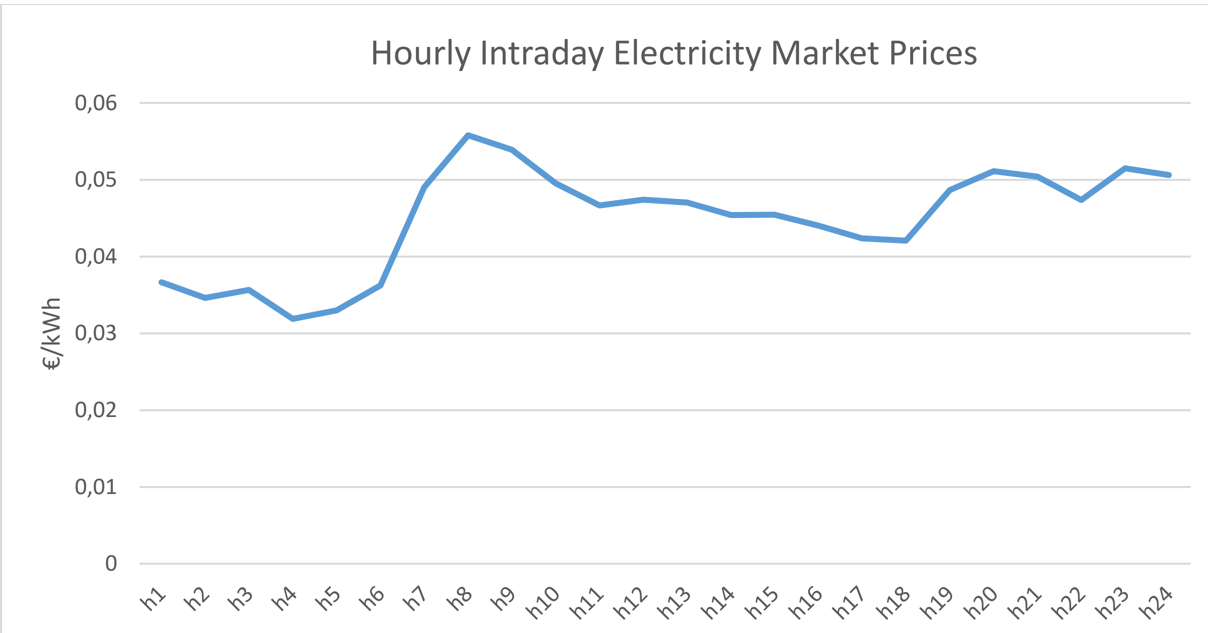

Figure 19 Intraday Electricity Prices[72]

The company is considered to have a 33% share of the total retail market share in terms of capacity and thus, is able to purchase a maximum of 1/3 of the total capacity offered in wholesale market. The size of the electricity market is considered to be 230,000 consumers. Consequently, the company can supply 76,600 customers.

$$\text{Total}ElDemand(w,h) = 76{,}600 \, * RetailElectricityDemand(w,h)$$

Equation 10 Total Electricity Demand

[72] Data derived from EPEX Spot, Intraday Continuous weighted average electricity prices for the French market (16/04/2019). These data can be accessed from Epexspot website at: https://www.epexspot.com/en/market-data/intradaycontinuous/intraday-table/2019-04-16/FR

A restriction in retail prices has been implemented in this model. Retail electricity prices are restricted between a minimum of $0 {€}/_{kWh}$ and a maximum price of $0.05 {€}/_{kWh}$.[73] These constraints were introduced in order for the company to be able to offer competitive prices.

The model implements a retail demand curve in order to determine customers' final electricity demand and retail electricity prices offered by the company. The demand function applied for electricity is the following:

$$RetailElectricityDemand(w,h) = HourlyElCons(w,h) - ElElasticity(w,h) * SEP(w,h)$$

Equation 11 Retail Electricity Demand Curve

Electricity demand is a function of scenario (w) and time (h). SEP is the final hourly electricity price charged by the company to its consumers. The hourly electricity price calculated by the model refers to the competitive part of electricity prices (energy price excluding taxes, transmission & distribution tariffs and other levies). ElElasticity is the hourly price elasticity of electricity. Literature review[74] indicates that electricity is price inelastic for a short-term and long-term periods. Polemis and Dagoumas (2013) indicate that short-run price elasticity of electricity consumption is -0.08, while Yusta et al (2005) choose values that vary between -0.01 and -0.25. Table 3 presents the retail price elasticities in absolute values. In order to capture the possibility that consumers might change their behavior and become price elastic in cases where they are offered real-time prices, this thesis proposes that electricity is price elastic at off-peak hours and inelastic at peak hours[75] (scenario w1 and w2). However, further research is needed in this subject in order to predict consumers' behavior when offered real-time prices.
In the first and second scenarios (w1 and w2 respectively) random values are used between -0.1 and -1.2 while in the third scenario (w3) price elasticity is considered to be constant to -0.08 as calculated by Polemis and Dagoumas (2013).

