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Faculty of Electrical Engineering

Doctoral Thesis

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MODERN VALUATION METHODS IN THE ENERGY SECTOR

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II. Contents

III. Abbreviations

BL	baseload
B-S	Black-Scholes formula
CAPEX	capital expenditures
CAPM	capital asset pricing model
CDS	clean dark spread
CF	cash flow
CO_2	carbon dioxide
CVaR	cumulated value at risk
D/E	debt to equity ratio
DCF	discounted cash flow
DS	dark spread
EBITDA	earning before interest, taxes, and depreciation
EBT	earnings before taxes
EEX	european energy exchange
EFET	european federation of energy traders
EU	European Union
EUA	European emission allowance
FCF	free cash flow
FX	foreign exchange
GAT	general arbitrage theory
GSS	grid support services
HPFC	hourly price forward curve
IRR	internal rate of return
MC	monte carlo simulation
MC	marginal costs

MtM	mark-to-market
NPV	net present value
NWC	net working capital
NYMEX	new york mercantile echange
O&M	operation&maintenance
OP	off-peakload
OTC	over-the-counter (bilateral contracts)
OTE	czech electricity and gas market operator
PL	peak load
PV	photovoltaic
PXE	prague energy exchange
RES	renewable resources
ROT	real option theory
SG	smart grid
TSO	transmission system operator
WACC	weighted average cost of capital

IV. Nomenclature

NPV	Monetary Unit	net present value
DCF	Monetary Unit	discounted cash flow
S_T	€/MWh	spot price of electricity
F	€/MWh	forward price of electricity
K	€/MWh	strike price of option
K_H	GJ/MWh	heat rate
C_T	€/GJ	spot price of coal in tons
C_a	MW	available capacity
Pe_t	€/MWh	spot price of electricity
Pf_t	€/GJ	spot price of the fuel
VOM	€/MWh	variable costs for operation & maintenance
$I_{Q_{n,p}}$	-	Quarter Index
$I_{M_{n,p}}$	-	Month Index
$I_{M_{n,p},D_{n,p}}$	-	Day Index
$Ih_{M_{n,p},D_{n,p},H_{n,p}}$	-	hour Index
hy, hy_n	hour	hour of the Year, sum of the hours
hq, hq_n	hour	hour of the Quarter, sum of the hours
hm, hm_n	hour	hour of the Month, sum of the hours
hd, hd_n	Hour	hour of the Day, sum of the hours
h, h_n	Hour	hour
S_p	€/MWh	spot price of electricity
FCF_t	Monetary Unit	free cash flow

$PV_{benefits}$	Monetary Unit	present value of benefits
$InvestmentCost_t$	Monetary Unit	investment costs
$WACC$	-	weighted average cost of capital
g	%	growth
rf	%	risk-free rate
w_d	%	weight of debt
w_e	%	weight of equity
k_d	% p.a.	cost of debt
k_e	% p.a.	cost of equity
tax	%	tax rate
k_{rf}	%	theoretical rate of return of zero-risk investment
k_m	%	expected return on a market portfolio
β	-	beta
$EBITDA_{tot}$	Monetary Unit	total EBITDA
$EBITDA_{opt}$	Monetary Unit	EBITDA resulting from optimization
$EBITDA_{res}$	Monetary Unit	planned EBITDA of non-tradable years
$FCF_{t,OPT}$	Monetary Unit	free cash-flow after optimization
$CF_{t,op}$	Monetary Unit	cash-flow from operations
$CF_{t,inv}$	Monetary Unit	cash-flow from investing
$CF_{t,fin}$	Monetary Unit	cash-flow from financing
$P_{\max}$	MW	maximal output of the unit
$P_{\min}$	MW	minimal output of the unit
RR	MW/hour	ramp rate

RaT	hour	ramp time
P_{req}, P_{end}	MW	required output
P_{start}	MW	starting output
P_{ef}	MW	output with maximal effectivity
q_{var}	-	slope coefficient of heat rate curve
$VC_{P\min}$	Monetary Unit	variable cost at minimal output of the unit
Tr	-	transition
f_C	-	heat rate function
GPP	MWh	gross power production
NPP	MWh	net power production
C_i	MW	installed capacity
C_{gss}	MW	capacity reserved for GSS
T_{tot}	hour	maximum working hours
T_{av}	hour	available working hours
T_{eff}	hour	effective working hours
T_{GO}	hour	general overhaul time
I_{AV}	-	availability factor
I_{TC}	-	capacity factor
R_{TLR}	%	transmission loss rate
R_{OC}	%	own consumption of the block
$VC(P)$	Monetary	variable costs related to output
C_{coal}	Monetary	costs of coal

C_{CO2}	Monetary	costs of CO_2
C_{FR}	Monetary	other fuel related costs
CAL	GJ/ton	calorific value
EF	ton/MWh	emission factor CO_2
GE	%	gross power efficiency
TC	Monetary	total costs
FC	Monetary	fixed costs
P_{coal}	Monetary	long-term contract coal price
P_{CO2}	Monetary	price of CO_2 emission allowances
$MVC(P)$	€/MWh	marginal variable costs related to power output
$FCFF_t$	Monetary	free cash-flow to the firm
Int	Monetary	interest expenses

V. Images

VI. Tables

1. Introduction

In recent times, the entire power industry sector has faced new strategic challenges. Efforts for CO_2 mitigation as well as applied liberalization result in changes to infrastructure on the supply and demand sides of the electricity market. In the viewpoint of the author of this manuscript, one of the most important aspects of recent development is the need to change the approach to energy investment valuation and the related investment decision process. Methodology described in this manuscript offers an approach suitable for today´s power industry.

Today, we are about to transform the entire sector of the power industry in a massive way. The transformation and structural changes are caused by many factors, primarily by sustainable energy development and future predicted lack of fossil fuels. The mentioned need for reliable valuation is also connected with environmental problems—particularly with CO_2 emissions. The transformation requires implementation of new and modern smart technologies that are often expensive and are not competitive without any subsidies. In addition, very little experience with these technologies represents risk, because after massive investment of some technologies, the results follow after a delay of many years. Therefore any implementation must be based on exhaustive and reliable valuation of all possibilities and means of market participant motivation. Today’s evaluation of any new technology implementation is generally accomplished by the classic methods of NPV or IRR. These methods are useful typically in the conditions of good future market knowledge. In the energy power sector, this condition is not always fulfilled. There are many uncertainties—particularly in the areas of future energy price development, amount and availability of fossil fuels, and price of CO_2 certificates. Furthermore, the value of the energy asset is also influenced by the operational flexibility of the source simultaneously with the hourly price forward curve structure. Therefore, the goal is to develop a modified approach of economic effectiveness valuation, which incorporates the above-mentioned limitations.

The large investments in power generation assets motivate many players to realize proper power plant valuations. Many changes in the energy sector have occurred in the last decade, mainly in the sectors of renewable resources, regulatory framework, and energy market. Considerable impacts are also expected with the implementation of smart metering and possible future changes in the design of the spot and balancing market. Due to this market improvement and the above-mentioned limitations, the classical valuation method of net present value (NPV) has to be enriched by the operational flexibility value of the power plant to adjust production decisions to electricity price movements and the hourly structure of the electricity curve. Therefore, this thesis works with the assumption that the plain NPV analysis disregards and underestimates the real plant value. The solution is to search for the additional value of flexibility value based on the optimization of the electricity production due to the spot market electricity prices or based on the forward HPFC curve methodology. NPV analysis is often structured to one or two phases of asset lifetime and perpetuity. Typically, the first two phases of evaluation, which are further described in this manuscript, are based on discounted cash-flow, which includes all outcomes for fuel, emission allowances, and CAPEX; and incomes for electricity, grid services(“GSS”), and heat. Obviously, many other methods that are based on treating power plants as a series of spread options ignore technical and/or contractual restrictions; conversely, they could overestimate real power plant value. Implementing the methodology and algorithm in Mathematica software enables evaluation and optimization of the operation of power plants, which produce electricity and support grid services. This optimization is based on the developed hourly price forward curve and technical restrictions of the plant.

1.1. Goals of this thesis

The goals of this work are to investigate the problematics of the energy market and power plant valuation, and to formulate methodology that optimizes electricity production based on the spot market prices and technical parameters of the unit. For this purpose, the link between optimization, valuation approach, and business approach incorporating risk management has to be established by presenting methodology aimed at combining these concepts. Statistical modelling and hourly price forward curve methodology is the basis for representing spot prices structure and valuation of power asset. This HPFC methodology is developed to be able to compile this forward curve from historical electricity spot price data in order to present the structure changes. The main utility´s risk drivers, such as price volatilities, imbalance prices, and price jumps are identified by incorporating the above-mentioned hourly price forward curve. Incorporating these specific features of electricity into the risk-management concept and valuation techniques is the key to successful management of power asset value. Additionally, the valuation techniques and stochastic modelling are similar to traditional financial market methods; nevertheless, they differ substantially from power markets due to technical characteristics of power plants. Power plant production will be hedged with standard electricity products. Many papers describe in detail the methodology of asset or company valuation, risk management tools, different methods to receive fair value of commodity or financial option, and the classical DCF method without considering the impact of those factors on final values. This thesis presents the modified DCF methodology of energy asset valuation using the hourly price forward curce to fully integrate structural changes of the energy market.

1.1.1. Description of energy industry and electricity market

For the deep analysis of the electricity market, the author describes electricity market development in the Czech republic and EU, including regulatory framework with its impact to the conventional power plants values. Structural changes of the electricity market are investigated and further valuted by using the hourly price forward curve.

Furthermore, this thesis contains detailed description of standard and financial commodity products and the commonly used approach of hedging the open position of electricity producer or consumer. Problematics of hedging and trading are also described in detail, including various approaches in the case of electricity or fuel hedging. This component of the thesis represents a crucial part of the theoretical background necessary for futher research and formulation of the main drawbacks of commonly used valuation methods.

1.1.2. Description of hourly price forward curve concept

The author describes and develops an approach for deriving the hourly price forward curve, which represents the spot hourly structure of long-term electricity contracts. The author performed detailed research of hourly price forward curve problematics and examined similar approaches that are described further in the state of the art section in chapter 2. This concept and research is further considered in formulation of a modified NPV method and optimization.

1.1.3. Description of valuation methods

The author describes the basic concept of DCF valuation to receive net value of asset and compares this approach with the real option methodology. Furthermore, a detailed description is provided of the concept of the modified NPV method to incorporate optimization, which includes value of flexibility of the source. A separate section discusses the basic concept of enterprise valuation. This theoretical background is necessary to be able to distinquish between different value concepts and to formulate correctly the modified net present value concept.

1.1.4. Formulation of optimization model and identification of real impact of methodology to valuation

The optimization model was formulated and programmed by the author in the Wolfram Mathematica software to incorporate technical aspects of power asset and hourly structure of electricity prices into the asset valuation. A later chapter presents an actual case study that demonstrates how technical and contractual market development affect power plant value. The main focus is on the spot market optimization. The case study assumes that the power plant is supporting grid services for TSO and selling residual load of electricity on the market.

1.2. Author´s Hypothesis

The author´s hypothesis is that the well-known DCF concept of power plant valuation using average mean value underestimates the value of conventional power plants with the possibility of output regulation flexibility. Therefore, it is expected that use of the net present value method, enriched and modified by optimized energy output discounted cash-flow, is valuable tool for the the power industry to receive the fair value of the power plant unit, which incorporates the value of output flexibility. This modified DCF is analysed and compared with traditional DCF. Moreover, the author identifies critical factors that affect power-plant value. Furthermore, this method uses the HPFC curve to incorporate the structure of the spot market into the future contracts and to value the flexibility to enable consideration of the technical aspects of the power plant.

1.2.1. Sub hypothesis 1

One reason for the underestimation of the energy asset value is the absence of hourly structured electricity long-term contracts to project hourly price structure of electricity to the value of the energy asset, in accordance with its operational flexibility. The HPCF curve is derived from the indexed futures based on the historical spot prices of electricity. Reliability of the HPFC curve was tested on the real data of spot prices of electricity in comparison with the derived HPFC curve to confirm that the HPFC curve is an appropriate valuation tool for energy contracts.

1.2.2. Sub hypothesis 2

The second reason for energy asset underestimation could be the omission of the energy output flexibility value. The optimization algorithm of electricity production incorporates all key technical aspect of power asset, hourly structure of electricity prices, and heat rates in relation to output. Therefore, incorporating this optimization model into valuation of the DCF equation leads to more accurate results of the energy asset value. Furthermore, this method considers technical restrictions of the unit.

1.3. Motivation

The electricity market was regulated for decades, and electricity was thought to be a non-tradable commodity. Electricity industry deregulation and liberalization was the key aspect of dramatic changes in the market that encouraged competition. In Europe the process of power market deregulation is tending to displace national markets with the common and more homogenous European power market. Currently, electricity is traded similarly to stocks in day-ahead spot markets and financial derivatives markets. Utilities and power companies are exposed to the arising risks due to volatility of electricity and other commodities. To be successful on the market, utilities have to work on feasible market strategies with defined risk profiles to achieve the primary goal, which is maximization of the firm´s value.

One of the key aspect of the success could be the reliable method of power plant valuation and its operational flexibility value.

In scientific manuscripts, no authors were found to have used the modified method of DCF, which incorporates specific technical aspects of power plant unit and optimized electricity output, considering and incorporating current market conditions projected into the HPFC curve, and further, to the value of energy assets producing electricity. Few scientific papers present a complex approach to incorporate specifics of electricity markets to the value of energy asset. Therefore, the results of this thesis could be useful in further development of appraisal methods to receive fair value of energy assets.

1.4. Structure of the Thesis

The structure of this thesis can be described as follows. In chapter 1 the goals and hypotheses for this dissertation thesis are formulated. The author describes his research methods in chapter 2. Electricity market design and structure of the spot prices of electricity are described in detail in chapter 3. This chapter also provides the necessary theoretical background of the hedging and trading of electricity. Hedging strategy is followed by hourly price forward curve methodology in chapter 4, which enables the author to valuate load diagram and electricity products.

Chapter 5 presents the theoretical background of the valuation concepts, with emphasis on net present value in comparison with the real options approach. In addition, it describes the basic appraisal concept of enterprise business. This chapter also discusses the new valuation concept of modified NPV, which is further used in chapter 6. Chapter 6 also describes the developed algorithm in Mathematica software, including the criteria of optimization and result explanation. The conclusion of this thesis contains the proposed methodology that should be suitable for energy asset valuation, followed by discussion of further research possibilities.

2. Methods of Research

Currently used methods of the energy asset valuation analysis originate in commonly used mathematical and statistical procedures using market data and technical criteria of power plants. The key aspect of the presented methodology, as described below, is in optimization of fuel utilization and profit maximization. Applicability of this methodology could be employed for all types of energy resources and commodities. In the more general aspect, the methodology is applicable for the smart grid (SG) concept as well. The methodology is applied on the power plant operation case study. The evaluation algorithm was programmed in Wolfram Mathematica software. The systematic analysis provides a relevant description of today´s energy market, structural changes of the market, and a commonly used valuation methodology of the energy asset. From the above-mentioned analysis and studied literature, and further mentioned in section 2.1., the author inducted impacts of the power plant optimization algorithm to the value of the energy asset value. The global hypothesis of this dissertation thesis was created by this induction. The author's research of the global hypothesis—that the well-known DCF concept of power plants' valuation using average mean value underestimates the value of conventional power plants with possibility of output regulation flexibility—is based on the synthesis of the research linked to sub-hypotheses solving two different coexisting drivers that are separately tested. Further factors could impact the global hypothesis. Nevertheless, the author selected the two above-mentioned hypotheses in section 1.2 as key elements of the research. The hypothesis was confirmed by deduction from the results received by the valuation model. The valuation model was based on the research with the quantitative approach.

Specifics of the author´s approach became more apparent during application on the real case study, which is provided in chapter 6. The undisputable fact, which was revealed to be significant during the author´s research, is that the power industry requires a unique application of the valuation method that involves specific technical parameters of the energy asset.

2.1. State of the art

Energy sector changes and their their effects on the structure of electricity price have been introduced to incorporate these changes to energy asset valuation. The structural changes of the electricity sector in Germany are described in literature [37] with the declaration that expansion of electricity generation from renewable resources has already changed the structure of electricity spot prices in Germany. This paper further describes challenges to assess the spot price effects of price-elastic demand and storage during times of surplus generation. The fundamental concept of the HPFC curve is presented in literature [40] and [41] with recommendation of *a-priori* quality checks for the resulting prices and methodology of HPFC construction. Literature [38] also implements Market Coupling effect, nevertheless we assume that this effect is recently marginal in the case of the Czech electricity market due to its long-term surplus. A paper [39] proposed an algorithm to calculate HPFC under market coupling conditions that incorporated demand and supply curves, transfer capacity, and weather indicators to calculate the HPFC. We assume that the approach incorporating weather is favorable in the case of short-term load valuation, especially of renewables sources of energy Hedging methodology presented in this author´s thesis was further inspired by the [31] and [26].

Real option valuation techniques have been introduced to analyse the value of flexibility or optionality of power asset investments, and to develop traditional methods of discounted cash flow (DCF). The fundamental concepts of this method are presented in literature by [10] as well as [9]. Option pricing methods, already well developed in the financial markets, can be used to price the option and estimate the power plant value. The analysis is much more complicated in the presence of production constraints such as switching costs, ramp rates, or minimum on/off times. Wang and Min (2013) [1] note correctly that option-based approach valuation can capture operational flexibilities and financial risks in a single framework. This literature considers deterministic variable costs and stochastic costs of electricity and fuel/gas. Prices of electricity and gas are simulated with the geometric mean-reverting process. Price simulation is used to provide further binary evaluation for the option of spark spread, incorporating minimum operating hours, forced outages, and startup costs. Many other papers consider deterministic variable costs of operation and maintenance. This paper also considers startup issues, minimum operating hours, and forced outages instead of the approach presented in this dissertation thesis. The author assumes and agrees with the literature presumptions that the above-mentioned approach is effective mainly for cycle gas power plants with very high ramp rates. Note that this methodology does not involve optimization based on specified ramp rate and effectivity curve of the plant. Moreover abovementioned paper is solving valuation in the short-term bases without extension to the hourly granularity for long-term contracts.

Option-based valuation of power plants has been studied in the literature.Paper [2] applied spark-spread options to estimate the value of tolling contract[1] and applied an analytical solution to estimate the plant value (several characteristics of plant operations are simplified—ramp-ups and ramp-downs of the facility can be done with very little advance notice, and the facility´s operating and maintenance costs are constant.) In our case, spark spread option value solved by traditional valuation approach used commonly in financial options is replaced by hourly price curve simulation and using deterministic model of production optimization. Literature [3] used simulation to obtain power plant values over a short period of time; they also considered physical constraints such as minimum uptime and downtime, including startup time and shutdown time. This paper formulates the power plant valuation as a multistage stochastic problem with the prices for electricity and the fuel characterized as uncertainties. Similar with the author´s approach, the paper mainly focuses on the valuing fossil-fueled steam (thermal) units whose unit-operation dynamics require time to start up or shut down the generator with minimum downtime and defined ramp rate and cost function. Furthermore, in their paper [4], was developed discrete-time price lattice models to solve a similar problem with time-efficient computation. Paper [5] further consider the optimal self-scheduling problem as a subject to the ramp constraints and price uncertainty. In the case when the market prices are known with certainty, a polynomial-time algorithm based on a network graph is proposed for solving the problem. A further-developed algorithm that evaluates various price scenarios uses the Monte Carlo method with regression to obtain the optimal dispatch policy. Paper [6] used lattice models to analyse the choice between natural gas and integrated gasification combined cycle technologies for producing electricity using either coal or natural gas as fuel. This paper does not consider ramp rates and technical constraints of the unit. Paper[8] used the utility indifference approach to develop an option-based evaluation model for power plants. An alternative method is the utility indifference pricing. This method has been studied for the pricing of European and American options; for example, Paper [11] presents a new pricing formula for the utility indifference price, considered as a linear expectation of the payoff plus a pricing premium, where the latter is represented by the solution of a functional differential equation. Another paper [13] describes valuation of commodity-based swing options, where the valuation methodology is based on the use of multilayered trinomial trees, which both discretize the stochastic process and permit the valuation of an option requiring multiple decision variables. The case of spark spread options valuation is descripted by [50], where behavior of spread options can be quite complicated and have negative vegas[2]—spread option value decrease with volatility, unlike for standard

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[1] Tolling contract provides buyer with a right to operate a power plant by paying a predetermined amount to the power plant owner.

[2] One of the key analysis techniques utilized in options trading is the Greeks' measurements of the risk involved in an options contract as it relates to certain underlying variables. Vega measures the sensitivity to the underlying instrument's volatility. Vega represents the amount that an option contract's price changes in reaction to a 1% change in the volatility of the underlying asset. Volatility measures the amount and speed at which price moves up and down, and is often based on changes in recent, historical prices in a trading instrument. Vega changes when there are large price movements (increased volatility) in the underlying asset,

options. The value of spark option is determined by joint distribution of both underlies, and this joint behavior is measured by linear correlation, which is in energy markets a challenging problem. The optimization algorithm methodology is inspired by literature: Papers [14] and [15] present and analyse a conjugate gradient algorithm and its implementation, based on an interpretation of the secant equation and on the inexact Wolfe line search conditions.

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and falls as the option approaches expiration. Vega is one of a group of Greeks used in options analysis, and is the only one not represented by a Greek letter.

3. EU electricity market framework and design

The purpose of this chapter is to provide the reader with the basic framework of the EU[3] electricity market and applicable data to prepare real-based valuation of the power asset in the case study in chapter 6. It is obvious that forecasting of market prices of the commodities such as electricity, emission allowances, heat, and grid system services on a long-term basis has to include consideration of regulatory framework, design of joint or internal market, and legislation regulating the energy industry. Regulation should provide an efficient interface between the public interest and the market; nevertheless, support schemes such as feed-in tariffs supporting RES[4] sources of energy could lead to massive discrepancy between the liberalized portion of the market and subsidized RES. This could lead to significant changes in merit order and supply curve of electricity. The same effect could occur on regulation of CO_2 emissions by emission allowances allocation, where market price of EUAs is strongly dependent on political decision of EU regulatory bodies and therefore hardly predictable on a long-term basis. The above-mentioned effects are considered further in this thesis. Therefore, to obtain the relevant value of a power asset, we have to consider levels of electricity prices and the outlook of the power asset, and also to structure electricity prices consistently with the mentioned structural changes.

Increasing RES energy sources with low operating costs and subsidies are causing important structural changes in the electricity markets. Electricity generation from RES is hardly fully predictable as well, as demand can change rapidly and not necessarily in the same direction. Therefore, a reliable system of energy utilities operation requires increasing balancing capacities and the ability to respond quickly and flexibly to changes in energy balance of the grid. RES generates electricity at very low marginal costs, supported by feed-in tariff, and therefore moves the capacity of thermal power plants higher in the merit order. This is an important milestone for strategy planning and forecasting future price of electricity. A critical effect of subsidized RES is depressing electricity prices, which challenges the feasibility of thermal power plants. This could result in the lack of investments in new capacity, plant closures, and insufficient balancing capacity for transmission system operators. It is obvious that an energy system with a high share of RES requires flexible free capacity. The increasing demand for flexibility could be seen among market players and system operators.

Valuation of an energy asset and its operational flexibility must incorporate many important drivers. Nevertheless, the important factor is the structure of the spot prices of electricity during the valuated period. Moreover, different generating

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[3] Power system architecture of the EU energy market is closely connected to objectives set by the governments and, for example, partly done in the European Roadmap 2050.

[4] One of the main objectives of EU is decarbonizing the energy sector.

technologies have different possibilities to provide flexible electricity. Some units with specific technology are able to start up from zero and then ramp up (increase the output) within seconds. Conversely, different technologies may take a number of hours to start up but they are still able to be flexible to provide system services.

Due to the possible lack of the flexible generation capacity, in the future there must exist an effective and transparent market with flexibility. An ineffective market with flexibility does not have relevant influence to incentivize investments in flexibility. Proper design of a power market should incentivize flexibility and ensure adequate and proper generation capacity. The typical design of a liberalized energy market consists of two parallel markets: the energy market (consisting of the wholesale electricity market—day ahead, intra-day, and balancing market) and the flexibility market (specific market with flexibility and system services). Design of the flexibility market[5] depends strongly on local regulation and legislation, but it is obvious that a competitive and effective flexibility market would be operated as an option market for flexibility. The procurement process of many TSOs could be seen as not sufficiently transparent, and flexibility volumes are often locked under long-term contracts. In this case, there is no possibility to use market data of the electricity option exchange to derive the value of flexibility for the local TSO area. A possible capacity market could be incorporated only in the case of lack of the capacity. The option holder may exercise the option by calling for energy to be delivered and may pay the availability fee (per MW) to the flexibility providers; a utilization fee (per MWh) is paid upon exercise of option. The energy market is very volatile and obviously unpredictable. The current high volatility of spot electricity prices strongly supports liquidity of an intra-day market, where all market players optimize their positions before cut-off time. This intra-day market development provides additional trade opportunity for flexible assets.

The key drivers of the energy asset correct valuation are the electricity and emission allowances market conditions strongly influencing revenue stream. These market drivers are dependent on the market conditions, which are further dependent, in part, on politic and legislation or regulation framework, as was mentioned previously. A crucial fact is that energy markets in EU are joint and connected, and are developed according to “Roadmap 2050”[6]. Connecting markets leads to price convergence in the joint area, which is also a key issue for electricity price forecasting based on the supply and demand development.

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[5] One solution discussed among many European Union member states considered capacity mechanism as a potential way to secure capacity adequacy and system reliability.

[6] The mission of the Roadmap 2050 project is to provide a practical, independent, and objective analysis of pathways to achieve a low-carbon economy in Europe, in line with the energy security, environmental, and economic goals of the European Union. The Roadmap 2050 project is an initiative of the European Climate Foundation (ECF) and has been developed by a consortium of experts funded by the ECF.

3.1. Czech electricity market and RES development

Some years ago, the electricity market at the Czech Republic was vertically integrated, and prices of this commodity were fully regulated[7] by the state-owned authority. The prices were therefore determined by well-known factors and changed rarely. After deregulation of the electricity market, prices have been determined according to the economic rule of supply and demand. Many countries settled electricity pools—energy exchanges, where bids of electricity sellers are matched with purchase orders of end users. These exchanges are trading with the long-term products and short-term products as well. The differences are only in the liquidity and volatility of the prices. This deregulation fully supported trading activities on derivatives markets, which allowed trading with financial electricity contracts as derivatives, in which the electricity is an underlying asset. Relatively high volatility of electricity prices and important specifics of this commodity has enforced many market players to manage price risk professionally. The basic concept of the risk-managent framework is mentioned in Appendix A.1. Hedging of the market risk is a well-known method of eliminating risk of the price changes, but the method also has its weak points, which are associated with the specific features of the electricity. Due to obvious specific factors of electricity, such as its unique non-storability, electricity prices are driven more likely by spot supply and demand, which is inelastic. Any shock in consumption or production may give rise to price jumps [4].

As seen in literature [37], the continuous expansion of electricity generation from intermittent RES has already changed the structure of electricity spot prices in EU countries. The developed method by the author must consider these changes in the valuation approach. The functional method that could incorporate relevant structural changes in the electricity market is the HPFC curve, discussed further in chapter 4. The impact of the price level changes is visible primarily on the long-term hedging of the open position. Conversely, the impact of changes of the electricity spot price structure is mainly visible on the HPFC curve and the valuation of operational flexibility. Figure 1 shows a visible increase of total RES production in Czech Republic between years 2004 and 2013, when the main impact to this increase had feed-in tariffs for PV plants, wind power plants, and biogas production. It is obvious that the structure of electricity spot prices is rapidly changing due to the RES implementation and massive increase of electricity produced from renewable resources. Structural changes of the spot market and its impact are further discussed and described in section 3.2.

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[7] Regulated prices had to reflect the cost of generation of electricity, and transmission and distribution of this commodity.

