E.ON Energy Research Center



E.ON Energy Research Center Series

Economic and Technical Evaluation of Enhancing the Flexibility of Conventional Power Plants

Barbara Glensk, Christiane Rosen, Ralf Bachmann Schiavo,
Sedigheh Rabiee, Reinhard Madlener, Rik W. De Doncker

Volume 7, Issue 3

RWTHAACHEN UNIVERSITY

E.ON Energy Research Center

E.ON Energy Research Center Series

Economic and Technical Evaluation of Enhancing the Flexibility of Conventional Power Plants

Barbara Glensk, Christiane Rosen, Ralf Bachmann Schiavo, Sedigheh Rabiee, Reinhard Madlener, Rik W. De Doncker

Volume 7, Issue 3

RWTH AACHEN UNIVERSITY

Contents

1 Executive Summary

The high shares of renewable energy sources in Germany and their low variable cost and promotion by means of guaranteed feed-in tariffs pose several challenges for the profitable operation of many modern conventional power plants. At the moment, conventional power plants are necessary to guarantee an adequate and stable functioning of the electricity system, even more so due to the fluctuating nature of the two dominant renewable energy sources, solar and wind. However, in recent years, conventional generation technologies have often been out-of-the-money, thereby placing a strain on the recovery of long-term investments. In order for conventional power plants to return to a profitable operation, they will have to be able to react in a more flexible manner to the fluctuations caused by renewables. An increased flexible operation could be achieved e.g. by the implementation of additional technical components as well as the introduction of new market mechanisms.

From this perspective, the first aim of this project was the analysis of the possible technical solutions needed to increase the flexibility of conventional power plants. The second aim of this project was the examination of current and possible future market designs to determine the most profitable markets for a new generation of more flexible power generation plants.

In order to achieve our goal of assessing the economic value of enhanced flexibility, the main objective of our work was the development of two real options models, acknowledging that the standard discounted cash flow model under today's market conditions can yield dangerous guidance to decision-makers and is, therefore, in many cases inadequate. First, we developed a model for the optimal timing of disinvestment, which simulates the situation occurring whenever the profitable operation of the analyzed power plant is no longer possible. Second, we proposed a real options model for the flexible operation of an enhanced gas-fired power plant and analyzed the investment in technical improvements.

The starting point of our research was an analysis of the specific technical aspects evaluated in the project. At the same time, a short review of real options theory in the context of the energy sector was followed by the development of the two real options models. An application of these models to the highly efficient gas-fired power plant was conducted to illustrate the functionality of the proposed approach. Finally, based on the principles that guide real options modeling, we estimated the "fair price" – a price that takes power generation costs as well as the costs of the flexibility-enhancing technological improvements realized explicitly into account.

The results obtained in this project could indeed improve the decision-making process for such long-term asset investments by taking into consideration the uncertainty and risks that are accounted for in the models. Nevertheless, based on the presented conclusions, the application of the real options approaches adopted needs further investigation, especially regarding the definition of the underlying asset.

Based on the results from these analyses, an interesting and important future research topic would be the development of a decision-making support tool that could be applied for investing in different technologies, such that the decision-maker (or investor) could choose between different parameters as decision variables (i.e. the underlying asset) in order to account for the prevailing market situation.

2 Introduction

In recent years, certain types of relatively modern conventional power plants, especially in Germany and other EU countries, have experienced unfavorable market conditions, which have led to difficulties in their profitable operation. As a consequence, highly efficient plants have been underutilized, and thus often unprofitable, or even decommissioned despite their state-of-the-art technical properties. This has brought up several questions concerning investments in this type of asset.

From an economic point of view, power generation technologies are (in most cases) characterized as irreversible investments with uncertain future rewards, but with the possibility of flexible timing as to when the investment can occur (Dixit and Pindyck, 1994, p.3). The success of the investment and, therefore, any future rewards, is uncertain because the price development cannot be perfectly predicted. Hence, a flexible timing of the investment is generally viewed favorably, especially with the prospect of increasing CO_2 and/or electricity prices, sunk costs, or advantageous market conditions at some point in the future.

A relatively new methodology for evaluating investment projects with uncertainties has been introduced with the real options approach (Dixit and Pindyck, 1994; Schwartz and Trigeorgis, 2001). This valuation technique is based on option pricing methods used in finance and developed by Black, Scholes, and Merton (Black and Scholes, 1973; Merton, 1973), who based their valuation on partial differential equations in continuous time and a closed-form solution. Cox et al. (1979) later developed a binomial lattice model for the numerical valuation of real options in discrete time.

Under current market conditions, modern, highly energy-efficient and newly-built gas-fired power plants (e.g. Irsching Block 5) often cannot be operated profitably. Also many other conventional (e.g. coal-fired) steam power plants have problems with the fluctuating generation of renewables-based power plants and cannot adjust their power generation to the changing market conditions. Along with reduced start-up times, these power adjustments are required to improve their ability of co-generation with volatile sources that are given priority in dispatching. As operating a power plant more flexibly may improve its profitability, some potentially cost-effective options for increasing the flexibility of steam power plants will be discussed and analyzed within the project.

On the management side, this leads to two possible actions relative to the wait-and-see strategy: One is to decide to disinvest and liquidate the plant; another is to invest in more flexibility. Both possibilities are to be scrutinized in this project using an interdisciplinary approach. From a financial point of view, both paths constitute options. These can be valued using a real options approach, which is an adaptation of conventional options theory for capital investment projects (for a useful overview of state-of-the-art research in this field see Rohlfs and Madlener, 2014a; Rohlfs and Madlener, 2014b; Rohlfs and Madlener, 2013 or Rohlfs and Madlener, 2011). Two real options models would be developed in detail for conventional power plants. They will be constructed in such a way that they can be applied to a number of different (large-scale) power generation technologies, including gas-fired power plants. The first one is the disinvestment option, in which the optimal timing is an essential parameter for the maximal profit. One important influence here is the fuel price, which impacts the resale price of the components significantly through the expected future profits that are to be obtained by the buyer. The second option considers the chance of operating the existing power plant more flexibly using additional components, such as power electronic converters, storage systems, or upgrades of the existing components. An increased flexibility can have several effects. By being able to control the power plant more efficiently, markets where ramp-up times are crucial might be entered more easily. Furthermore, when lower levels of power are required, the adjustment can be achieved quickly without substantial loss of power plant efficiency. As a limiting factor, the minimum feasible load level needs to be determined as well as the efficiency factors at several working points. Moreover, the investment in upgrading equipment can be regarded as irreversible, thus justifying the real options approach.

2.1 Goals and project outcome (objective of the project) / Added value

The main goal of this research project was to find a way to make conventional power plants more flexible in operation and, at the same time, more profitable. In particular, the following objectives ware formulated: (1) the development of a real options model for the optimal timing of *dis*investment in conventional power plants (in contrast to the optimal investment timing – a common research subject in this field); (2) the development of a real options model for the flexible operation of an enhanced gas-fired power plant, undertaken in collaboration with the Institute for Power Generation and Storage Systems (PGS) and focusing on the technical modifications which can support the increase of flexibility; (3) the examination of current and possible future market designs to determine the most profitable markets for enhanced power plants; (4) the analysis of the possible improvements for large-scale conventional power plants to increase flexibility; (5) the analysis of the technical solutions required to increase the flexibility of small gas-fired power plants with power electronics for the main generator.

This interdisciplinary approach involving both engineering and economic expertise goes beyond standard approaches used in practice (e.g. static and standard project valuation methods, such as the net present value method) and is a further development of the classic valuation methods used in decision-making processes. Moreover, the models developed for gas-fired power plants can be easily transferred to other conventional power generation technologies in operation today.

2.2 Prior art, state-of-the-art, technology background (at state of project)

Real options theory, developed by Dixit and Pindyck (1994), Trigeorgis (1996), and Schwartz and Trigeorgis (2001), is based on the framework used for the pricing of financial options developed by Black, Merton and Scholes (Black and Scholes, 1973; Merton, 1973), and extended for real assets. This project evaluation method goes beyond the traditional approaches taking into account the irreversible character of the investment, uncertainties of future rewards, and the flexibility regarding a decision's timing. According to this theory, a decision-maker has the right, but not the obligation, to invest (or disinvest, abandon, expand, contract etc.) or to wait until better market information is available. The methodology developed by Dixit and Pindyck (1994) has raised the interest in the use of the real options analysis in different sectors of the economy, including energy sector, as an evaluation approach especially for projects under uncertainty. In comparison to traditional methods, real options theory benefits from uncertainty and focuses on the valuation of managerial flexibility.

In a decision-making process, the energy utilities are confronted with a complex and uncertain future. The increase in competition and sources of risk (such as market or regulatory risks) makes the decision process more difficult and forces the energy providers to change their decision support toolbox. The application of real options analysis (ROA) provides the opportunity to adequately capture the uncertainties and dynamics of energy market development in situations of managerial flexibility and irreversible investment[1].

2.3 Positioning of the project within the E.ON ERC strategy

From an electricity provider's point of view, we aim at capturing the changing and complex dynamics of the energy market, especially regarding the increase in use of renewable energy technologies and the issues associated with the profitable operation of conventional (e.g. gas-fired) power plants. The analysis of the operation of conventional power plants from a technical as well as an economic perspective is an important focus of the E.ON Energy Research Center (E.ON ERC). The present project touches upon important problems in energy system modeling in general, and the optimal composition of future energy technology mixes in particular, one of the strategic goals of E.ON ERC.

[1] The term "irreversible investment" refers to a situation where an investment involves sunk costs, i.e. that it cannot be reversed, as in the case of financial assets, either due to technical/practical reasons (e.g. dismantling of a hydro power dam or a nuclear power plant) or because the asset cannot be sold easily in a secondary market due to inexistence or illiquidity of such a market.

3 Results of work packages based on list of deliverables / Accomplishments

3.1 Technical solutions to increase the flexibility of conventional power plants

The German power system is experiencing a substantial transition. It is expected that by the year 2020, 40% of electric energy in Germany will be generated by renewable energy sources, mainly solar and wind power (see VDE, 2012b; Agora, 2013). In this scenario, only between 10 GW and 25 GW from conventional power generation will be required for between 6,000 and 8,000 hours per year. This means that conventional power plants will no longer be operated to supply the base load.

An example of this effect can be seen in Figure 3.1, which presents the power demand and generation traces of renewable and conventional sources. The difference between the demand and the power generation of renewable energy sources is defined as the residual load, which should be supplied by conventional power plants in order to match supply and demand.