Table 3 Short-run electricity price elasticity[76]

	h1	h2	h3	h4	h5	h6	h7	h8	h9	h10	h11	h12	h13	h14	h15	h16	h17	h18	h19	h20	h21	h22	h23	h24
w1	0.9	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.6	0.15	0.2	0.2	0.3	0.3	0.2	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.5	0.7
w2	0.8	1	1	1	1	1	1	1	0.4	0.05	0.1	0.1	0.2	0.2	0.1	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.2	0.5
w3	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08

[73] These prices refer to the competitive part of electricity price as tariffs, levies and taxes are not included in this model. The maximum price is determined based on maximum 20% margin compared to wholesale and spot market prices.
[74] Papers reviewed where: Lijesen (2007), Genc (2016) , Fisher and Kaysen (1962), Narayan and Smyth (2005), Naraya, Smyth & Prasad (2007), Hondroyiannis (2004), Yoo, Lee & Kwak (2007), Donatos & Mergos (1991), Rapanos & Polemis (2006), Dergiades & Tsouflidis (2009), Polemis & Dagoumas (2013), Dagoumas & Polemis (2017), Chern & Bouis (1988), Maddala et al (1997), Zachariadis & Pashourtidou (2007), Sa'ad (2007), Yusta et al (2005), Labandeira, Labeaga & Lopez-Otero (2016) and Aslanoglou (2016)
[75] Genc (2016) calculated two different wholesale price elasticities for peak and off-peak hours. A similar approach is also implemented for retail price elasticities.
[76] Elasticities presented in this table are in absolute values.

HourlyElCons, is the electricity consumption of day d-1 and is a function of scenario and time. This is used in order to correlate total electricity consumption between two consecutive days. Figure 20 illustrates the residential electricity consumption of day d-1 for 24 hour period for three different scenarios.

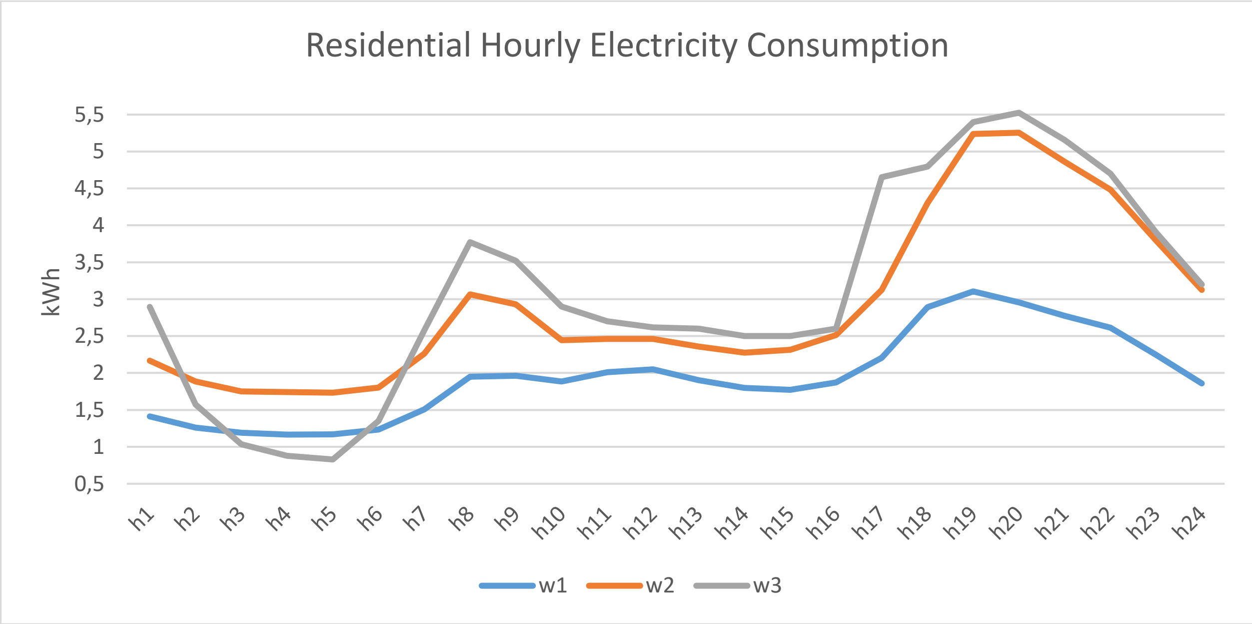

Figure 20 Residential Hourly Electricity Consumption

Chapter 4 – Results

In this chapter the results from the implementation of the model analyzed in the previous sections are presented. Various scenarios have been applied in order to simulate energy wholesale and retail markets and calculate the profitability of the examined company. The model calculates the company's optimal power scheduling between day-ahead and spot market in order to maximize its profits and reduce its exposure to price surges. Results indicate that gas-fired power plants could still be profitable even when CO_2 prices reflect the real cost of emissions to society. It is also shown that the optimal energy prices offered to customers should be constant during the 24-hour period examined.