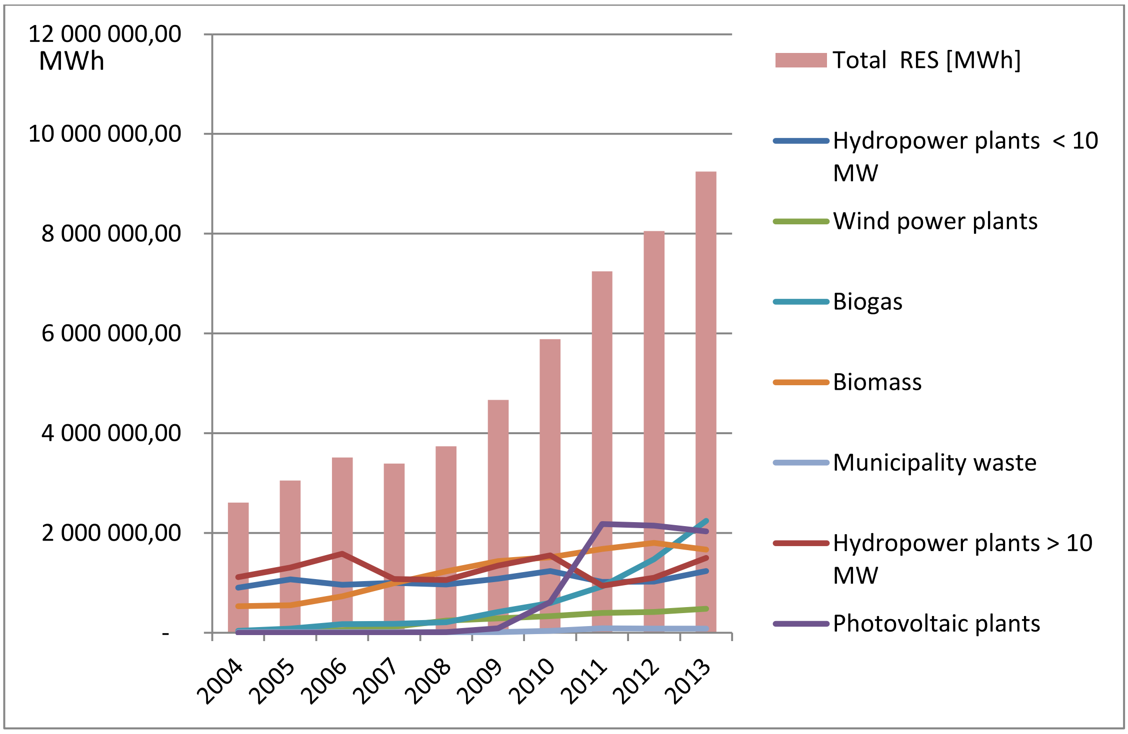

Figure 1: Supply side of RES - structure and total production (data source www.ceps.cz)

Figure 2 presents the structure of installed capacity of different energy sources in the Czech Republic in December 2013. Important roles are played by conventional thermal power plants, with 51% share due to historical preferences caused primarily by low prices of lignite, nuclear power plants with 20% share from total production, and also RES, where PV plants make up 10% of total production. The structure of the installed capacity is obviously changing due to RES implementation and decommissioning of old lignite thermal power plants.

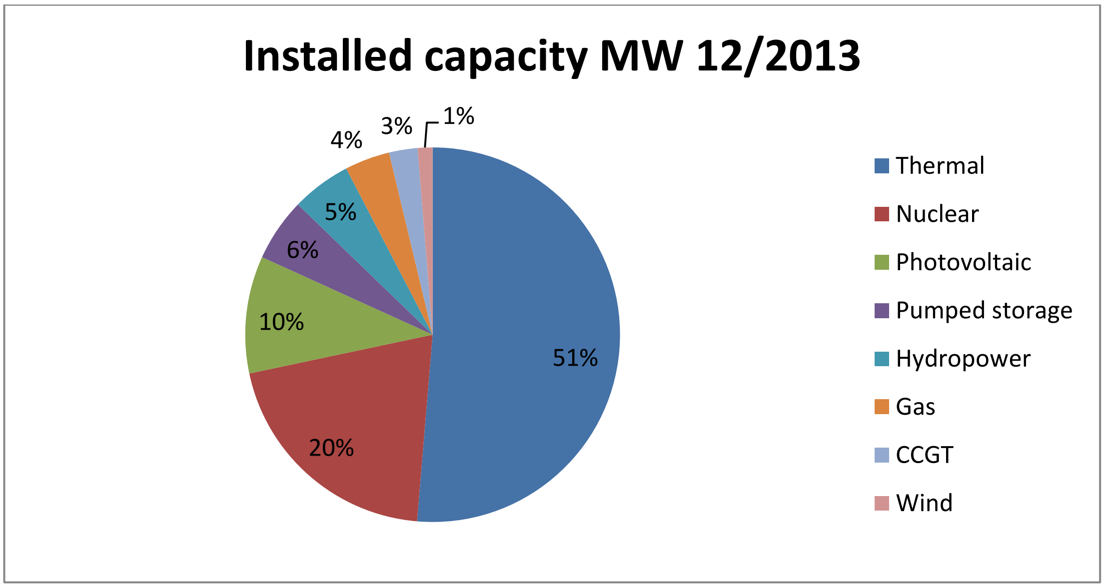

Figure 2: Installed capacity MW (data source www.ceps.cz)

On the demand side visualized in Figure 3, there is visible decrease of total consumption during the financial crisis starting in 2009. This decrease was caused mainly in the industry sector, as is obvious from the consumption structure development. This consumption decline had negative impact to trading portfolios which were fully hedged at the level of 100% standard consumption. Therefore, many traders since the crisis have implemented risk management concepts with an emphasis on volumetric and market risk[8].

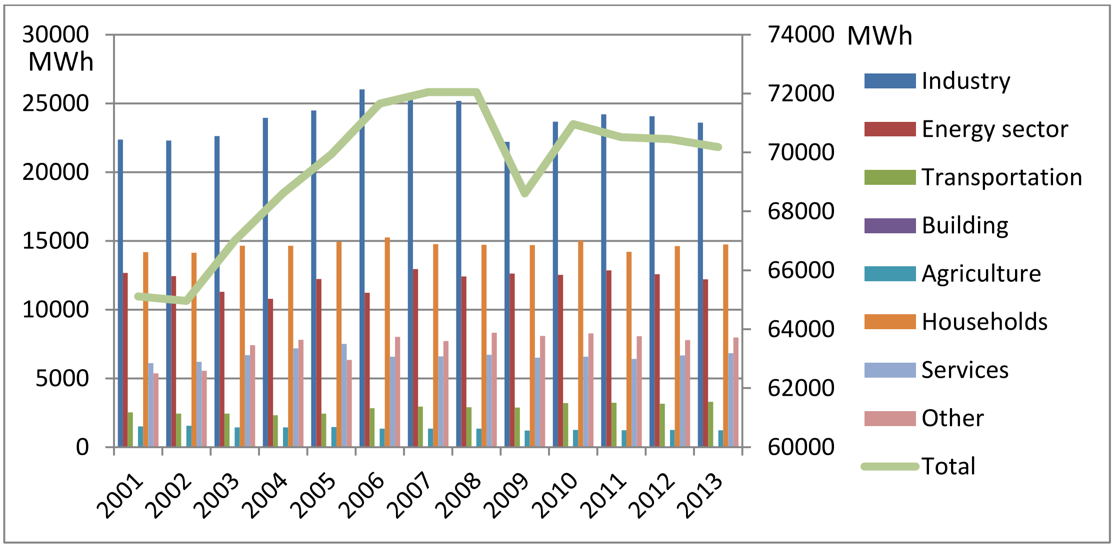

Figure 3: Demand side - structure and total consumption(data source www.ote-cr.cz)

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[8] Further explained in Appendix 1

As is visualized in Figure 4, prices of calendar year baseload contract at the Czech market have been rapidly decreasing since 2011. This decrease likely is caused primarily due to a decrease of global electricity consumption and supply side structure changes caused by implementation of RES in Czech Republic, which is visible from Figure 1 and Figure 3.

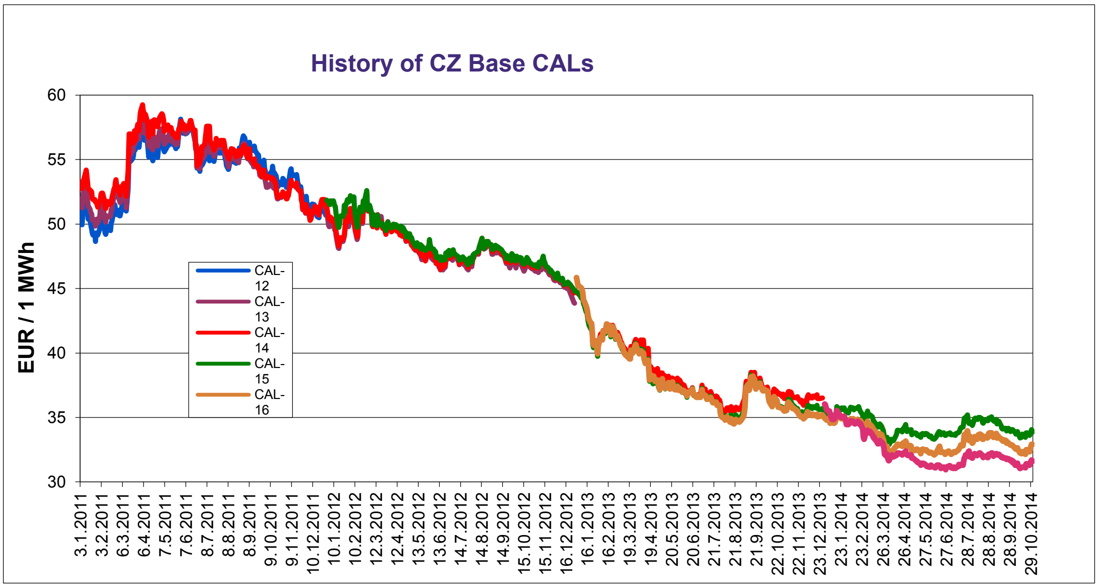

Figure 4: History of year contract baseload (source: www.pxe.cz)

3.2. Spot market structural changes

This chapter describes an important part of the electricity market, with considerable impact to valuation of electricity products and assets. The spot electricity market is the mirror of prompt supply and demand and therefore indicator of the real energy balance of the local grid at the moment. The spot market does not indicate any expectations of the prices due to speculative positions. The electricity spot market in the Czech Republic is organized by the institution OTE[9], which is also responsible for the measurement and data pooling. Spot prices in the case study were analysed from obtainable data of the spot market in the Czech Republic. The graph in Figure 5 shows the difference between daily spot price and weighted average in years 2005-2013. There are obviously visible changes of load profile character, with increased volatility during peak hours. In our case, spark spread option value solved by traditional valuation approach used commonly in financial options is replaced by hourly price

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[9] http://www.ote-cr.cz/

curve simulation and using deterministic model of production optimization.

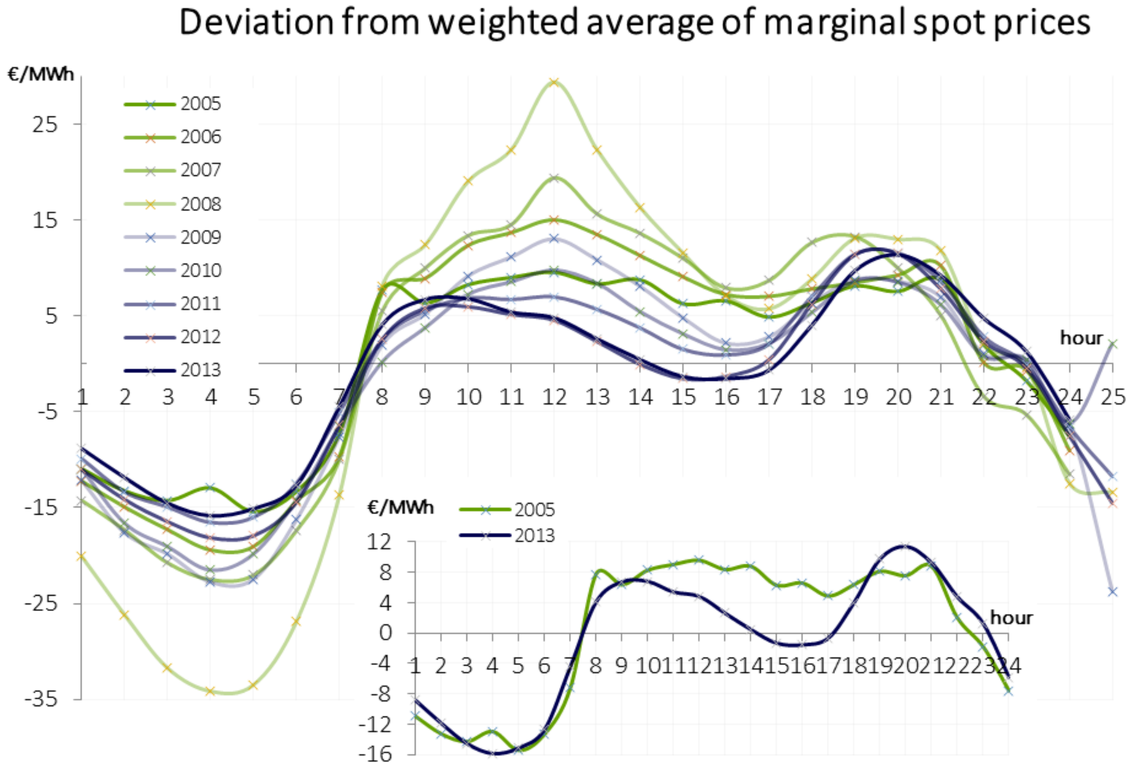

Figure 5: Deviation from weighted average of marginal spot prices (data source www.ote-cr.cz)

The hourly price forward curve and further electricity price modelling does not analyse consumer behavior from the global point of view and does not expect any substantial changes. It is assumed that major structural changes are caused on the supply side. Spot electricity prices during peak load hours were relativly stable in year 2005; instead, considerable price decrease occurred after 10 a.m. during year 2013. This effect is typically caused by PV plants producing electricity mainly during peak load hours. These changes are primarily due to incorporating RES into electricity production. Therefore, it could be assumed that these changes are primarily visible in the areas of the merit order and structure of daily spot prices as well. The mentioned structural changes have to be sufficiently involved in power asset valuation. A possible way is to use the HPFC curve based on the current market data, presenting the hourly structure of spot prices in relation to year baseload contract.

3.3. Electricity products – financial and physical instruments

This section describes various electricity financial or physical electricity product instruments traded on the commodity exchanges (PXE,EEX) and OTC markets to be able to distinguish key differences for the trading and hedging purpose. Hedging problematics are described in detail in section 3.4. The major volume of the electricity futures and options on futures are traded on the European Energy Exchange EEX.

However, the trading volume of electricity futures on the power Exchange in Czech Republic PXE is lower than the volume of the electricity forwards traded on the over-the-counter (OTC) markets, presumably due to lower trading fees. A large variety of the electricity derivatives are traded among market participants on the OTC markets, including forward contracts, swaps, plain vanilla options, and exotic options (spark spread options, swing options, and swaptions). Other important contracts for hedging the market risk of long-term cash flow are tolling agreements and load-serving full requirement contracts.

3.3.1. Electricity forwards, futures, and swaps

The basic forms of electricity derivatives are forwards, futures and swaps traded either on the exchanges or over the counters. In the trading activities of financial electricity are also currently interested former banks widening their trading floors. These electricity contracts play the primary roles in hedging open positions for traders and producers.

3.3.1.1. Electricity forwards

Electricity forward contracts represent the obligation to buy or sell a fixed amount of electricity at a specified contract price, known as the forward price, at a certain time in the future (called maturity or expiration time/date). In other words, electricity forwards are ”custom-tailored“ supply contracts between a buyer and a seller, where the buyer is obligated to take electricity and the seller is obligated to supply. The payoff of a forward contract promising to deliver one unit of electricity at price F at a future time T is shown in Equation 1:

Payoff of a Forward Contract = $(S_T - F)$ (1)

where S_T is the electricity spot price at time T

The settlement spot price S_T calculation is usually based on the average spot price of electricity over the delivery period at the maturity time T. Consider a forward contract for the peakload electricity on day T. Peakload refers to the electricity delivered over the peak-period, traditionally defined by the exchanges as 08:00–20:00 hour. In this case, S_T is obtained by averaging the 12 hourly prices from 08:00 to 20:00 on day T. Independent electricity producers are typically the sellers of electricity forwards.The maturity of an electricity forward contracts ranges from hours to years, although contracts with maturity beyond two or three years are not sufficiently liquid. Some electricity forwards could be traded as financial contracts, which are settled only through financial payments based on a certain market price index at maturity. Electricity forward contracts are the primary instruments used in electricity market risk management to hedge market participants' positions of their portofolios.

3.3.1.2. Electricity futures

Electricity futures contracts have the same payoff structure, defined by equation (1), as electricity forwards. However, electricity futures contracts, as with other financial futures contracts, are fully standardized in contract specifications, clearing, and settlement procedures. Electricity futures are exclusively traded on the organized power exchanges, while electricity forwards are traded over-the-counter in the form of bilateral (typically EFET) transactions. Currently, electricity futures contracts are mainly settled by financial payments rather than physical delivery. An important point is that credit risk of positions closed with futures are much lower than those closed on the OTC forward market, because power exchanges (PX´s) implement strict margin requirements to ensure financial performance of all trading parties. The OTC transactions embody higher risk of financial non-performance due to counterparties' defaults. Margining of future contract, where the gains and losses of electricity futures are paid out on a daily baisis instead of one sum payment in forward trading, reduces the credit risks[10] in futures trading. In summary, the advantages of electricity futures lie in the price transparency, reduced transaction and monitoring costs, and lower credit risk profile due to margining policy.

3.3.1.3. Electricity swap

Electricity swaps are financial contracts that offer to their holders to pay a fixed/hedged price for underlying electricity contract during a contracted time period, regardless of the floating electricity price, or vice versa. Electricity swaps can be viewed as a strip of electricity forwards with multiple settlement dates and constant forward price for each settlement. The scheme of the swap is visualized by Figure 6.

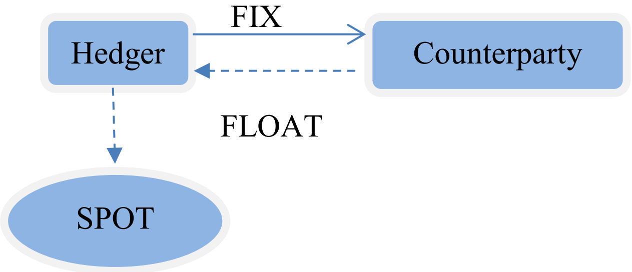

Figure 6: Electric swap scheme

3.3.2. Electricity options

The development and liberatization of the electricity wholesale markets and modern risk management techniques have led electricity option products to be based

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[10] Further described in Appendix 1

not only on the underlying price attribute (as in the case with plain vanilla electricity call and put options), but also on other attributes such as volume and fuel type (see [9] for introduction to various kinds of financial options). The following sections present a general description of a sample of electricity options that are commonly used in trading and risk management applications in the generation and power supply market. These options typically have maturity times from a month to a couple of years.

3.3.2.1. Plain call and put options

Despite the high volatility of electricity prices, demand for electrical power electricity power options is still minimal, and liquidity on the power exchanges of these power derivatives is still quite low. One of the reasons is the uncertainty about how to evaluate these electricity options and how to calculate the correct fair value of this product. Electricity call and put options offer their purchasers the right, but not the obligation, to buy or sell a defined amount of underlying electricity at a specified strike price S_t at the option maturity/expiration time. Electricity options have similar payoff structures as those of regular call and put options on financial securities and other commodities. The payoff of an electricity call option is defined by Equation 2:

Payoff of an electricity call option$= \max(S_t - K, 0)$ (2)

where S_t is the electricity spot price at time T and K is the strike price

Electricity call and put options are an effective tool available to power producers and power market participants for hedging market risk, because electricity generation capacities can be essentially viewed as call options on electricity, particularly when generation costs are fixed.

Electricity consumers use call options to place a maximum cap price that they will pay for the commodity at a specified exercise time. Market participants often use combinations of calls and puts to ensure a particular price range. Electricity producers often use put options to guarantee a minimum price of the produced electricity in conjunction with the physical sale of electricity. A model case is presented in Figure 7. A power producer could, by this product, benefit from increases in commodity prices but would avoid the risk of lower prices. Consider that the futures contract price is €43/MWh and the generator of electricity would like to receive at least this amount due to profit analysis. Therefore, the power producer has to purchase a put option, for €3/MWh, which the producer will pay for. If the price of electricity increases, the generator would sell electricity into the spot market and receive the higher spot price. If the price of electricity falls, the generator would sell electricity to the option holder for €43/MWh or sell his option at its exercise value €43/MWh on or before its expiration date.

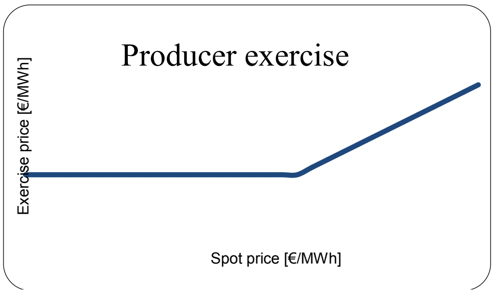

Figure 7: Producent exercise long put

A consumer is solving the opposite problem and, in the case of hedging, would use a call option to avoid the risk of higher prices while keeping the ability to participate on potentially lower prices. Consider that the futures contract price is €40/MWh, and the consumer would like to pay maximally this price. In this case, the customer would buy a call option €3/MWh, which the consumer has to pay in advance. If the price of electricity decreases, the consumer would buy electricity in the spot market. If the price increases, the consumer would buy electricity from the option holder for €40/MWh or sell his call option for its exercise value €40/MWh on or before its expiration date.

3.4. Hedging and trading

Hedging is closing a deal to reduce the risk of adverse price movements in an asset. Typically , a hedge consists of taking an offsetting position in a related commodity, such as a futures contract for delivering electricity. Conversely, trading is buying and selling electricity, generally on a short-term basis to make profits in the meaning of the speculative positions. As the electricity market becomes deregulated and more competitive, changes of supply and demand are increasingly translated into price volatility and fluctuations. A crucial driver was also the financial crisis, which had considerable impact of the changes of the stock and financial markets to the commodity markets. Considerable price volatility due to fluctuations in electricity supply and demand is visible on a daily spot market, where the price is primarily influenced by inelastic demand and short-term supply. The important link between approach of business strategy and trading strategy is the risk-management concept and risk profile of the owner of asset or investor. The key target of risk management, further described in Appendix A.1, is to eliminate such a market risk by hedging. From Appendix A.1, is obvious that risk management should be implemented completely for the entire scale of possible risks affecting the running ofbusiness. Key aspects of risk management design for the purpose of the energy business is sufficiently described in the mentioned chapter.

The main volume of electricity derivatives is not used to hedge risks connected with daily price volatility, but it is used to hedge risks associated with fundamental trend fluctuations and seasonal price volatility. Therefore, market participants often use year, quarter, and monthly derivatives described in section r 3.3. Therefore, n a competitive electricity market, daily fluctuations in spot electricity prices will be the most dramatic driver of price volatility. Two different approaches of hedging depend on the type of market participant.

1st **case: Producer** as an entity that owns a power plant has a natural "long" electricity position, and the value of this position increases and decreases with the price of electricity. When power prices increase, the value of the electricity produced increases, and vice versa.

2nd **case: An electricity consumer** is naturally "short" and in the opposite way, consumers benefit when prices fall and have to suffer loss when prices increase. Price volatility introduces considerable risks for producers, consumers, and traders (brokers). In a competitive electricity market, producers could sell some of their produced electrical power at volatile spot markets, but they indeed bear risk if spot prices are lower than generation costs. The role of the risk management of a company is to eliminate and minimize this market risk by hedging positions.

Hedging of risk by a company should be in principle motivated by the aim to maximize the firm's value. As the competitive and volatile electricity markets become liberalized, generation companies and power market participants seek certainty in their costs and revenues streams through effective hedging practices and active trading.

Such activities involve quantifying and controlling trading risks in power markets. Therefore, they require appropriate risk management tools and valuation methodology. Risk management tools and metrics are described in detail in Appendix 1. Critical risks associated with electricity hedging via futures traded at energy exchanges are cash-flow problems. This liquidity problem is outgoing from insufficient initial and variation margin for MtM ("Mark-to-Market") based on the energy exchange futures value difference between time of deal and actual market value. The result is that the intended hedging transaction reaches becomes to the speculation position after the margin call, for which is the holder is not able to pay. The second case is unhedged price risk, which results from inadequate hedging of open positions. This happens often and is associated with the volumetric risk of the portfolio, where the majority of producers and trading companies do not have accurate information about electricity consumption in real time and have to bear a cost implicated by the system imbalance.

Most electricity consumption result from the short-term conditions, and there are not enough strict plans or "take or pay" contracts that will motivate customers to consume in pace with the contracted volume. Gains and losses from hedging activities that occur in the futures market when a hedge is undertaken must be viewed as part of the electricity price that the market participant provides to its customers. The same approach has to be undertaken in the case of the options premiums. Sometimes the market player takes profit in the futures market and loses in the spot market; sometimes the reverse situation occurs. It is clear that hedging profits and losses must be treated simply as part of the cost of purchasing energy. With an imperfect hedge, the market player could earn less on its futures position than it loses between its fixed price contract and the spot market, or it could earn more.

The cash flow risk is exponentially increasing due to margin calls as the maturity of the long-term hedge increases. Risk management of utilities and energy business companies works with the assumption that the increaseof risk is faster than linear because of two reasons. The first reason is that the price volatility increases approximately in proportion to the square root of the length of the hedge. The second reason is that the amount being hedged is generally proportional to the length of the hedge because the market player will be hedging a constant volume over the time. The primary risk associated with long-term hedging is again associated with margin calls risk. As was mentiond in section 3.3, the key difference between forward and futures contracts is in the cash settlement, which is performed by the clearing bank in the case of futures. Buyer or seller of a futures contract will have to realize short-term losses or gains as the futures price changes. This cash settlement is performed daily. In the case of a forward contract, profit and loss is realized only at maturity, and there is not a cash flow problem due to the payment of variation margin. Alternatively, counterparties trading forwards on the OTC market have to prove their financial stability and solvency by bank guarantees or deposits. Another more important specific feature which could make forward less interesting for smaller business units is credit risk exposure exposition of the electricity seller. This credit risk and also market risk is, in the case of futures, solved by MtM (daily cash settlement) clearing. It is obvious that the money lost on the future is entirely regained from the added profit on the fixed price contract that was sold at the start of this example. If the loss is quite large, it may be impossible for the hedging market participants to raise the cash margins necessary to meet the variation margin requirement. In this case, the clearing bank has the right to close all open positions of counterparties. The hedging over longer periods puts traders at risk for extremely large margin calls. The consequence is that long-term hedging requires significant financial resources to meet variation margin requirements. There are many ways to hedge open position; nevertheless, in all situations consideration should be given to standardized contracts traded at energy exchange, horizon of hedge, and measure of hedge effectiveness. The hedging horizon depends primarily on liquidity of markets and typically is between one and three years.

3.5. Production hedging

The valuations model distinguishes generally between several cases of production hedging. Power plant production could be valuated in one moment with hourly priced forward HPFC and afterward compared to the possibility of hedging open position in the maximum effective way and maximal volume. Also to be considered is the short position of coal necessary to produce electricity and emission allowances. This leads to the idea of hedging dark spread or clean dark spread of production in the sense that selling electricity is confirmed in the same moment as purchase of the coal and emission allowances. Hedging could be solved by selling standard electricity products either flexibly composed from put option and forward or simply from call option. Many hedging contracts are standard tradable contracts or structured contracts. All hedging strategies basically wish to maximize profit with minimal risk. Differences will obviously occur for different fuels, as a coal-fired power plant and gas unit. Hedging production of power plant means selling electricity forwards and buying emission allowances and fuel to avoid market risk due to volatility of commodities.

The power industry has several typical segments to hedge:

1. **Heat production** – existing power plants often sell residual heat to improve their cash-flow and economic situation. This fact assumes that the power plant will not be offline for a longer period to be in a cold state afterward; in other words, it is supposed to ensure continuity of heat or cold production. The price of heat is often regulated by state authority and has to be in accordance with the regulatory framework condition realized with reasonable profit.

2. **Grid support services** – there are several types of GSS with different impacts to power plant operation. It must be distinguished between primary, secondary, and tertiary GSS by the system of market and technical specifications. GSS services are often auctioned.

3. **Standard products** – based on spark or dark spread; there is at any time possibility to evaluate closing of position and make a decision. In this case a comparison should be made of profit margin from such a trade with average costs of production.

4. **Flexibility** – similar product to GSS but offering to business counterparties, not to TSO. Similarly to GSS, there should be blocked sold flexibility capacity as a permanent state/blocked disposable output of power plant. This flexibility can be utilized after implementation of Smart tariffs and dispatching driven by traders.

5. **Spot market optimization –** linked with the real option methodology or flexibility value. The question was raised whether it is worth evaluating the entire power plant as a strip of spark spread options or if it would be better to use the plain NPV method enriched by valuation of flexibility with approach similar to real life power plant operation.