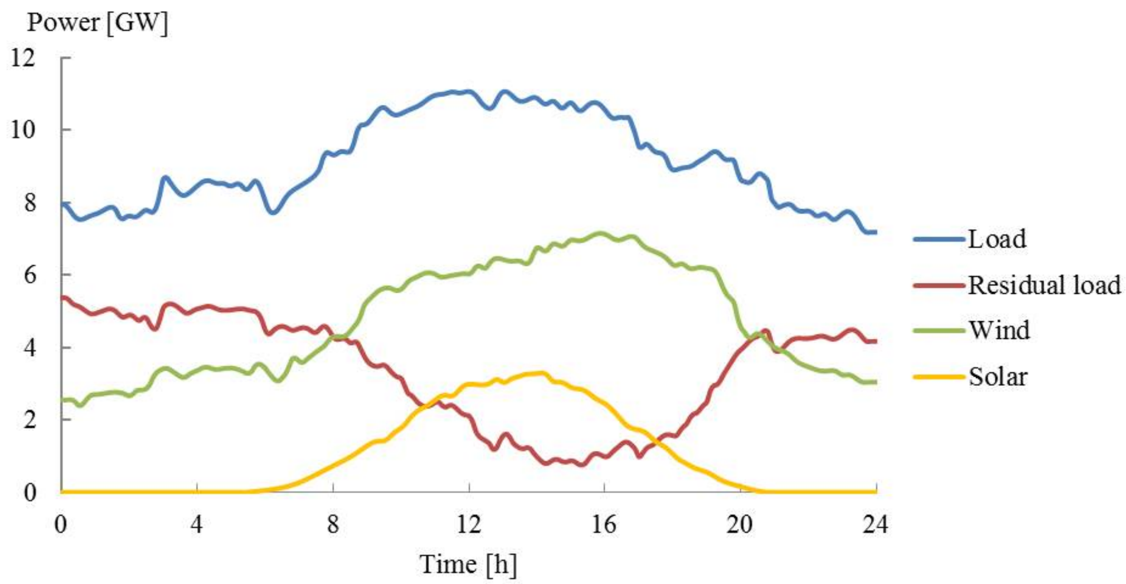


Figure 3.1: Traces of generated energy from renewable sources and fossil-fired power plants (residual load) in the 50Herz transmission system, May 12, 2012 (50Hertz, 2015a)

Now, conventional power plants need to adjust their operating point and cycle to follow the residual load. In order to fulfill this increasingly demanding task, it is advantageous to modify the plants in such a way as to obtain more convenient technical characteristics, such as faster starting time, lower starting cost, wider loading range, higher efficiency, and larger loading gradients. The dynamic characteristics are represented in Figure 3.2 (stylized).

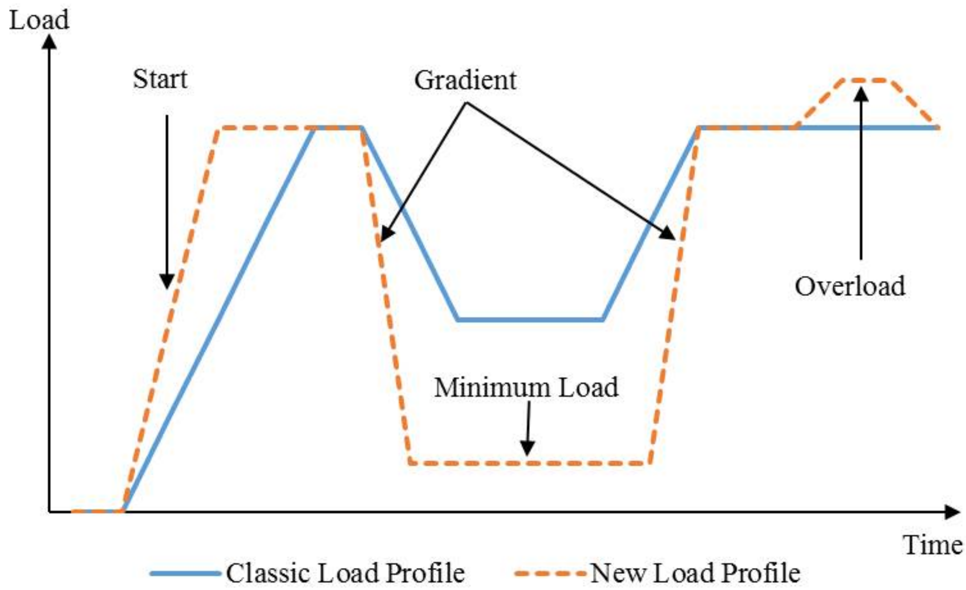


Figure 3.2: Flexibility enhancement of a power plant, stylized (Schimkat, 2013)

On the one hand, due to the higher fuel cost and lower capital investment, gas-fired single and combined cycle power plants are typically optimized as peaking power plants. Therefore, they can respond to residual load changes rapidly. On the other hand, coal-fired power plants are typically used to supply the base-load, due to the cheaper fuel and the long time constants of the thermal processes inherent to the steam cycle. Table 3.1 summarizes the dynamic characteristics of different types of conventional power plants.

Table 3.1: Dynamic characteristics of conventional power plants based on VDE (2012b). The first value represents typical values which satisfy the requirements; the second value represents the state-of-the-art of the technology; the third value represents the potential performance according to the technical literature

Characteristic	Hard coal	Lignite	Gas turbine combined cycle	Gas turbine single cycle
Load gradient (% of nominal / min)	1.5 / 4 / 6	1 / 2.5 / 4	2 / 4 / 8	8 / 12 / 15
Minimum load (% of nominal)	40 / 25 / 20	60 / 50 / 40	50 / 40 / 30	50 / 40 / 20
Hot start time (< 8 h)	3 / 2.5 / 2	6 / 4 / 2	1.5 / 1 / 0.5	<0.1
Cold start time (> 48 h)	10 / 5 / 4	10 / 8 / 6	4 / 3 / 2	<0.1

Given the inferior dynamic performance, the main focus of our investigation lies on coal-fired power plants. An alternative approach also considered in this work is the deployment of different generation and storage technologies which are capable of partially compensating the fluctuation of renewable power generation, thus reducing this burden from less flexible conventional power plants.

3.1.1 Solutions for large-scale thermal power plants

In this section, the solutions that are applicable to coal-fired power plants of rated power larger than 100 MW are presented.

Variable speed drives

The power consumption of the auxiliary loads within a thermal power plant ranges from 7% to 15% of the plant's nominal power when operating at nominal conditions (see ABB, 2009). This value is largely dependent on the air pollution abatement equipment (if installed), fuel variability, thermodynamic cycle set-up, and performance degradation (aging) of the power plant.

The auxiliary loads are mostly composed of pumps and fans. Dampers and throttling valves are widely used for water and air flow regulation. However, this approach is inefficient at partial load, because the amount of energy consumed by the pumps and fans is considerably higher than the amount theoretically required to produce the reduced flow.

In order to evaluate the efficiency improvement that variable speed drives can introduce to the power plant, the affinity laws for pumps and fans should be considered:

- the flow is proportional to the shaft speed,
- the pressure is proportional to the square of the shaft speed,
- the power is proportional to the cube of the shaft speed.

By running the pumps and fans at just the speed required to supply the required air and water flow, their power consumption can be reduced, thus increasing the overall system efficiency. Furthermore, pump and fan drive systems are typically over-sized, considering various contingency factors such as the deviation of air or gas density especially during unit start up, when the air or gas is colder than normal and there are draft system leakages, deviations in draft system resistance, and abnormal operations due to pluggage of draft system components (see IEEE, 2003). This means that even at nominal operation of the power plant, the auxiliary loads are operating at partial load, and the variable speed drive can contribute to efficiency gains in these circumstances as well.

Other positive effects of using variable speed drives for pumps and fans are:

- soft start: reduction of the starting current,
- power factor correction,
- motor monitoring and protection.

Several examples of the benefits obtained in retrofitted power plants are presented in ABB (2009).

Medium-voltage DC system for auxiliary loads

This measure is proposed by De Doncker R. (2011), and is recommended for steam power plants with carbon capture technology, such as the one presented in Figure 3.3. In such power plants, the CO_2 resulting from the combustion process is liquefied by a compressor, which is rated at approximately 5% of the nominal electric power of the plant. This compressor is typically driven by a steam turbine. Steam is fed to this turbine from the same steam generator that feeds the main turbine. This additional auxiliary load obviously reduces the overall power plant efficiency.

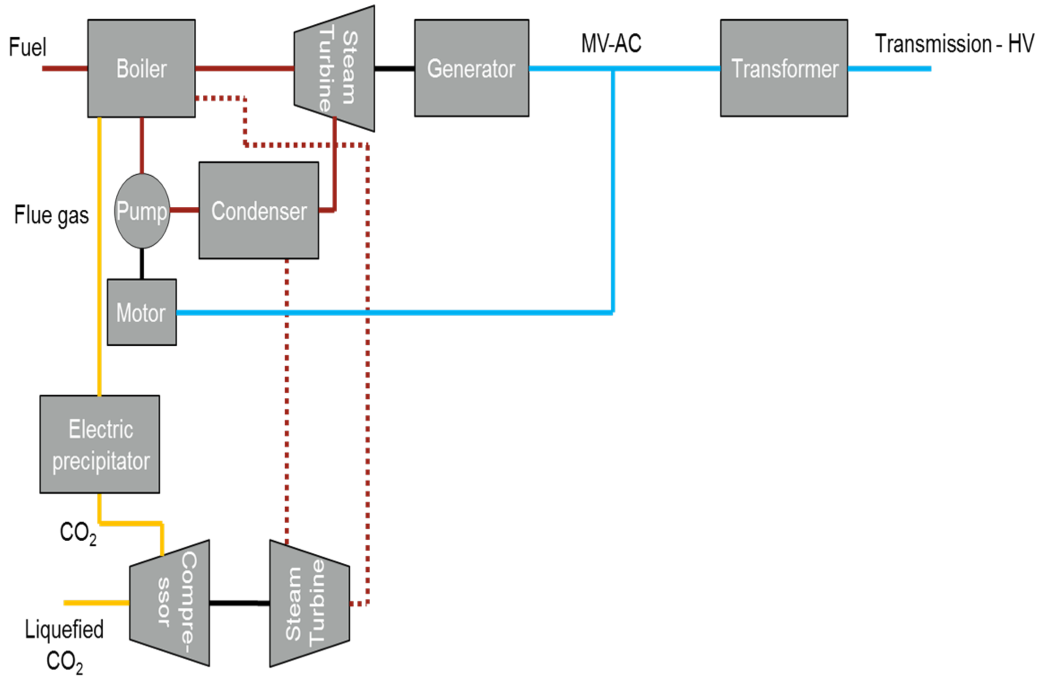


Figure 3.3: Flowchart of a steam power plant with carbon capture technology

Carbon capture retrofitting of existing power plants requires considerable infrastructure modifications. In order to simplify its implementation, a medium-voltage direct-current (MVDC) system is proposed, as presented in Figure 3.4. An active medium-voltage rectifier connected to the AC medium-voltage bus bar is used to feed a DC bus bar. A frequency converter is used to control a speed-variable electric machine, which drives the compressor, thereby avoiding the need for a steam turbine.