Price of CO_2 emissions have a significant impact on the company's profitability. In many cases, they also affect the viability of power generators. Three different emission prices have been implemented in order to estimate its impact on the profitability of power generating companies. Table 4 and Table 5 illustrate this effect by presenting the company's profits, revenues and costs. EU's decision to withdraw around a quarter of CO_2 emission permits illustrates the challenging conditions power producers will face in the near future as carbon prices are set to significantly increase[77].

Table 4 Wholesale Profits, Revenues and Costs per day in Euros

CO2 Price (€/kgCO2eq)	Wholesale Profits per day (€)	Wholesale Revenues per day (€)	Total Production Cost per day (€)	Variable Cost (CPP) per day (€)	CO2 Emissions Cost (TCCO2) per day (€)
0.052	15,824.61	145,128.07	129,303.46	108,990.86	20,312.60
0.02407	27,035.38	143,752.09	116,716.70	107,506.99	9,209.71
0.01556	30,393.30	143,065.01	112,671.71	106,778.80	5,892.91

[77] Bloomberg.com. (2019). Bloomberg - Betting Against Europe's Safest Bonds Costs Trader $22 Million. [online] Available at: https://www.bloomberg.com/news/articles/2019-05-16/betting-against-europe-s-safest-bonds-costs-trader-22-million

Table 5 Wholesale Profits, Revenues and Costs per year in Euros[78]

CO2 Price (€/kgCO2eq)	Wholesale Profits per year (€)	Wholesale Revenues per year (€)	Total Production Cost per year (€)	Variable Cost (CPP) per year (€)	CO2 Emissions Cost (TCCO2) per year (€)
0.052	5,775,982	52,971,745	47,195,763	39,781,665	7,414,098
0.02407	9,867,915	52,469,512	42,601,597	39,240,051	3,361,546
0.01556	11,093,555	52,218,729	41,125,175	38,974,262	2,150,913

The company's average wholesale profits, revenues and total production costs per year are € 8.9m, € 52.5m and € 43.6m respectively. However, in the first case where CO2 shadow prices are used for the calculation of emissions cost, the company's wholesale profits are as low as €5.7 m per year. This fact indicates that gas-fired power plants' profitability is significantly affected nevertheless, these power plants could still be profitable in such cases. However, high emission prices could possibly affect the viability of coal-fired power plants due to the fact that they release greater volumes of CO_2 per unit of electricity.

Scheduling of power generators follows a similar pattern for different emission prices. An indicative example is presented in Figure 21 for 0.02407 €/kgCO2eq emission price. In this diagram R6 is the generating unit of the company examined. Results show that R6 has a significant role in power production generating on average approximately 19.5% of the total electricity demand.

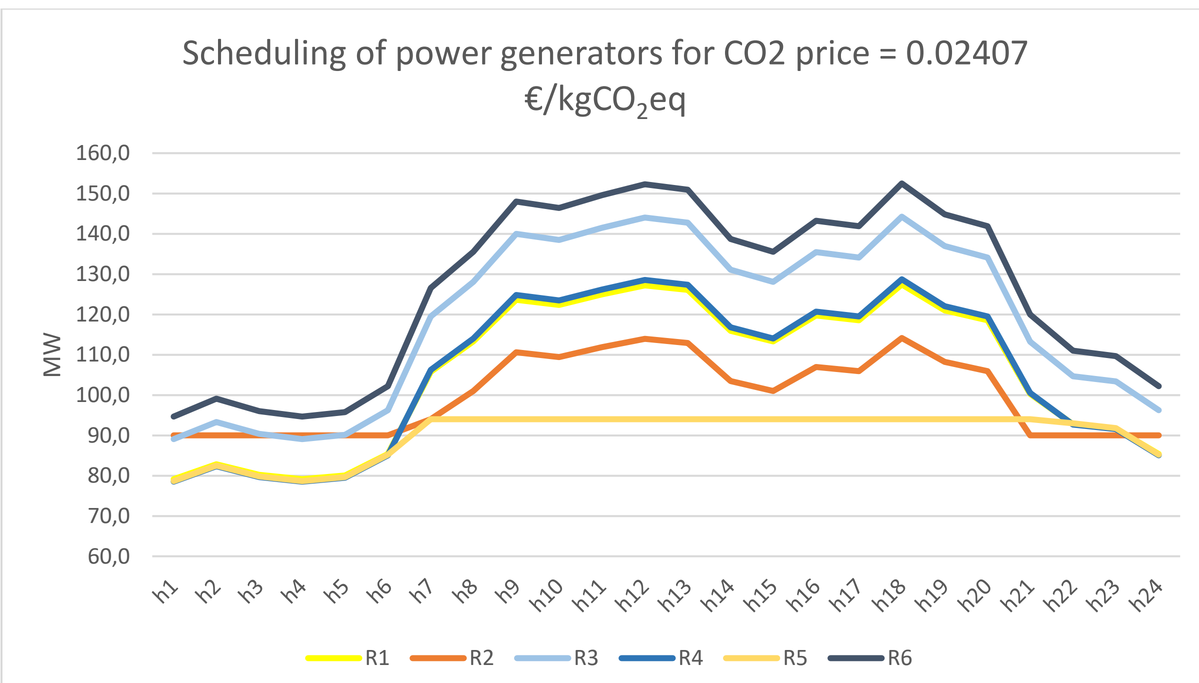

Figure 21 Scheduling of power generators for CO_2 price = 0.02407 €/kgCO_2eq

[78] Yearly profits presented in this table are earnings before payment of taxes and interests.