3.6. Generation plant as spark spread options

An important class of non-standard electricity options is the spark spread option. Spark spreads are cross-commodity options paying out the difference between the price of electricity sold by generators and the price of the fuels used to generate it. The amount of fuel that a generation asset requires to produce one unit of electricity depends on the asset's fuel efficiency or heat rate HR.The holder of a European spark spread call option written on fuel Pf_t at a fixed heat rate HR has the right, but not the obligation, to pay at the option's maturity the fuel price and receive the price of one unit of electricity. Thus, the payoff at maturity time *t* is represented by Equation 3:

Payoff of a spark spread call = $\max(Pe_t - HR \times Pf_t, 0)$ (3)

where Pe_t and Pf_t are the electricity and fuel prices at time *t*

Abstracting away the operational characteristics of a fossil fueled power generator (e.g. startup cost, ramping, and other technical constraints), the profit per kW of holding the right to use the generator is equivalent to having 1 kW spark spread call option with a strike heat rate matching the generator's operating heat rate. It is clear that spark spread call options play important roles in hedging the market risk of the produced electricity of coal or gas-fueled power plants and further serve as key instruments in valuing those generation assets [1]. With the assumption that the power plant can react immediately to price changes (mainly gas unit, and with some constraints also coal unit), than the cashflow of a unit will be given by Equation 4:

$$CF_{unit} = \sum_{t=0}^{N} C_i \times \max(Pe_t - HR \times Pf_t - VOM, 0) \tag{4}$$

where C_i is available capacity, Pe_t is market spot price of electricity produced, HR is the heat rate, Pf_t is the market spot price of fuel, and VOM is the variable for operation and maintenance costs. This cash flow of the unit also could be valuated as a strip of spark spread option. The value of the plant is in that case given by the appropriate risk-neutral expectation in Equation 5:

$$E_0^*[CF_{unit}] == \sum_{t=0}^{N} C_i \times E_0^*[\max(Pe_t - HR \times Pf_t - VOM, 0)] \tag{5}$$

For the simplest case, when the power and fuel prices are jointly lognormal and the VOM are zero, it is possible to use the standard formula for valuation of spread options developed by [49]**.** Detailed analysis of valuation of spark spread options in the general case can be found in [50].

Behavior of spread options can be quite complicated and have negative vegas[11]—spread option value decrease with volatility, unlike for standard options. The value of spark option is determined by joint distribution of both underlies, and this joint behavior is measured by linear correlation, which is in energy markets a challenging problem. Another weakness of this approach is missing technical constraints, which could rapidly modify the real value of the power asset.

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[11] One of the key analysis techniques utilized in options trading is the Greeks measurements of the risk involved in an options contract as it relates to certain underlying variables. Vega measures the sensitivity to the underlying instrument's volatility. Vega represents the amount that an option contract's price changes in reaction to a 1% change in the volatility of the underlying asset. Volatility measures the amount and speed at which price moves up and down, and is often based on changes in recent, historical prices in a trading instrument. Vega changes when there are large price movements (increased volatility) in the underlying asset, and falls as the option approaches expiration. Vega is one of a group of Greeks used in options analysis, and is the only one not represented by a Greek letter.

4. HPFC methodology

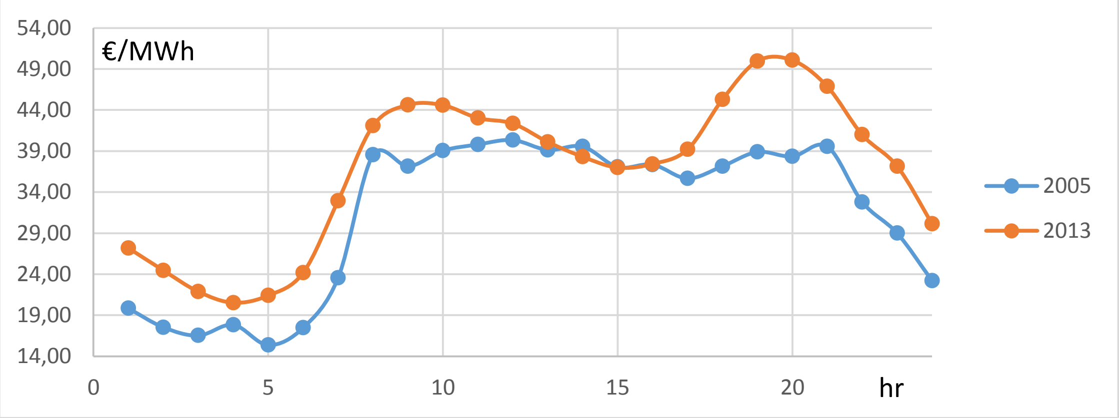
The Hourly Price Forward Curve (HPFC) is a method of hourly price profile construction based on the history of electricity spot prices. There is a lack of consensus on the requirements of reliable HPFC and quality measure, and therefore it is necessary measure quality of such a HPFC curve by comparison with the market results. Furthermore, it is favourable to compare quality of the HPFC curve by testing holiday and weekend pattern, arbitrage free condition, correct seasonal profile, and also independence from the past extreme events. Modelling of the HPCF curve works with assumptions that the one-year date-back history structure of the prices is reliable for modelling of the HPFC curve without any other impacting factors. A main purpose of the HPFC methodology is to reflect structural specifics on the market embodied from the portfolio of electricity supply and local demand behavior (with assumption of consistent weather). Most sensitive and volatile is the short-tail of the curve close to delivery realization (forward market for specific hours exists and is liquid only as a day-ahead). Incorporation of weather and load forecasts into the HPFC model make sense only for short-term HPFC. The hourly profile of HPFC carries all the information about the shape of the curve without a price level characterized by future products. The most important property of the hourly profile is the seasonal pattern. Aspects of intra-day, weekly, and yearly seasonality must be incorporated. The intra-day seasonality must incorporate peak and off-peak difference (specification of peak hours by market regulation is expected as 8:00-20:00)—it could be seen that peak hours show a considerable seasonal behavior. Another problem is incorporating holidays and bridge days/periods between holiday and weekend. It also must be defined whether the model of the HPFC curve will incorporate negative spot prices as a result of low demand and often the large supply of RES. Since the hourly profile of the HPFC curve represents the average, the profile should not show any spikes, which are the result of unexpected external impacts such as power plant shutdowns. The deployment and huge investments to RES subsidized by feed-in tariff results in structural changes in the price profile structure. In the EU countries, we consider mainly wind and photovoltaic power plants, where the impact on spot market power prices is different in the case of wind and photovoltaic power plants with production only during daylight hours. This results in a decreasing peak-base load price spread, particularly during the summer. Wind power plants in general lower the prices during the year. An important characteristic of the HPFC is that the curve is arbitration free to the future products. Since the monthly products must be arbitrage free to the quarterly product, both three monthly or one quarterly product generally can be used. The developed model further used in chapter 6 is working with HPFC curves to incorporate differences in price structures between years 2005 and 2013. The change in the structure is visible from Figure 5 in section chapter 3.2. The average spot price in the year 2005 was 31,1 €/MWh, and average price in year 2013 was 43,82 €/MWh.

The goal of the developed model is to set the artificial hourly forward curve for the year hourly profile based on the 2013 hourly price structure and set to the average price of 31,1 €/MWh to demonstrate influence of the price structure to the value of flexibility. In Figure 8 is a visible history of spot prices relating to the hour of the day for years 2005 and 2013. Data are collected from the OTE for the area of the Czech Republic. As presented in Figure 8, the structure of prices in 2005 was flatter than in 2013. The key driver of the structural change is the implementation of solar power plants into the grid.

Table 1: Average spot price of BL and PL www.pxe.com

2005		
BL	31,1	€/MWh
PL	47,36	€/MWh
2013		
BL	36,74	€/MWh
PL	55,53	€/MWh

Figure 8: Electricity spot prices 2005 and 2013, source: www.ote-cr.cz



4.1. Regression Model

The developed approach of the regression model by the author is similar and was derived from literature [39]. The author considered working with a three-stage approach instead of a two-stage approach. All drivers other than seasonal patterns were eliminated. In the first step, it is important to identify seasonal structure during a year with quarter and month prices; in the second step, identify month structure with daily prices; and in the third step, analyse the hourly structure of the specific day. The goal of this approach is to derive an hour index of spot price related to a specified hour of the year. Due to many possible variables of daily patterns, it is possible to make a reduction of daily price patterns by pooling certain days into one group, respectively; for example, every working day independently on the day and then non-working days as a Saturday, Sunday, and holidays together. The developed HPFC curve methodology doesn´t work with this concept due to possible discrepancy of daily and weekly pattern result.

The developed methodology works with 9 defined days of the week, when the 8th day is a holiday on a working day and the 9th day is a holiday on a weekend. Further methodology assumes 13 months to separate, where the 13th month is assigned to holidays (day 8 and day 9). In other words, there are a standard number of 7 days of the week, and holidays are the 8th or 9th day of the week. Due to an increased number of months, the model works with implementation of a 5th quarter. This allow capturing of holidays separately. Nevertheless, a discrepancy could occur between the specific number of holidays for every year, which are not consistent on a year- to-year basis. All indexes are calculated for peak load (“PL”), off-peak (“OP”), and baseload (“BL”) pattern.

Calculation of Quarter Index $I_{Q_{n,p}}$ defined by Equation 6 as average of spot hours due to specified pattern of defined quarter divided by year average of specified pattern.

$$I_{Q_{n,p}} = \frac{\sum_{hq \in Q_{n,p}} \frac{S_p(hq)}{hq_n}}{\sum_{hy \in Y_p} \frac{S_p(hy)}{hy_n}} \tag{6}$$

Variables $S_p(hq)$ and $S_p(hy)$ represent spot price in specified hour of defined quarter or year, ***n*** is the number of quarter, and ***p*** represents the type of pattern (peak load, base load, off-peak). Variables hq_n and hy_n are numbers of hours in defined quarters or year. Quarter indexes $I_{Q_{n,p}}$ allow calculation of quarter prices as a multiple of index and price of year contract traded. $I_{Q_{n,p}} \times Py_{product}$

Calculation of Month Index

$$I_{M_{n,p}} = \frac{\sum_{hm \in M_{n,p}} \frac{S_p(hm)}{hm_n}}{\sum_{hq \in Q_{n,p}} \frac{S_p(hq)}{hq_n}} \tag{7}$$

Month index is defined by Equation 7, where variable $S_p(hm)$ is the spot price in specified hour of defined month or year, ***n*** represents the number of quarter, and ***p*** is the type of pattern (peak load, base load, off-peak). Variables hq_n and hm_n represent the numbers of hours in defined quarters or months. With month indexes $I_{M_{n,p}}$ it is possible to calculate month prices as a multiple of index and price of quartal contract traded or calculated: $I_{M_{n,p}} \times Pq_{product}$.

Calculation of Day Index

$$I_{M_{n,p},D_{n,p}} = \frac{\sum_{hd \in M_{n,p},D_{n,p}} \frac{S_p(hd)}{hd_n}}{\sum_{hm \in Q_{n,p}} \frac{S_p(hm)}{hm_n}} \tag{8}$$

Day index is defined by Equation 8, where variable $S_p(hd)$ is the spot price in specified hour of defined day of month, ***n*** represents the number of months or days, and ***p*** is the type of pattern (peak load, base load, off-peak). Variables hq_n and hd_n are the numbers of hours in defined days or months. With day indexes $I_{(M,D)_{n,p}}$ (in the developed model at least 252 indexes – 12 months x 7 days x 3 patterns), it is possible to calculate day prices as a multiple of index and price of month contract traded or calculated: $I_{(M,D)_{n,p}} \times Pm_{product}$.

Calculation of Hour Index

$$Ih_{M_{n,p},D_{n,p},H_{n,p}} = \frac{\sum_{h \in M_{n,p},D_{n,p},H_{n,p}} \frac{S_p(h)}{h_n}}{\sum_{hd \in M_{n,p},D_{n,p}} \frac{S_p(hd)}{hd_n}} \tag{9}$$

Hour index is defined by Equation 9, where variable $S_p(h)$ is the spot price in specified hour of defined day and month and pattern, ***n*** is the number of hours or days, and ***p*** represents the type of pattern (peak load, base load, off-peak). Variables h_n and hd_n are the numbers of hours in defined hours or days. With day indexes $Ih_{M_{n,p},D_{n,p},H_{n,p}}$ (in the developed model at least 2016 indexes – 12 months x 7 days x 3 patterns*8 hours), it is possible calculate spot prices, respectively, for the HPFC curve using Equation 10, as a multiple of index and price of month contract traded or calculated.

$$HPFC_t = Ih_{M_{n,p},D_{n,p},H_{n,p}} \times P_{product} \tag{10}$$

In Table 2 and further in Appendix A.2 is an Excel spreadsheet with the outputs.

Table 2: Example of HPFC indexation

D	H	Spot price (EUR/MWh)	Spot price(CZK/MWh)	FX rate CZK/EUR (ČNB)	M	Day of Week	Day of Week	Day of Year	Q	PL/OP/BL	Holidays Y/N	Index	Price HPFC (CZK/MWh)
01.01.2013	1	-0,75	-18,86	25,14	13	2	8	1	4	0	1	0,549	119,571
01.01.2013	2	-25,00	-628,50	25,14	13	2	8	1	4	0	1	0,119	25,968
01.01.2013	3	-55,00	-1 382,70	25,14	13	2	8	1	4	0	1	-0,405	-88,281
01.01.2013	4	-30,04	-755,21	25,14	13	2	8	1	4	0	1	-0,579	-126,150
01.01.2013	5	-30,09	-756,46	25,14	13	2	8	1	4	0	1	-0,619	-134,800
01.01.2013	6	-25,52	-641,57	25,14	13	2	8	1	4	0	1	0,036	7,810
01.01.2013	7	-20,00	-502,80	25,14	13	2	8	1	4	0	1	0,263	57,302
01.01.2013	8	-20,00	-502,80	25,14	13	2	8	1	4	0	1	1,724	375,407
01.01.2013	9	-16,94	-425,87	25,14	13	2	8	1	4	1	1	0,975	788,545
01.01.2013	10	0,00	0,00	25,14	13	2	8	1	4	1	1	1,044	844,310
01.01.2013	11	0,01	0,25	25,14	13	2	8	1	4	1	1	1,052	850,374
01.01.2013	12	2,22	55,81	25,14	13	2	8	1	4	1	1	1,073	867,451
01.01.2013	13	9,48	238,33	25,14	13	2	8	1	4	1	1	0,992	802,166
01.01.2013	14	13,07	328,58	25,14	13	2	8	1	4	1	1	0,927	749,401

The key question of this approach is the problem of different numbers of holidays in the specified years. Respectively, the HPFC curve is modeled from the data of previous years with different structure and length of holidays. That is why the average of HPFC prices could differ from the base-load contract price. Testing of relevant variants in the developed model shows that this difference is lower than 0,1% and therefore is insignificant. According to [39], this approach could be upgraded by incorporating the impact of weather forecast. Chapter 6 of this thesis presents a demonstration of key differences of the power plant profit optimalization between years 2005 and 2013. The author also uses comparison of the HPFC for the year 2013 modeled from the history of year 2012 spot prices and real prices to prove that HPFC methodology has satisfactory results.

Table 3: Differences of HPFC vs. real data

Difference	***Frequency***	**% of the sample**
1%	956	11%
5%	665	48%
10%	266	70%
15%	134	80%
20%	72	85%
25%	74	89%

From Table 3, it is obvious the result of the HPFC curve modeled from the year 2012 spot market prices and the real spot prices of the year 2013. Figure 9 presents a logarithmic histogram of differences by frequency from the main sample. Based on presented comparisons and statistics, the developed methodology of the HPFC curve can be considered to be reliable for the purpose of the electricity load and linear product valuation.

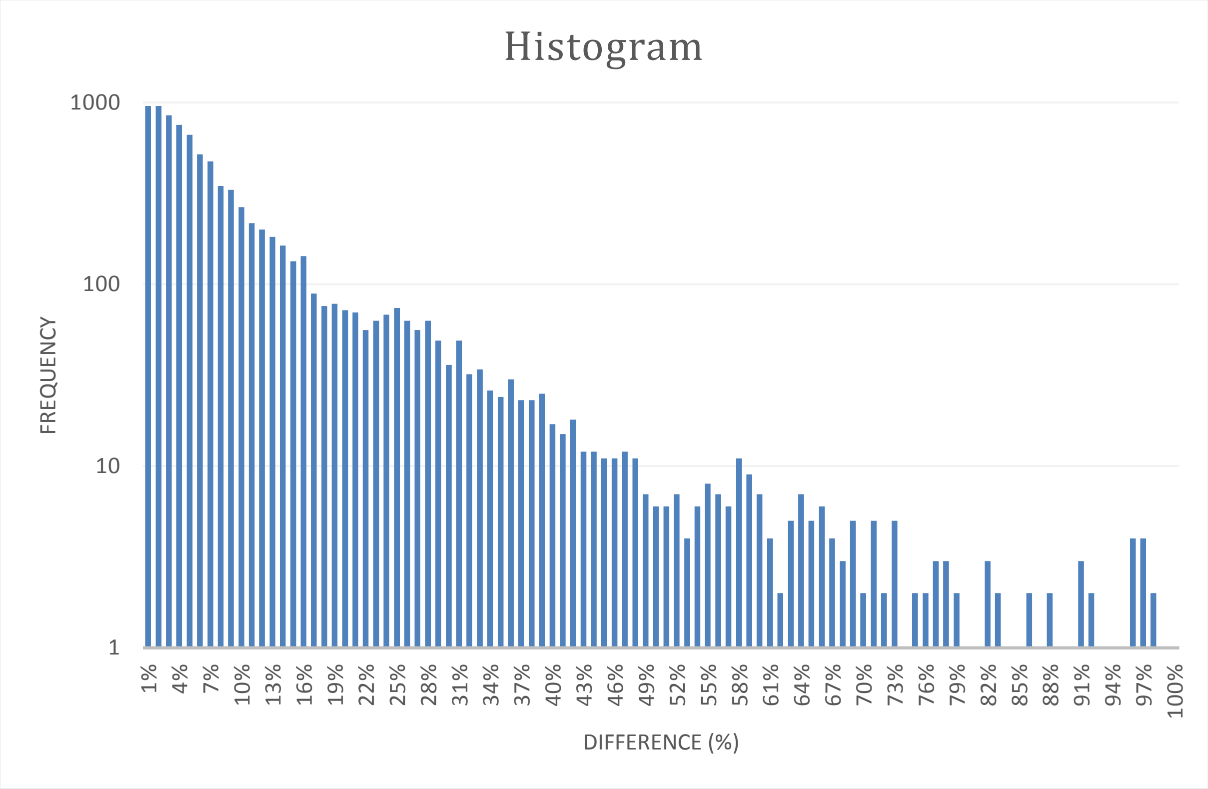


Figure 9: Histogram of HPFC differences

5. Valuation methods, basic concept of DCF, and real options

With the introduction of competitive and liberalized electricity markets and EU regulatory framework, power plant investment analysis has become an important issue for electricity companies. Since the time when Professor Stewart Myers mentioned the term of real options in his paper observing the valuations of investment as a call option on real assets, many researchers have accepted investment opportunity under uncertainty by using a real options approach. The application of the concept of real options theory (ROT) has been extended from natural resources investment to a wide range of investment problems and situations. Today, the real options theory has been widely accepted as an important and innovative tool for asset valuation. The ROT argues that it could avoid downside scenarios of an investment and maintain the upside scenarios with profit by responding appropriately to the outcome of the invested project. This is also a key way in which the ROT is different from the traditional discounted cash flow (DCF) method.

The DCF concept, described here in further detail, assumes that the investor has to accept all the possible outcomes of a project once the investment has been decided and views an investment as a "now-or-never" opportunity. In real options theory, the investor may wait for some time until additional important information validates the investment commitment. The energy industry has a couple reasons to use real options applications. Typical examples are an oil field development and a power plant investment due to very high investment expenditure calls for reliable valuation and decision-making tools. The second, and very important, reason is the existence of certain types of operational flexibilities, which are the sources of option values that are incorporated in energy assets. The real options theory could fit very well into the valuation of power plant investment opportunities due to the operational flexibility and the opportunities to invest in power plants. A base-load power plant can be considered as a string of forward contracts, and the peak-load power plant can be regarded as a string of call options on spark spreads. When valuing a power plant or power plant investment opportunities, the typical calculation is based on the electricity prices and fuel prices with the specification of certain heat rates. This reduces valuation to a real options problem with the underlying variable following an Arithmetic Brownian motion process. In a classic real options framework, the theoretical thresholds to invest in a base-load power plant, to upgrade a base-load into a peak-load power plant, can be derived.

The goal of this thesis is to capture development of an energy market in the valuation of energy assets. Due to literature sources [1],[10] and [9], it could be considered that real options are a relevant method for energy asset valuation but with considerable limitations. The concept of real options represents the concurrence concept to “classical” NPV method and decision criterium. The market situation is constantly changing. Therefore, the decisions for some market participants according to economic impacts would be different every time. When some market participants have the possibility to decide often, and simultaneously could change their minds in a short time with little costs, this represents the suitable situation for the real options decision process. This provides higher flexibility of the decision process based on real options. It is important to mention that real options can serve not only concurrent to NPV, but also can serve as complement. Some decisions could be made based on the classical NPV approach, and real options could serve for future decision flexibility enhancement. Let us suppose some photovoltaic power plant. The very first decision about investment could be done according to the classical NPV model. Option to delay could be used afterward for the decision process of some following investment (e.g. accumulation device). This option to delay will serve, with regard to market conditions, to find the most appropriate time for this investment. Another following real option decision process could be option to expand. This expansion could be enlargement of accumulation capacities in the way to use buying of cheap off-peak electricity and selling it under the peak conditions. In this case, these following options are indeed compound options.

Pros and cons of both valuation approaches are addressed further. First, a financial model of the project must exist, because real options analysis requires, the same as for NPV, the use of discounted cash-flow. Second, specific uncertainties must exist; otherwise, the option value is worthless. If everything is determined in advance, then a discounted cash-flow model gives relevant results. These uncertainties have to affect decisions and therefore will become risk—then real options can be used to hedge the downside risk and take advantage of the upside uncertainties when management must have strategic flexibility and ability to execute options. In the case of a power plant unit, we experience several uncertainties such as market prices of electricity, and fuel and emission allowances. Traditional valuation methods assume that the investment is an all-or-nothing strategy and often do not incorporate managerial[12] or market flexibility[13] that exists.

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[12] Managerial flexibility in the sense of hedging strategy and capacity planning. Furthermore, it is the ability of the management of a company to make investment decisions and production decisions based on current market conditions.

[13] Market flexibility in the sense of the available capacity to participate on balancing, GSS, or intra-day market.

Key advantages of the DCF concept are that this is a relatively simple method; it is widely accepted; it is clear; and it works with consistent decision criteria for all projects. DCF gives the same results regardless of risk preferences of investors and is not vulnerable to accounting conventions (depreciation, inventory valuation). In a stochastic world, such as an energy sector, using deterministic models such as the discounted cash flow (DCF) may potentially underestimate the value of the project. This model does not include any value in operational flexibility that could be the cause of the underestimation. The classical concept of NPV embodies the following disadvantages:

- Investment (independently in the meaning of recovery and renovation of current assets or enlargement of business) decisions are made now, when cash flow streams are fixed for the future. In reality, not all decisions are made today, as some may be deferred to the future, when uncertainty of particular solutions becomes manageable and resolved. The developed method partly solves this problem by simulating hourly structure of long-term electricity contracts when the optimization is behaving as forward looking with the maximal profit criteria.

- Once launched or acquired, all units are “passively” managed,and a respective hedging strategy is fixed in the business plan. Conversely, power plant units and possible expanding projects have to be actively managed through project or asset life cycle.

- DCF support valuation with relevant results in the case when future free cash flow streams are all highly predictable and deterministic, but in the case of power plant unit it may be difficult to estimate future cash flows as they are usually stochastic and risky in nature.

As was described in section 1.1, the goal of this thesis and the author´s hypothesis, the classical NPV method is expected to underestimate valuation of energy asset. Alternatively, with regard to the previous valuation methodic assessment, real option theory is not suitable for the case of incorporating value of operational flexibility of the power plant due to disregarding technical specifics (especially non-linear heat rate curve) of the operating power plant. Therefore, the author developed a modified methodology of NPC calculation with incorporation of power plant operation optimization.

5.1. Real options

Real options are used primarily for valuation of certain decision processes. It is based on analogy between some decision processes and financial derivative derivate options. In financial and economic theory, real options apply call and put option valuation techniques to investment decisions. A real option is a right to undertake some business decision. Real options are based on mathematical techniques, developed for financial options. Real option techniques could be also combined with standard techniques as a net present value (NPV), for example.

Nevertheless, the standard project valuation technique NPV ignores the flexibility of a project, and NPV therefore assumes that there is no chance to change the project during its life. Real options methods are working in the opposite way, implicitly assuming the possibilities of modifying the project as necessary.

Real options can be distinguished into a few groups:

- **Option to wait with investment**. This option is represented by the American call option. This option method could delay the investment activity.
- **Option to abandon project**. This option is represented by the American put. This method could help with the decision process on whether or not to abandon the project.
- **Option to expand (contract) project**. This method is represented by the American call (put) option. In case of more decision points, the characteristic could change into the Bermudan option.
- **Option to switch**. This method evaluates a possibility of switching between different types of inputs (e.g. various types of fuel).
- **Compound option**. This option is represented by a combination of various mutually following options.

5.2. NPV calculations methodology

The methodology of classical NPV calculation is modified by incorporating the optimization function. Let us sum up the comprehensive approach of net present value. The following equations (11-13) describe the basic calculation approach of enterprise appraisal, or simply project valuation. In the basic principle, the net present value method sums up the present value of free cash-flow FCF_t during the lifetime of the asset. The present value of the cash-flow is influenced mainly by the discount rate ($WACC$) and resulting time value. The appraisalprocess generally considers the principle of going concern and value asset as incorporating the terminal value ($Tvalue$). The author´s methodology does not consider this part of the valuation and assumes that it does not change.

$$NPV = \sum_{t=1}^{T} \frac{FCF_t}{(1+WACC)^t} \tag{11}$$

$$Tvalue = \frac{FCF_n(1+g)}{(WACC-g)} \, or \, \frac{FCF_n}{WACC} .. \tag{12}$$

$$WACC = w_d k_d (1-tax) + w_e k_e \tag{13}$$

Equation 12 assumes that the WACC rate must be greater than g (assumes constant growth rate to perpetuity). Free cash flow that is influenced by market risk should be discounted at the market risk-adjusted rate (usually depends on market demand market prices, etc.), while cash-flows that have private risk should be discounted at the risk-free rate because the market will only compensate the firm for taking on the market risk. Operational WACC calculation is followed by Equation 13, where the variable w_d is percentage weight of financing by debt and w_e is percentage weight of financing that is equity. Furthermore, variable k_d stands for cost of debt, and k_e is the variable which represents cost of equity, further solved by capital asset pricing model with Equation 14. Cost of the equity is the return that the stockholder requires for a company and represents the compensation that the market demands in exchange for owning the asset and bearing the risk of ownership.

$$CAPM : k_e = k_{rf} + \beta(k_m - k_{rf}) \tag{14}$$

Equations 13 and 14 include following variables:

1. **Risk free rate** k_{rf} is the theoretical rate of return of an investment with hypothetical zero risk (for instance, U.S. treasury 30y yield), and this rate also represents the required interest an investor would expect from an absolutely risk-free investment related to a specified time period. In the case of using different risk free rate from the location of valuated project, it must be incorporated, as well as country risk premium[14].
2. **Unlevered Beta** β is a specific metric that compares the risk of an unlevered company without debt to the risk of the market. This rate provides information regarding how much systematic risk a firm´s equity has in comparison to the market. In financial assets, it is possible to calculate beta through covariance between a firm´s stock prices and the market portfolio, divided by the

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[14] Country risk premium is additional risk associated with investing in an international project or company rather than the local market. Volatile exchange rates (incorporating interest rates different than forward rates), economic growth rate, political stability, and other macroeconomic factors cause investors to require a premium for investing in such a country.

variance. Beta is therefore the sensitivity factor of co-movements of equity prices due to the market (this calculation can lead to very volatile beta figures). Nevertheless, Beta cannot be calculated in this way for nontraded physical assets.

3. **D/E Ratio** – The debt-to-equity ratio indicates the relative proportion of a shareholder´s equity and debt used to finance an operation of a company or its assets. This ratio is often calculated based on figures from the firm’s balance sheet, but it also may be calculated from the market values of both components. Debt typically includes only the long term debt (interest-bearing). (The composition of equity and debt and its influence on the value of the firm is described in the Modigliani-Miller theorem. A high D/E ratio means that a company is aggressive in financing its operation with debt. This can result in higher credit risk of such a company. Beta levered is the beta reflecting a capital structure that includes debt.