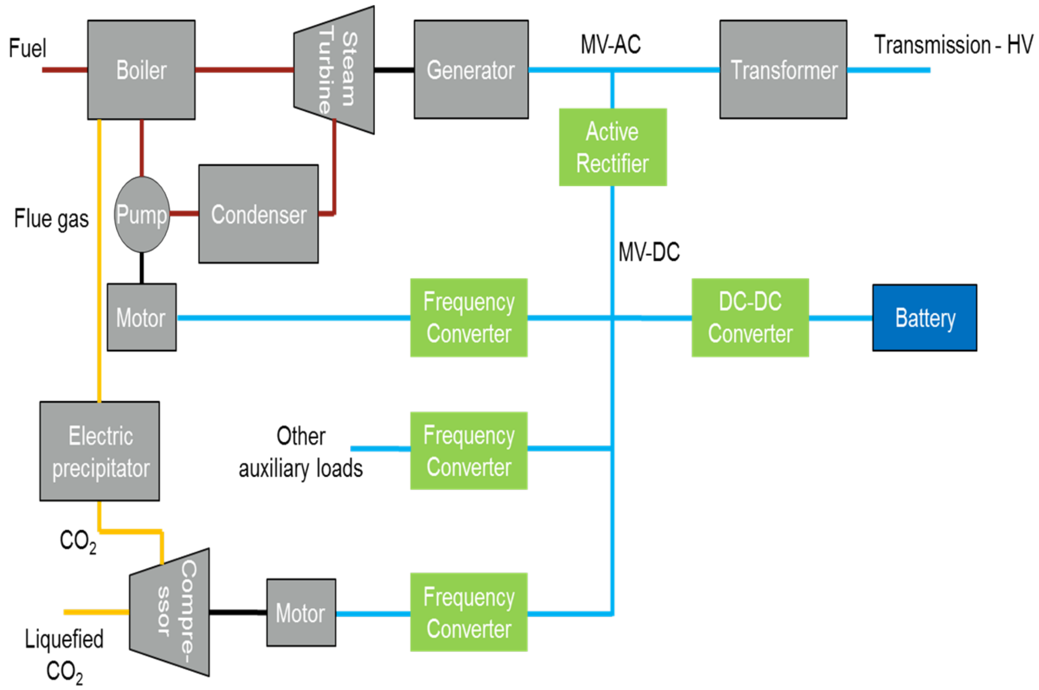


Figure 3.4: Steam power plant with carbon capture and storage improved by a medium-voltage direct-current (MVDC) system for auxiliary load and storage system connection

This implementation offers several advantages. The active rectifier can be used for power factor correction, optimizing the utilization of the generator. Furthermore, as mentioned in the previous section, the auxiliary loads may be driven by frequency converters in order to improve technical efficiency due to speed variability. The direct connection of the frequency converters to the DC system allows cost reductions and efficiency improvements, because the rectifier stage is no longer necessary.

Furthermore, the MVDC system simplifies the integration of batteries since only DC-DC converters are required. The batteries can be used to compensate short-term load variations, which avoid adjusting the operating point of the steam turbine. Additionally, primary and secondary reserves can be provided by the batteries depending on the dimensioning of the system. Furthermore, the power plant is able to start without absorbing electric energy from the grid (black-start), because the batteries can supply the auxiliary load during the start-up.

The proposed dimensioning of the storage system is 5% of the nominal electric power of the plant. It is estimated by De Doncker R. (2011) that 6% of the output energy of the plant can be saved. The main reason is that some unfavorable operation scenarios may be avoided in some circumstances, such as adjusting the operating point of the turbine for short-term load changes, operating the turbine at partial load, and keeping the plant as rotating reserve. The proposed concept can be implemented in existing power plants and does not require changes to the main turbine system, which minimizes the need for a long term shutdown of the power plant.

Firing system modernization

Several improvements of the firing system of thermal power plants are mentioned by Plewnia (2014), based on the proposals made by Maaß (2013). The main points are summarized in this section. Unless specifically mentioned, the proposals are intended for hard coal power plants.

Since coal-fired power plants have historically been run as base-load plants, the coal mills and the burner are typically optimized for efficient operation at around the nominal load. The interaction of both components can, however, be optimized for a broader range of efficient operation and a stable burning process. With this modification, the minimum load of the power plant can be reduced, and the efficiency in part load operation increased. The implementation of this improvement is expected to take nearly six months (Maaß, 2013).

An upgrade of the burners can reduce the minimum firing level while maintaining stable combustion. This results in a reduction of the minimum load and consequently of emissions. Additionally, stabilizing the burning process increases the load gradient capability. A down-time of nearly one and a half months is expected for this upgrade (Maaß, 2013).

In the case of lignite power plants specifically, Maaß (2013) suggests the conversion to dry lignite power plants for optimizing the ignition process, auxiliary firing, and operational firing. The lignite is ground and dried through a heat changer and by hot steam before being injected into the burner. The lignite is also stored in silos to supply the burner during discontinuities in fuel supply. The minimum firing rate is reduced to 10%, reducing the minimum load. Load gradient and efficiency are increased, and the dry lignite can replace the more expensive oil used for starting up the power plant. The expected upgrade time is eighteen months, including two to three months at standstill (Maaß, 2013).

Just like for the case of lignite power plants, for hard coal power plants, too, it is possible to add storage silos for the pulverized coal. In this case, the start-up process is decoupled from the grinding process. Additional coal can be ground during times of low demand, and the grinding power can be reduced during times of high demand, thus increasing load gradients by up to 10% (Maaß, 2013). It is worth mentioning that this value is not in accordance with Table 3.1, provided by VDE (2012b).

All the upgrades presented here are expected to cost nearly 30% of the price of a new, equivalent power plant. Additionally, the cost of a lignite drying system is estimated to be nearly € 50 million for 100 tons per hour capacity (Maaß, 2013).

Steam generator

Unless specifically mentioned, the proposals presented here are intended for hard coal power plants.

Bypassing the economizer allows the reduction of the minimum load, at the expense of decreased efficiency. A positive side effect is the increase of the life expectancy of the selective catalytic reduction (SCR). This upgrade demands half a month of power plant outage (Maaß, 2013).

Installing a heat exchanger in the vaporizer contributes to stabilizing the latter and to increasing the mass flux density. This upgrade reduces the minimum load and allows a faster start-up, with lower losses. This installation takes approximately one year, including a two months' outage (Maaß, 2013).

Maaß (2013) also proposes an upgrade of the steam generator together with the steam turbine and the inclusion of a topping gas turbine. The heat of the gas turbine flue-gas is partially transferred to the water in the water/steam cycle. The benefits are a faster start-up and an efficiency improvement of between 2% and 4%. The rated power of the topping gas turbine should not exceed 20% of the rated power output of the power plant. The estimated upgrade time is eighteen months, with a plant outage of between four and nine months, depending on the scope of the upgrade.

In order to start the plant faster, pre-heating of the steam generator is also an upgrade option. During the start-up, the boiler absorbs a considerable amount of heat, and it therefore takes some time until it is able to produce steam. By using external steam or a heat storage system, the steam turbine can be started earlier, thus reducing the start-up time of the power plant. This upgrade is estimated to take six months, including a one-month's outage (see Maaß, 2013).

An increase of the permissible load gradient is achieved by reducing the wall thickness and by using improved materials for several components, such as boiler and pipes. Due to the reduced mass of the components, the operation temperatures can be reached faster, and the risk of micro-cracks is reduced, given that the components have a more homogeneous temperature distribution (see Plewnia, 2014). These modifications require twenty-four months, including a twelve-months' outage of the plant (Maaß, 2013).

The modifications presented in this section can be realized within two years at an approximate cost of 30% of a newly built coal-fired steam power plant, excluding the topping gas turbine (Maaß, 2013).

Steam turbine and water-steam cycle

The feed water can be recirculated to reduce the minimum load and to increase the flue-gas temperature to the minimum required by the SCR. This recirculation system can be installed in one year, including a one-month outage of the plant (see Maaß, 2013).

A proposal by Diantonio et al. (2010) is to include an overload valve, which would feed steam to the intermediate or low pressure section of the turbine directly from the boiler, bypassing the high pressure section of the turbine. This modification allows the plant to be operated at higher maximum load and lower minimum load, also increasing the load gradient at partial load. This modification takes less than one year, including a half-a-month' outage (see Maaß, 2013).

Heat storage within the power plant improves the load gradient and starting time of the plant. Additionally, by conveniently charging and discharging the storage system, higher maximum load and lower minimum load are achievable, broadening the load range. An example of such systems is provided by Alstom (2013). According to Maaß (2013), implementing this upgrade requires less than six months, including a one-month' outage of the plant.

Optimization of the control and measurement system of the turbine and steam cycle allows for a better monitoring and operation of the plant. The start-up time and the life cycle of different components can be improved by a more detailed knowledge of their operating state. As noted by Maaß (2013), this upgrade requires less than six months, including a half-a-month' outage of the plant.

All the upgrades presented in this section can be realized within one year, and the estimated cost is in the medium two-digit million Euros range.

Flue-gas treatment and secondary devices

One of the improvements proposed by Maaß (2013) is the stabilization of the temperature of the boiler in order to maintain a proper temperature range for the selective non-catalytic reaction (SNCR). As a result, the NO_x emissions are reduced and can be kept within a given limit in partial load. This upgrade requires less than a year, including a half a month of plant outage.

Improved heat isolation can be applied to flue-gas ducts in order to keep them warm while the power plant is not operating. Thermal stress on the affected components is then reduced, which allows faster plant start-up. This upgrade requires six months, including a one-month plant outage (Maaß, 2013).

3.1.2 Solutions at power system level

Some further possible upgrades of thermal power plants are also mentioned in Maaß (2013) and can also be considered for flexibility enhancement.

However, the ongoing trend is to further reduce the operating hours of thermal power plants with a consistent increase in the renewable energy penetration of the power system. Besides, the flexibility improvement potential is rather limited for these technologies. Therefore, it makes sense to also evaluate solutions at the power system level, such as the deployment of other generating technologies, storage systems, distributed generation, and supply demand management. Some of these alternatives are discussed in this section.

Reciprocating engine power plants

Dispatchable generation is not restricted to gas, steam and hydro turbines. Internal combustion engines can be an interesting alternative due to some of their advantageous characteristics.

Some advantages pointed out by Wärtsilä (2015) are the capability of starting and loading the reciprocating engine generator sets faster even than single-cycle gas turbine units. Some thermal and mechanical constraints during the start-up of gas turbines are the airflow velocity limit through the compressor in order to avoid stall, vibration limits, and combustion temperature limits. These constraints, and the fact that the starting cycles of reciprocating engines result in considerably lower fuel and maintenance costs, may lead to enhanced profitability of cycling operation, which tends to be increasingly the case for gas-fired power plants, due to the high fuel cost. Power generation that can be quickly brought online reduces the inefficiency of relying on part-load operation during periods of low demand. An example of these advantages is presented in Ascend (2014), which compares the performance of a single-cycle turbine rated at nearly 200 MW and a modular power plant consisting of several 18 MW combustion engines, with a total capacity of approximately 200 MW.

Besides, the load gradient achievable by such units is around 100% of the nominal load within one minute, according to Wärtsilä (2015), which is clearly superior to that of single-cycle gas turbine power plants. Additionally, the efficiency along the whole load range is higher than in the case of single-cycle gas turbines, reaching nearly 45% at nominal load, and slightly less at partial load.

Power plants of several hundred MW can also be built by using reciprocating engines. Since they are built with several units in a modular way, the flexible characteristics remain the same as for a single unit, and the operation cost may be reduced due to a centralized operation. Additionally, very low minimum load operation is possible (less than 10% of the nominal load of the plant) by running a single unit of the group, which also constitutes a great advantage.

According to Klimstra (2014), power plants based on this technology have lower installation costs than coal-fired power plants, but run on a – at least in Europe – more expensive fuel (natural gas). When compared with combined cycle power plants, the installation cost is lower and the flexibility higher, while the efficiency is also lower. Given the trend of non-renewable power plants now running fewer hours per year, the investment costs have gained even greater importance, while the fuel cost difference is not as critical as for base-load operation. Therefore, reciprocating engines constitute an interesting alternative for improving power supply flexibility, increasingly so with the higher penetration by renewable power generation sources.

Storage systems

Energy storage systems will certainly be a key component of the power system if the target of reaching 80% of power generation from renewable energy sources by 2050 is to be achieved. However, their role in the nearer future is to be considered in this section.

A scenario with 40% renewable energy penetration in Germany's power sector is considered, as presented in VDE (2012a). In this case, electric energy production from renewable energy sources exceeds the demand during only 44 out of the 8,760 yearly hours. This means that storage systems are still not needed to store excess renewable energy.