Table 6 illustrates the company's profits, revenues and costs from all its activities for the scenarios examined using the auction prices (0.02407 €/kgCO2eq).

Table 6 Total profits and costs per year in Euros[79]

	Profits (€)	Profits from Retail (€)	Profits from Wholesale (€)	Revenues (€)	Total Cost (€)	Cost of electricity from the wholesale/DA market (€)	Cost of electricity from the spot market (€)	Total gas cost (€)	Total production cost (€)
w1	16,152,978	6,285,063	9,867,915	119,414,489	103,261,510	45,545,775	14,226,652	887,487	42,601,597
w2	18,397,653	8,529,738	9,867,915	153,104,065	134,706,412	55,700,955	35,077,568	1,326,293	42,601,597
w3	17,233,471	7,365,556	9,867,915	157,765,882	140,532,411	57,049,224	39,951,397	930,193	42,601,597
Average	17,261,368	7,393,453	9,867,915	143,428,145	126,166,777	52,765,318	29,751,872	1,047,991	42,601,597

Gas Prices

Retail gas prices offered by the retailer to its customers, as calculated by the model, remain constant at 0.03€/kWh throughout the day for all scenarios. In this case, the retailer sets the price at the maximum allowed value which maximizes its profits. Thus, customers' gas consumption (Figure 22) follows a similar pattern compared to the consumption recorded on the previous day (d-1).

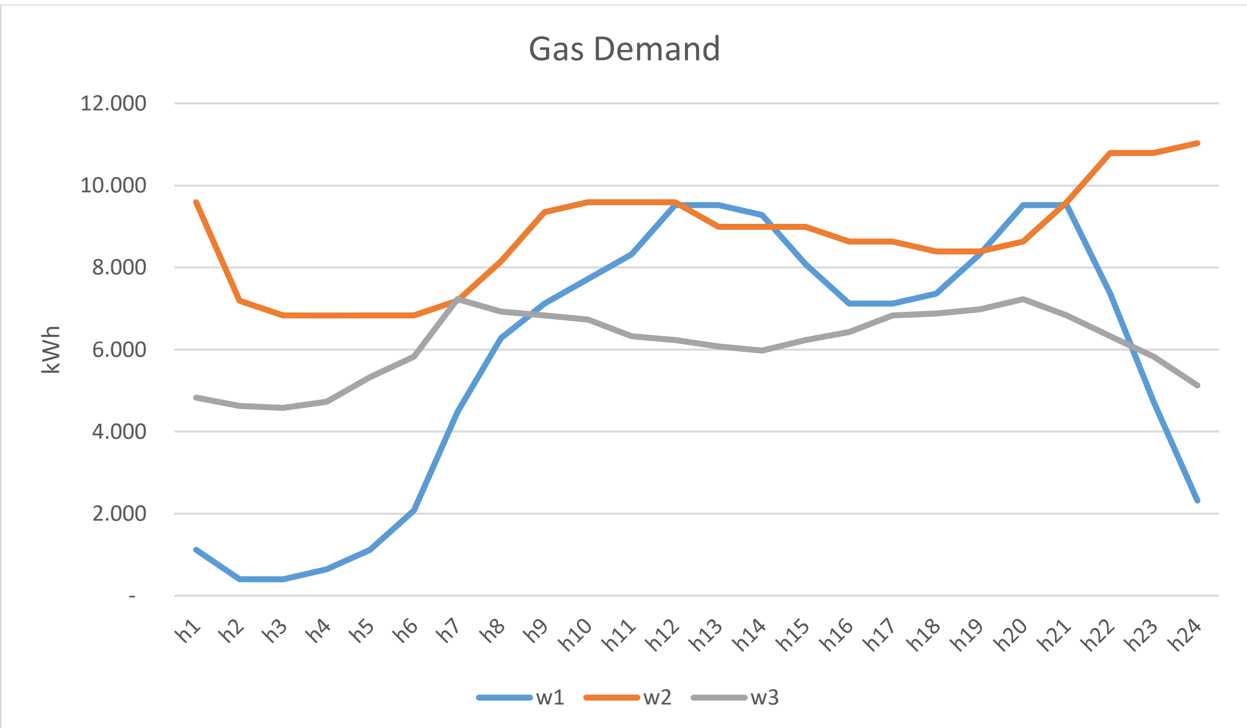

Figure 22 Gas Demand in kWh

[79] Yearly profits presented in this table are earnings before payment of taxes and interests.