4. **Market risk premium** $(k_m - k_{rf})$ is the difference between the expected return on a market portfolio and the risk-free rate; it is equal to the slope of the security market line (“SML”) defined by capital asset pricing model. This market risk premium could be considered as a required, historical, or expected market premium.

The discount rate is generally calculated from a WACC[15] based on the capital asset-pricing model (“CAPM”)[16]. Discount rate is a sensitive variable and is very tricky to set up. One of the WACC inputs is the cost of own equity that is usually derived by using the CAPM model, with which it is very difficult to calculate beta β. Once an unlevered beta is estimated, the cost of equity (k_e) can be solved using the CAPM. Figure 10 is an illustrative scheme of weighted average cost of capital (“WACC”) and NPV calculation. Valuation of the energy asset in chapter 6 is realized as the firm or the entity value (further described in section 5.4). Therefore, methodology further works with free cash-flow to the firm $FCFF_t$ concept defined by Equation 16 and literature [54]. Free cash-flow to the firm (Equation 15) results primarily from cash-flow from operations and investments in fixed capital (CAPEX).

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[15] Weighted Average Cost of Capital (WACC). The cost of capital (discount rate) determined by the weighted average, at market values, of the cost of all financing sources in the business enterprise's capital structure.

[16] Capital Asset Pricing Model (CAPM). * A model in which the cost of capital for any stock or portfolio of stocks equals a risk-free rate plus a risk premium that is proportionate to the systematic risk of the stock or portfolio.

The mentioned concept of the firm value is further visualized in Figure 10.

$$FCFF_t = CF_{op} + CF_{inv} \tag{15}$$

$$FirmValue = \sum_{t=1}^{T} \frac{FCFF_t}{(1+WACC)^t} \tag{16}$$

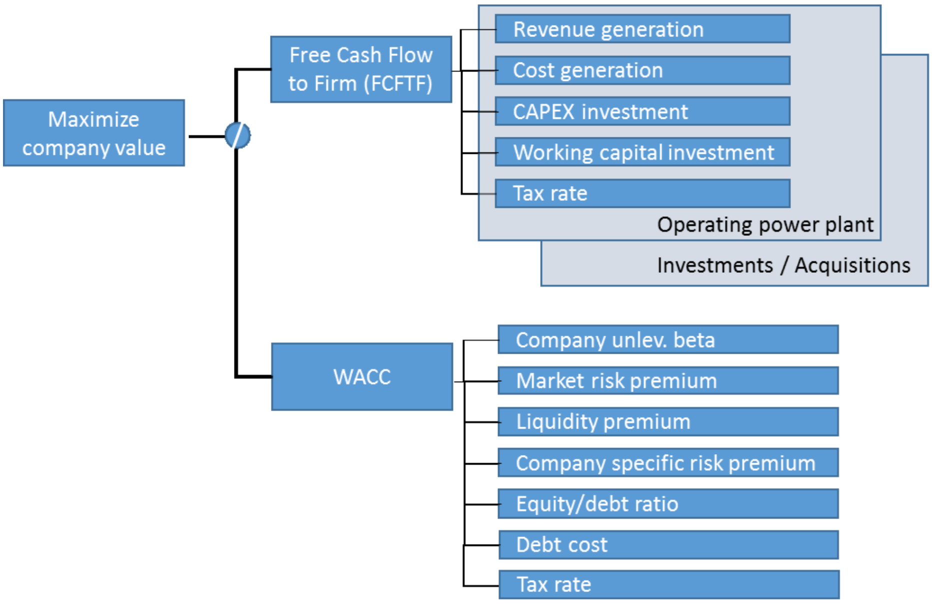

Figure 10: Company value scheme

Forecasting cash flows many years into the future is often very difficult and requires strong analytical background and experience. A recommended method is not to create a one-point cash flow prediction but to run more scenarios or use Monte Carlo simulation and assess the relevant probabilities with a specific discount rate. The issue of terminal value is a crucial component of a discounted cash flow model. Several methods of calculating terminal values exist, including the Gordon constant growth model (GCM) and zero-growth perpetuity represented by Equation 12. The GCM is calculated as the free cash flow at the end of the forecast period multiplied by a relative growth rate, divided by the discount rate less the long-term growth rate. This growth rate works with fixed rate, and the terminal value is obviously highly sensitive to this growth rate assumption.

5.3. DCF concept with implemented optimization

In this chapter is defined the model income statement of a thermal power plant prepared for the purpose of the business model evaluation. Main components of revenues are power and heat sales, revenues from system services (GSS), and state subsidies. It is obvious that the reported gross margin is the difference between sales/revenues and costs related to the core business (fuel and transport costs, etc).

In further analysis, this difference could be used to valuate spark spread or dark spread in accordance to analysis of the difference between price of electricity and fuel (fuel costs calculated from efficiency rate/heat rate and fuel price). In the case of clean dark spread calculation, also incorporated are costs for CO_2 emission allowances. It is obvious that the often used factor, clean dark spread (also “CDS”), incorporates key components of gross margin, and that is the primary motivation for modelling CDS and evaluating its impact to profitability of project. As further mentioned, emission allowances are a critical point of energy asset evaluation due to their regulatory character and price stochastic behaviour. Modeling and valuation of CDS incorporating the modern approach of electricity load valuation by the HPFC curve, consistently with optimization that considers technical specifications of the power plant is the main goal of this thesis. It is assumed that there are also personnel costs, operation and maintenance costs, and other costs, but they are easily captured and their development is much less stochastic and unpredictable, as in the case of gross margin or CDS. Table 4 represents a typical income statement for powet asset.

Table 4: Income statement

Income Statement			Row No.
1	SALES	(r2+r3+r4)	1
		Total Power & Heat Sales	2
		GSS Revenue	3
		Revenue through electricity subsidy (biomass cofiring, etc.)	4
		Fuel costs (Lignite, black coal, gas, biomass, oil)	5
		Other fuel related costs (Cost of Limestone , fuel transport, cost of ash-off take)	6
		CO2 costs	7
		Power purchase costs	8
		Other variable costs (Enviromental fees, river water, etc.)	9
2	GROSS MARGIN (r1 - r5-r6-r7-r8-r9)		10
		O&M costs (operation and maintenance)	11
		Materials and services	12
		IT costs	13
		Personnel costs	14
		Net other op. inc./exp.	15
3	EBITDA (r10-r11-r12-r13-r14-r15)		16
		D&A (Depreciation and Amortization)	17
4	EBIT (r16-r17)		18
		Net financial result (Interest paid etc.)	19
5	EBT (r18-r19)		20
		Tax	21
6	NET INCOME (r20-r21)		22

Regarding comments of the enriched NPV method by the optimization, the valuation model has to separate traditional EBITDA, with respect to CF, into two components, as mentioned. The developed methodology separates part of inputs valuated by optimization algorithm $EBITDA_{opt}$ (revenues, variable costs, and part of fixed costs independent of the volume of production) and the remaining items of income statement $EBITDA_{res}$. For the purpose of the cash-flow calculation methodology, assume that $EBITDA_{tot} = EBITDA_{opt} + EBITDA_{res}$ (17)

Inputs for optimization model resulting in $EBITDA_{opt}$ are the following:

1. Total Power & Heat sales (r.2) – Case study consider only GSS services[17] and power production as a standalone, without considering any residual heat produced[18] and state subsidies[19].
2. Fuel costs (r.5) – Fuel costs are involved in optimization algorithm by implementation of heat rate function.
3. Other fuel related cost (r.6) – (limestone, fuel transport, cost of ash-off take) are solved by linear function related to the amount of burned fuel in tonnes, respectively in GJ.
4. CO2 costs (r.7) – Linear function, CO_2 factor related to the type of fuel (coal, lignite, gas)

In the optimalization method are not considered any power purchase costs or other variable costs. The above inputs are evaluated in the optimization algorithm, and the output, $EBITDA_{opt}$, considers all technical specifications (further described in chapter 6) of the unit and current market prices of futures contracts indexed by the historical distribution to spot prices (HPFC). The cash-flow model statement defines calculation of free cash flow after debt service. Nevertheless, the author´s methodology considers accurate thec firm value concept regarding free cash-flow to the firm (Equation 15). Impact of operations and investments to the cash-flow to the firm is solved using Equation 18. Variables $CF_{op}, CF_{inv}, CF_{fin}$ are defined further in Table 5. Nevertheless, firm valuation methology will incorporate only variables of cash-flow from operations and CAPEX.

$$FCFF_{t,OPT} = CF_{op} + CF_{inv} \qquad (18)$$

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[17] Methodology considers specific character of GSS services for TSO. The GSS concept is based on the reserved power capacity of the unit prepared during specified period for possible starts initiated by TSO. GSS revenues are payed for reserved capacity in MW and than separately for strike price.

[18] We could consider residual heat as an upside benefit of power producing where the unit is designed as a condensation turbine.

[19] Potential subsidy is related to the power produced from the ecological unit, for example biomass unit or biomass co-firing.

For the purpose of developed model valuation, CF_{op} is set as:

$$CF_{op} = EBITDA_{opt} + EBITDA_{res}; t \in (0; t_{tradableCA}) \tag{19}$$

$$CF_{op} = EBITDA_{t,PRE}; t > t_{tradableCA} \tag{20}$$

Table 5: Cash Flow Statement

Cash Flow Statement	**Row No.**
1 EBITDA(2 components)	1
Working capital changes	2
Change in ST assets / liabilities (other short-term liabilities change - other current asset change)	3
Taxes paid	4
2 CF from operations (CF_{op})	5
Capex	6
3 CF from investments (CF_{inv})	7
Change in share capital (Equity drawdown/decrease)	8
Repayment third party debt (Bank loan drawdown/repayment)	9
Change in shareholder loan (drawdown/repayment)	10
Interest paid (net)/net financial result	11
Other financial expenses (net)	12
4 CF from financing (CF_{fin})	13
FCF after debt service (r1+r5+r7+r13)	14
Actual dividend paid	15
Increase / (decrease) in cash	16
Cash at start	17
5 Cash at end	18

Components of working capital change structure are defined below:

Table 6: Changes in NWC

Changes in NWC	**Row No.**
Inventory (Sales-Gross margin) x Days Inventory / 365	1
Days Inventory	2
Accounts Receivable (Sales x Days Receivable/365)	3
Days Receivable	4
Accounts Payables (Sales-Gross margin) x Days payable / 365	5
Days Payable	6
Net Working Capital (r1+r3-r5)	7
Working Capital Changes (y/y)	8

This well-known method of NPV is described in detail in the previous chapter. However, it is necessary to further develop this method by incorporating "plug-in" of optimalization part $EBITDAt,_{opt}$ which is involved for the period $t_{tradableCAL}$ of tradable contracts at energy exchange. A further important step in discounted cash flow valuation is determining relevant cash-flow and revenue development for the non-tradable period involved in the valuation model as $EBITDA_{t,PRE}$. Determination of relevant cash-flow is often a big challenge for companies due to the many unknown drivers, such as a stochastic and unpredictable market development, or accounting methods. It must be considered that estimation of future cash-flow is based also on expected changes in operating costs, taxes, and working capital. Another key issue is discount rate and the method of its calculation. The assumption is that all these factors are in the methodology set as constant in ceteris paribus.

The modification of net present value equation is defined by the following equations:

$$FirmValue_{OPT} = \sum_{t=1}^{T} \frac{FCFF_{t,OPT} + FCFF_{t,PRE}}{(1+WACC)^t} \tag{21}$$

where

$$\begin{aligned} FCFF_{t,OPT} &= CF_{t,op} + CF_{t,inv}; t \in (0; t_{tradableCAL}) \\ FCFF_{t,PRE} &= CF_{t,op} + CF_{t,inv}; t > t_{tradableCAL} \end{aligned} \tag{22}$$

This traditional DCF concept could be developed for the purpose of calculating the NPV of a thermal power plant, where specific parts of inputs are replaced by developed optimized energy revenue streams and separate traditional NPV models into 2 parts:

1. $FCFF_{t,OPT}$ is the cash-flow output from the production of electricity production incorporating HPFC curve methodology with production optimization model. This production optimization model also considers technical parameters of the power plant, including efficiency curve. Therefore, the cash-flow output is the difference between electricity produced and cost for the fuel (coal) fired[20] and emission allowances.
2. Part: $FCFF_{t,PRE}$ is the cash-flow output from the prediction of electricity production based on available prediction methods.

It is very important to mention that the cash flow concept based on EBITDA remains the same. The separation of $EBITDA_{t,opt}$ "Energy revenues stream" is accomplished in the "income statement".

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[20] Revenue generation – cost generation – emission allowance, in other words cash-flow from CDS.

5.4. Basic concept of enterprise valuation

Regardless of valuation method, it is important to distinguish significant differences between value standards and measures of value. As a first step, it is necessary to define enterprise as a specific activity to realize profit and as a specific complex of tangible and intangible assets which serve the purpose of current and future business activity. In the further developed case study presented in chapter 6, methodology assumes that the power plant unit including boiler/steam generator, turbine, and generator is the part of the asset which serves to produce electricity and heat to keep the purpose of the business plan.

It is critical to distinguish between three key measures of value:

1. **Equity value** - as the market value of equity measures the difference between the market value of all assets and the market value of debt. Typical M&A offer sets this value at the price for 100% interest in company with the consideration of debt repayment, etc. Equity value scheme is visualized in Figure 11.

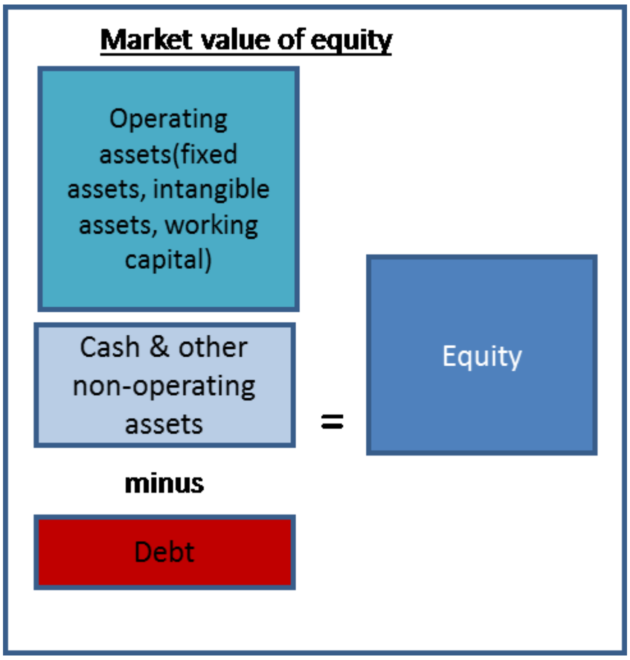

Figure 11: Equity value

2. **Firm value** - the sum of the market value of equity and the market value of debt. The market value of the firm measures the market's assessment of the values of all assets. The firm value concept is visualized in Figure 12.

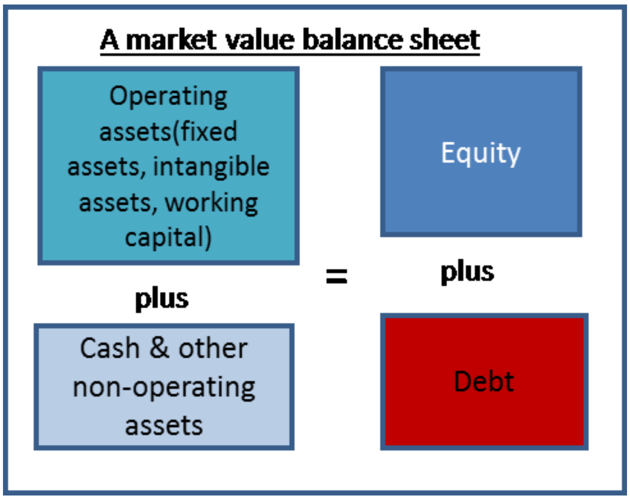

Figure 12: Balance sheet value

3. **Enterprise value** - market value nets out the market value of cash & other non-operating assets from firm value to arrive at enterprise value. With the balance sheet format, you can see that enterprise value should be equal to the market value of the operating assets of the company.

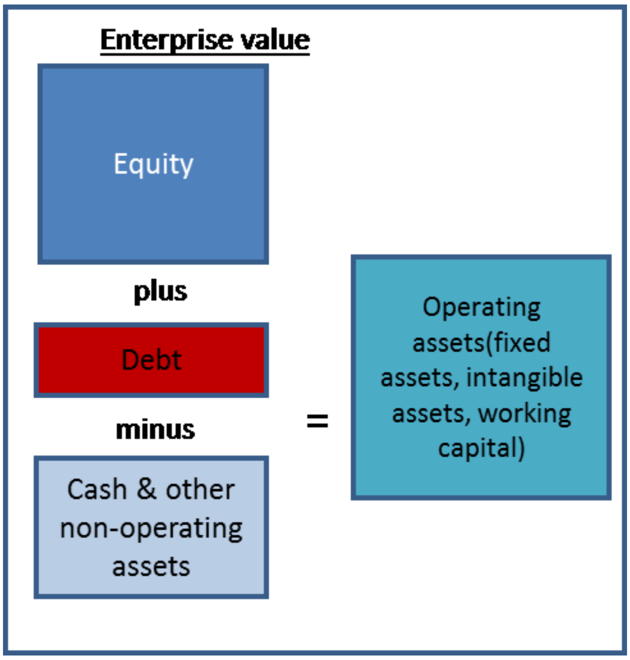

Figure 13: Enterprise value

Debt – The firm and enterprise values of a company should reflect the market value of all debt claims on the company, but in practice, this is almost never possible for two reasons: considered debt is non-traded or it is partly off-balance debt (bank guarantees).

Cash – methodology distinguishes between operating versus non-operating cash: there are two problems in making this distinction between operating and excess cash. The first is that operating cash needs will be different across different businesses, with some businesses requiring little or no operating cash and others requiring more. The second is that cash needs are changing over time due to business counterparties credit risk requirements and margin-calls of energy exchanges, as discussed in chapter 3 regarding market conditions and specifics of the energy industry.

5.4.1. Valuation standards commonly used by appraisals

For further discussion, it is important to set up a consistent appraisal framework which is presented in accordance with developed methodology of energy asset valuations. Business valuation is a process of determining the value of a business enterprise. During the preparation of business valuation, assets must be defined with the following specifications:

- Intended users (shareholders, creditors, etc.) and the purpose or intended use of the appraisal (buy vs. sell)
- The business enterprise to which the valuation relates and the type of entity (e.g. corporation, limited liability company, partnership or other)
- The standard of value applicable to the valuation (e.g. fair market value, investment value, or other)
- The premise of value (e.g. going concern[21], liquidation[22], or other)
- The level of value (e.g. strategic control, financial control, marketable minority, or nonmarketable minority) in the context of the standard of value, the premise of value, and the relevant characteristics of the interest
- The effective (or "as of") date of the appraisal
- Any extraordinary assumptions used in the assignment

5.4.2. Value standards

Appraisal standards distinguish primarily between different views of potential investors with the intent to develop strategic position and synergy effects, and obvious fair market value for the purpose of tax institutions and accounting.

1) **Fair market value**

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[21] Going concern is the assumption about the status of the business considering that the business is without threats or discontinuance.

[22] Liquidation value means the net amount that can be realized if the business is terminated and all assets sold.

This value standard is the most widely recognized and accepted, and it is also used as the legal standard. It is simultaneously universally accepted as a cash-equivalent or price at which property would be traded between willing seller and willing buyer, both being adequately informed of the relevant facts and neither being compelled to buy or sell. This concept assumes prevalent economic and market at the date of valuation. Machinery and equipment can be valued with “fair market value in place” considered as a part of total operating facility or plant. Typically it is assumed that the assets return would economically justify the investment into facility.

2) Investment value

This value is based on expected earnings or return to an investor and therefore on individual investment requirements. Market value and investment value coincide when an investor’s criteria are consistent with those that are typical in market. Investment value is personal and subjective. There are many cases and reasons for the investment value to one owner to be different from the fair market value:

- Difference in estimates of future earnings and cash-flow
- Difference in taxes
- Difference in perception of risk
- Synergies with other assets

Discounted cash flow of case study project is essentially oriented toward developing an investment value. Whether or not this value represents fair market value depends obviously on the assumptions—and whether would be accepted by a market.

5.4.3. Business and financial analysis

The appraiser shall analyse and adjust the relevant information necessary to perform a valuation relevant to the character of the business. Such information regarding core business typically shall include the following:

- Characteristics of the business entity (including rights and obligations, factors affecting control, and agreements restricting sale or transfer)
- Historical results and outlook of the business and relevant industries with substantial impact on the business. In the case of the energy industry, it is necessary to capture historical results of revenues from electricity, heat, and GSS.
- Historical financial information (balance sheet, income statement, and cash-flow statement) of the business. Financial statements should be analysed and, if appropriate, adjusted. Data analysis and further discussion of a company's financial statements is an important part of a business valuation. Any adjustments in financial business plan made to the reported historical financial data must be satisfactorily explained.
- Economic and market factors affecting the business. In the case of a thermal power plant, these factors must be considered mainly regulatory framework and key market factors affecting the revenue stream as an electricity price, and fuel and emission allowances prices. It is also very important to analyse and forecast properly electricity supply and demand development in the specified area, incorporating the influence of the joint market with interconnections.
- Capital markets providing relevant information; e.g. available rates of return on alternative investments, relevant public stock market information, and relevant merger and acquisition information.

5.4.4. Valuation approach

A valuation approach is the methodology used to determine the fair market value of a business. The most common valuation approaches are the asset-based approach, the market approach, and the income approach.

1) Asset-Based Approach

The asset-based approach is a common way of determining a value indication of a business based on the value of the assets net of liabilities. The asset-based approach is similar to the cost approach of other valuation methods. This approach should be considered in valuations involving an investment or business appraised on a basis other than as a going concern, and it is critical to mention that this asset-based approach should not be the sole appraisal method used in valuations relating to companies appraised as going concerns. Book value represents an accounting term; it signifies the sum of the asset accounts (usually based on historical cost), net of depreciation and amortization, less the liability accounts, as shown on a balance sheet. The difference between book and market value of debt is likely to be insignificant for healthy firms, but particularly large for unstable companies with negative economic outlook.

2) Income Approach to Business Valuation

The income approach is a general way of valuation of a business by using methods through which highly expected cash-flow is converted into value. Both capitalization of benefits methods and discounted future benefits methods are well known. In capitalization of benefits methods, a representative benefit level is divided or multiplied by an appropriate capitalization factor to convert the benefit to value. In discounted future cash-flow methods, cash-flow is estimated for each of future periods. This cash-flow is converted to value by applying an appropriate discount rate and using present value calculation. Cash-flow should be estimated by considering the business analysis with regard to historical performance and future outlook of the business entity, relevant economic factors, and capital structure.

Expected cash-flow is further converted to value by using the procedures mentioned in section 5.2, primarily incorporating determination of discount rate, rates of return expected by investors, and risk profile of investment.

3) Market Approach

The market approach is a commonly used method of valuation that employs methods that compare on a relevant basis the subject to comparable businesses that have been sold. Comparisons are mainly made through the use of valuation ratios. The computation of such ratios should provide significant insight about the value of the subject, considering all relevant factors. The quality of data, and respective valuation ratios, are based on the appropriate selection of the underlying data and time periods used to compute the valuation ratios.The developed valuation methodology presented in chapter 6 assumes that the power plant unit valuation is a going concern with strategic control and that valuation is accomplished to set up the investment enterprise value based on the defined WACC and expected prices of inputs. It uses the income approach defined above. The purpose of this thesis is not to further develop the model considering different views of creditors or sellers, etc. Additionally, methodology does not consider any business and financial analysis to simplify the methodology. Furhtermore, there is not included debt for financing of business.

6. Power plant valuation by modified NPV incorporating physical constraints and optimization algorithm

6.1. Optimization approach

The algorithm evaluates a defined string of electricity market spot prices (HPFC curve) with respect to the technical constraints of the power plant. This optimization algorithm of an operating power plant is based on a real life operating approach that divides the year into separated day stages that are optimized in accordance with the spot price of the loaded HPFC curve. The evaluation starts at a defined location of power output and examines all possible states in further output levels and periods. The current state of power plant operation is dependent on the previous state and the decision made in the previous period. The optimization algorithm developed in Wolfram Mathematica[23] software is based on gradient method optimization, which finds optimal operation strategy to maximize profit by incorporating technical constraints. The model of the power plant works with the basic economic rule, which is maximization of profit. Each hour of potential power production is evaluated due to the clean dark spread.

6.2. Key business issues of coal power plant operation and profitability

1) Long-term coal contract (lignite coal) –long contracts are typical indexed to electricity price by the year-to-year inflation and consumer price index. The final price is also influenced by the weights of those two variables, although electricity price inflation plays a major role. This electricity price inflation is evaluated after the end of the previous calendar year based on real data of the traded electricity product as a following year futures baseload year-to-year change. Another key point of the long-term coal contract is the contracted volume of coal where the optimization model assumes optionality of consumed volume in the given range. In other words, it is supposed that there is any "take or pay" formula in the current contract for lignite. Nevertheless, it is basically supposed that the lower limit of contracted coal has to respond to contracted heat production and GSS, and the upper limit of contracted coal is defined by the full output of the power plant. The specifics of the brown coal/lignite contracts market are primarily in the design of the market. Exchange traded products exist only for steam (black) coal specified by much higher liquidity and traded worldwide. The reason is the mainly higher calorific value which leads to the more effective transport. The key reason to hedge dark spread position by commodity market products as a futures for electricity, emission

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[23] http://www.wolfram.com/mathematica/

allowances, and steam coal (ARA[24] exchange) is therefore only in the case of a power plant burning steam coal.

2) Electricity prices – the model of the optimized power plant considers tradable forward curve from energy exchange (using data from EEX European energy exchange) with hourly priced forward curve (“HPFC”) structure based on the structuring long term forwards to the indexed hour prices by historic structure of electricity spot prices. Furthermore, the model works with the 3 years ($t_{tradableCAL}$) forward curve indexed with the historic structure. Methodology of the derived HPFC curve is defined only by indexation of the historic data of spot price related to average price of the future product traded at the energy exchange, described in detail in chapter 4. The key condition of reliability of indexed HPFC curve is that average price of indexed spot price is equal to the price of traded calendar year futures.

3) Emission allowances – the optimization model considers a consistent approach of EU institutions developing regulatory framework and excludes ideas regarding backloading of EUAs or any non-market activities and regulations to be able to plan a stable level of emission allowances price.

4) Grid support services – the valuation model of the power plant also considers impact of the GSS contract with TSO of the operated area. Several types of GSS could have totally different impacts; therefore, there must be a defined purpose of chosen GSS.

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[24] ARA – Amsterdam, Rotterdam, Antwepen

6.3. Technical parameter implementation

According to the methodology, there is defined typology of the various physical constraints of conventional power plants. Considerable impact for valuation and hedging have technical characteristics as start-up costs, ramp rates, heat curves, fuels used, and emission rates. There are three main categories of power plants[25]. **Baseload** is a unit with high start-up costs, mainly using gas, coal, oil, or nuclear with low ramp rates and low heat rates. **Peaking plant** is a unit with moderate start-up costs, using oil and gas and with high ramp rates and high heat rates. **Cycling plant** is considered to be a unit with characteristics between baseload and peaking plant, at moderate level.

Key performance characteristics of the generation units are the following:

- **Capacity** C_i - technical constraint of the maximum output, also known as the nominal capacity or installed capacity, refers to the intended technical full–load sustainable output of a power plant. For dispatchable power plants, this capacity depends on the internal technical capability of the plant to maintain output for a reasonable period and without considering external events such as maintenance. Actual output can be different from nominal capacity for many reasons, depending on equipment and circumstances. For non-dispatchable power plants, particularly renewable energy sources ("RES"), nominal capacity refers to the energy generation under ideal conditions. Output is generally limited by weather conditions, hydroelectric dam water levels, and other outside forces. Outages and maintenance usually contribute less to the capacity factor reduction than the regular variation of the power source.

- **Capacity Factor** I_{TC} - Capacity factor of a power plant is the ratio of its actual output over a defined period of time, to its potential output if it were possible for it to operate at full nominal capacity indefinitely (total amount of energy the plant produced during a defined period of time divided by the amount of energy the plant would have produced at full capacity.) Capacity factors vary greatly depending on the type of fuel that is used and the design of the plant.

- **Heat rate** - efficiency of the unit – efficiency characteristic curve related to the power output. The heat rate of a generation unit is not constant. As the output increases, the heat rate increases as well. Generally, a generating unit is most efficient when it is operated at or near its maximum capacity.