Nevertheless, it should be considered that conventional generation still plays a crucial role for frequency regulation, i.e. by providing primary, secondary, and tertiary reserves. Hence, more conventional generation should remain connected to the power system than is required by the demand in several situations. With the aim of avoiding expensive start-up cycles, storage systems can be employed to store excess energy. This stored energy can then be supplied when the demand rises, reducing the required load gradient of the conventional power plant.

There are several storage system technologies that can be used for this purpose. In VDE (2012a), power-to-gas is proposed for long-term storage, whereas short-term storage is suggested as a combination of batteries (lead-acid and lithium-ion), demand-side management, pumped hydroelectric storage, and compressed air energy storage. With this storage system composition, the electric energy cost is expected to have risen by 10% by 2050, assuming an 80% penetration of renewable energy and the operation of combined heat and power plants based on meeting the heat demand.

Distributed generation

Combined heat and power plants (CHPs) are promoted in order to achieve higher fuel efficiency and to reduce CO_2 emissions, because the waste heat resulting from electricity generation is used for the heating of residences, industrial processes, etc.

CHPs generated 96 TWh of electric energy in 2012 (Diermann, 2015). Large conventional power plants (10 MW-800 MW) accounted for 53% of this energy, whereas industrial plants (500 kW-20 MW), residential and commercial plants (1 kW-50 kW), and biogas plants accounted for the rest.

As was mentioned by Clausen (2015a), CHPs are very capital-intensive. Therefore, they require considerable heat demand and rely on self-consumption in order to be financially justifiable. Conventional power plants are operated based on the electric demand of the system. However, it is typically convenient for the CHPs to select the operating point based on the heat demand due to the current low electricity prices, especially the ones with high installed thermal power compared to the installed electric power (Westner and Madlener, 2011; Westner and Madlener, 2012a; Westner and Madlener, 2012b). The generated electrical energy is simply a by-product.

An alternative for CHPs to contribute to the power system stability is to base their operation on electricity demand. In order to still meet the heat demand, thermal storage units and eventually an additional boiler can be included in the CHP plant, which would grant the operation flexibility needed. This idea is discussed by Clausen (2015b). Incentives or market definition are probably needed to promote electricity-oriented operations of CHPs.

Government targets are to increase the participation of CHPs in electric energy generations to reach 25% by 2020, as pointed out in Agora (2013). Therefore, in the medium-term, these plants will account for a considerable portion of the controllable generation in Germany. It is therefore crucial for these plants to enhance power system frequency stability.

Gas turbines with rated power of up to 30 MW may reach a rotational speed of 15,000 rotations per minute. Hence, a gearbox is required for coupling a two-pole synchronous generator, which operates with 3,000 rotations per minute when connected to the grid.

The use of a frequency converter to interface the generator and the grid is proposed by Mura, F., De Doncker, R.W., Persigehl, B., Jeschke, P., and Hamayer, K. (2011). In this case, the electric frequency of the grid and of the generator do not need to match.

One implication of this modification is that the generator may be designed for high-speed operation to match the speed of the turbine, thus avoiding the need for a gearbox in the system. Additionally, it allows operation of the turbine at variable speed, which is convenient for obtaining an improved efficiency at partial load. The reason for this is that by reducing the speed of a single-shaft turbine (which has the compressor attached to the same shaft), the air flow of the compressor is also reduced. At partial load, less fuel is required, and the mass of compressed air can be adjusted to obtain optimum combustion, resulting in higher efficiency and reduced emissions. This obtained efficiency improvement is exemplified in Figure 3.5.

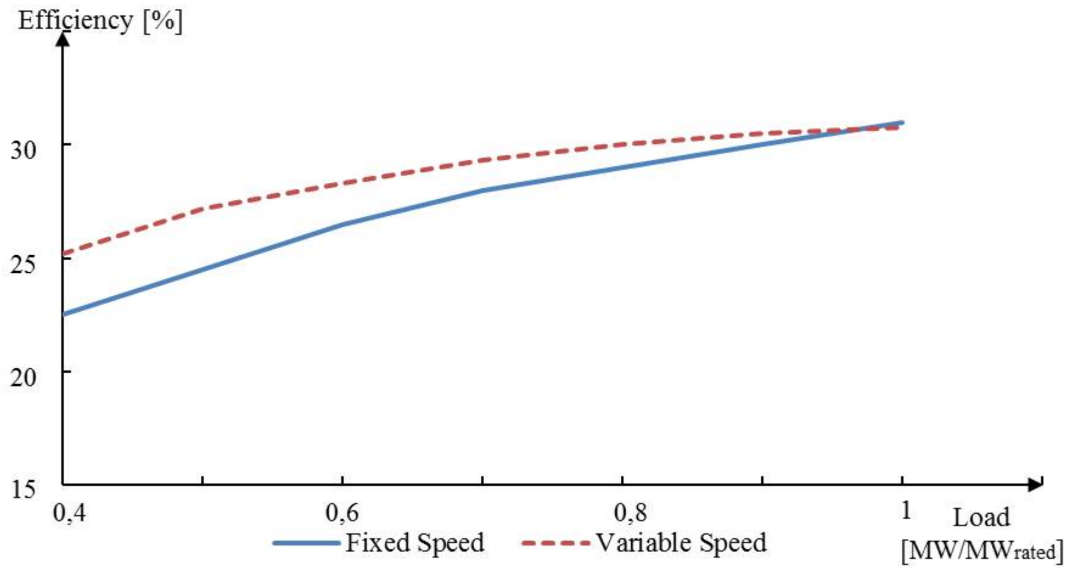


Figure 3.5: Impact of variable speed operation on gas turbine efficiency (Mura, F., De Doncker, R.W., Persigehl, B., Jeschke, P., and Hamayer, K., 2011)

3.2 Development of real options models for flexible power plant investments and disinvestments

3.2.1 Motivation

The net present value (NPV) criterion is commonly used as an evaluation tool in the investment decision-making process. However, under uncertain future market conditions, the use of NPV is in many cases inadequate and does not properly capture any existing managerial flexibility in the investment decision process, which can adapt decisions dynamically to unexpected market developments. In order to capture unexpected market developments, more powerful approaches, such as real options analysis (ROA), an approach that is based on option pricing theory developed in the finance literature, can be applied.

ROA offers a large set of different options models and solution approaches, depending on the analyzed problem (see, e.g., Guthrie, 2009 or Mun, 2006). A comprehensive review of the current state-of-the-art in the application of ROA in the energy sector (for non-renewable as well as for renewable energy sources) is provided by Fernandes et al. (2011). The authors briefly present various applications of ROA in the oil industry, power generation, energy markets, as well as emission mitigation policy. Nevertheless, the evaluating of disinvestment projects under uncertainty is a relatively rare approach in comparison to the investment options also in the energy sector. So far only in a few applied articles, especially in the fields of agriculture (Musshoff et al., 2012), dairy (Feil and Musshoff, 2013), and production planning (Fontes, 2008) has the real options models for disinvestment has been discussed.

Interesting insights on the real options model for investments in flexibility measures for gas-fired power plants can be found in Näsäkkälä and Fleten (2005) as well as Fleten and Näsäkkälä (2010). Näsäkkälä and Fleten (2005) study investments in base-load or peak-load gas-fired power plants, using a two-factor model for price processes and consider both the short-term mean reversion and long-term uncertainty. For this model, they use the spark spread, which is defined as the difference between the electricity price and the cost of gas necessary for power generation. They find that the increase in the variability of spark spread, on the one hand, increases the value of a peak-load power plant (i.e. the investment is more attractive); on the other hand, it delays the investment. Fleten and Näsäkkälä (2010) further elaborate a model initially proposed in Näsäkkälä and Fleten (2005). They implement a two-factor model for price processes to investigate the investment and technology upgrade of a gas-fired power plant. Their analysis, among other things, highlights the inclusion of a power plant's ramping abilities as an important investment factor.

Further investigation regarding the application of ROA in the evaluation of gas-fired power plants undertaken by Deng and Oren (2003) showed that start-up and shut-down costs, ramp-up constraints, as well as the operating-level-dependent heat rate should be included in the power plant valuation process. Their empirical research shows that the mentioned operational characteristics affect the valuation of the power plants, but also depend on the operating efficiency as well as the assumptions made regarding the development of electricity and fuel prices (choice between mean-reversion or Brownian motion process). Also Tseng and Lin (2007) pointed out the importance of operational constraints, such as start-up, shut-down, and ramp-up times, in the decision making-process.

Taking into account the insights gained from the different studies, the two real options models for the present study (for disinvestment and investments in flexibility measures) were developed.

3.2.2 Methodology

Real options model for disinvestment from a gas-fired power plant

The real options model for disinvestment from a gas-fired power plant is a rather novel application of the real options approach in comparison to common research areas, such as the optimal timing of new investment. The investigation of the decision problem with the option to disinvest is already mentioned in the literature on real options (see, e.g. Mun, 2006), but the practical usefulness of this decision is most relevant for our application. In our case, the optimal time of project abandonment (disinvestment) can be defined using a binomial tree approach. This approach specifies how the underlying assets change over time. As presented in Figure 3.6, from the current state only two future states are possible (up/down), where so-called “up” and “down” movements correspond to good and bad market developments. More precisely, we discretize the problem and set up a discrete-valued lattice, for which the dynamic programming model is applied that can be solved by backward induction.

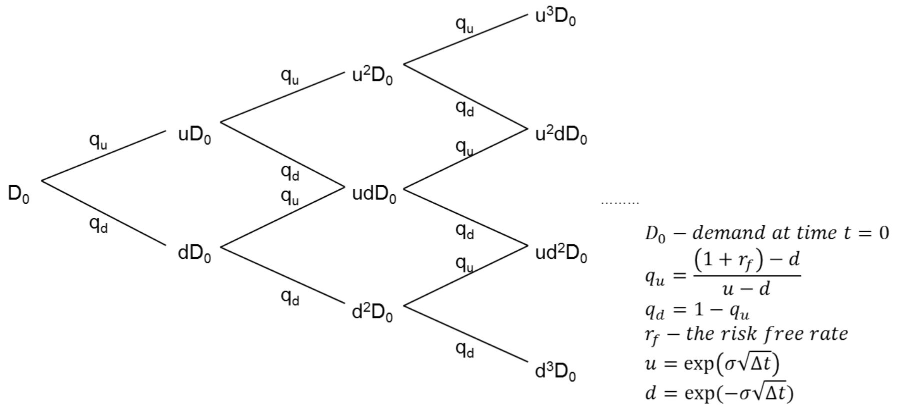


Figure 3.6: Binomial lattice, based on Mun (2006)

In the proposed real options model, the so-called shut-down option is considered. This implies that the power plant operator receives an abandonment (residual) value (i.e. the selling price obtained for the power plant components minus its decomposition costs) in the case when the present value of the power plant in operation is less than the residual value. Considering the assumptions:

- The time horizon for the real options model is equal to the residual lifetime of the power plant analyzed,
- The underlying asset is the power plant's capacity factor (number of full-load hours),
- This capacity factor is normally distributed and approximated by a binomial distribution, resulting in a standard binomial lattice,
- Electricity, CO_2, and gas prices are defined as stochastic variables (with underlying distributions) and are introduced in the calculation of the power plant's cash-flow,

the shut-down option is chosen when the present value of the power plant at the given electricity demand is less than the cost (fixed cost) resulting from the power plant being in operation / or than the residual value of the power plant. The real options model, where the optimal project value is a function of the capacity factor, $PV_{i,t}(CF_{i,t})$, is given by:

$$PV_{i,t}(CF_{i,t}) = max \begin{cases} RV_t \\ PCF_{i,t} + \frac{\alpha \cdot PV_{i,t+1}(CF_{i,t+1}) + (1-\alpha) \cdot PV_{i+1,t+1}(CF_{i+1,t+1})}{1+r_f}, \end{cases} \tag{3.1}$$

where RV_t denotes the residual value, $PCF_{i,t}$ the project cash flow for ith "down" move at current time period t, α defines the probability of "up" movement, $CF_{i,t}$ denotes the capacity factor for the ith "down" move at time t, r_f denotes the risk-free rate, and i is the number of "down" movements (i=1,$\ldots$,$T-1$). In other words, the project value in each period is obtained as the maximum between the sum of the optimal current period's project profit plus the optimal continuation value (for the last period the continuation value is equal to zero) and the abandonment value.