Electricity Prices

Similar to retail gas prices, model calculations suggest that the retailer should offer constant retail electricity prices at 0.05 €/kWh over the 24-hour period in order to maximize the overall profits of the company. The retailer maximizes its revenues/profits when implementing prices at their maximum allowable values. As the demand is rather inelastic, as shown from Figure 23, which shows the consumption pattern of the customer, the effect of this maximization profit strategy does not affect considerably its revenues.
As a result, customers' consumption follows a similar pattern to the consumption recorded on the previous day (d-1).

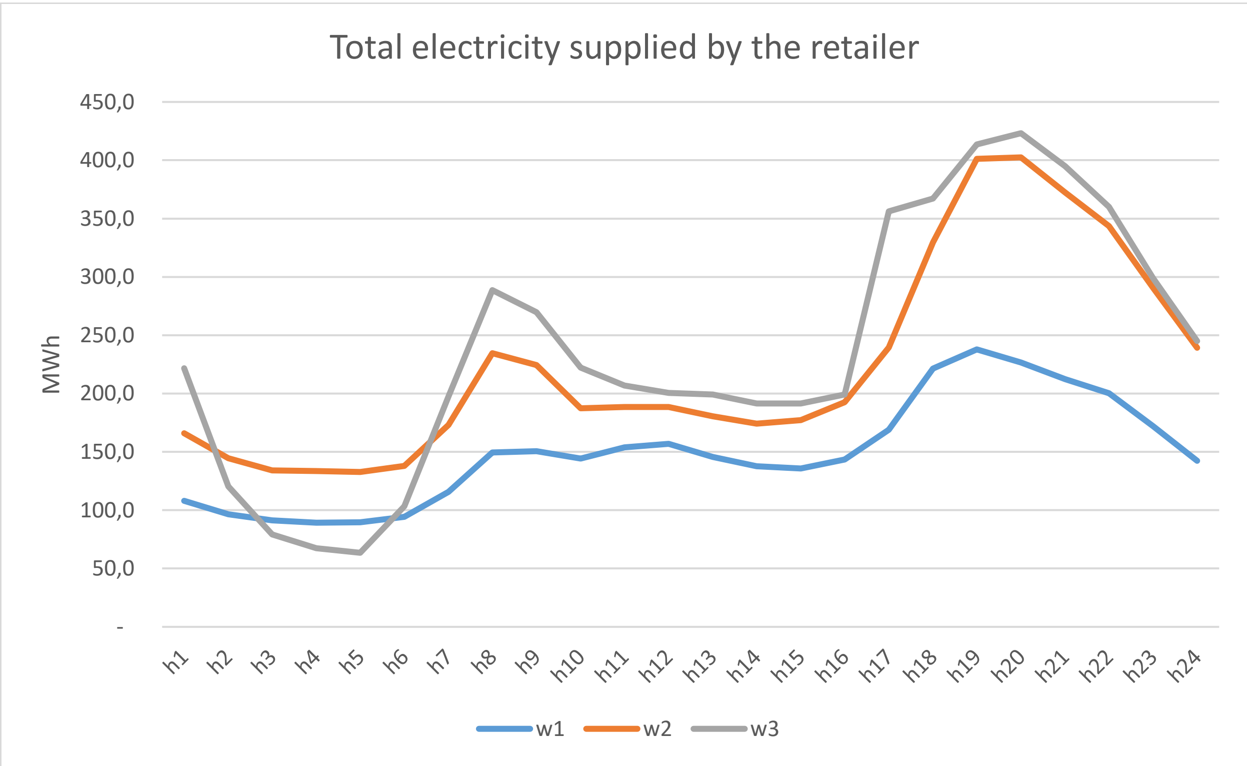

Figure 23 Total electricity supplied by the retailer

The retailer can purchase electricity either from the day-ahead market or from the spot market depending on his forecasts on DA and spot market prices. The company's optimal power scheduling for scenarios w1, w2 and w3 is depicted in Figure 24, Figure 25 and Figure 26 respectively. The company acquires more than 50% of its energy needs from the DA market while the remaining is obtained from the spot market mainly during nigh hours where spot market prices are lower than the day-ahead prices.