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[25] In the basic principle, steam turbines expand pressurized steam to a lower pressure level and use the extracted mechanical energy to drive an electricity generator. The operating modes for steam turbines can be classified into three categories: off mode, production, and transitional modes (startup and shutdown).

- **Maximal and minimal generation level -** variables $P_{\max}$ and $P_{\min}$ – technical and contractual constraints or grid support services requirements.

- **Availability factor** I_{AV} – the availability factor of a power plant is the amount of time that it is able to produce electricity over a certain period, divided by the amount of the time in the period. Occasions where only partial capacity is available may or may not be deducted. Where they are, the metric is titled Equivalent Availability Factor (EAF). The Availability Factor should not be confused with the capacity factor. The Capacity Factor for a period will always be less than the Equivalent Availability Factor for the same period. The difference depends on the utilization of the power plant. The availability of a power plant depends mainly on the operational characteristics, type of fuel, and the design of the plant. Everything else being equal, plants that are started less frequently have higher availability factors because of less maintenance. Most thermal power stations, such as coal and nuclear power plants, have availability factors between 70% and 90%. Newer plants tend to have significantly higher availability factors, but preventive maintenance is as important as improvements in design and technology. Gas turbines have relatively high availability factors, ranging from 80% to 99%. The availability factor of RES (wind and solar power plants) depends on weather periods when the plant is operational, but there is no wind or sunlight, are counted as available, unavailable, or disregarded. If they are counted as available during these times, photovoltaic plants have an availability factor approaching or equal to 100%. Modern wind turbines also have very high availability factors, about 98%. However, solar and wind plants have relatively low capacity factors. (Wind plants with range from 20-40% and solar capacity factors in EU are about 15-20%.) This makes wind and solar availability factors much lower if times when sunlight or wind are not available are taken into account.

- **Maintenance rate** – a certain period of the time is needed for the maintenance of a generation unit. Similar to a forced outage rate, a maintenance rate represents the percentage of maintenance hours to the entire number of hours in a year.

- **Ramp rates** - the rate at which the generation level can be changed, in case study separately set for increasing and decreasing output. Typically, a generation unit needs a certain length of time to move from zero MW to its full capacity. The ramp rate is a measure of how fast a generator can move up or down from its current state.

- **Startup and Shutdown costs** - used in calculating the cost of bringing unit on or off line. There are two components for a start: a straight cost component and a fuel cost. These two depend on whether the start is hot or cold.

- **Min/max offline time, min/max runtime** - most generation units cannot be turned on and off as frequently as we expect. Every flexible unit may need to remain online for several hours before they can be shut down. Similarly, most units cannot be restarted immediately if the current status is off.

- **Forced outage -** generation units sometimes break down unexpectedly due to technical problems. A forced outage rate represents the percentage of forced down hours to the entire number of hours in a year. For instance, a single forced outage rate of 10% means that the unit has a 90% probability of being available during any course of time. Forced outages are actually random events.

- **General overhaul** T_{GO} – process of restoring and maintaining equipment and the trial-run prior to returning item to its full operating level.

- **Own consumption** R_{OC} – the consumption of self-produced energy by plant equipment to run operation of unit.

- **Transmission loss rate** R_{TLR} – transmission and distribution losses in transmission between sources of supply and points of distribution.

In Table 7 are defined key technical parameters considered for the valuation of specified unit by classical and simultaneously by modified NPV concept. Specification of technical parameters implemented to optimization algorithm is mentioned further and works with a narrower set of parameters.

Table 7: Technical parameters

Block parameters	**Unit**	
Installed capacity	MW	**800,0**
Maximum hours per year	hours/year	**8760,0**
General overhaul in hours	hours/year	**1500,0**
Capacity reserved for GSS	MW	**30,0**
Availability factor	%	**75,0%**
Capacity factor	%	**90,0%**
Own consumption	%	**8,0%**
Transmission loss rate	%	**3,0%**
Ramp Rate(up/down)	MW/hour	**+200/-200**

Model of optimization algorithm implemented in Wolfram Mathematica considers the following drivers:

1) $P_{\max}$ as a maximal output of power plant in MW
2) $P_{\min}$ as a minimal output of power plant in MW. Case study power plant considers permanent minimum output which will be held to meet requirements of support grid services. Due to long delays and high costs for decommissioning and commissioning the power plant, it is comfortable to work with the range of minimum and maximum output of the power plant offering support grid services and optimizing production due to market development.
3) The ramp time in MW/min, which is the time period between operating output and required output. We distinguish between positive and negative ramp time.

Another key characteristic of the power plant is the operational efficiency, generally known as the capacity factor or load factor, which measures the current output from energy production compared to the maximum possible output of the unit. This operational efficiency could be significantly affected primarily when the plant operates in partial load mode. A plant operating with low average output will return lower efficiencies compared with full loaded plants.[26] Energy efficiency is often referred to as the heat rate. For example, a power plant using fossil fuels with a heat rate of 10,3 MJ/MWh would have an energy efficiency of 35%. A 1% change of heat rate would change efficiency value by the 0,35 percentage point. In general terms, efficiency is the output of a production process compared to the input and could be defined in terms of economic efficiency, energy efficiency, or operational efficiency.

Production parameters further implemented to the valuation are solved by Equations 23 to 27. Volume of Gross power production GPP is the result of the available capacity C_a and effective working hours T_{eff} conjunction (Equation 23), where available capacity (Equation 24) is the installed capacity C_i decreased by capacity reserved for grid support services C_{gss}.

$$GPP = C_a * T_{eff} \tag{23}$$

$$C_a = C_i - C_{gss} \tag{24}$$

Effective working hours (Equation 25) are the product of available working hours T_{av} and capacity factor I_{TC} decreased by the time for general overhaul T_{GO}.

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[26] Steam turbines' heat consumption is characterised by a Willans line, which shows that total heat consumption incorporates incremental and fixed elements, where there is non-zero consumption at zero load.

According to the previous variable, available working hours T_{av} are the product of maximum working hours T_{tot} and availability factor I_{AV} as shown in Equation 26.

$$T_{eff} = T_{av} \times I_{TC} - T_{GO} \tag{25}$$

$$T_{av} = T_{tot} \times I_{AV} \tag{26}$$

Volume of net power generation NPP solved by Equation 27 results from gross power production decreased by the own consumption R_{OC} and transmission loss rate R_{TLR}.

$$NPP = (C_i - C_{gss}) \times (T_{tot} \times I_{AV} \times I_{TC} - T_{GO}) \times (1 - R_{TLR}) \times (1 - R_{OC}) \tag{27}$$

Table 8 contains examples of production calculations for specified years based on considered technical parameters:

Table 8: Example of production calculation

Block Power production		**2 015**	**2 016**	**2 019**
Installed capacity	MW	800	800	800
Capacity reserved for GSS	MW	30	30	30
Available capacity	MW	770	770	770
Maximum working hours	hours	8 760	8 760	8 760
Availability factor	%	75,0%	75,0%	75,0%
Available working hours	hours	6 570	6 570	6 570
Capacity factor	%	90,0%	90,0%	90,0%
General overhaul	hours	0	0	2 500
Effective working hours	hours	5 913	5 913	3 413
Gross power generation	GWh	4 553	4 553	2 628
Own consumption	%	8,0%	8,0%	8,0%
Transmission loss rate	%	3,0%	3,0%	3,0%
Net power generation	**GWh**	**4 063**	**4 063**	**2 345**

Other assumptions which are implemented to valuation model are presented in Table 9.

Table 9: Other valuation assumptions

Other assumptions	**Unit**	
Gross power generation efficiency	%	35,00%
Caloric value of coal	GJ/t	12
Reservation capacity change from 2015 (GSS)	%	-2,00%
Useful life of assets	years	20
Corporate income tax rate	%	19,00%

6.4. Financial aspects of production planning and optimization

The valuation model expects the principle of the perfectly competitive[27] market (mainly due to the existence of the energy exchange and many supply firms that provide the same products as standardized products) and hypothetical attainable barriers to entering an energy sector. These conditions lead to simplification of the case study; however, many energy markets are still fully regulated. Otherwise, a perfect competitive market could be considered only for electricity production and not for the regulated business of transmission of electricity and distribution of heat. Business strategy of the model is profit maximalization in the sense of producing output where marginal costs are equal to, or lower than, the price expressed generally by Equation 28 and Equation 29, where at a given time, P_i results from the intersection of the demand curve and the aggregated supply curve.

$$MC(Q) \leq P \tag{28}$$

$$\max P_t \cdot Q_t - TC_t(Q_t) \tag{29}$$

---

[27] A perfectly competetive market works with necessary characteristics that all market participants must be price-takers and the industry output is a standardized product. This market is characterized by free entry and exit. The optimal production is the level at which marginal revenues equal marginal cost.

Total revenues of the model are set up from electricity sales and grid support services. Other possible revenue sources are considered as zero. The optimization criterial function of profit maximalization is represented by Equation 30.

$$\max \sum_{t=1}^{T} (P_t \cdot Q_t - VC_t - FC_t) \tag{30}$$

Electricity revenues are formed by the sold electricity and grid support services. The model works with two alternatives of electricity revenues:

1) Market prices of the tradable electricity long-term contracts for the first three years, followed by expected prediction for further years

2) By optimized output with Mathematica algorithm based on the HPFC curve for the period of the first three years, followed by expected prediction part for further years

Grid support services are divided into reservation revenues and activation revenues. Due to the absence of the official marketplace of the grid support services in the Czech Republic, it is necessary to set appropriate prices for both revenue lines. Based on expert opinion, the study works with 15 €/MWh for reservation revenues and 35€/MWh for activation revenues.

Costs implemented to the financial model of the unit are formed by variable costs related to output and fixed costs incorporating overheads in the following structure :

Variable costs are defined by Equation 31; set up of variable costs function for the purpose of the Mathematica algorithm is mentioned further in section 6.4.1.

$$VC(P) = C_{coal} + C_{CO2} + C_{FR} \tag{31}$$

1) **Coal consumption costs** C_{coal} are defined by Equation 32 with specified price P_{coal} and calorific value CAL, where the volume of the coal is also influenced by the gross power efficiency GE. Due to the absence of the official market with lignite in the Czech Republic, the model works with an expert opinion price for the 1st year, and further with the well-known and -used indexation by the annual change of electricity price.

$$C_{coal} = P_{coal} \times (\frac{GPP \times 3,6}{CAL \times GE}) \tag{32}$$

2) **CO2 cost**s are defined by emission factor EF and price P_{CO2}. As was just mentioned, prediction of EUA´s prices is relatively complicated due to the regulatory framework of this product. CO2 costs are further defined by Equation 33.

$$C_{CO2} = P_{CO2} \times EF * GPP \tag{33}$$

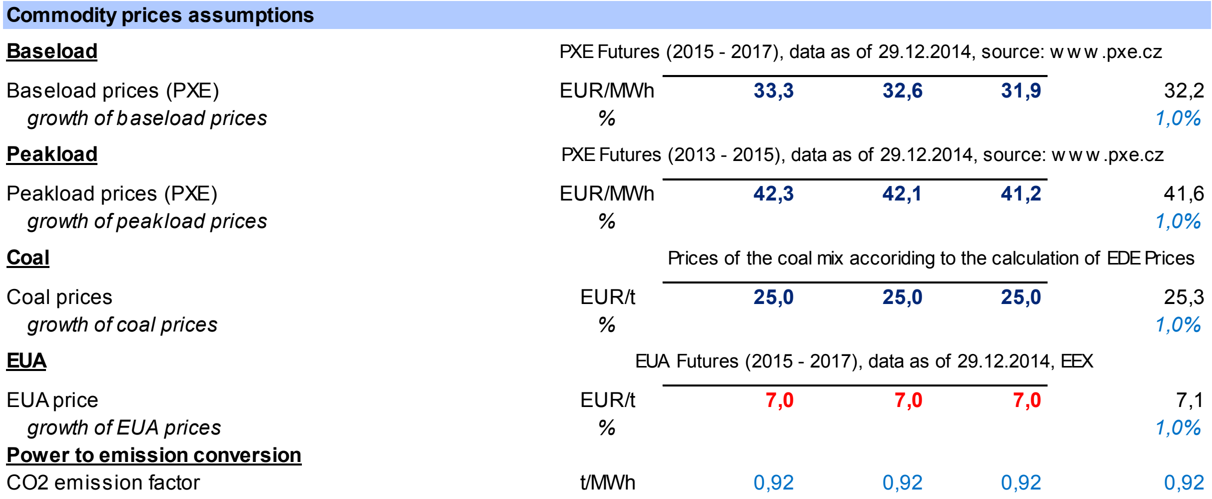
3) **Other fuel related cost** C_{FR} are linked primarily to limestone consumption to meet emission standards of the unit. Marginal variable costs related to net power production are set by using Equation 34.

$$MVC(P) = \frac{C_{coal} + C_{CO2} + C_{FR}}{NPP} \tag{34}$$

Fixed costs FC are in the model considered as a constant to simplify the concept of the net present value calculation. Nevertheless, the financial model contains these costs in the structure of personal costs, other fixed costs—divided further to overhead costs (IT, services), repair and maintenance, and other operating costs. All financial figures are mentioned in the attached dataset in Excel spreadsheets to support the reader with a full picture of the valuation method.

Market prices inputs:

Electricity prices were set as a three year (2015-2017) average of the PXE energy exchange market data as of 29/12/2014 (equal to date of appraisal based on the assumptions from chapter 5). The average price of BL 2015 -2017 was 32,6 €/MWh. Prices of CAL products from PXE of BL and PL were afterward initialized to the HPFC model to receive the hourly price forward curve for the period of 2015-2017. Price of the electricity for the years 2018-2035 is indexed by 1% annually in accordance with the coal contract indexation, as shown in Figure 14 . The price of coal/lignite for years 2015-2017 was fixed at 25€/t for the coal and the transport, and for further years increased by 1% annually. Price of emission allowances was also set constant for the first three years with the conversion factor of 0,92 ton/MWh of electricity produced. GSS revenues were modeled with the reservation price 15€/MWh and 35€/MWh strike price of the activation with probability of 10% of start for full output of 60MW for 1 hour. GSS services are annually decreased by 2%. Discount rate works with WACC considered by author´s opinion at 10%.



Commodity prices assumptions					
Baseload	PXE Futures (2015 - 2017), data as of 29.12.2014, source: www.pxe.cz				
Baseload prices (PXE)	EUR/MWh	**33,3**	**32,6**	**31,9**	32,2
growth of baseload prices	%				*1,0%*
Peakload	PXE Futures (2013 - 2015), data as of 29.12.2014, source: www.pxe.cz				
Peakload prices (PXE)	EUR/MWh	**42,3**	**42,1**	**41,2**	41,6
growth of peakload prices	%				*1,0%*
Coal	Prices of the coal mix accoriding to the calculation of EDE Prices				
Coal prices	EUR/t	**25,0**	**25,0**	**25,0**	25,3
growth of coal prices	%				*1,0%*
EUA	EUA Futures (2015 - 2017), data as of 29.12.2014, EEX				
EUA price	EUR/t	**7,0**	**7,0**	**7,0**	7,1
growth of EUA prices	%				*1,0%*
Power to emission conversion					
CO2 emission factor	t/MWh	0,92	0,92	0,92	0,92

Figure 14: Commodity market price

6.4.1. Variable costs function implemented to model

Selected drivers of the variable cost function of production electricity are costs for coal, other fuel related costs, and CO_2 emission allowances costs. As was mentioned, the model works with consideration that there is an option to consume a specified volume of coal due to final production of electricity. In other words, the model works with fixed marginal costs for coal without any option premium or take-or-pay contract condition. Furthermore, the model incorporates an efficiency curve of the electricity production, considered as a downward-slopping curve of the efficiency with peak at 95% of the maximal installed capacity, depending on power output. Equation 35 relates variable costs implemented to the model:

$$f_C(P) = VC_{P\min} \times \left(1 + q_{\text{var}} \times \left(\frac{P - P_{ef}}{P_{\max}}\right)^2\right) \tag{35}$$

Variable $VC_{P\min}$ represents minimal variable costs of function, where this variable is equal to previously mentioned marginal variable costs $MVC(P)$. Variable P_{ef} is the output of the unit with highest production efficiency (it is assumed that this value will be at 95% of maximal output). Variable q_{var} represents the slope curve coefficient. Variable cost function of the considered coal unit with the above-mentioned assumptions is shown in Figure 15.

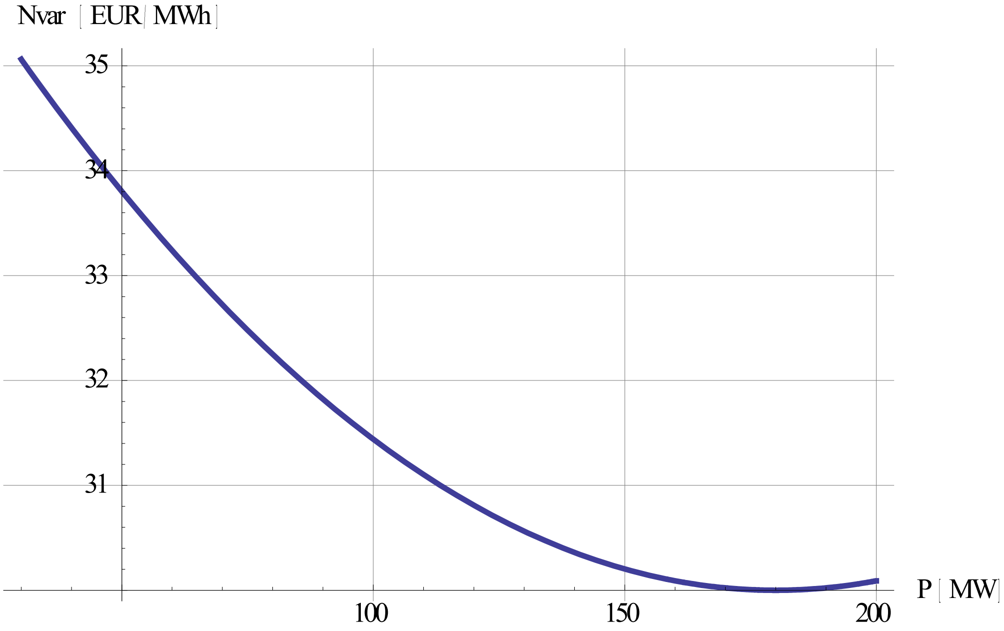


Figure 15: Variable costs function

6.4.2. Optimization Method

This chapter uses the description of the method primarily from the Wolfram Mathematica tutorial [51]. The optimization method is focused on conjugate gradient methods applied to the nonlinear unconstrained optimization problem by function $\min\{f(x) : x \in \Re^n$, where $f : \Re^n \mapsto \Re$ is a continuously differentiable function, bounded from below. A nonlinear conjugate gradient method generates a sequence $x_k, k \geq 1$, starting from an initial guess $x_0 \in \Re^n$ with recurrence $x_{k+1} = x_k + \alpha_k p_k$, where the positive step size α_k is obtained by a line search and the directions p_k.

Conjugate gradient ("CG") methods are part of unconstrained optimization algorithms which are characterized by strong local and global convergence properties. The basis for a nonlinear conjugate gradient method is to effectively apply the linear conjugate gradient method, where the residual is replaced by the gradient. A model quadratic function is never explicitly formed, so it is always combined with a line search method. The first conjugate gradient method was proposed by Fletcher and Reeves (further desribed in [52] and[53]) as follows. Given a step direction p_k, use the line search to find α_k such that $x_{k+1} = x_k + \alpha_k \cdot p_k$. Then compute

$$\beta_{k+1} = \frac{\nabla f(x_{k+1}) \cdot \nabla f(x_{k+1})}{\nabla f(x_k) \cdot \nabla f(x_k)} \tag{36}$$

$$p_{k+1} = \beta_{k+1} \cdot p_k - \nabla f(x_{k+1}) \tag{37}$$

It is essential that the line search for choosing α_k satisfies the stronge Wolfe conditions; this is necessary to ensure that the directions p_k are descent directions. An alternate method, which generally works better is the Polak and Ribiere (further desribed in [52] and[53]) , where equation 36 is replaced with

$$\beta_{k+1} = \frac{\nabla f(x_{k+1}) \cdot (\nabla f(x_{k+1}) - \nabla f(x_k))}{\nabla f(x_k) \cdot \nabla f(x_k)} \tag{38}$$

In equation 38, it is possible that β_{k+1} can become negative, in which case Mathematica employs the algorithm modified by using $p_{k+1} = \max(\beta_{k+1}, 0) \cdot p_k - \nabla f(x_{k+1})$. In Mathematica, the default conjugate gradient method is Polak-Ribiere, but the Fletcher-Reeves method can be chosen by using the method option. The advantage of conjugate gradient methods is that they require no numerical algebra, and each step is quite fast. The disadvantage is that they typically converge much more slowly than Newton or quasi-Newton methods. Also, steps are typically poorly scaled for length, so the line search algorithm may require more iterations each time to find an acceptable step. One issue that arises with nonlinear conjugate gradient methods is when to restart them. As the search moves, the nature of the local quadratic approximation to the function may change substantially. The local convergence of the method depends on that of the linear conjugate gradient method, where the quadratic function is constant. With a constant quadratic function for n variables and an exact line search, the linear algorithm will converge in n or fewer iterations. By restarting (taking a steepest descent step with $\beta_{k+1} = 0$) every so often, it is possible to eliminate information from previous points, which may not be relevant to the local quadratic model at the current search point. If you look carefully at the example, you can see where the method was restarted and a steepest descent step was taken. One option is to simply restart after every k iterations, where $k \le n$. You can specify this using the method option "RestartIterations"->k. An alternative is to restart when consecutive gradients are not sufficiently orthogonal according to the test

$$\frac{\left|\nabla f(x_k)\cdot\nabla f(x_{k-1})\right|}{\nabla f(x_k)\cdot\nabla f(x_k)} \prec v \tag{39}$$

With a threshold v between 0 and 1.

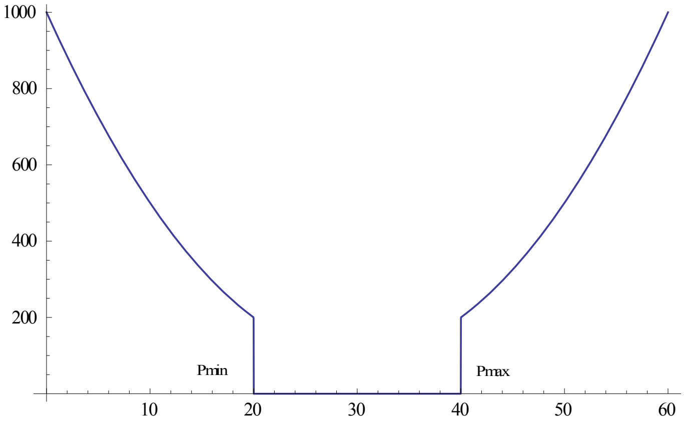


Figure 16: Mathematica penalization function

The above-mentioned method was applied in the case of finding the maximum possible profit from the output optimization. The optimization criterial function of profit maximalization is represented by Equation 30. To ensure maximal speed and feasibility of the method, it is necessary to incorporate a penalization function. Figure 16 shows a schematic example of the penalization function with the example of $P_{\min}$ of 20 MW and $P_{\max}$ of 40 MW. This penalization method leads to shorter computation time to evaluate the algorithm and also to run algorithm without Boolean if conditions replaced by the contionuous smooth tangent functions. The algorithm works with the assumption that states and transition between them are not discrete but continual. Due to regulatory framework and technical parameters defined by the TSO model, consider that power output during the business hour is defined by the integral of the load curve. Therefore, the algorithm works with three transition possibilities resulting in different computation of energy produced during transition state. Figure 17 illustrates the schema of transition state.

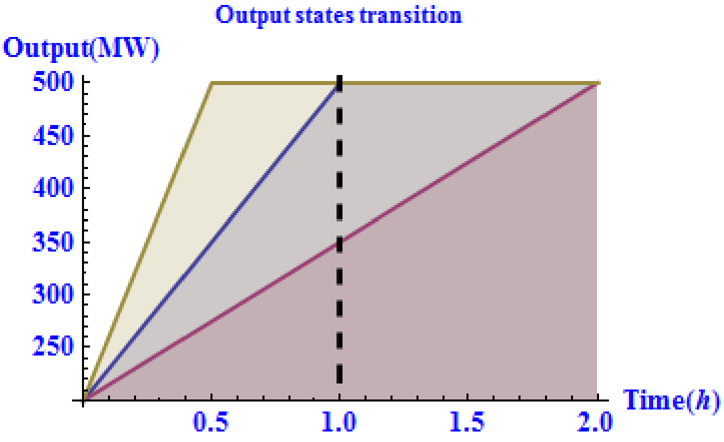


Figure 17: Output states transition

The considered ramp rate of the power plant and its impact to output energy computation is obvious from Figure 17. The picture shows the increasing output of the power plant from 200 MW to 500 MW, when the power plant with ramp rate 5 MW/minutes reaches the required output in one hour (blue line), the unit with a higher ramp rate reaches the required output faster, and vice versa. To incorporate all three transition possibilities, the algorithm works with two possible integration formulas 40, 41 implemented to the algorithm.:

$$\begin{aligned} & RaT \le 1 \\ & E = \frac{1}{2}(P_{start} + P_{end}) \cdot RaT + P_{end} \cdot (1 - RaT) \\ & RaT \ge 1 \\ & E = \frac{1}{2}(2 \cdot P_{start} + RR) \end{aligned} \qquad (40)$$

Finally, the cost function results from the variable cost function defined by Equation 35. This cost function defined as a general parabolic function is defined by Equation 41.

$$C = c_0 + c_1 \cdot P + c_2 \cdot P^2 \qquad (41)$$

where coefficients c_0, c_1, c_2 are further derived from Equation 35 and then implemented to Equation 44. Total costs function visible in Mathematica code is addressed next, along with results from the ramp time function and variable costs function 35.

$$VC = -(-1 + RaT) \times P_{end} \times (c_0 + P_{end}(c1 + c2 \times P_{end})) + \frac{1}{12} \times RaT \times (6c_0 \times (P_{start} + P_{end}) +$$
$$3c_2 \times (P_{start} + P_{end}) \times (P_{start}^2 + P_{end}^2) + 4c_1 \times (P_{start}^2 + P_{start} \times P_{end} + P_{end}^2)$$

(42)

Integral of variable cost spent to power production in a defined period with specific heat rate is defined by Equation 43 with two components, constant component and ramp component defined as a linear function. The integral could be simplified to the following equations depending on the ramp time.

$$VC = \int_0^{RaT} Tr \cdot f_C(P_{end})dt + \int_{RaT}^{1} P_{end} \cdot f_C(P_{end})dt \tag{43}$$

After simplification of Equation 43, we obtain the following:

$$VC = (P_{end} - RaT \cdot P_{end}) \cdot f_C(P_{end}) + \int_0^{RaT} \frac{\left((RaT \cdot P_{start} + (P_{end} - P_{start})) \cdot t \cdot f_C\left(P_{end} + \frac{P_{end} - P_{start}}{RaT} \cdot t \right)\right)}{RaT} dt \tag{44}$$

After simplification and substitution of coefficients we have Equation 44. The algoritm considers that the output transition (from starting states P_{start} to P_{end}) is a linear function defined by equation 45 and ramp time RaT is defined by equation 46.

$$Tr = P_{start} - \frac{(P_{start} - P_{end}) \times t}{RaT} \tag{45}$$

$$RaT = \frac{P_{end} - P_{start}}{RR} \tag{46}$$

6.5. Case study optimization results – modified NPV calculation:

The model of HPFC optimization implemented in Wolfram Mathematica 9.0 Software considered technical and economical parameters discussed in sections 6.3 and 6.4 to perform calculation of free cash flow to the firm, and discounted profit of the operating power plant. Optimization of energy production first was tested with technical and economical data for the period of one month and week. The result of optimization of the one-month and one-week period is shown in Figures 18 and 19. Month and week profile results are more transparent for presenting. From the week profile optimization, the impact of the price to the output of the power plant for profitability of the specific hours is obvious.