In the proposed model it is also anticipated that at the beginning of the investigated period the expected discounted future cash flows will be significantly higher than the residual value of the power plant. This difference should then decrease over time.

The proposed solution procedure consists of the following three steps:

- **Step 1.** Definition of the state variable (capacity factor in our case) and determination of its "up" and "down" movements used to set up the binominal tree for the underlying asset. The "up" and "down" movements as well as risk-neutral probabilities can be calculated using the probability distribution parameters from the underlying asset (see, e.g., Mun, 2006). Assuming a normal distribution of the capacity factor, the "up" and "down" movements are determined as follows:

  $$up = e^{(\sigma\sqrt{\Delta t})} \text{ and } down = e^{(-\sigma\sqrt{\Delta t})}, \tag{3.2}$$

  where σ is the associated volatility and Δt is the time step.

- **Step 2.** Determination of the future cash-flow values of the existing project (power plant) in each period using Monte Carlo simulation (in the software Crystal Ball®) to capture the stochastic character of some of the cash-flow parameters.
- **Step 3.** The optimal project value is then calculated using recursive dynamic programming according to equation (3.1). If $PV_{i,t}(CF_{i,t})$ is equal to the residual value (RV_t), the power plant should be shut down, otherwise the power plant should be kept in operation.

Real options model for the flexible operation of an enhanced gas-fired power plant

With the real options model for the flexible operation of an enhanced gas-fired power, the main questions that arise are: (1) which technical measures can make gas-fired power plants more flexible/profitable, and (2) when should the owner of the power plant decide to retrofit? To find the answers, a three-step procedure is proposed and conducted on an hourly basis to maximize expected profit (see Figure 3.7).

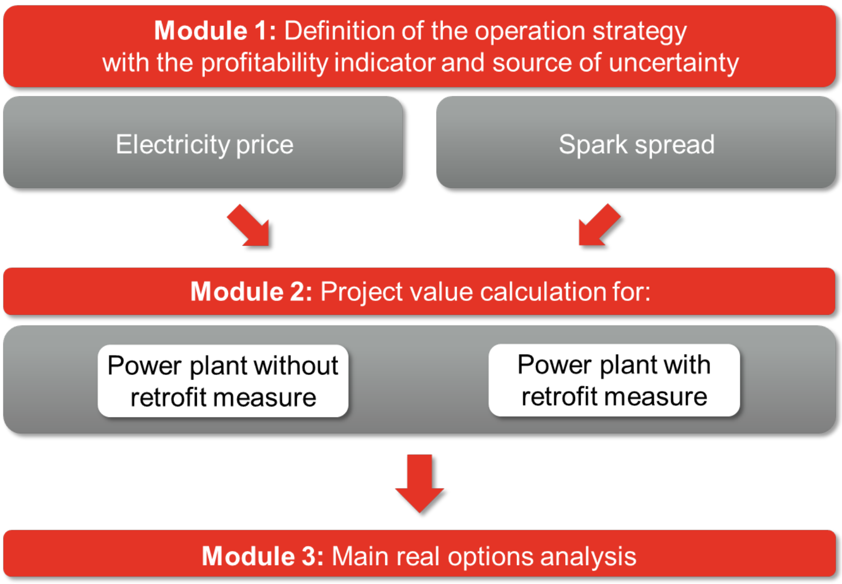


Figure 3.7: Calculation procedure

Definition of the operation strategy (operation regime) is the first step of this procedure[1]. The operation strategy can be established using the development of the profitability indicator and source of uncertainty, which can be presented either by the electricity price or the spark spread. Because of the dependency between the net thermal efficiency of the power plant and its load level, we

[1]The approach proposed for the definition of the operation regime is simplified and does not belong to the main goals of the project. It should facilitate an understanding of the proposed model.

propose the following definition of the spark spread ($Spread_t$):

$$Spread_t = P_{elec,t} - \left(\beta \cdot \frac{P_{gas,t}}{\eta(load\ max)} + (1-\beta) \cdot \frac{P_{gas,t}}{\eta(load\ min)}\right), \tag{3.3}$$

where $P_{elec,t}$ and $P_{gas,t}$ denote the electricity and gas price, respectively, $\eta(\cdot)$ is the load-level-dependent net efficiency of the power plant, and $\beta \in [0,1]^2$.

The development of the electricity price as well as spark spread (eq.(3.3)) is described by the arithmetic Brownian motion (ABM) process, which offers an alternative to the standard geometric Brownian motion process usually used in ROA (Alexander et al., 2012, p. 122), defined as S_t:

$$S_t = S_{t-1} + \alpha dt + \sigma dZ_t, \tag{3.4}$$

where α (drift) and σ (volatility) are constants, and Z_t represents a standard Brownian Motion process.

Assuming for simplicity that the power plant has only three possible operational load (output) levels: maximum, minimum, and zero, the determination of the operation strategy for each hour is conducted according to the following conditions:

$$\text{if} \quad P_{elec\ abm,t} \quad \text{or} \quad Spread_{abm,t} \leq MCT_{load\ max} \quad oper = 0 \tag{3.5}$$

$$\text{if} \quad MCT_{load\ max} < P_{elec\ abm,t} \quad \text{or} \quad Spread_{abm,t} \leq MCT_{load\ min} \quad oper = load\ min \tag{3.6}$$

$$\text{if} \quad MCT_{load\ min} < P_{elec\ abm,t} \quad \text{or} \quad Spread_{abm,t} \quad oper = load\ max, \tag{3.7}$$

where $P_{elec\ abm,t}$ and $Spread_{abm,t}$ denote the electricity price or spark spread modeled as an ABM process and given with eq.(3.3), and the marginal cost of technology (MCT) is given as:

$$MCT_{load} = \frac{P_{gas} + P_{CO_2} \cdot e_{spec}}{\eta(load)} + OM_{var} \tag{3.8}$$

for the electricity price and

$$MCT_{load} = \frac{P_{CO_2} \cdot e_{spec}}{\eta(load)} + OM_{var} \tag{3.9}$$

for the spark spread as a profitability indicator and source of uncertainty. Moreover, P_{gas} and P_{CO_2} denote the gas and CO_2 price, respectively, e_{spec} is the specific emission factor for gas, OM_{var} denotes the variable operation and maintenance (O&M) costs, and $\eta(load)$ is the load level-dependent net thermal efficiency of the power plant.

[2]We assume in our case study that $\beta = 0.5$. The dependency between the fuel use and different load levels can be also considered regarding different values of $beta$. Moreover, this dependency should be changed constantly. Note that this problem was not addressed in this project but left for future research.

The project's cash flow calculation, in the second phase of the procedure, is related to the operation regime from the first step. Moreover, the CO_2 price developments, variable O&M costs (OM_{var}), start-up, shut-down, and marginal ramping costs ($c_{start\text{-}up}$, $c_{shut\text{-}down}$, $c_{ramp\text{-}up}$), as well as the electricity price, gas price, and spark spread developments are included in the project's cash flow calculations. Following the model proposed by Deng and Oren (2003), only three operational stages (S1 – the power plant is off, S2 – the power plant is at min load operation, and S3 – the power plant is at max load operation) and only three possible actions (A1 – the power plant runs at full-capacity level (load max), A2 – the power plant runs at low-capacity level (load min), and A3 – the power plant is turned off) are considered. The operating cash flow of the power plant for each hour can thus be presented as follows:

$$CF_t(P_t, A_t, S1) = \begin{cases} \text{for} \quad A_t = A1 : -c_{start\text{-}up} - c_{ramp\text{-}up}(load\ max_t) \\ \text{for} \quad A_t = A2 : -c_{start\text{-}up} - c_{ramp\text{-}up}(load\ min_t) \\ \text{for} \quad A_t = A3 : 0 \end{cases} \tag{3.10}$$

$$CF_t(P_t, A_t, S2) = \begin{cases} \text{for} \quad A_t = A1 : -c_{ramp\text{-}up}(load\ max_t) \\ \text{for} \quad A_t = A2 : P_t(load\ min_t) \\ \text{for} \quad A_t = A3 : -c_{shut\text{-}down} \end{cases} \tag{3.11}$$

$$CF_t(P_t, A_t, S3) = \begin{cases} \text{for} \quad A_t = A1 : P_t(load\ max_t) \\ \text{for} \quad A_t = A2 : P_t(load\ min_t) \\ \text{for} \quad A_t = A3 : -c_{shut\text{-}down} \end{cases} \tag{3.12}$$

where

$$P_t(load_t) = \left(P_{elec\ abm,t} - \frac{P_{gas\ abm,t}}{\eta(load_t)} - \frac{P_{CO_2\ abm,t} \cdot e_{spec}}{\eta(load_t)} - OM_{var}\right) \cdot load_t \tag{3.13}$$

or

$$P_t(load_t) = \left(Spread_{abm,t} - \frac{P_{CO_2\ abm,t} \cdot e_{spec}}{\eta(load_t)} - OM_{var}\right) \cdot load_t \tag{3.14}$$

for electricity price and spark spread, respectively, and $load_t \in \{load\ max_t, load\ min_t\}$.

The hourly power plant's operating cash flows (eqs. (3.10)-(3.12)) are used to calculate the project value (PV_t) by using the net present value (NPV) principle:

$$PV_t = \sum_{t=0}^{T} \frac{CF_t - OM_{fixed,t} - Dep_t}{(1 + WACC)^t}, \tag{3.15}$$

where, additionally, the fixed O&M costs ($OM_{fixed,t}$), depreciation (Dep_t) and weighted average cost of capital (WACC, used as the discount rate) are taken into consideration.

The determination of investment time is the last step of the proposed procedure, where the optimal time for the decision considers two alternatives: to continue the power plant operation or to invest in a retrofit of the plant. This investment decision is seen as the option to expand (Trigeorgis, 1996, p.11), where the decision process can be defined as follows:

$$\text{if} \quad PV_t < Option\ to\ expand \quad \text{invest in the considered flexibility measure} \tag{3.16}$$

$$\text{if} \quad PV_t \geq Option\ to\ expand \quad \text{wait with the retrofitting,} \tag{3.17}$$

where

$$Option\ to\ expand = max\left(RPV_{t+\Delta t} - retrofit_{investment}, 0\right) \tag{3.18}$$

and RPV_t defines the project value after the retrofit (calculated by using eq. (3.15)), and Δt describes the time needed for the retrofit when the power plant is turned off.

3.2.3 CCGT technology analyzed and results obtained

Analyzed technology

The main challenge today for conventional power plants is that of how to meet the unforeseeable increase in electricity demand at short notice, which is caused by the sudden loss of electricity generation from renewables.