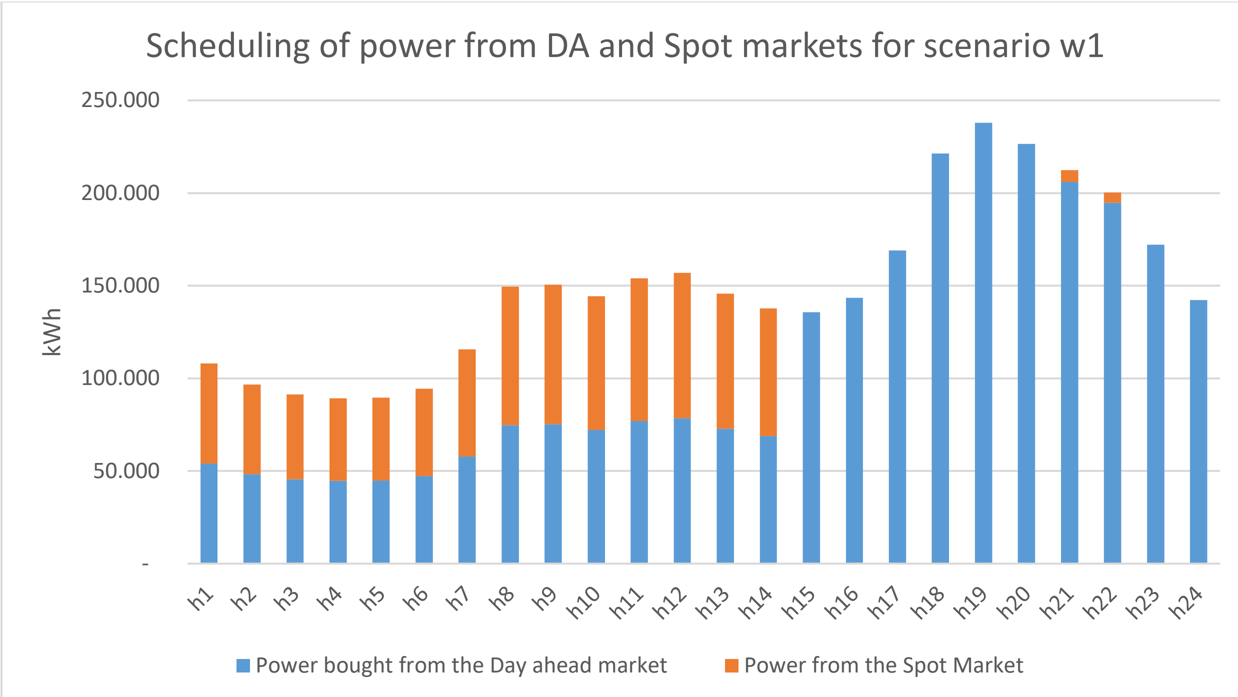

Figure 24 Scheduling of power from DA and Spot markets for scenario w1

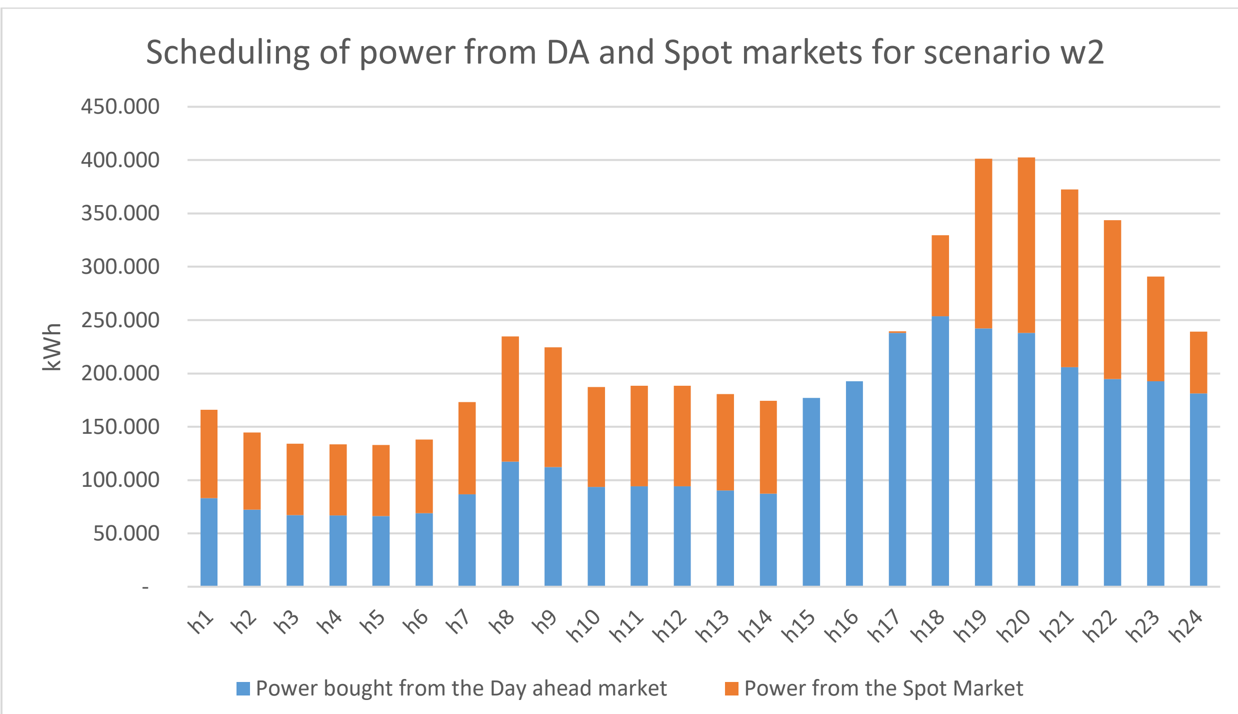

Figure 25 Scheduling of power from DA and Spot markets for scenario w2

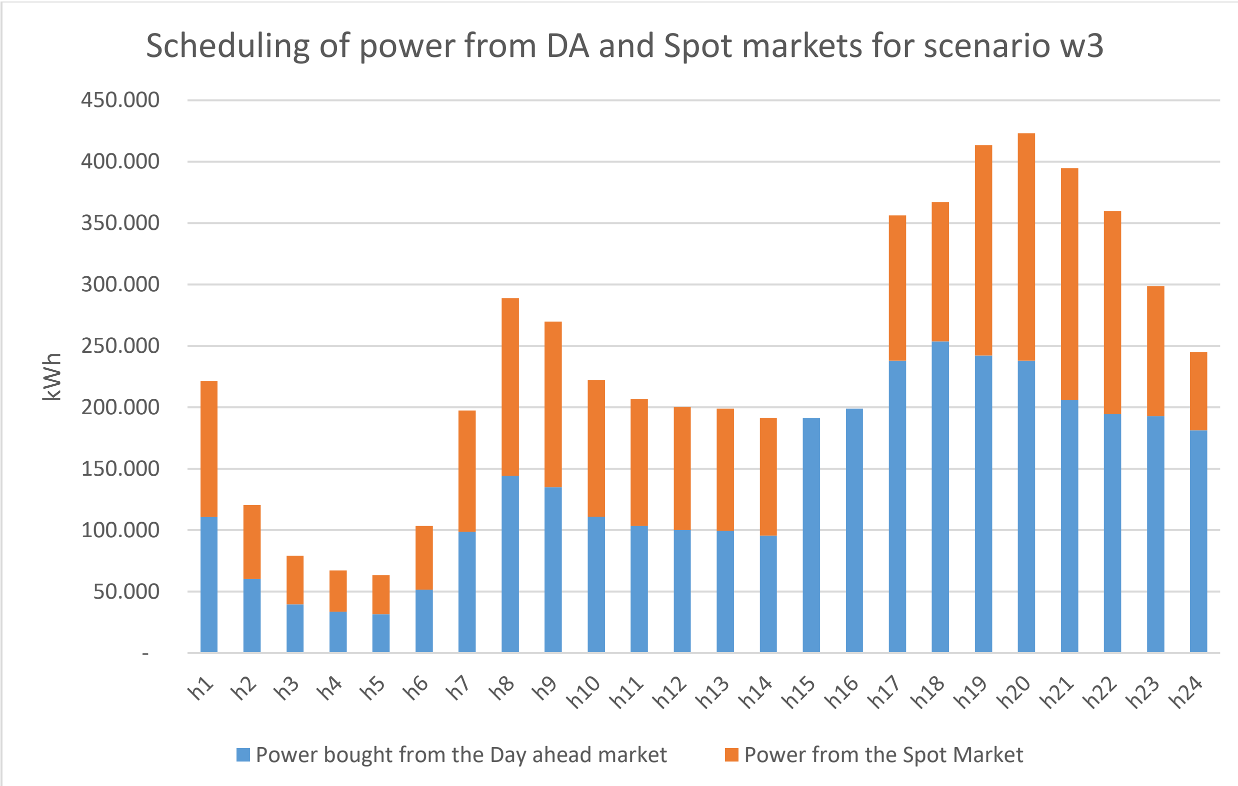

Figure 26 Scheduling of power from DA and Spot markets for scenario w3

Chapter 5 – Conclusions and next steps

The aim of this thesis is to maximize the profits of a vertically integrated company which sells natural gas and electricity to its customers. Wholesale and retail markets are integrated in a model which is separated into two parts and optimized as a NLP model. The first part of the model is DED model that minimizes wholesale market's total cost by calculating the optimal scheduling of all power plants involved in the market. The second part of the model is an econometric model that maximizes the profits of the company examined by calculating the optimal electricity and natural gas hourly retail prices offered to price responsive customers. The model also calculates the company's optimal power scheduling regarding the amount of electricity bought from the day-ahead and the spot market.

Results highlight the important role of the company under examination in the frame of power generation. The company's wholesale profits per year are € 8.9m on average for all scenarios while its revenues and costs are € 52.5m and € 43.6m respectively. The model also illustrates the impact of different CO_2 emission prices on the company's profitability. Using CO_2 shadow prices, which reflect the real cost of emissions to society, for the calculation of emission costs, significantly reduce the company's profits. High emission prices affect the profitability of gas-fired power plants but is crucial for the viability of coal-fired power plants.

Results showed that retail electricity and natural gas prices offered to customers are constant at 0.05 €/kWh and 0.03 €/kWh respectively during the 24-hour period for all scenarios. In both cases (electricity and gas), the retailer maximizes its profits when prices are at the maximum allowed level. The model calculates the company's total profits per year at €17.3 m on average for all scenarios while its revenues and costs are €143.4 m and €126.2 m respectively.