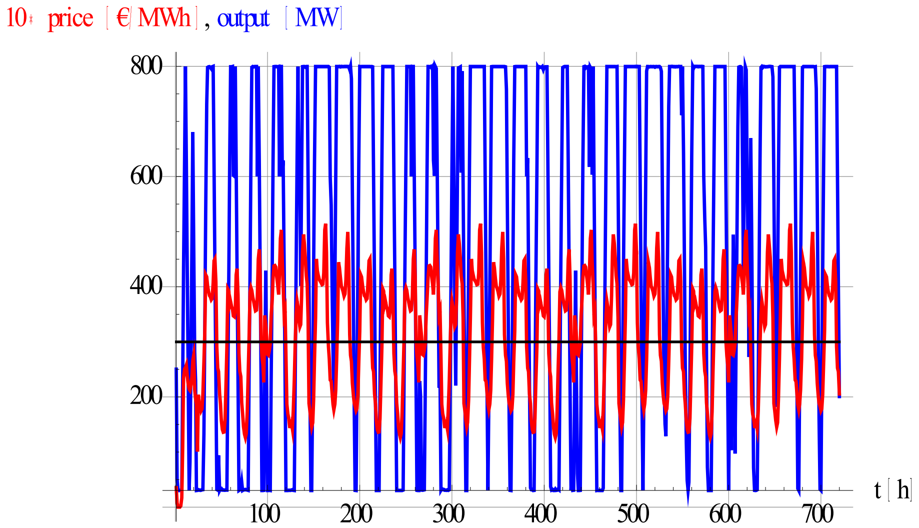


Figure 18: Month profile optimization

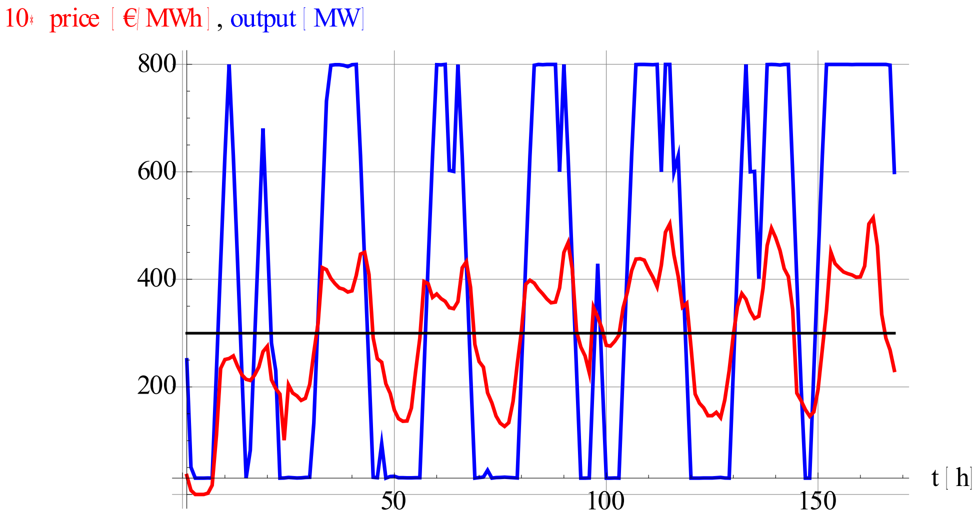
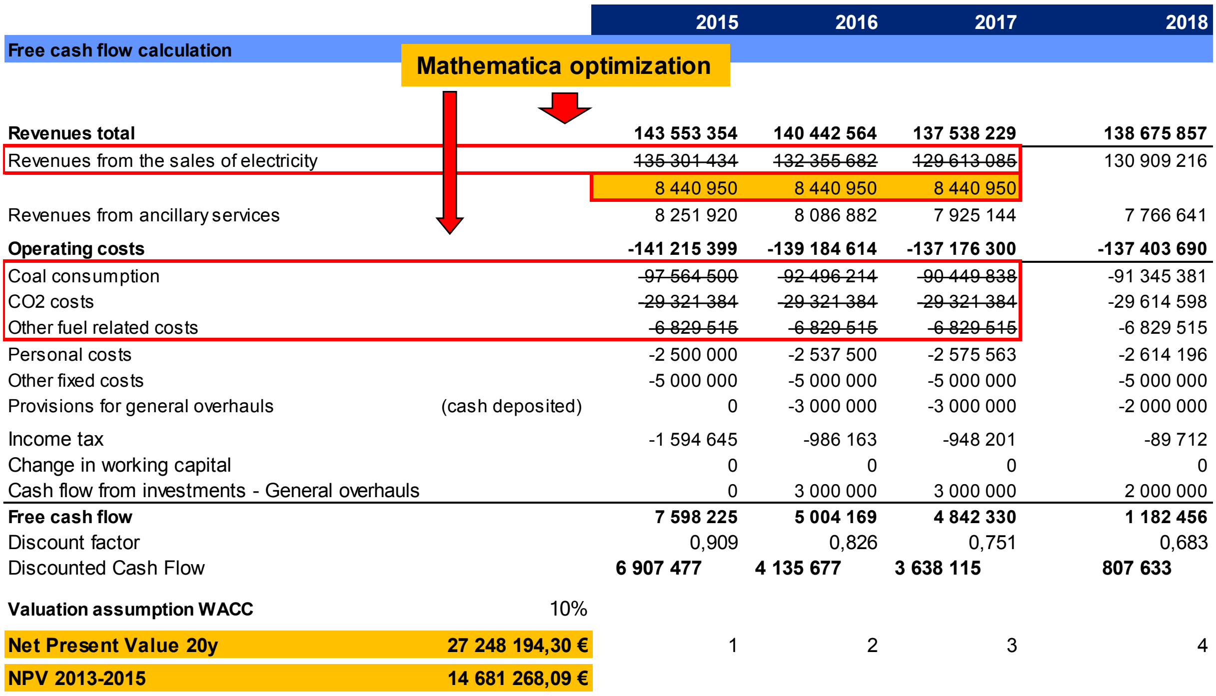


Figure 19: Week profile optimization

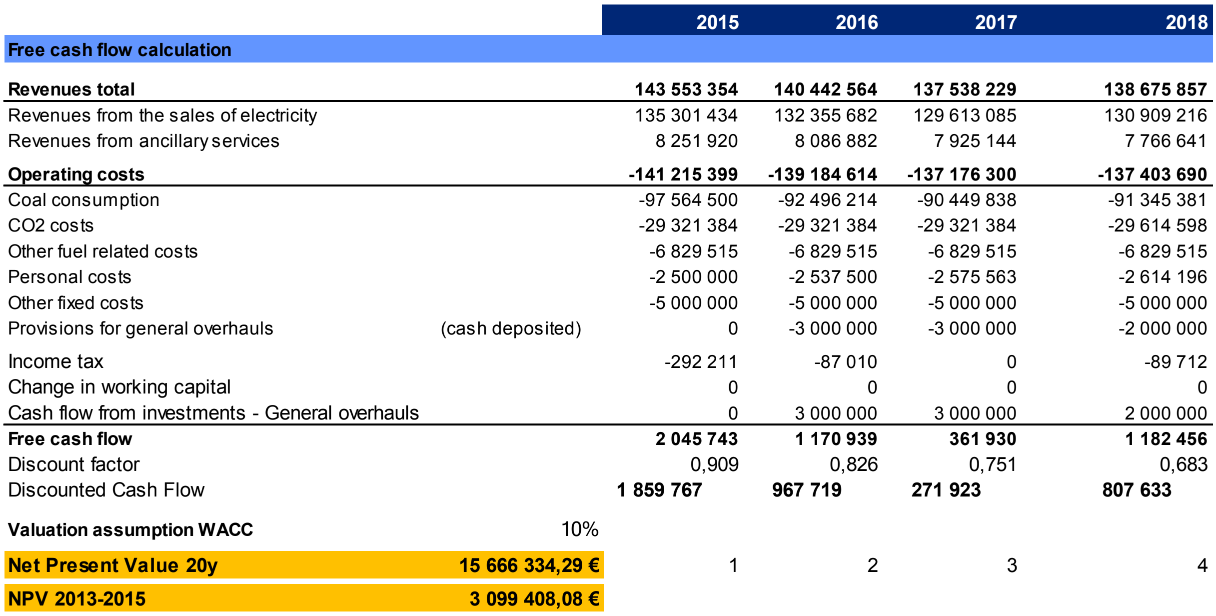
Free cash flow calculation of optimized block is obvious from Figure 20. Net present value of this optimized unit is 14.681 ths €. The optimalized profit from the Mathematica model is indexed by effective production rate, which adjusts the full capacity production optimization to the real effective working hours assumption. The concept of the firm value calculation is implemented from section 5.3. The first thee years of free cash flow to the firm results primarily from Mathematica optimization. In addition, prediction of prices is provided.



Free cash flow calculation		2015	2016	2017	2018
Revenues total		**143 553 354**	**140 442 564**	**137 538 229**	**138 675 857**
Revenues from the sales of electricity		~~135 301 434~~	~~132 355 682~~	~~129 613 085~~	130 909 216
		8 440 950	8 440 950	8 440 950	
Revenues from ancillary services		8 251 920	8 086 882	7 925 144	7 766 641
Operating costs		**-141 215 399**	**-139 184 614**	**-137 176 300**	**-137 403 690**
Coal consumption		~~-97 564 500~~	~~-92 496 214~~	~~-90 449 838~~	-91 345 381
CO2 costs		~~-29 321 384~~	~~-29 321 384~~	~~-29 321 384~~	-29 614 598
Other fuel related costs		~~-6 829 515~~	~~-6 829 515~~	~~-6 829 515~~	-6 829 515
Personal costs		-2 500 000	-2 537 500	-2 575 563	-2 614 196
Other fixed costs		-5 000 000	-5 000 000	-5 000 000	-5 000 000
Provisions for general overhauls	(cash deposited)	0	-3 000 000	-3 000 000	-2 000 000
Income tax		-1 594 645	-986 163	-948 201	-89 712
Change in working capital		0	0	0	0
Cash flow from investments - General overhauls		0	3 000 000	3 000 000	2 000 000
Free cash flow		**7 598 225**	**5 004 169**	**4 842 330**	**1 182 456**
Discount factor		0,909	0,826	0,751	0,683
Discounted Cash Flow		**6 907 477**	**4 135 677**	**3 638 115**	**807 633**
Valuation assumption WACC	10%				
Net Present Value 20y	**27 248 194,30 €**	1	2	3	4
NPV 2013-2015	**14 681 268,09 €**				

Figure 20: Firm value of optimized production

Discounted free cash-flow to the firm of the standard valuation method, shown in Figure 21, is lower than in the case of the incorporated optimization. The discounted free cash flow to the firm of the first three years of power plant operation is 3.099 ths €. The reason for such a big discrepancy is that optimized production does not include possible loss from the hours with spot price lower than marginal costs. This result confirms that the valuation method incorporating production optimization embodies additional value for operational flexibility of the source.



		2015	2016	2017	2018
Free cash flow calculation					
Revenues total		**143 553 354**	**140 442 564**	**137 538 229**	**138 675 857**
Revenues from the sales of electricity		135 301 434	132 355 682	129 613 085	130 909 216
Revenues from ancillary services		8 251 920	8 086 882	7 925 144	7 766 641
Operating costs		**-141 215 399**	**-139 184 614**	**-137 176 300**	**-137 403 690**
Coal consumption		-97 564 500	-92 496 214	-90 449 838	-91 345 381
CO2 costs		-29 321 384	-29 321 384	-29 321 384	-29 614 598
Other fuel related costs		-6 829 515	-6 829 515	-6 829 515	-6 829 515
Personal costs		-2 500 000	-2 537 500	-2 575 563	-2 614 196
Other fixed costs		-5 000 000	-5 000 000	-5 000 000	-5 000 000
Provisions for general overhauls	(cash deposited)	0	-3 000 000	-3 000 000	-2 000 000
Income tax		-292 211	-87 010	0	-89 712
Change in working capital		0	0	0	0
Cash flow from investments - General overhauls		0	3 000 000	3 000 000	2 000 000
Free cash flow		**2 045 743**	**1 170 939**	**361 930**	**1 182 456**
Discount factor		0,909	0,826	0,751	0,683
Discounted Cash Flow		**1 859 767**	**967 719**	**271 923**	**807 633**
Valuation assumption WACC	10%				
Net Present Value 20y	**15 666 334,29 €**	1	2	3	4
NPV 2013-2015	**3 099 408,08 €**				

Figure 21: Firm value without optimization

As is obvious from Figure 20 and Figure 21, the optimization process has very considerable impact to the value of the power plant. Furthermore, Table 10 presents the important relation of ramp rate and average profit in €/MWh, including the output curve. The relation between the variables from Table 10 are visualized in Figure 22. Based on this visualization and data from Table 10, it is obvious that increasing the ramp rate of the unit has considerable and positive impact to the value of the energy asset.

Table 10: Ramp rate vs. profit

Ramp Rate +/- [MW/h]	**RR in % of Pmax**	**Profit (VC) €/MWh**	**€ Profit (VC)**	**MWh**	**Profit (TC) €/MWh**	**€ Profit (TC)**
60	8%	13,83	83 150 400,00	6 012 102,68	3,83	23 029 373,19
80	10%	14,21	83 897 300,00	5 902 090,86	8,21	48 484 754,83
100	13%	14,36	84 615 800,00	5 893 570,31	8,36	49 254 378,16
200	25%	15,72	87 117 700,00	5 542 332,01	9,72	53 863 707,94
300	38%	16,16	88 367 300,00	5 467 129,07	10,16	55 564 525,57
400	50%	16,84	88 990 000,00	5 285 308,28	10,84	57 278 150,30
500	63%	16,92	90 174 900,00	5 329 191,33	10,92	58 199 752,04
600	75%	17,12	90 549 300,00	5 289 068,03	11,12	58 814 891,81
700	88%	17,06	91 087 900,00	5 340 575,73	11,06	59 044 445,62
800	100%	17,25	91 448 500,00	5 300 246,67	11,25	59 647 019,98

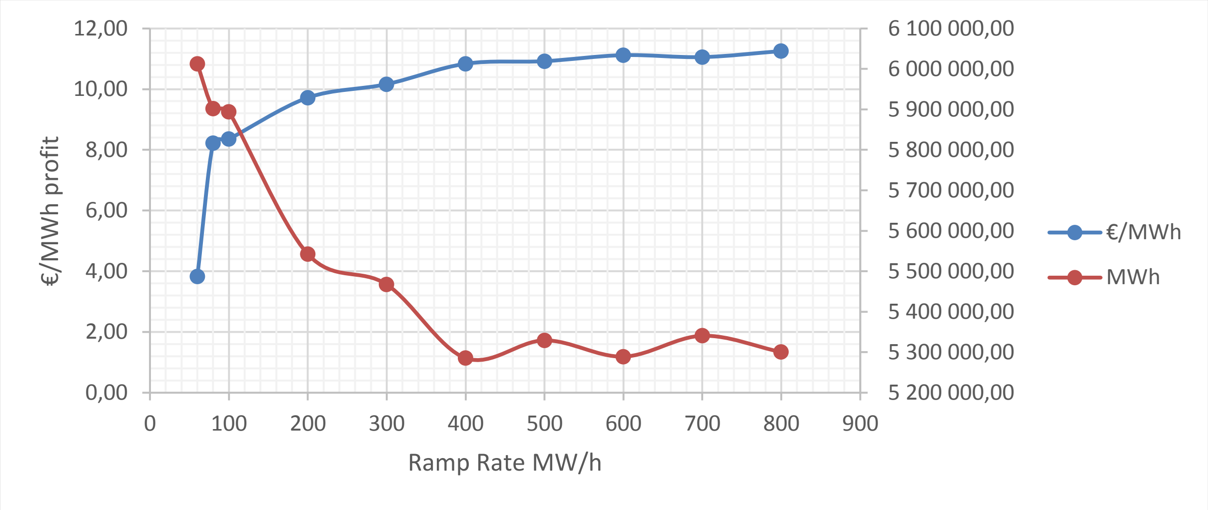


Figure 22: Ramp rate vs. profit and production

The optimalization algorithm was also used to perform calculation of production profitability due to the different structure of electricity spot prices in years 2005 and 2013, as was discussed in section 3.2. The implementation and the construction of the HPFC curve was based on the chapter 4 methodology. As obvious from Table 11, the result of the optimization implementing structure of the year 2005 is higher than in the case of year 2013. The main reason is that the peakload hours of the year 2005 embodies a more stabile pattern.

Table 11: Different HPFC structure impact

Ramp Rate +/- [MW/h]	RR in % of Pmax	Profit (VC) €/MWh	€ Profit(VC)	MWh	CV (€/MWh)	HPFC structure
100	13%	10,959543	50 680 300,00	4 624 307,77	var 25	2013
100	13%	11,967088	55 339 500,00	4 624 307,77	var 25	2005

7. Results

This dissertation thesis describes research based on systematic analysis of energy market and available appraisal methods. The electricity market design and hedging strategy in coordination with appropriate risk management served as a theoretical basis for the optimization algorithm to perform production optimization with the goal of maximal profit. The author describes modified net present value to obtain goals of this thesis formulated in section 1.1. The author applied his systematic approach, developed methodology of hourly price forward curve, and optimized DCF methodology in chapter 6. All results were verified by the author´s testing of hypothesis. The structured result of this thesis follows.

7.1. Goal of this thesis

The goals of this dissertation thesis were fulfilled and accomplished according to their submission in section 1.1 and are described further below.

7.1.1. Description of energy industry and electricity market

Chapter 3 presents a deep description of the current energy market in EU and the Czech Republic. The actual situation places primary emphasis on renewable energy source implementation and smart-grid integration. These innovative trends are changing the energy market rapidly, and any energy asset valuation has to consider these developments. From the discussed spot price statistics, it is obvious that there is apparent change of daily and seasonality price pattern, likely due to the increasing amount of production from renewable resources. The key differences that are important for energy asset valuation is the difference between levels of baseload and peakload hours. Analysis of spot prices between years 2005 and 2013 embodies decreasing price differences of PL and BL hours, primarily during summer period. Moreover, section 3.3 describes standard electricity products used to hedge open position and traded on energy exchange or OTC. The role of energy exchange is very important from the appraisal intention point of view to work with reliable data. Section 3.4 and provide the reader with information about different business strategies according to risk profile of the investor and perception of the risk of the investor. The basic framework of risk-management supervision typical for the energy business is generally described in Appendix A.1. Appropriate risk-management in accordance with business strategy is an important factor resulting in the best position for production optimalization.

7.1.2. Description of hourly price forward curve concept

In chapter 4 the author uses a systematic research of the hourly price curve concept to develop a simplified method of hourly structure indexation without incorporation of weather and other stochastic variables. The presented methodology is based on market price of calendar year electricity contract indexation with respect to historical structure of spot prices.

This method allows the optimization model to valuate production flexibility based on different clean dark spread profits in particular hours of the year. Reliability of such a HPFC curve was tested by day-to-day difference calculation to further confirm the hypothesis.

7.1.3. Description of appraisal methods

Chapter 5 gives a detailed description of key aspects of the enterprise appraisal method, with emphasis on the discounted cash-flow method. Based on the research, it is very important to consider all relevant drivers with considerable impact to the asset value. Generally, it is quite important to choose methodology of value computation which enables incorporation of all specifics of the considered asset. For the purpose of this thesis, it was assumed that the main specifics in the case of energy asset valuation are linked with stochastic behavior of electricity prices and technical aspects of power plants, which differ in flexibility values. As was discussed here, net present value as it is standardly used could considerably underestime the value of the asset; alternatively, the real option method is more complicated to incorporate technical specifics of the power plant—especially with implementation of the quadratic heat rate curve and output optimalization. All pros and cons of both methods are widely described to afford complete information for objective selection of the method. Based on the above-mentioned arguments, the author decided to extend net present value methodology by optimization the algorithm, in accordance with chapter 6. In order to meet all requirements of valuation operational flexibility of energy asset, a DCF concept was developed that was enriched by energy production optimalization and was further implemented using Mathematica software. Other important information considering valuation standard, business, and financial analysis with value segmentation were presented in section 5.4.

7.1.4. Formulation of optimization model and identification of real impact of methodology to valuation

Chapter 6 describes in detail all inputs of technical and economical data necessary for model valuation. Before the model valuation, the author widely analyses and describes the basic principle of profit maximalization in the conditions of a perfect market. All key technical parameters of the unit were mentioned and described. The optimization model considers only the influence of minimal and maximal output with ramp-rate and evaluates the variable costs function on every level of output to maximize possible profit of the power plant. The model was tested in two separate ways to confirm the hypotheses. The first test was specialized on the impact of the hourly forward curve optimized by the algorithm to support the sub-hypothesis 1 about tenable influence of this method to the value of the asset. The second logic stream was performed in accordance with sub-hypothesis 2 tested the differences between energy assets with different flexibilities

7.2. Author´s hypothesis

As it is obvious from the goals reached in this thesis, the impact of net present value optimization based on hourly price forward curve is appropriate and sufficient for the appraisal process of the energy asset. As presented in section 0 with the case study, the difference between standard NPV calculation and optimization calculation for the first three years was considerable. The author´s hypothesis that the well-known DCF concept of power plants valuation underestimates the value of conventional power plants with possibility of output regulation flexibility is confirmed by numerical results. Furthermore, the positive relation between ramp rate and unit value presented in this chapter confirmed the hypothesis as well. Moreover, the hypothesis that enriched and modified NPV by optimized energy output discounted cash-flow is relevant in power industry to obtain the fair value of a power plant unit is confirmed by this result.

7.2.1. Sub hypothesis 1

This sub-hypothesis that one reason of energy asset value underestimation is the absence of hourly structured electricity long-term contracts to project hourly price structure of electricity to the value of the energy asset is confirmed by numerical results in section 0. It is obvious that the structure of the hourly price forward curve has impact to the optimized production of the power plant and therefore to the value of the asset as well. Case study confirmed the assumption that implementing RES slightly modified the structure of the curve and leads to higher volatility of the spot prices during peak-load hours. Statistical test and histogram in chapter 4 supports the idea that year electricity forward price structured with hourly granularity which is based on real historical data by indexation method is a consistent and reliable method for valuation of any structured load of electricity. The HPFC computatation were tested by day-to-day differences, and the result is that 80% of data samples embody differences lower than 15%. The computation of HPFC based on developed methodology followed by comparison with real data showed that this method is reliable.

7.2.2. Sub-hypothesis 2

This sub-hyopthesis is that another reason of energy asset value underestimation could be caused by omitting the energy output flexibility value. Results of the Mathematica algorithm presented in section 0 for optimizing electricity production by incorporating key technical drivers of power asset confirm that energy assets with higher flexibility parameters embody a higher value of energy asset, and vice versa. In other words, this method considers technical restrictions of the unit important for relevant value.

8. Conclusion

The author´s methodology appears to be exploitable for energy asset valuation. The developed and presented methodology identifies the additional value of operational flexibility of a power plant, with verified results. The optimization methodology was used to perform calculations with limited technical restrictions due to required feasibility of gradient optimization algorithm and the demanding computional time for the yearly spot structured curves. Contemporary development of the energy markets requires valuation and optimization tools enhanced by technical flexibility and other specific aspects of energy assets. As it is obvious from the presented research of energy markets specifics and the performed production optimizations on different structures of hourly price forward curve, considering different years structure between years 2005 and 2013, the energy market structural changes are likely mainly due to massive implementation of renewable resources. These structural changes have, in light of the developed optimization algorithm, considerable impact to the value of the energy asset and to their everyday operation. Moreover, operational flexibility of the energy asset is the important driver impacting to the value. Nevertheless, it is necessary to consider other technical aspects of cycling a power plant with impact to decreased lifetime an effective production time. Each aspect and driver of the asset value was considered from a systematic viewpoint, although some technical limitations were omitted to simplify the optimization algorithm. Computational time of the algoritm considering all technical aspects could be very long, and disrete functions implemented to the optimization algorithm will complicate such an optimization process. The author assumes that future power systems of low-carbon energy and implementing smart grids will favor resources that have low marginal costs and provide system flexibility (see Table 13: Technology differences in Appendix A.1); in fact, the ability to cycle on and off to follow rapid changes of spot and balance market.

8.1. Discussion

There are several important aspects of energy asset valuation that could enhance the methodology to receive an even more exact approach of valuation. One of the drivers is the quality of the hourly price forward curve. As mentioned in chapter 4, a HPFC curve could incorporate also weather forecast information. This approach is especially useful in the case of valuation of renewable resources of energy as with a wind power plant or solar power plant; however, this approach has considerable impact above all in the short-term period. Another important factor of energy asset valuation is the ability to cycle on and off to follow spot and balancing market prices. Question remains whether coal plants can cost-effectively continue to operate if they cycle ordinarily. Some experiences from the CGS plant demonstrates that coal plants can become flexible resources with the simultaneous requirement of hardware modification. The coal units were designed to start cold minimally and to run at full output. Cycling of the power plant impacts its lifetime compared to standard operations . The negative impact of this cycling lies in the thermal stress within single components or between components when materials heat up at different rates. Therefore, it is matter of further research of the impact of such a cycling including cold states to the lifetime, operational characteristics, and profitability of the coal power plant. Moreover, further research could be pointed at involving Monte Carlo simulation of a significant number of HPFC curve samples of defined distribution. Every sample of Monte Carlo simulation would be evaluated in the optimization algorithm to calculate the value of optionality of operation flexibility in the terms of real option theory, and the studied literature mentioned in section 2.1. However, enhancing the developed methodology of optimization, including other technical specifics and Monte Carlo simulation, will be very demanding on the computational time, because the current run of optimizion for the year HPFC curve and the limited number of technical limitations last for approximately five minutes. Numerous samples such as 10 ths. of HPFC curves optimized by the developed algorithm in Wolfram Mathematica 9.0, running on the platform Intel Core i5 four core technology, would last at least over one month, which is undesirable. Therefore, such a concept requires further research and development of the optimization algoritm to meet the above-mentioned criteria in the feasibile time period.

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Appendix A.1. Designing risk management in energy business

The purpose of this chapter is to describe key basics of risk management and illustrate well-known and commonly used concepts on the power asset case. Liberalization of energy markets is exposing investors to different types of risks. The key issue is how the incorporation and internalization of risk affects decision-making of investors. Key corporate business risks in producing electricity are following:

- Demand for the electricity (also depends on economy performance factors)
- Regulatory framework and political risk
- Market/price risk of the electricity market and exchange rates
- Volumetric risk in a sold positions to counterparties
- Market risk in a fuel price

The volume of risk anticipated by an investor to the power plant is in the power asset valuation reflected by discount rate and expected return. The volatility and uncertainty of electricity prices and emission allowances creates most fundamental risk for the investor in the energy industry. Thermal power plant is a technology with relatively low fuel prices and higher ratio of investment to capacity, and therefore the impact of electricity price and EUA´s volatility is considerable. This market risk is relevant also for period of projecting and construction of the power plant and more important for large power plant projects with lower capital costs per MW (due to economies of scale[28]) .

The volatility of fuel price can also cause another significant risk, considerable mainly for technologies with high proportion of fuel costs to total costs. Therefore, gas technology presents a higher risk than lignite thermal power plant. The key factor for the lignite thermal power plant is the clean dark spread (“CDS”). Therefore, the price of emission allowances has a strong influence on the electricity price.

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[28] The cost advantage that arises with increasing output of production, because of inverse relationship between the quantity produced and per-unit fixed costs

For the better orientation of the risk facors related to power plant technology, see the table below.

Table 12: Technology differences

Technology	Unit Size	Capital Cost/MW	Operating Cost	Fuel Cost	CO2 cost	Regulatory risk
Coal	Large	High	Medium	Medium	High	High
CCGT	Medium	Low	Low	High	Medium	Low
Nuclear	Very large	High	High	Low	-	High
Hydro	Large	Very high	Low	-	-	Low
PV	Small	Very high	Low	-	-	High
Wind	Small	Very high	Low	-	-	High

As it is obvious from the above-mentioned table 12 renewables (PV solar plants and wind plants) are capital intensive, but are compensated with low risk characteristics, no fuel and emission allowance costs, and finally are supported by incentive support. On the other hand, this incentive could be subject to regulatory risk (changing incentive conditions retrospectively). Furthermore, the value of the plant is decreased by stochastic and hardly predictable characteristic of production. Coal power plants are also capital intensive project in order to meet criteria of fuel efficiency and environmental rules. Alternatively, gas power plants have the benefit of low capital cost, but the market and political risk of the gas price provide significant disadvantage for the investor.

The following are key building blocks for value-based risk management:

- Appropriate risk metrics due to risk classification
- Risk measurement
- Available risk capital
- Management tools

Due to the purpose of this thesis targeting the energy business valuation approach, this chapter excludes the management tools, risk measurement, and available risk capital problematic chapter and keeps the target primarily on the risk metrics and risk measurement. The risk metrics purpose is to have a global top-level risk metric which is consistent with the risk measurement and available risk capital and suitable for the decision maker or investor. Risk measurement starts with identifying risks of value drivers in a company with their classification and assessing. Afterward it is possible to determine distributions and correlations between risk parameters with individual risk aggregation to obtain the overall risk position for a specific time horizon. Estimating profitability of an investment must be based on data analysis and modelling of the future revenues and their possible volatility. Available financial techniques also help to quantify the impact of these risk on the entire investment value. Generally, energy business distinguishes between the following key categories of risk.