Possible solutions in this case are the investment in flexible operation or disinvestment. Regarding flexible operation, gas-fired and especially combined-cycle (CC) gas power plants offer, from an environmental perspective, a relatively benign grid stabilization and allow for the start of power generation in a rather short time span. The increase in flexibility can be achieved, for example, by a reduction of the start-up and shut-down times and costs, the reduction of the minimum load, an increase in efficiency in part-load operation, or an increase of the load gradient (see e.g. Litau, 2015 or Plewnia, 2014). These effects can be reached by installing new and additional technical components, or by upgrading already existing ones.

In the project analyzed, the gas-fired power plant considered is a highly energy-efficient (net thermal efficiency factor 59.7%) and recently built power plant in Germany (commissioned in year 2010). Despite its high energy efficiency and flexible operation, this power plant is currently not economically viable (Stromklar, 2014). On the one hand, the gas price has developed unfavorably (i.e. risen) and, on the other hand, the electricity price at the wholesale market has decreased significantly. Moreover, the increasing share of renewable energy sources pushed power plants with larger marginal costs, such as gas-fired power plants, to the right of the merit order curve.

The techno-economic parameters used to analyze the gas-fired power plant are summarized in Table 3.2.

Table 3.2: Technical and economic parameters for the CCGT power plant analyzed

Techno-economic parameter	Value
Total installed power(2,7)	845 MW (net)
Commission time(2,7)	2010
Total life time (technical)	25 years
Net thermal efficiency for max load level(2,7)	59.7%
Net thermal efficiency for min (ca. 40%) load level(1)	49%
Specific power plant CO_2 emission(3)	0.351 t CO_2/MWh
Investment costs(7)	456.62 €/kW
Fixed O&M costs	10 €/kW(6); 20 €/kW(4)
Variable O&M costs(9)	0.33 €/MWh
WACC(8)	7.5%
Corporate tax(5)	29.58%
Electricity price (hourly)	Time series 01.01.2004–31.12.2012
Gas price (daily)	Time series 01.01.2004–31.12.2012
CO_2 price (daily)	Time series 03.03.2005–31.12.2012

[1] According to Bine Informationsdienst (2015)
[2] E.ON (2014)
[3] Erdmann and Zweifel (2010)
[4] Freund et al. (2012)
[5] http://www.tradingeconomics.com/germany/corporate-tax-rate
[6] Konstantin (2009)
[7] Mainova Press Releases (2010)
[8] Pretax cost of capital E.ON (2013)
[9] Roques et al. (2007)

Real options model for disinvestment from a gas-fired power plant – results

To investigate the influence of the capacity factor as a stochastic variable on the power plant's output and thus also on its current value, different values of the probability distribution parameters for the capacity factor were analyzed[3].

As shown in Table 3.3, the first tree (binomial lattice) represents the development of the capacity factor over the years given with the mean value $\mu = 0.14$ and standard deviation $\sigma = 0.10$ over the whole remaining operation time. The yellow part of this tree illustrates the value of the capacity factor which exceeds the 100% mark, and thereby illustrates the alternatives that, from a purely technical point of view, are not achievable (i.e. technically not feasible). These states for the capacity factor are represented as the "unreachable" decision on the second tree (lower half of the Table 3.3), the so-called decision tree. Tables 3.4 and 3.5 represent the development of the capacity factor for the mean value $\mu = 0.11$ and standard deviation $\sigma = 0.30$ as well as for the mean value $\mu = 0.18$ and standard deviation $\sigma = 0.60$, respectively, with the corresponding decision trees.

[3] Information obtained from the existing literature, and available online data regarding the full-load hours of gas-fired power plants.

Table 3.3: Binomial tree for the capacity factor with $\mu = 0.14$ and $\sigma = 0.10$ (upper table) and decision tree (lower table)

							Operation year						
0	**1**	**2**	**3**	**4**	**5**	**...**	**18**	**19**	**20**	**21**	**22**	**...**	**26**
0.1400	0.1547	0.1710	0.1890	0.2089	0.2308	...	0.8470					...	
	0.1267	0.1400	0.1547	0.1710	0.1890	...	0.6934	0.7664	0.8470			...	
		0.1146	0.1267	0.1400	0.1547	...	0.5677	0.6274	0.6934	0.7664	0.8470	...	
			0.1037	0.1146	0.1267	...	0.4648	0.5137	0.5677	0.6274	0.6934	...	
				0.0938	0.1037	...	0.3806	0.4206	0.4648	0.5137	0.5677	...	0.8470
					0.0849	...	0.3116	0.3443	0.3806	0.4206	0.4648	...	0.6934
						...	0.2551	0.2819	0.3116	0.3443	0.3806	...	0.5677
						...	0.2089	0.2308	0.2551	0.2819	0.3116	...	0.4648
						...	0.1710	0.1890	0.2089	0.2308	0.2551	...	0.3806
						...	0.1400	0.1547	0.1710	0.1890	0.2089	...	0.3116
						...	...	...	...	...	...	...	...
							0.0231	0.0256	0.0283	0.0312	0.0345	...	0.0515
								0.0209	0.0231	0.0256	0.0283	...	0.0422
									0.0189	0.0209	0.0231	...	0.0345
										0.0171	0.0189	...	0.0283
											0.0155	...	0.0231
												...	0.0189
												...	0.0155
												...	0.0127
													0.0104

							Operation year						
0	**1**	**2**	**3**	**4**	**5**	**...**	**18**	**19**	**20**	**21**	**22**	**...**	**26**
Continue	Continue	Continue	Continue	Continue	Continue	...	Continue	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
	Continue	Continue	Continue	Continue	Continue	...	Continue	Continue	Continue	Unreachable	Unreachable	...	Unreachable
		Continue	Continue	Continue	Continue	...	Continue	Continue	Continue	Continue	Continue	...	Unreachable
			Continue	Continue	Continue	...	Continue	Continue	Continue	Continue	Continue	...	Unreachable
				Continue	Continue	...	Continue	Continue	Continue	Continue	Continue	...	Continue
					Stop	...	Continue	Continue	Continue	Continue	Continue	...	Continue
						...	Continue	Continue	Continue	Continue	Continue	...	Continue
						...	Continue	Continue	Continue	Continue	Continue	...	Continue
						...	Continue	Continue	Continue	Continue	Continue	...	Continue
						...	Continue	Continue	Continue	Continue	Continue	...	Stop
						...	...	...	...	...	...	...	...
							Stop	Stop	Stop	Stop	Stop	...	Stop
								Stop	Stop	Stop	Stop	...	Stop
									Stop	Stop	Stop	...	Stop
										Stop	Stop	...	Stop
											Stop	...	Stop
												...	Stop
												...	Stop
												...	Stop
													Stop

Table 3.4: Binomial tree for the capacity factor with $\mu = 0.11$ and $\sigma = 0.30$ (upper table) and decision tree (lower table)

							Operation year						
0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**...**	**20**	**21**	**22**	**...**	**26**
0.1100	0.1485	0.2004	0.2706	0.3652	0.4930	0.6655		...				...	
	0.0815	0.1100	0.1485	0.2004	0.2706	0.3652	0.4930	...				...	
		0.0604	0.0815	0.1100	0.1485	0.2004	0.2706	...				...	
			0.0447	0.0604	0.0815	0.1100	0.1485	...				...	
				0.0331	0.0447	0.0604	0.0815	...				...	
					0.0245	0.0331	0.0447	...				...	
						0.0182	0.0245	...				...	
							0.0135	...	0.6655			...	
								...	0.3652	0.4930	0.6655	...	
								...	0.2004	0.2706	0.3652	...	
								...	0.1100	0.1485	0.2004	...	0.6655
								...	0.0604	0.0815	0.1100	...	0.3652
								...	...	...	...	...	...
									0.0003	0.0004	0.0005	...	0.0016
										0.0002	0.0003	...	0.0009
											0.0001	...	0.0005
												...	0.0003
												...	0.0001
												...	0.0001
													0.0000

							Operation year						
0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**...**	**20**	**21**	**22**	**...**	**26**
Continue	Continue	Continue	Continue	Continue	Continue	Continue	Unreachable	...	Unreachable	Unreachable	Unreachable	...	Unreachable
	Continue	Continue	Continue	Continue	Continue	Continue	Continue	...	Unreachable	Unreachable	Unreachable	...	Unreachable
		Continue	Continue	Continue	Continue	Continue	Continue	...	Unreachable	Unreachable	Unreachable	...	Unreachable
			Stop	Continue	Continue	Continue	Continue	...	Unreachable	Unreachable	Unreachable	...	Unreachable
				Stop	Stop	Continue	Continue	...	Unreachable	Unreachable	Unreachable	...	Unreachable
					Stop	Stop	Stop	...	Unreachable	Unreachable	Unreachable	...	Unreachable
						Stop	Stop	...	Unreachable	Unreachable	Unreachable	...	Unreachable
							Stop	...	Continue	Unreachable	Unreachable	...	Unreachable
								...	Continue	Continue	Continue	...	Unreachable
								...	Continue	Continue	Continue	...	Unreachable
								...	Continue	Continue	Continue	...	Continue
								...	Stop	Stop	Continue	...	Stop
								...	...	...	...	...	...
									Stop	Stop	Stop	...	Stop
										Stop	Stop	...	Stop
											Stop	...	Stop
												...	Stop
												...	Stop
												...	Stop
													Stop

Table 3.5: Binomial tree for the capacity factor with $\mu = 0.18$ and $\sigma = 0.60$ (upper table) and decision tree (lower table)

Operation year													
0	**1**	**2**	**3**	**...**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**...**	**26**
0.1800	0.3280	0.5976		...								...	
	0.0988	0.1800	0.3280	...								...	
		0.0542	0.0988	...								...	
			0.0298	...								...	
				...								...	
				...								...	
				...								...	
				...	0.5976							...	
				...	0.1800	0.3280	0.5976					...	
				...	0.0542	0.0988	0.1800	0.3280	0.5976			...	
				...	0.0163	0.0298	0.0542	0.0988	0.1800	0.3280	0.5976	...	
				...	0.0049	0.0090	0.0163	0.0298	0.0542	0.0988	0.1800	...	
				...	0.0015	0.0027	0.0049	0.0090	0.0163	0.0298	0.0542	...	0.5976
				...	0.0004	0.0008	0.0015	0.0027	0.0049	0.0090	0.0163	...	0.1800
				...	...	...	...	...	...	...	...	...	...
											0.0000	...	0.0000
												...	0.0000
												...	0.0000
												...	0.0000
													0.0000

Operation year													
0	**1**	**2**	**3**	**...**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**...**	**26**
Continue	Continue	Continue	Unreachable	...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
	Continue	Continue	Continue	...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
		Stop	Continue	...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
			Stop	...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
				...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
				...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
				...	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
				...	Continue	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
				...	Continue	Continue	Continue	Unreachable	Unreachable	Unreachable	Unreachable	...	Unreachable
				...	Continue	Continue	Continue	Continue	Continue	Unreachable	Unreachable	...	Unreachable
				...	Stop	Stop	Continue	Continue	Continue	Continue	Continue	...	Unreachable
				...	Stop	Stop	Stop	Stop	Continue	Continue	Continue	...	Unreachable
				...	Stop	Stop	Stop	Stop	Stop	Stop	Stop	...	Continue
				...	Stop	Stop	Stop	Stop	Stop	Stop	Stop	...	Stop
				...	...	...	...	...	...	...	...	...	...
											Stop	...	Stop
												...	Stop
												...	Stop
												...	Stop
													Stop

From the presented results we find that the decision-making process regarding disinvestment is highly dependent on the initial values of the capacity factor. “Down” movements of the capacity factor cause a decrease in the project value and lead to a faster shut-down decision in contrast to “up” movements, which cause an increase of the project value and further operation of the power plant.