In order to further expand the model additional research is required in the fields mentioned below.

i. Further research concerning customers' short-run elasticity when offered real-time prices will be extremely important to retail companies in order for them to maximize their profits.
ii. Another gap identified is the customers' elasticity in changing energy retail companies. An analysis of customers' behavior concerning their preferable retailer could be useful for energy retail companies by helping them calculate the optimal price offered to consumers supplied by competitive companies in order to attract them and change retailer.
iii. Pricing strategy is extremely important for the profitability of retail companies. Bundling electricity and natural gas could be a useful strategy for such companies in order to maximize their profits. Consequently, customers' elasticity for bundled energy products could be used as an input for the model and combined with customers' elasticity in changing energy retailers could further expand the model.

Annex – Model formulation

This annex presents in a detailed and comprehensive manner the formulation of each part of the model.

1st part

- The **technical constraints** imposed in the first part of the model are the following:
  1. $P_R(h) > P_{R,\ Minimum}$
  2. $P_R(h) < P_{R,\ Maximum}$
  3. $P_R(h+1) - P_R(h) < P_{R,\ Rump\ Up}$
  4. $P_R(h+1) - P_R(h) < P_{R,\ Rump\ Down}$

- The **energy balance** of the Wholesale (DA) market must be maintained throughout the day
  $$\sum_R P_R(h) = WholesaleCons(h)$$

- **Objective function**

  The objective of the 1st part of the model is to minimize total production cost of all stakeholders/power producers while also meeting market's demand. The objective function subject to minimization is the following:

  $$OF = \overbrace{8220 + 5480 + 5480 + 4930 + 7400 + 2740}^{\text{Constant O\&M costs of power plants}} + \sum_h (3.1 * P_R(h) + a * P_R{}^2(h) + b * P_R(h) + c) + PCO2 * (\sum_h (d * P_R{}^2(h) + e * P_R(h) + f))$$

- **Financial performance** of the company examined from its wholesale activities

  $ProfWhole = RevWhole_{R6} - TotProductionCost_{R6}$

  Where
  1. Revenues: $RevWhole_{R6} = \sum_h (P_{R6}(h) * PWhole(h))$
  2. Total production costs: $TotProductionCost_{R6} = CPP_{R6} + TCCO2_{R6}$

  where CPP is the total production cost (constant and variable O&M and fuel costs):

  $$CPP_{R6} = 8220 + \sum_h 3.1 * P_{R6}(h) + a * P_{R6}{}^2(h) + b * P_{R6}(h) + c$$

  and TCCO2 is the total emissions cost:

  $$TCCO2_{R6} = PCO2 * \sum_h d * P_{R6}{}^2(h) + e * P_{R6}(h) + f$$

2nd part

- **Retail price constraints**

  0 (€/kWh) ≤ Selling electricity price (SEP) ≤ 0.05 (€/kWh)
  0 (€/kWh) ≤ Selling gas price (SGP) ≤ 0.03 (€/kWh)

- **Residential and total electricity/gas demand function**

  Residential electricity demand
  $RetailElectricityDemand(w,h) = HourlyElCons(w,h) - ElElasticity(w,h) * SEP(w,h)$

  Total electricity demand
  $\text{Total}ElDemand(w,h) = 76{,}600 \, * RetailElectricityDemand(w,h)$

  Residential gas demand
  $RETAILGASDEMAND(w,h) = HourlyGasCons(w,h) - GasElasticity(w,h) * SGP(w,h)$

  Total gas demand
  $GASDEMAND(w,h) = \; 6000 * RETAILGASDEMAND(w,h) + 1.82 * P(R6,w,h)$

- The **Electricity balance** must be maintained throughout the day

  The company purchases electricity from DA and spot markets in order to meet the demand of all of its customers:

  PSM (w,h) + PDA (w,h) = TotalElDemand(w,h)

- **Market constraints**
  In order to minimize the risk of high spot prices, the company purchases more than 50% of its electricity needs from the DA market:

  PDA(w,h) ≥ PSM(w,h)

  Consequently, the power which is available to be purchased from the spot market is the following:
  PSM(w,h) ≤ $\sum_R P_R(h)$ - PDA(w,h)

- **Financial performance** of the company examined from all its activities

  Revenues from all of the company's activities:
  Revenues (w) = $\sum_h [\big(SEP(w,h) * TotalElDemand(w,h)\big) + \big(SGP(w,h) * GASDEMAND(w,h)\big) + RevWhole_{R6}]$

Costs:

Costs (w) $= TotProductionCost_{R6} + \sum_h \left[\left(GASDEMAND(w,h) * GASPRICE(h) \right) \right] + \sum_h \left[\left(PDA(w,h) * PWhole(w,h) \right) + \left(PSM(w,h) * IntradayPrice(h) \right) \right]$

- **Objective function**

Consequently, the company's profits from all its activities for each scenario is:

Profits(w) = Revenues(w) – Costs(w)

The objective of the 2nd part of the model is to maximize the company's total average profits from all its activities. The **objective function** subject to maximization is the following:

$$z = \sum_{w} Profits(w) * prob(w)$$

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