A.1.1. Risk classification

This thesis consider basic classification of the risk factors into four groups as shown in Figure 23 below and also on the risk map – Figure 24. Further specific risks will be assigned to these groups independently on any method to sufficiently capture risk profile of typical energy asset with its possible impact to cash flow of project.

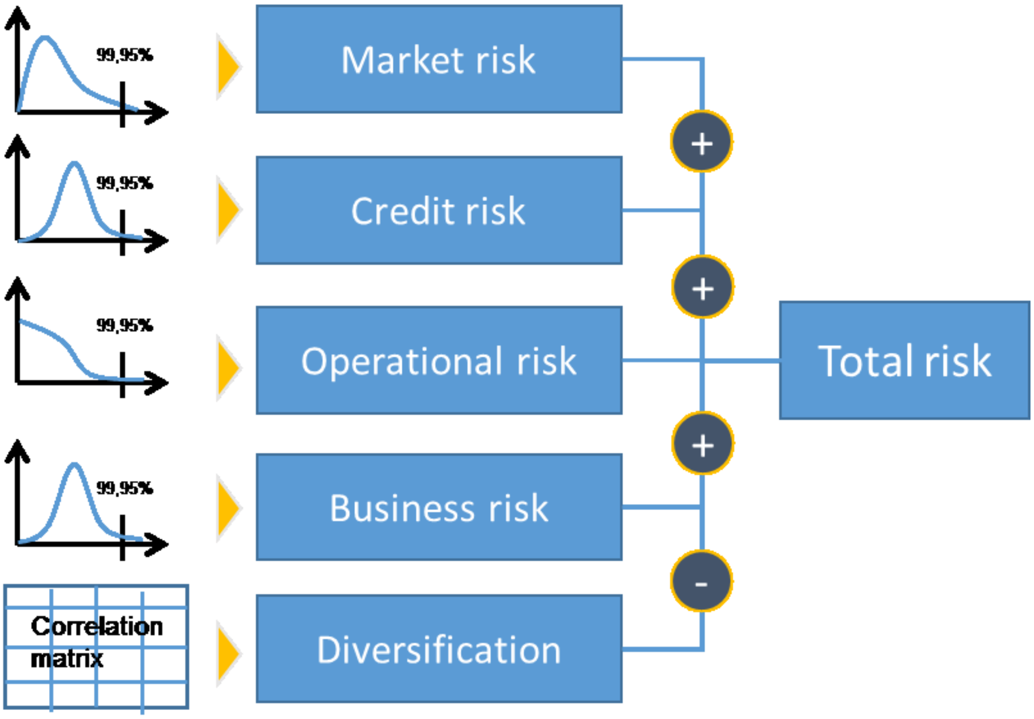


Figure 23: Risk management classification

Market risk

Market risk is defined as a potential risk of loss caused by the value change of closed agreements or open positions on the purchase or sale of electricity. The key assumption is that the change of value is the result of the open positon. As a power plant participating on the wholesale market, there is possibility to close specific agreements with fixed delivery volume without volumetric risk except counterparty or credit risk. Therefore, market risk in the case of a thermal power plant is connected typically with unhedged open position on the sell side of electricity against fuel contract volume. Short position on fuel means the situation when the power plant has already closed a sell future long-term contract on the electricity and hasn't purchase adequate volume of a lignite yet.

On the other hand, a closed long-term contract on the lignite with "take-or-pay" clause without relevant electricity sold means, again, market risk. According to the risk map in Figure 24, this category includes fuel and commodity price risk, foreign exchange risk, and interest rate risk.

Credit risk

The risk of loss from a counterparty failure to meet contractual obligation. Credit risk management is based primarily on the following principles:

- Credit limits based on the shareholder risk tolerance
- Counterparty scoring (risk rating) and review process
- Hedging tools
- Reporting of credit utilization

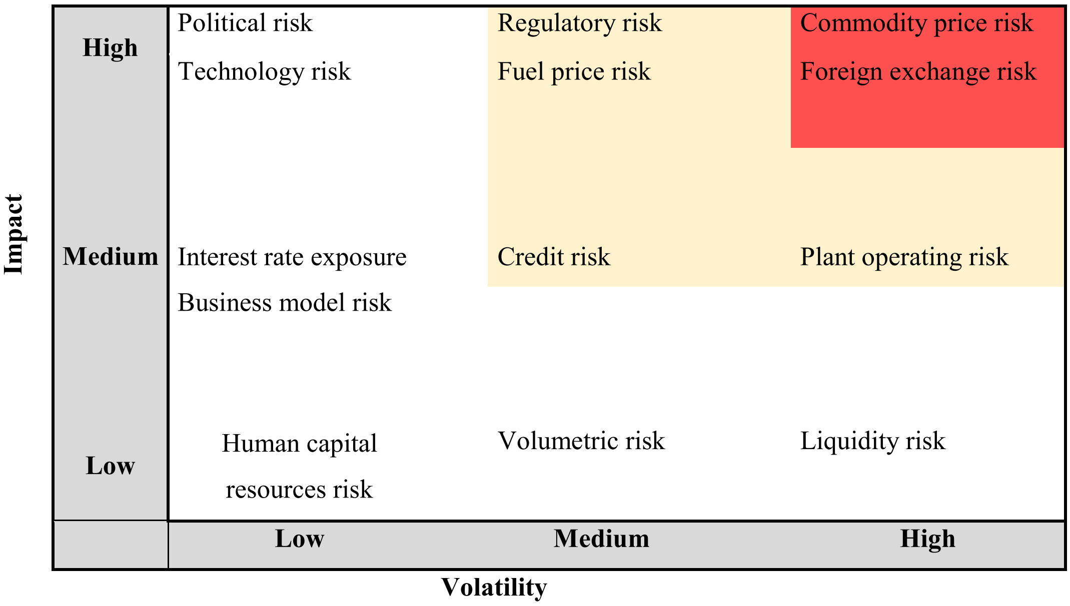
Another important part of risk management is managing contracts and legal documents to maximize credit protection. Effective contract management is typically realized by EFET agreements by specifying clauses regarding thresholds and credit limits. These contracts offer a different way of protection against counterparty default such as netting agreements or the right to demand collateral from a counterparty. Ensuring that collateral is obtained quickly can effectively minimize credit risk. The risk map in Figure 24 incorporates this category to credit risk.

Operational risk

Risk or loss resulting from a breakdown in the internal procedures, people, or systems. Operational risk is not connected with systematic or financial risk. The risk map includes with this category human capital resources risk, plant operating risk, and technology risk.

Business risk

The risk that a company will have lower than anticipated profits or loss. Business risk is influenced by sales volume, fuel and electricity costs, competition, government regulations, and overall economic situation. The presented risk map in Figure 24 includes to this category volumetric risk, regulatory risk, political risk, technology risk, and business model risk. The risk map shown in Figure 24 organizes the risk factors due to their value impact and volatility. This structure is set up for the purpose of the energy utility or the trader. It is evident from the table that factors with high impact and high volatility are commodity price risk and foreign exchange risk, impacting clean dark spread of the power plant.



Impact	Low	Medium	High
High	Political risk Technology risk	Regulatory risk Fuel price risk	Commodity price risk Foreign exchange risk
Medium	Interest rate exposure Business model risk	Credit risk	Plant operating risk
Low	Human capital resources risk	Volumetric risk	Liquidity risk
	Volatility		

Figure 24: Risk map

On Figure 25 below is the illustration of risk factors' impact to revenues and cost of the typical power asset.

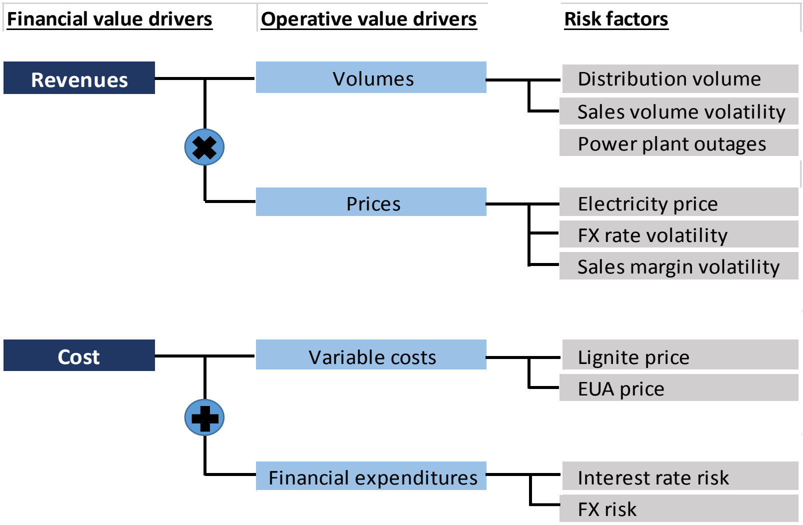


Figure 25: Risk factors

Another important part of the risk-management system is the risk metric which is crucial for the risk exposure valuation. A well-arranged structure is illustrated on the schema below, where is mentioned a description of relevant risk measures, including weaknesses and strengths. This chapter will further describe only commonly used Value ar Risk metrics for illustration.

Table 13: Risk metrics

	Value at Risk (V@R)	Cash Flow at Risk (CF@R)	Capital at Risk (C@R)	Coefficent of Variation (CV)
Description	Statistical estimate of downside exposure of position, measured by NPV or asset values (maximum likely loss within a given confidence limit)	Similar to V@R definition, but uses CF as measure	Represent expected value of capital investments that project requires	Compares standard deviation of investments to expected return
Strengths	Commonly applied	Ability to manage CF volatility, which is directly linked to shareholder value	Strong focus on capital investments	simple to calculate
Weaknesses	Focus on value instead of CF (may not capture price and volume risk adequately)	requires complex analyses of market factors affecting CF	Only investment oriented	Only part of risk measured

Value at Risk (V@R)

The definition of the Value at Risk metric is the maximum loss not exceeded with a given probability defined as the confidence level, over a given period of time.Calculation of VaR has three parameters:

- The time period to be analysed which relates to the time period over which company is committed to holding its portfolio or the time required to liquidate assets or positions. Typical periods using VaR are 1 day, 10 days, or 1 year.
- The confidence level as a probability at which the VaR will not be exceeded by the maximum loss. Commonly used confidence levels are 99% or 95%.
- VaR is given in a unit of the currency.

Many models exist for estimating VaR, each with a specific own set of assumptions, but the most common assumption is based on historical market data. Common models include Variance – covariance method, assuming that risk factor returns are always (jointly) normally distributed and that the change in portfolio value is linearly dependent on all risk factor returns and the historical simulation, assuming that asset returns in the future will have the same distribution as they had in the past (historical market data).

Appendix A.2. Data overview and calculation

Inputs - P&L		2015	2016	2017	2018	2019	2020	2021	2022	2023	2032	2033	2034	2035
Revenues														
Net annual production of power	MWh	**4 063 106**	**4 063 106**	**4 063 106**	**4 063 106**	**3 032 384**	**4 063 106**	**4 063 106**	**4 063 106**	**4 063 106**	**4 063 106**	**4 063 106**	**4 063 106**	**4 063 106**
Block	MWh	4 063 106	4 063 106	4 063 106	4 063 106	3 032 384	4 063 106	4 063 106	4 063 106	4 063 106	4 063 106	4 063 106	4 063 106	4 063 106
Baseload / peakload split														
Off-peakload	%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Peakload	%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Power sales														
Power production - baseload	MWh	2 031 553	2 031 553	2 031 553	2 031 553	1 516 192	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553
Off-peakload power price	EUR/MWh	24,3	23,1	22,6	22,8	23,1	23,3	23,5	23,8	24,0	26,2	26,5	26,8	27,0
Power production - peakload	MWh	2 031 553	2 031 553	2 031 553	2 031 553	1 516 192	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553	2 031 553
Peakload power price	EUR/MWh	42,3	42,1	41,2	41,6	42,0	42,4	42,9	43,3	43,7	47,8	48,3	48,8	49,3
Total power sales	**EUR**	**135 301 434**	**132 355 682**	**129 613 085**	**130 909 216**	**98 677 388**	**133 540 491**	**134 875 896**	**136 224 655**	**137 586 902**	**150 476 768**	**151 981 536**	**153 501 351**	**155 036 365**
Grid support services														
Reservation revenues	EUR	7 884 000	7 726 320	7 571 794	7 420 358	7 271 951	7 126 512	6 983 981	6 844 302	6 707 416	5 592 293	5 480 447	5 370 838	5 263 421
Activation revenues	EUR	1 839 600	1 802 808	1 766 752	1 731 417	1 696 788	1 662 853	1 629 596	1 597 004	1 565 064	1 304 868	1 278 771	1 253 196	1 228 132
Gross margin from power production	%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Costs for capacity activation	EUR	1 471 680	1 442 246	1 413 401	1 385 133	1 357 431	1 330 282	1 303 677	1 277 603	1 252 051	1 043 895	1 023 017	1 002 556	982 505
Grid support services	**EUR**	**8 251 920**	**8 086 882**	**7 925 144**	**7 766 641**	**7 611 308**	**7 459 082**	**7 309 900**	**7 163 702**	**7 020 428**	**5 853 266**	**5 736 201**	**5 621 477**	**5 509 048**
Total revenues	EUR	**143 553 354**	**140 442 564**	**137 538 229**	**138 675 857**	**106 288 696**	**140 999 574**	**142 185 797**	**143 388 358**	**144 607 330**	**156 330 035**	**157 717 737**	**159 122 828**	**160 545 412**

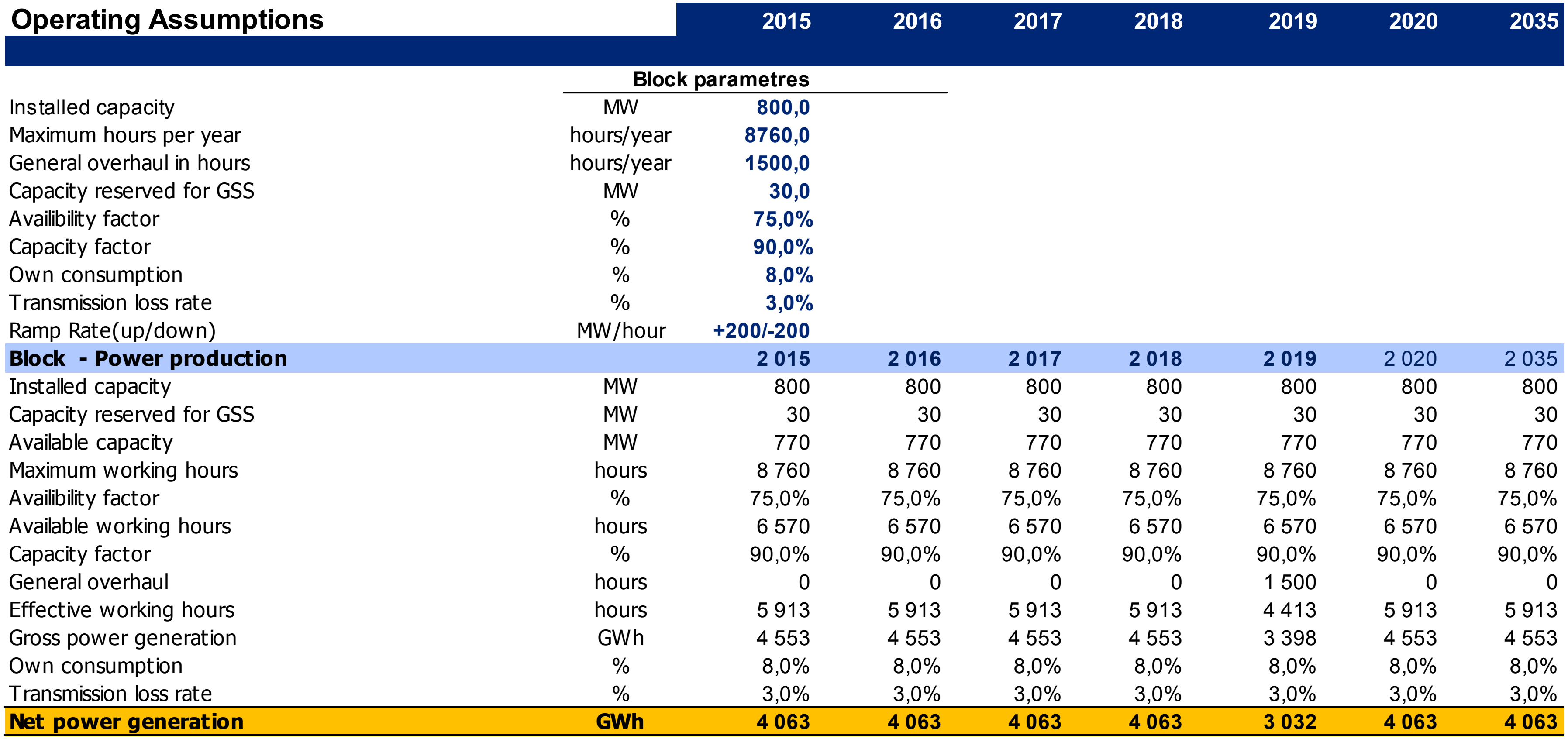
Figure 26: Revenues - case study

Inputs - P&L		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2032**	**2033**	**2034**	**2035**
Variable costs														
Coal consumption														
Gross power production	MWh	4 553 010	4 553 010	4 553 010	4 553 010	3 398 010	4 553 010	4 553 010	4 553 010	4 553 010	4 553 010	4 553 010	4 553 010	4 553 010
Gross power efficiency	%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%	35,0%
Caloric value	GJ/t	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0
Coal consumption	t	3 902 580	3 902 580	3 902 580	3 902 580	2 912 580	3 902 580	3 902 580	3 902 580	3 902 580	3 902 580	3 902 580	3 902 580	3 902 580
Coal price - own purchases	EUR/t	25,0	23,70	23,18	23,41	23,64	23,87	24,11	24,35	24,59	26,87	27,13	27,40	27,67
Total coal costs	EUR	97 564 500	92 496 214	90 449 838	91 345 381	68 848 017	93 163 155	94 085 562	95 017 102	95 957 866	104 855 149	105 893 319	106 941 768	108 000 597
CO2 costs														
CO2 emission factor	t/MWh	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92
CO2 emissions	t	4 188 769	4 188 769	4 188 769	4 188 769	3 126 169	4 188 769	4 188 769	4 188 769	4 188 769	4 188 769	4 188 769	4 188 769	4 188 769
EUA price	EUR/t	7,0	7,0	7,0	7,1	7,1	7,2	7,3	7,4	7,4	8,1	8,2	8,3	8,4
Total CO2 costs	EUR	29 321 384	29 321 384	29 321 384	29 614 598	22 323 036	30 209 852	30 511 950	30 817 070	31 125 240	34 041 217	34 381 629	34 725 445	35 072 700
Other fuel related costs(limestone etc.)														
Costs per MWh	per 1 MWh	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50
Other variable costs for fuel	EUR	6 829 515	6 829 515	6 829 515	6 829 515	5 097 015	6 829 515	6 829 515	6 829 515	6 829 515	6 829 515	6 829 515	6 829 515	6 829 515
Total variable costs	**EUR**	**133 715 399**	**128 647 114**	**126 600 737**	**127 789 494**	**96 268 069**	**130 202 521**	**131 427 027**	**132 663 687**	**133 912 621**	**145 725 881**	**147 104 463**	**148 496 728**	**149 902 812**
Fixed costs														
Personal costs														
Wage inflation			1,50%	1,50%	1,50%	1,50%	1,50%	1,50%	1,50%	1,50%	1,50%	1,50%	1,50%	1,50%
Total personal costs	EUR	2 500 000	2 537 500	2 575 563	2 614 196	2 653 409	2 693 210	2 733 608	2 774 612	2 816 231	3 220 051	3 268 352	3 317 377	3 367 138
Other fixed costs														
Overhead costs (IT, services)	EUR	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000
Repair and maintanance	EUR	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000	2 000 000
Other operating costs	EUR	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000	1 000 000
Reserves for overhaul														
General overhauls	EUR				5 000 000	5 000 000								
Provissions for general overhaul	EUR		3 000 000	3 000 000	2 000 000	2 000 000								
Total fixed costs	EUR	7 500 000	10 537 500	10 575 563	9 614 196	9 653 409	7 693 210	7 733 608	7 774 612	7 816 231	8 220 051	8 268 352	8 317 377	8 367 138
Total costs	**EUR**	**141 215 399**	**139 184 614**	**137 176 300**	**137 403 690**	**105 921 477**	**137 895 731**	**139 160 636**	**140 438 299**	**141 728 853**	**153 945 932**	**155 372 815**	**156 814 105**	**158 269 949**

Figure 27: Costs - case study

Operating Assumptions		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2035**
Commodity prices assumptions								
Baseload	PXE Futures (2015 - 2017), data as of 29.12.2014, source: www.pxe.cz							
Baseload prices (PXE)	EUR/MWh	**33,3**	**32,6**	**31,9**	32,2	32,5	32,9	38,2
growth of baseload prices	%				*1,0%*	*1,0%*	*1,0%*	*1,0%*
Peakload	PXE Futures (2013 - 2015), data as of 29.12.2014, source: www.pxe.cz							
Peakload prices (PXE)	EUR/MWh	**42,3**	**42,1**	**41,2**	41,6	42,0	42,4	49,3
growth of peakload prices	%				*1,0%*	*1,0%*	*1,0%*	*1,0%*
Coal		Prices of the coal mix accoriding to the calculation of EDE Prices						
Coal prices	EUR/t	**25,0**	**25,0**	**25,0**	25,3	25,5	25,8	29,9
growth of coal prices	%				*1,0%*	*1,0%*	*1,0%*	*1,0%*
EUA	EUA Futures (2015 - 2017), data as of 29.12.2014, EEX							
EUA price	EUR/t	**7,0**	**7,0**	**7,0**	7,1	7,1	7,2	8,4
growth of EUA prices	%				*1,0%*	*1,0%*	*1,0%*	*1,0%*
Power to emission conversion								
CO2 emission factor	t/MWh	0,92	0,92	0,92	0,92	0,92	0,92	0,92
Other assumptions								
Gross power generation efficiency	%	35,00%						
Caloric value of coal	GJ/t	12						
Reservation capacity change from 2015 (GSS)	%	-2,00%						
Useful life of assets	years	20						
Corporate income tax rate	%	19,00%						
CO2 emission calculations								
Net power production	MWh	4 063 106	4 063 106	4 063 106	4 063 106	3 032 384	4 063 106	4 063 106
Gross power production	MWh	4 553 010	4 553 010	4 553 010	4 553 010	3 398 010	4 553 010	4 553 010
CO2 emissions	t	4 188 769	4 188 769	4 188 769	4 188 769	3 126 169	4 188 769	4 188 769
CO2 costs	EUR	29 321 384	29 321 384	29 321 384	29 614 598	22 323 036	30 209 852	35 072 700

Figure 28: Operating assumptions I



Operating Assumptions		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2035**
	Block parametres							
Installed capacity	MW	**800,0**						
Maximum hours per year	hours/year	**8760,0**						
General overhaul in hours	hours/year	**1500,0**						
Capacity reserved for GSS	MW	**30,0**						
Availibility factor	%	**75,0%**						
Capacity factor	%	**90,0%**						
Own consumption	%	**8,0%**						
Transmission loss rate	%	**3,0%**						
Ramp Rate(up/down)	MW/hour	**+200/-200**						
Block - Power production		**2 015**	**2 016**	**2 017**	**2 018**	**2 019**	2 020	2 035
Installed capacity	MW	800	800	800	800	800	800	800
Capacity reserved for GSS	MW	30	30	30	30	30	30	30
Available capacity	MW	770	770	770	770	770	770	770
Maximum working hours	hours	8 760	8 760	8 760	8 760	8 760	8 760	8 760
Availibility factor	%	75,0%	75,0%	75,0%	75,0%	75,0%	75,0%	75,0%
Available working hours	hours	6 570	6 570	6 570	6 570	6 570	6 570	6 570
Capacity factor	%	90,0%	90,0%	90,0%	90,0%	90,0%	90,0%	90,0%
General overhaul	hours	0	0	0	0	1 500	0	0
Effective working hours	hours	5 913	5 913	5 913	5 913	4 413	5 913	5 913
Gross power generation	GWh	4 553	4 553	4 553	4 553	3 398	4 553	4 553
Own consumption	%	8,0%	8,0%	8,0%	8,0%	8,0%	8,0%	8,0%
Transmission loss rate	%	3,0%	3,0%	3,0%	3,0%	3,0%	3,0%	3,0%
Net power generation	**GWh**	**4 063**	**4 063**	**4 063**	**4 063**	**3 032**	**4 063**	**4 063**

Figure 29: Operating assumptions II

Financial Summary	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Profit and loss statement										
Currency: EUR										
Revenues total	**143 553 354**	**140 442 564**	**137 538 229**	**138 675 857**	**106 288 696**	**140 999 574**	**142 185 797**	**143 388 358**	**144 607 330**	**145 842 791**
Revenues from the sales of electricity	135 301 434	132 355 682	129 613 085	130 909 216	98 677 388	133 540 491	134 875 896	136 224 655	137 586 902	138 962 771
Revenues from ancillary services	8 251 920	8 086 882	7 925 144	7 766 641	7 611 308	7 459 082	7 309 900	7 163 702	7 020 428	6 880 020
Operating costs	**141 215 399**	**139 184 614**	**137 176 300**	**137 403 690**	**105 921 477**	**137 895 731**	**139 160 636**	**140 438 299**	**141 728 853**	**143 032 426**
Coal consumption	97 564 500	92 496 214	90 449 838	91 345 381	68 848 017	93 163 155	94 085 562	95 017 102	95 957 866	96 907 944
CO2 costs	29 321 384	29 321 384	29 321 384	29 614 598	22 323 036	30 209 852	30 511 950	30 817 070	31 125 240	31 436 493
Other fuel related costs	6 829 515	6 829 515	6 829 515	6 829 515	5 097 015	6 829 515	6 829 515	6 829 515	6 829 515	6 829 515
Personal costs	2 500 000	2 537 500	2 575 563	2 614 196	2 653 409	2 693 210	2 733 608	2 774 612	2 816 231	2 858 475
Other fixed costs	5 000 000	5 000 000	5 000 000	5 000 000	5 000 000	5 000 000	5 000 000	5 000 000	5 000 000	5 000 000
Provisions for general overhauls	0	3 000 000	3 000 000	2 000 000	2 000 000	0	0	0	0	0
	0									
EBITDA	**2 337 955**	**1 257 950**	**361 930**	**1 272 167**	**367 219**	**3 103 842**	**3 025 161**	**2 950 058**	**2 878 478**	**2 810 364**
EBITDA margin	*1,6%*	*0,9%*	*0,3%*	*0,9%*	*0,3%*	*2,2%*	*2,1%*	*2,1%*	*2,0%*	*1,9%*
Depreciation	800 000	800 000	800 000	800 000	800 000	800 000	800 000	800 000	800 000	800 000
EBIT	**1 537 955**	**457 950**	**-438 070**	**472 167**	**-432 781**	**2 303 842**	**2 225 161**	**2 150 058**	**2 078 478**	**2 010 364**
EBT	**1 537 955**	**457 950**	**-438 070**	**472 167**	**-432 781**	**2 303 842**	**2 225 161**	**2 150 058**	**2 078 478**	**2 010 364**
Income tax	292 211	87 010	0	89 712	0	437 730	422 781	408 511	394 911	381 969
Net income	**1 245 743**	**370 939**	**-438 070**	**382 456**	**-432 781**	**1 866 112**	**1 802 381**	**1 741 547**	**1 683 567**	**1 628 395**