Moreover, based on the presented trees, the probability of the continuation or interruption of the power plant operation can be calculated (see Table 3.6). Here we can observe that with increasing volatility of the capacity factor, the probability of the continuation decreases faster and a “stop decision” is observed earlier. Moreover, more technically unreachable states are observed.

Further results from this study can be found in Glensk et al. (2015) and Glensk et al. (2016), where, to simplify the presentation of the analysis, the maximum time period during which the decision should be made was assumed to be only six years. From the results presented there, it is possible to see that the higher the capacity factor value is, the longer the time period is during which the power plant can remain in service.

Furthermore, the residual value RV_t defined in eq. (3.1) has a significant impact on the final decision regarding how long the power plant's operation can be continued. The determination of its value is one of the important and difficult points in this model. In our case study, the residual value is assumed to be constant, computed by accounting for a linear depreciation.

Table 3.6: Probability values of actions taken for different distribution parameters of the capacity factor

Capacity factor 14(10)

	Operation year												
	0	1	2	3	4	5	...	18	19	20	21	22	...	26
Stop	0.0000	0.0000	0.0000	0.0000	0.0085	0.0026	...	0.0068	0.0117	0.0189	0.0098	0.0156	...	0.3892
Unreachable	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	...	0.0000	0.0010	0.0007	0.0051	0.0037	...	0.0236
Continue	1.0000	1.0000	1.0000	1.0000	0.9915	0.9974	...	0.9932	0.9873	0.9804	0.9852	0.9807	...	0.5872

Capacity factor 11(30)

	Operation year													
	0	1	2	3	4	5	6	7	...	20	21	22	...	26
Stop	0.0000	0.0000	0.0000	0.0826	0.0360	0.1172	0.0599	0.1347	...	0.2091	0.2739	0.2040	...	0.6242
Unreachable	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0324	0.0183	...	0.1596	0.2365	0.1862	...	0.2372
Continue	1.0000	1.0000	1.0000	0.9174	0.9640	0.8828	0.9078	0.8470	...	0.6313	0.4896	0.6097	...	0.1386

Capacity factor 18(60)

	Operation year													
	0	1	2	3	...	16	17	18	19	20	21	22	...	26
Stop	0.0000	0.0000	0.2201	0.1033	...	0.1590	0.2292	0.1659	0.2327	0.1714	0.2354	0.3066	...	0.4513
Unreachable	0.0000	0.0000	0.0000	0.1496	...	0.3093	0.4110	0.3299	0.4268	0.3483	0.4409	0.3648	...	0.3938
Continue	1.0000	1.0000	0.7799	0.7471	...	0.5317	0.3598	0.5042	0.3405	0.4803	0.3238	0.3286	...	0.1550

Real options model for the flexible operation of an enhanced gas-fired power plant – results

In the case study in this project, the option to expand was considered as a chance to operate the existing power plant more flexibly by using additional technical components or by upgrading existing components. Therefore, it was important to define the optimal timing for the extension of existing power plants.

In this project, the improvements in minimum-load and part-load efficiency were analyzed as an exemplary case study. The improvements in minimum load can be achieved, for instance, with variable-pitch guide vanes at the gas turbine compressor or with an air pre-heater (Pickard and Meinecke, 2011). The implementation of these technical improvements brings some additional expansion costs and takes some time, divided into realization time (i.e. from a few months up to one year) and the time when the power plant should be totally turned off (several months) (Maaß, 2013). Furthermore, the additional expansion costs, which depend on the technical component, can be approximated at 30-35% of the price of a new power plant (Maaß, 2013; FDBR Fachverband Anlagenbau Energie. Umwelt. Prozessindustrie, 2013). In the analyzed case study, these costs were assumed to be only 5% of the price of a new power plant[4].

For the model calculations, the information about costs and times for start-up was assumed, based on the conducted research. Gas-fired power plants need today about 1.5 hours for start-up or 4 hours when the turned-off phase was less than 8 hours or more than 48 hours, respectively. Regarding the state of technology, the times needed for the start-up are 1 and 3 hours, respectively,

[4]Information obtained from the discussion with the industry partners involved in the project.

but the optimization potential lies at 0.5 and 2 hours (Brauner, 2012; Hille, 2012). Start-up costs, for the so-called “hot start”, are assumed to be 57.2 €/MW, for the warm start (the power plant was switched off for more than 5 hours) at 83.0 €/MW, and for the cold start (the power plant was switched off for more than 40 hours) at 117.0 €/MW (Götz et al., 2014)[5].

For the analysis of the gas-fired power plant mentioned above in Section 3.2.3 (Analyzed technology), the model proposed in Section 3.2.2 for investment in flexible operation was used[6]. There, the operation regime of the power plant was established first, where the electricity price (Figure 3.8) and spark spread (Figure 3.9) were used as a profitability indicator and source of uncertainty, respectively.

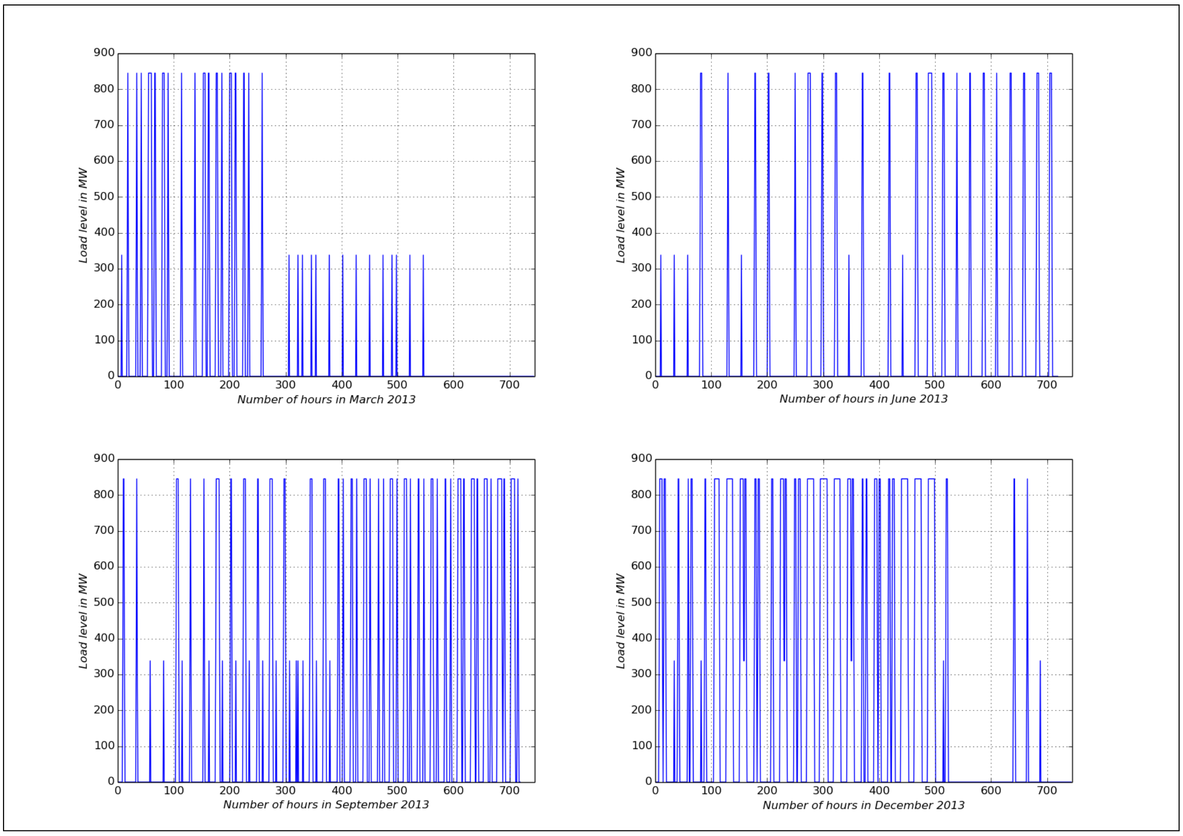


Figure 3.8: Operation strategy for March, June, September, and December 2013 with electricity price as profitability indicator and source of uncertainty

Comparing Figures 3.8 and 3.9, we observe many periods where the power plant should be shut down. It is caused, of course, by the significant market impact of the electricity generation from renewables technologies (e.g. solar and wind power) here observed especially in spring (Figure 3.8 – March 2013), summer (Figure 3.8 – June 2013), and early autumn (Figure 3.8 – September 2013). In December, the low number of working hours occurs typically over the Christmas period. As

[5]For more information, see Glensk and Madlener (2015).
[6]The proposed model was implemented in script programming language Python 2.7.

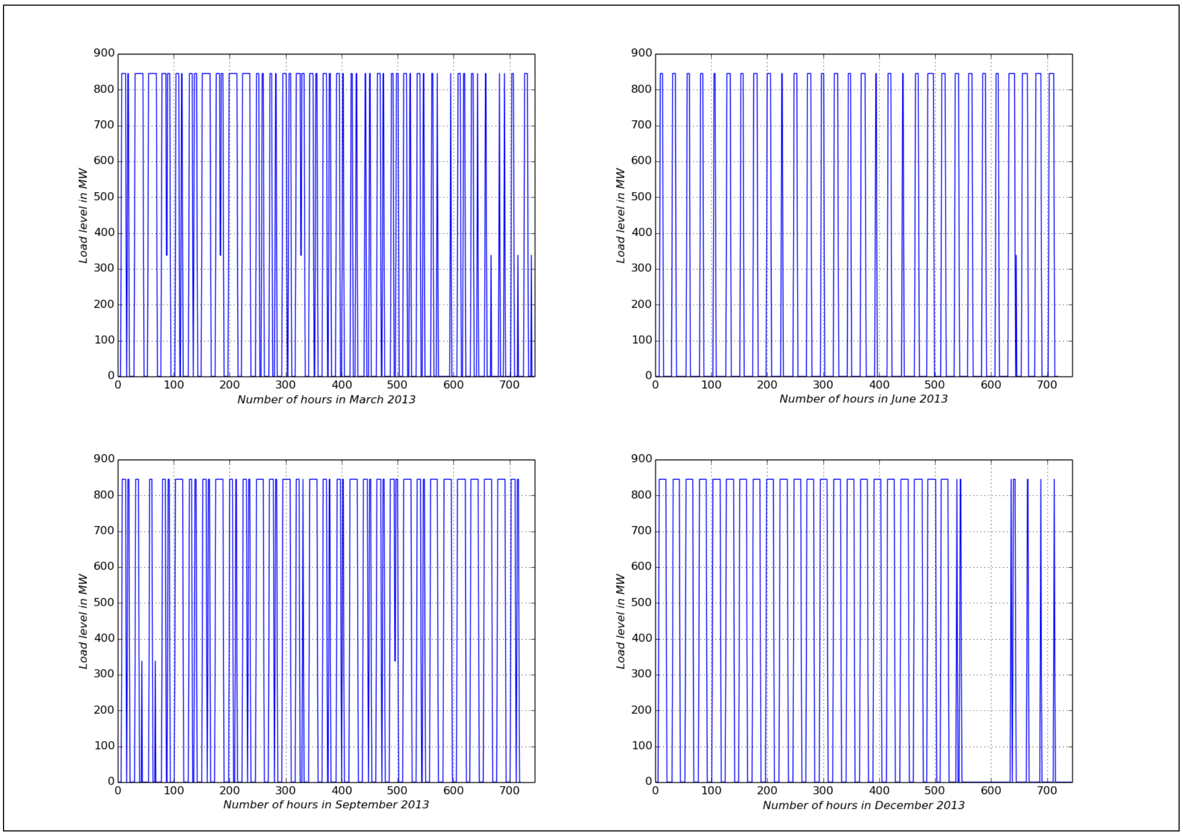


Figure 3.9: Operation strategy for March, June, September, and December 2013 with spark spread as profitability indicator and source of uncertainty

mentioned in Section 3.2.2, the definition of the operation strategy was simplified for the better understanding of the proposed real options approach. For this reason the last profiles presented on the Figures 3.8 and 3.9 should be considered with some caution.