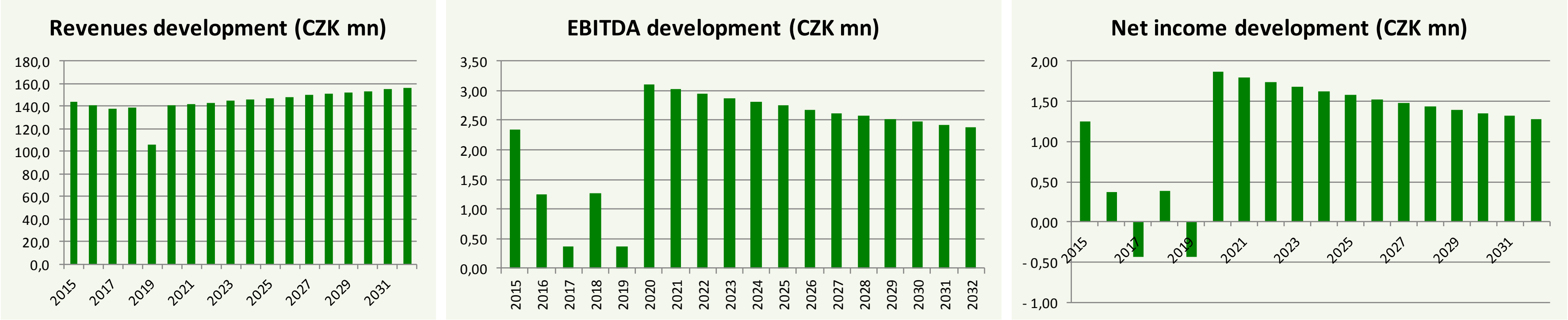
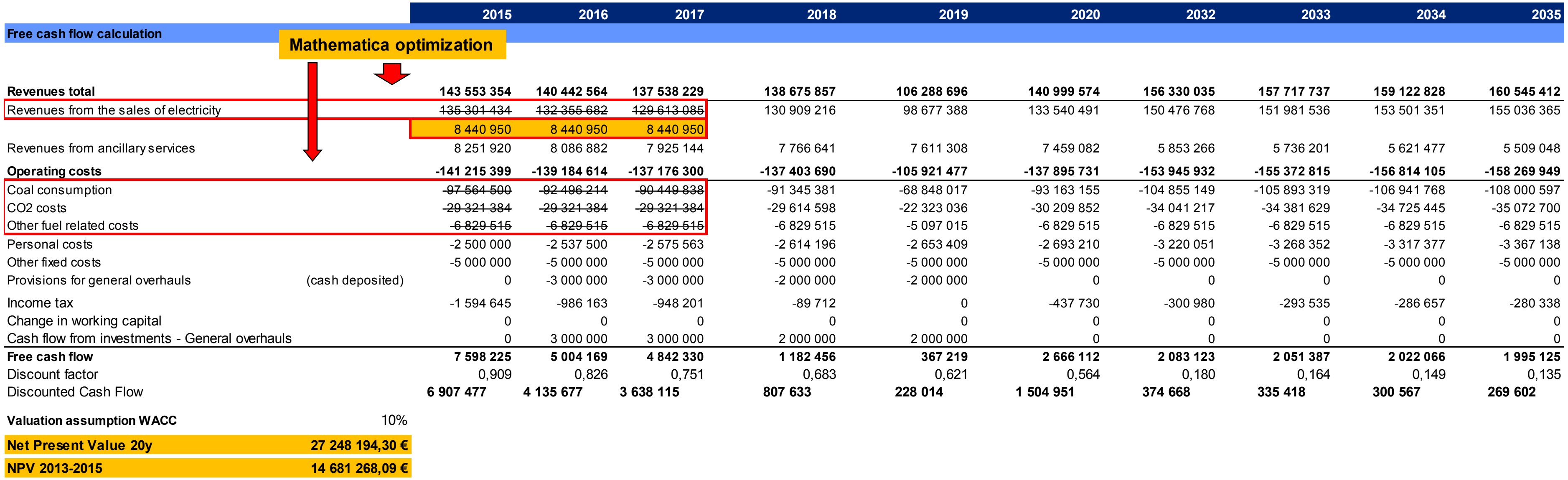
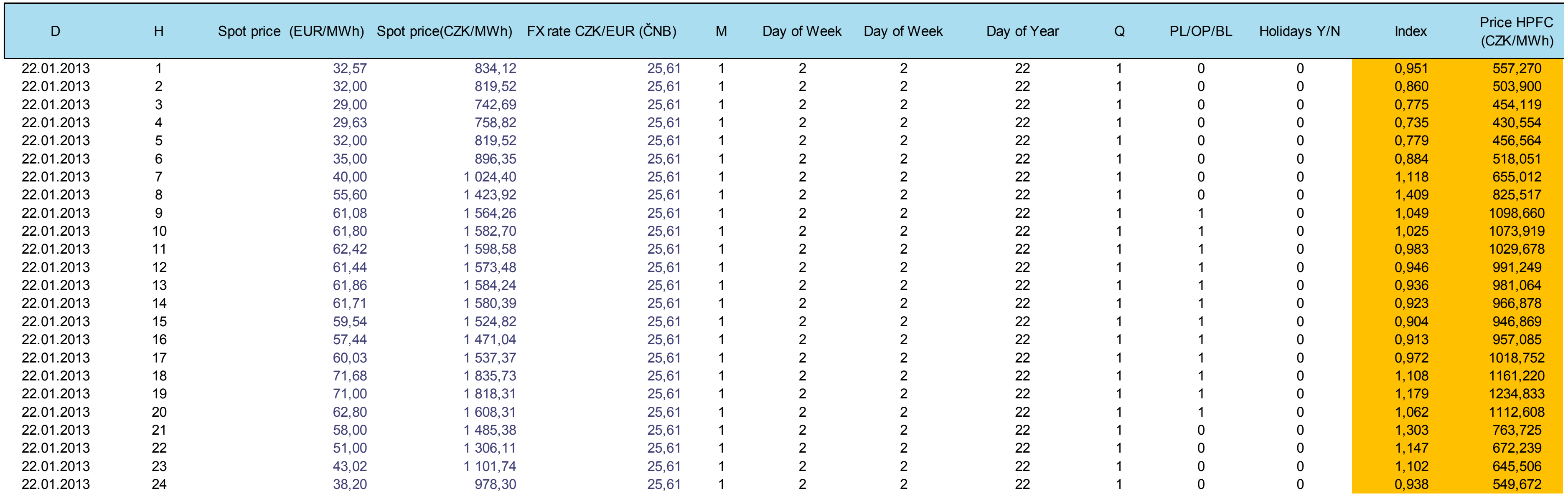


Figure 30: Financial Summary



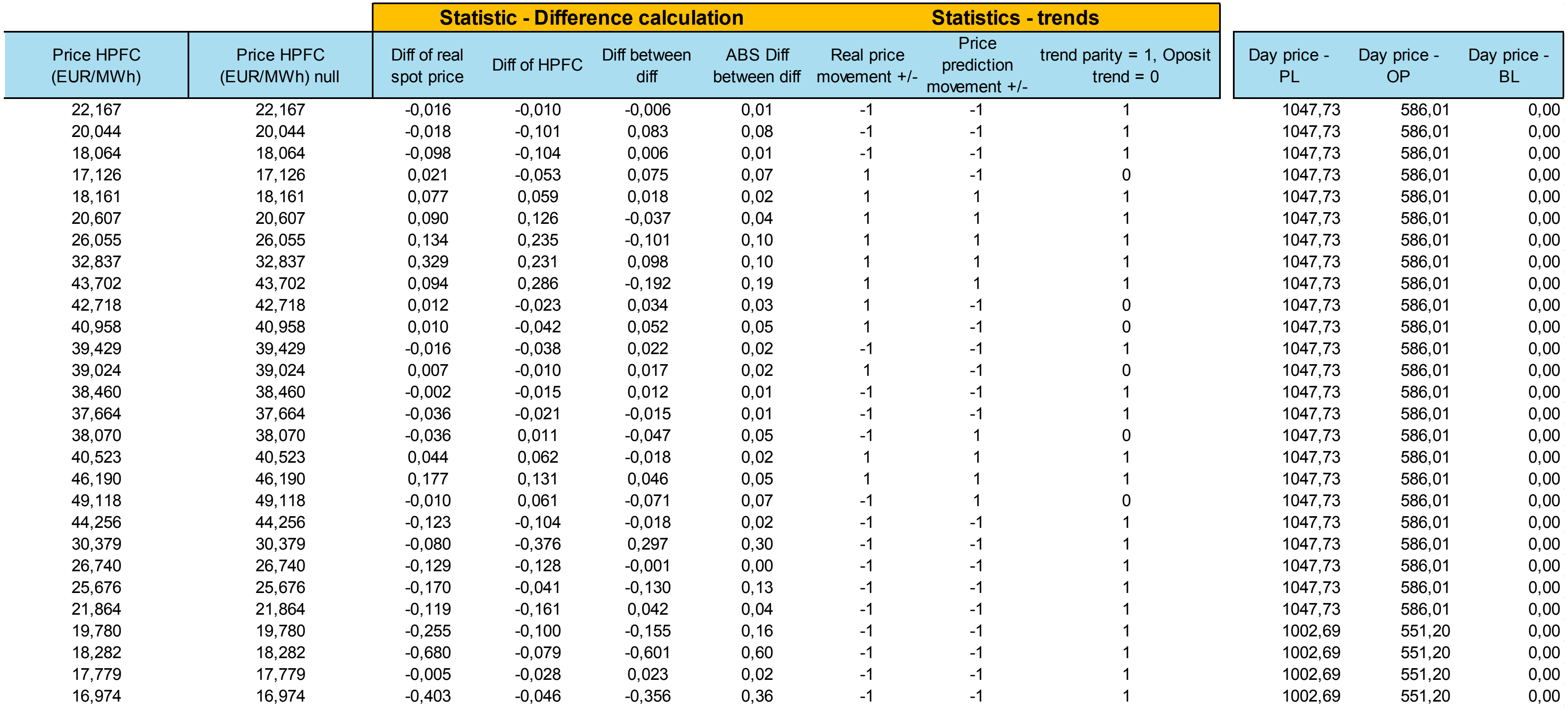
Free cash flow calculation		2015	2016	2017	2018	2019	2020	2032	2033	2034	2035
Revenues total		**143 553 354**	**140 442 564**	**137 538 229**	**138 675 857**	**106 288 696**	**140 999 574**	**156 330 035**	**157 717 737**	**159 122 828**	**160 545 412**
Revenues from the sales of electricity		~~135 301 434~~	~~132 355 682~~	~~129 613 085~~	130 909 216	98 677 388	133 540 491	150 476 768	151 981 536	153 501 351	155 036 365
		8 440 950	8 440 950	8 440 950							
Revenues from ancillary services		8 251 920	8 086 882	7 925 144	7 766 641	7 611 308	7 459 082	5 853 266	5 736 201	5 621 477	5 509 048
Operating costs		**-141 215 399**	**-139 184 614**	**-137 176 300**	**-137 403 690**	**-105 921 477**	**-137 895 731**	**-153 945 932**	**-155 372 815**	**-156 814 105**	**-158 269 949**
Coal consumption		~~-97 564 500~~	~~-92 496 214~~	~~-90 449 838~~	-91 345 381	-68 848 017	-93 163 155	-104 855 149	-105 893 319	-106 941 768	-108 000 597
CO2 costs		~~-29 321 384~~	~~-29 321 384~~	~~-29 321 384~~	-29 614 598	-22 323 036	-30 209 852	-34 041 217	-34 381 629	-34 725 445	-35 072 700
Other fuel related costs		~~-6 829 515~~	~~-6 829 515~~	~~-6 829 515~~	-6 829 515	-5 097 015	-6 829 515	-6 829 515	-6 829 515	-6 829 515	-6 829 515
Personal costs		-2 500 000	-2 537 500	-2 575 563	-2 614 196	-2 653 409	-2 693 210	-3 220 051	-3 268 352	-3 317 377	-3 367 138
Other fixed costs		-5 000 000	-5 000 000	-5 000 000	-5 000 000	-5 000 000	-5 000 000	-5 000 000	-5 000 000	-5 000 000	-5 000 000
Provisions for general overhauls	(cash deposited)	0	-3 000 000	-3 000 000	-2 000 000	-2 000 000	0	0	0	0	0
Income tax		-1 594 645	-986 163	-948 201	-89 712	0	-437 730	-300 980	-293 535	-286 657	-280 338
Change in working capital		0	0	0	0	0	0	0	0	0	0
Cash flow from investments - General overhauls		0	3 000 000	3 000 000	2 000 000	2 000 000	0	0	0	0	0
Free cash flow		**7 598 225**	**5 004 169**	**4 842 330**	**1 182 456**	**367 219**	**2 666 112**	**2 083 123**	**2 051 387**	**2 022 066**	**1 995 125**
Discount factor		0,909	0,826	0,751	0,683	0,621	0,564	0,180	0,164	0,149	0,135
Discounted Cash Flow		**6 907 477**	**4 135 677**	**3 638 115**	**807 633**	**228 014**	**1 504 951**	**374 668**	**335 418**	**300 567**	**269 602**
Valuation assumption WACC	10%										
Net Present Value 20y	**27 248 194,30 €**										
NPV 2013-2015	**14 681 268,09 €**										

Figure 31: Optimized NPV calculation



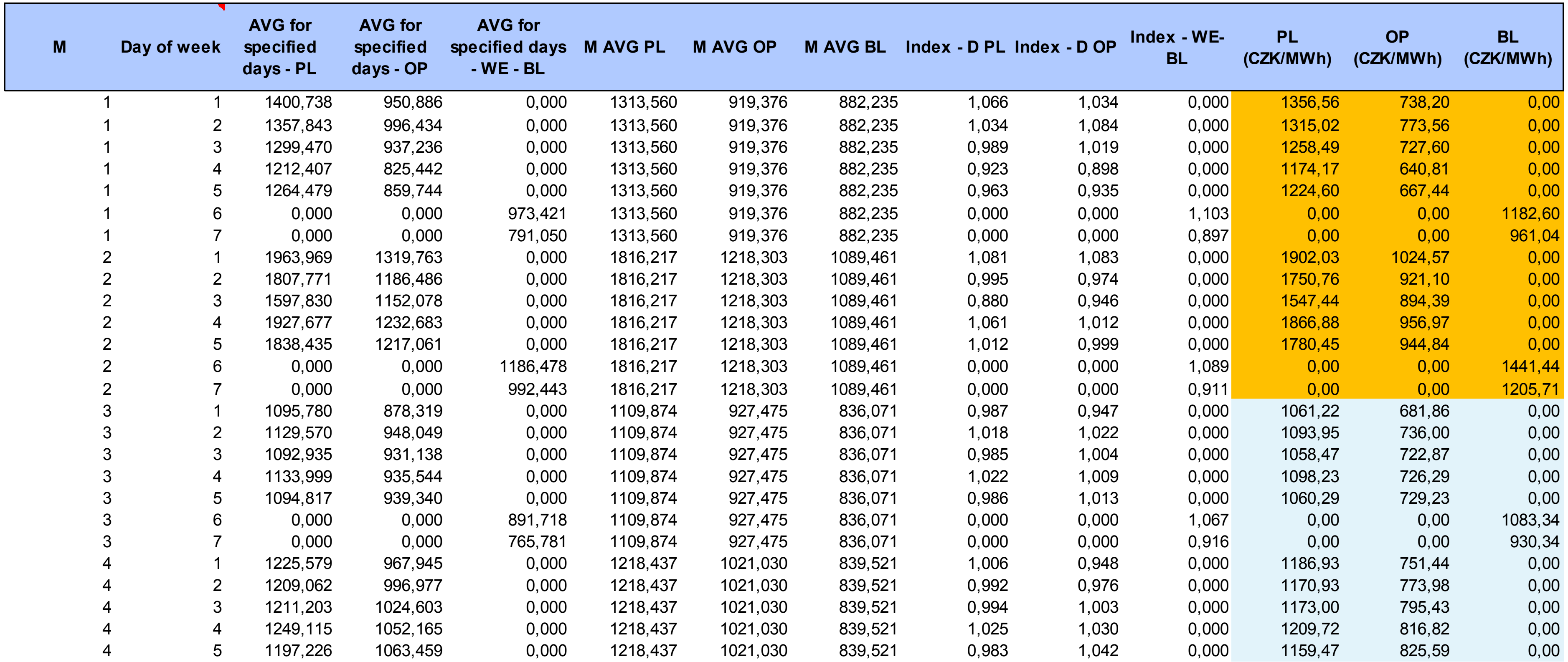
D	H	Spot price (EUR/MWh)	Spot price(CZK/MWh)	FX rate CZK/EUR (ČNB)	M	Day of Week	Day of Week	Day of Year	Q	PL/OP/BL	Holidays Y/N	Index	Price HPFC (CZK/MWh)
22.01.2013	1	32,57	834,12	25,61	1	2	2	22	1	0	0	0,951	557,270
22.01.2013	2	32,00	819,52	25,61	1	2	2	22	1	0	0	0,860	503,900
22.01.2013	3	29,00	742,69	25,61	1	2	2	22	1	0	0	0,775	454,119
22.01.2013	4	29,63	758,82	25,61	1	2	2	22	1	0	0	0,735	430,554
22.01.2013	5	32,00	819,52	25,61	1	2	2	22	1	0	0	0,779	456,564
22.01.2013	6	35,00	896,35	25,61	1	2	2	22	1	0	0	0,884	518,051
22.01.2013	7	40,00	1 024,40	25,61	1	2	2	22	1	0	0	1,118	655,012
22.01.2013	8	55,60	1 423,92	25,61	1	2	2	22	1	0	0	1,409	825,517
22.01.2013	9	61,08	1 564,26	25,61	1	2	2	22	1	1	0	1,049	1098,660
22.01.2013	10	61,80	1 582,70	25,61	1	2	2	22	1	1	0	1,025	1073,919
22.01.2013	11	62,42	1 598,58	25,61	1	2	2	22	1	1	0	0,983	1029,678
22.01.2013	12	61,44	1 573,48	25,61	1	2	2	22	1	1	0	0,946	991,249
22.01.2013	13	61,86	1 584,24	25,61	1	2	2	22	1	1	0	0,936	981,064
22.01.2013	14	61,71	1 580,39	25,61	1	2	2	22	1	1	0	0,923	966,878
22.01.2013	15	59,54	1 524,82	25,61	1	2	2	22	1	1	0	0,904	946,869
22.01.2013	16	57,44	1 471,04	25,61	1	2	2	22	1	1	0	0,913	957,085
22.01.2013	17	60,03	1 537,37	25,61	1	2	2	22	1	1	0	0,972	1018,752
22.01.2013	18	71,68	1 835,73	25,61	1	2	2	22	1	1	0	1,108	1161,220
22.01.2013	19	71,00	1 818,31	25,61	1	2	2	22	1	1	0	1,179	1234,833
22.01.2013	20	62,80	1 608,31	25,61	1	2	2	22	1	1	0	1,062	1112,608
22.01.2013	21	58,00	1 485,38	25,61	1	2	2	22	1	0	0	1,303	763,725
22.01.2013	22	51,00	1 306,11	25,61	1	2	2	22	1	0	0	1,147	672,239
22.01.2013	23	43,02	1 101,74	25,61	1	2	2	22	1	0	0	1,102	645,506
22.01.2013	24	38,20	978,30	25,61	1	2	2	22	1	0	0	0,938	549,672

Figure 32: HPFC curve sample I



		Statistic - Difference calculation				Statistics - trends					
Price HPFC (EUR/MWh)	Price HPFC (EUR/MWh) null	Diff of real spot price	Diff of HPFC	Diff between diff	ABS Diff between diff	Real price movement +/-	Price prediction movement +/-	trend parity = 1, Oposit trend = 0	Day price - PL	Day price - OP	Day price - BL
22,167	22,167	-0,016	-0,010	-0,006	0,01	-1	-1	1	1047,73	586,01	0,00
20,044	20,044	-0,018	-0,101	0,083	0,08	-1	-1	1	1047,73	586,01	0,00
18,064	18,064	-0,098	-0,104	0,006	0,01	-1	-1	1	1047,73	586,01	0,00
17,126	17,126	0,021	-0,053	0,075	0,07	1	-1	0	1047,73	586,01	0,00
18,161	18,161	0,077	0,059	0,018	0,02	1	1	1	1047,73	586,01	0,00
20,607	20,607	0,090	0,126	-0,037	0,04	1	1	1	1047,73	586,01	0,00
26,055	26,055	0,134	0,235	-0,101	0,10	1	1	1	1047,73	586,01	0,00
32,837	32,837	0,329	0,231	0,098	0,10	1	1	1	1047,73	586,01	0,00
43,702	43,702	0,094	0,286	-0,192	0,19	1	1	1	1047,73	586,01	0,00
42,718	42,718	0,012	-0,023	0,034	0,03	1	-1	0	1047,73	586,01	0,00
40,958	40,958	0,010	-0,042	0,052	0,05	1	-1	0	1047,73	586,01	0,00
39,429	39,429	-0,016	-0,038	0,022	0,02	-1	-1	1	1047,73	586,01	0,00
39,024	39,024	0,007	-0,010	0,017	0,02	1	-1	0	1047,73	586,01	0,00
38,460	38,460	-0,002	-0,015	0,012	0,01	-1	-1	1	1047,73	586,01	0,00
37,664	37,664	-0,036	-0,021	-0,015	0,01	-1	-1	1	1047,73	586,01	0,00
38,070	38,070	-0,036	0,011	-0,047	0,05	-1	1	0	1047,73	586,01	0,00
40,523	40,523	0,044	0,062	-0,018	0,02	1	1	1	1047,73	586,01	0,00
46,190	46,190	0,177	0,131	0,046	0,05	1	1	1	1047,73	586,01	0,00
49,118	49,118	-0,010	0,061	-0,071	0,07	-1	1	0	1047,73	586,01	0,00
44,256	44,256	-0,123	-0,104	-0,018	0,02	-1	-1	1	1047,73	586,01	0,00
30,379	30,379	-0,080	-0,376	0,297	0,30	-1	-1	1	1047,73	586,01	0,00
26,740	26,740	-0,129	-0,128	-0,001	0,00	-1	-1	1	1047,73	586,01	0,00
25,676	25,676	-0,170	-0,041	-0,130	0,13	-1	-1	1	1047,73	586,01	0,00
21,864	21,864	-0,119	-0,161	0,042	0,04	-1	-1	1	1047,73	586,01	0,00
19,780	19,780	-0,255	-0,100	-0,155	0,16	-1	-1	1	1002,69	551,20	0,00
18,282	18,282	-0,680	-0,079	-0,601	0,60	-1	-1	1	1002,69	551,20	0,00
17,779	17,779	-0,005	-0,028	0,023	0,02	-1	-1	1	1002,69	551,20	0,00
16,974	16,974	-0,403	-0,046	-0,356	0,36	-1	-1	1	1002,69	551,20	0,00

Figure 33: HPFC curve sample II



M	Day of week	AVG for specified days - PL	AVG for specified days - OP	AVG for specified days - WE - BL	M AVG PL	M AVG OP	M AVG BL	Index - D PL	Index - D OP	Index - WE-BL	PL (CZK/MWh)	OP (CZK/MWh)	BL (CZK/MWh)
1	1	1400,738	950,886	0,000	1313,560	919,376	882,235	1,066	1,034	0,000	1356,56	738,20	0,00
1	2	1357,843	996,434	0,000	1313,560	919,376	882,235	1,034	1,084	0,000	1315,02	773,56	0,00
1	3	1299,470	937,236	0,000	1313,560	919,376	882,235	0,989	1,019	0,000	1258,49	727,60	0,00
1	4	1212,407	825,442	0,000	1313,560	919,376	882,235	0,923	0,898	0,000	1174,17	640,81	0,00
1	5	1264,479	859,744	0,000	1313,560	919,376	882,235	0,963	0,935	0,000	1224,60	667,44	0,00
1	6	0,000	0,000	973,421	1313,560	919,376	882,235	0,000	0,000	1,103	0,00	0,00	1182,60
1	7	0,000	0,000	791,050	1313,560	919,376	882,235	0,000	0,000	0,897	0,00	0,00	961,04
2	1	1963,969	1319,763	0,000	1816,217	1218,303	1089,461	1,081	1,083	0,000	1902,03	1024,57	0,00
2	2	1807,771	1186,486	0,000	1816,217	1218,303	1089,461	0,995	0,974	0,000	1750,76	921,10	0,00
2	3	1597,830	1152,078	0,000	1816,217	1218,303	1089,461	0,880	0,946	0,000	1547,44	894,39	0,00
2	4	1927,677	1232,683	0,000	1816,217	1218,303	1089,461	1,061	1,012	0,000	1866,88	956,97	0,00
2	5	1838,435	1217,061	0,000	1816,217	1218,303	1089,461	1,012	0,999	0,000	1780,45	944,84	0,00
2	6	0,000	0,000	1186,478	1816,217	1218,303	1089,461	0,000	0,000	1,089	0,00	0,00	1441,44
2	7	0,000	0,000	992,443	1816,217	1218,303	1089,461	0,000	0,000	0,911	0,00	0,00	1205,71
3	1	1095,780	878,319	0,000	1109,874	927,475	836,071	0,987	0,947	0,000	1061,22	681,86	0,00
3	2	1129,570	948,049	0,000	1109,874	927,475	836,071	1,018	1,022	0,000	1093,95	736,00	0,00
3	3	1092,935	931,138	0,000	1109,874	927,475	836,071	0,985	1,004	0,000	1058,47	722,87	0,00
3	4	1133,999	935,544	0,000	1109,874	927,475	836,071	1,022	1,009	0,000	1098,23	726,29	0,00
3	5	1094,817	939,340	0,000	1109,874	927,475	836,071	0,986	1,013	0,000	1060,29	729,23	0,00
3	6	0,000	0,000	891,718	1109,874	927,475	836,071	0,000	0,000	1,067	0,00	0,00	1083,34
3	7	0,000	0,000	765,781	1109,874	927,475	836,071	0,000	0,000	0,916	0,00	0,00	930,34
4	1	1225,579	967,945	0,000	1218,437	1021,030	839,521	1,006	0,948	0,000	1186,93	751,44	0,00
4	2	1209,062	996,977	0,000	1218,437	1021,030	839,521	0,992	0,976	0,000	1170,93	773,98	0,00
4	3	1211,203	1024,603	0,000	1218,437	1021,030	839,521	0,994	1,003	0,000	1173,00	795,43	0,00
4	4	1249,115	1052,165	0,000	1218,437	1021,030	839,521	1,025	1,030	0,000	1209,72	816,82	0,00
4	5	1197,226	1063,459	0,000	1218,437	1021,030	839,521	0,983	1,042	0,000	1159,47	825,59	0,00

Figure 34: HPFC curve sample III

M	Q	AVG M PL	AVG M OP	AVG M BL	AVG Q PL	AVG Q OP	AVG Q BL	Index -M PL	Index - M OP	Index - M BL	PL (CZK/MWh)	OP (CZK/MWh)	BL (CZK/MWh)
1	1	1313,560	919,376	882,235	1407,017	1018,694	932,088	0,934	0,903	0,947	1272,13	713,74	1071,82
2	1	1816,217	1218,303	1089,461	1407,017	1018,694	932,088	1,291	1,196	1,169	1758,94	945,80	1323,57
3	1	1109,874	927,475	836,071	1407,017	1018,694	932,088	0,789	0,910	0,897	1074,87	720,02	1015,73
4	2	1218,437	1021,030	839,521	1228,711	973,873	766,595	0,992	1,048	1,095	1180,01	792,65	1019,92
5	2	1173,629	959,967	762,574	1228,711	973,873	766,595	0,955	0,986	0,995	1136,62	745,25	926,44
6	2	1293,578	942,868	697,243	1228,711	973,873	766,595	1,053	0,968	0,910	1252,78	731,97	847,07
7	3	1309,013	970,173	765,833	1355,704	1038,579	850,046	0,966	0,934	0,901	1267,73	753,17	930,40
8	3	1357,427	1074,980	895,174	1355,704	1038,579	850,046	1,001	1,035	1,053	1314,62	834,54	1087,54
9	3	1402,766	1066,521	889,735	1355,704	1038,579	850,046	1,035	1,027	1,047	1358,53	827,97	1080,93
10	4	1376,858	971,643	883,654	1456,106	932,985	835,649	0,946	1,041	1,057	1333,43	754,31	1073,54
11	4	1486,531	938,684	855,657	1456,106	932,985	835,649	1,021	1,006	1,024	1439,65	728,73	1039,53
12	4	1520,183	876,625	788,038	1456,106	932,985	835,649	1,044	0,940	0,943	1472,24	680,55	957,38
13	5	769,431	264,854	784,685	769,431	264,854	784,685	1,000	1,000	1,000	745,16	205,61	953,31

Figure 35: HPFC curve sample IV

Q	AVG Q PL	AVG Q OP	AVG Q BL	Index -Q PL	Index - Q OP	Index -Q BL	PL (CZK/MWh)	OP (CZK/MWh)	BL (CZK/MWh)
1	1407,017	1018,694	932,088	1,048	1,054	1,105	1362,64	790,84	1132,38
2	1228,711	973,873	766,595	0,915	1,008	0,909	1189,96	756,04	931,33
3	1355,704	1038,579	850,046	1,010	1,075	1,008	1312,95	806,28	1032,71
4	1456,106	932,985	835,649	1,085	0,966	0,990	1410,18	724,30	1015,22
5	769,431	264,854	784,685	0,573	0,274	0,930	745,16	205,61	953,31

Figure 36: HPFC curve sample V

Appendix A.3. Mathematica Notebook Code

Wolfram Mathematica 9.0 Notebook code with the optimization algoritm follows. Nine pages of A.3 have numbering from the Mathematica environment. This code is attached separately.