Regarding the spark spread as a profitability indicator and source of uncertainty, the observations are similar (Figure 3.9). The slightly higher number of working hours for the spark spread (in comparison to the electricity process) depends on the definition of the spark spread as well as the marginal costs of technology[7].

The results presented here indicate clearly that the continuous operation of the gas-fired power plant, from an economic point of view, is no longer efficient and consists of many short time periods, as already mentioned in other studies, e.g. VDE (2012b) or Pickard and Meinecke (2011). Technical improvements for the flexible and economical operation of the plant at the minimum load level instead of a shut-down and start-up of the plant are, from this perspective, needed.

Considering the technical improvements mentioned before, the optimal investment time was found using ROA for the case when the electricity price and spark spread are used as a profitability indi-

[7] For more information, see Glensk and Madlener (2015).

cator and source of uncertainty (see Tables 3.7 and 3.8, respectively). Moreover, in the conducted calculations it was assumed that the annual variable operation and maintenance costs are 0.33 €/MWh (more results for different values can be found in Glensk and Madlener, 2015), and that the investment phase where the power plant has to be shut down lasts from 2 to 10 months. As can be seen in Tables 3.7 and 3.8, the decision about the investment in the technical improvements should be made immediately (i.e. in the first period analyzed) regarding the principle of the model described in eqs. (3.16)-(3.17) despite of the negative values obtained.

Table 3.7: Present value of the retrofitted power plant, option value, and decision (with electricity price as source of uncertainty and fixed O&M costs of 10 €/kW)

Turn-off time during realization [in months]	RPV of power plant [in €]	Option value [in €] according to eq. (3.18)	Decision for $PV_{01,2013} = -169,414,781.29$
2	-100,792,111.95	0.00	invest
3	-99,941,125.63	0.00	invest
4	-99,383,841.43	0.00	invest
5	-98,906,139.45	0.00	invest
6	-98,523,480.74	0.00	invest
7	-99,087,585.81	0.00	invest
8	-98,740,655.60	0.00	invest
9	-97,508,996.80	0.00	invest
10	-98,113,813.07	0.00	invest

Table 3.8: Present value of the retrofitted power plant, option value, and decision (with spark spread as source of uncertainty and fixed O&M costs of 10 €/kW)

Turn-off time during realization [in months]	RPV of power plant [in €]	Option value [in €] according to eq. (3.18)	Decision for $PV_{01,2013} = -77,069,139.35$
2	-3,748,871.22	0.00	invest
3	-2,858,149.63	0.00	invest
4	-1,089,553.10	0.00	invest
5	220,123.11	0.00	invest
6	600,109.20	0.00	invest
7	-122,454.36	0.00	invest
8	1,057,882.73	0.00	invest
9	1,462,912.91	0.00	invest
10	-663,053.88	0.00	invest

In the conducted analysis, and based on the available data and assumptions made, the power plants values obtained both without as well as with retrofitting were almost negative. Only in some cases did the present value of the power plant, especially with retrofitting (see Table 3.8), achieve a positive value. This indicates that, in some of the periods, the improvements undertaken could increase the profitability of the operation. On the other hand, for the case of the power plant's present value without retrofitting, the model obtained negative values that were always worse than those obtained when the power plant underwent retrofitting. As a consequence of this, the decision "to invest" in retrofitting was expected.

3.3 Market design implications for an enhanced gas-fired power plant

3.3.1 Motivation

The ongoing energy system transformation has led to an increasing share of fluctuating renewable energy. This has been accompanied by an increasing demand for flexible energy generation to keep the system balanced. To enable timely reactions to supply-demand imbalances, technical modifications and investments in power plant technology are required. Hence, flexibility is not only valuable, but also costly for those who provide it, and there is no mechanism to remunerate this service.

We analyze whether the current market environments offer sufficient possibilities for flexible power plants to earn the revenues needed to recoup their investments, or whether additional mechanisms are necessary. In this context, flexibility can be treated as an option, bought by those who need to balance their portfolio and called when the imbalance occurs. Flexibility is related to the capability of a generation unit or a consumer to adapt the energy output or consumption to external changes.

There is no common energy market in Europe. In fact, each market faces different challenges. The French market, for example, is dominated by nuclear power and has developed balancing mechanisms that take this into account. The German market, on the other hand, is quite different. With the ongoing energy transition (*Energiewende*), the share of renewable, intermittent energy generation has increased significantly to the point of dominating, or at least influencing, the infrastructure. Flexibility is therefore of particular interest in this market and a reason to focus on the German market in the analysis.

Currently, there are three markets in Germany with different time horizons: the futures exchange (between a few days and up to six years ahead of delivery), the day-ahead market (supports trading for the upcoming day until 12 a.m. on the day before delivery), and the intraday market (up to 45 minutes before delivery). Products in these markets are highly standardized. However, more customized products are also available, especially in over-the-counter (OTC) bilateral trading. While the trading volume at the exchange is relatively small compared to the overall volume in wholesale trading, it has an important signaling effect for prices in OTC trading (BNetzA, 2014).

The above-mentioned markets can be summarized as the "energy-only" markets, where only energy, and not capacity, is traded. This is different for the reserve energy market. Here, capacity is reserved, and can later be called whenever needed. There are three different qualities, which differ in response time: The fastest is primary reserve, followed by secondary and tertiary reserve. These reserves are needed for balancing fluctuations in the grid, which result from imprecise forecasts of demand or supply (hereby mainly from renewables) as well as other unforeseen events, such as outages or distortions.

The number of ideas on flexibility markets have already been formulated. Buchholz et al. (2012) propose adding a fourth segment to the existing reserve energy market. Rautkivi and Kruisdijk (2013) also introduce a flexibility market as a day-ahead option market. Wärtsilä (2014) notes that the current German electricity and reserve energy market design does not set any incentives for flexible energy provision. They propose several measures for linking the balancing mechanisms to market forces. Some of the above-mentioned mechanisms are already option-based and offer a good foundation for including the flexibility dimension.

3.3.2 Methodology

A fair price for a flexibility option should consider the costs it produces. These are captured in the so-called "levelized cost of electricity" (LCOE) and include capital costs, fixed and variable operation costs, fuel costs, as well as an interest rate for the entire lifetime of a power plant. This full-cost approach provides an amount in €/MWh, which can be translated into a minimum average price.

IEA (2010) suggests the following formula for determining the $LCOE$:

$$LCOE = \frac{\sum_{t=0}^{T}((Invest_t + O\&M_t + Fuel_t + CO_{2t} + Dec_t) \cdot (1+r)^{-t})}{\sum_{t=0}^{T}(Electricity_t \cdot (1+r)^{-t})}. \tag{3.19}$$

Costs of flexibility can be categorized accordingly. The most important distinction is between a more flexible operation of a power plant and the flexible operation of a power plant that has been retrofitted with a suitable flexibility measure. Under both circumstances, operation and maintenance costs increase. This is due to the increased stress that parts experience during more variable generation. Fuel costs can increase for partial loads, which are more frequent in flexible operation, because the efficiency factor decreases.

For a flexible power plant, we can thus define the $LCOE_{flex}$ as follows:

$$LCOE_{flex} = \frac{\sum_{t=0}^{T}((Invest_{t,flex} + O\&M_{t,flex} + Fuel_{t,flex} + CO_{2t,flex} + Dec_{t,flex}) \cdot (1+r)^{-t})}{\sum_{t=0,flex}^{T}(Electricity_{t,flex} \cdot (1+r)^{-t})}. \tag{3.20}$$

The option price should now be determined from the difference of the $LCOE$ and the $LCOE_{flex}$. Both give costs in €/MWh, which can then be used for the value of an option:

$$Opt = (LCOE_{flex} - LCOE) \cdot P \cdot t, \tag{3.21}$$

where P is the maximum capacity which can be used when exercising the option, and t determines which time period is covered by the option. The option price is thus given in €.

3.3.3 Case study with results

For obtaining a comprehensive picture of possible option prices, we create an optimistic, a realistic, and a pessimistic scenario. The optimistic scenario relates to the lower bounds of the costs given in Table 3.9, the realistic scenario to the median values, and the pessimistic scenario to the upper bounds[8].

Table 3.9: Cost variables and their specifications for determination of option price

Type of costs	Variable	Optimistic	Realistic	Pessimistic
Investment costs	$Invest_{t,flex}$	1.4 mio €	14.85 mio €	26.9 mio €
Operation and maintenance costs	$O\&M_{t,flex}$	35 €/MW	90 €/MW	145 €/MW
Fuel costs	$Fuel_{t,flex}$	unknown(1)		
CO_2 costs	$CO_{2t,flex}$	unknown(1)		
Additional operating hours p.a.	$Electricity_{t,flex}$	1,000	1,000	1,000

[1] The additional fuel and CO_2 costs that arise due to less efficient working points of the power plant are very hard to estimate. Since we only want to determine an option price, and not the strike price, we can disregard them in our analysis. The full cost of providing the energy when exercising the option should, however, be considered in the strike price.

For the discount factor, we will stick to the lower proposition of the IEA (2010), i.e. 5%, because this seems currently more realistic than the otherwise proposed 10%. These values are subsequently used for determining the *Opt*. For better comparability, Table 3.10 shows prices in € per MW. They refer to the scenario calculations as described above and are independent from the underlying technology.

Table 3.10: Option prices by scenario per unit of capacity

Scenario	Opt price [in €/MW]
Optimistic	0.32
Realistic	3.14
Pessimistic	5.67

Table 3.10 indicates that the prices for a flexibility option are fairly low. To put them into perspective, it makes sense to compare them with the prices for balancing energy. For example, in February 2014 the TSOs charged on average 61 €/MW for every quarter of an hour (50Hertz, 2015b). Keeping in mind that the above-mentioned option prices can be regarded as minimum prices for a fair remuneration of providing flexibility, it becomes apparent that the system costs for achieving more flexibility are manageable. This is especially important since flexibility is one of the cornerstones for the energy transition process (*Energiewende*).

[8] For further details regarding the composition and approximation of the cost variables, see Rosen and Madlener (2015).

We have looked into possibilities for a fair remuneration of flexible electricity. We take a cost-based approach for determining the value of a flexibility option. This relies on the "levelized costs of electricity" for producing flexible and non-flexible energy. The difference thereof is the minimum price that a power plant operator should receive. We have shown that this approach results in reasonable prices compared to prices for balancing energy, which would otherwise have to be paid.

4 Summary, conclusions and recommendations

The decision-making process for complex investments requires to account for as much relevant information as possible, and importantly that related to uncertainties and the value of flexibility. As many practical studies have shown, real options analysis – a very powerful approach – can be successfully applied for project valuation in various sectors, including the energy industry. However, a special characteristic of the energy market is the need to adapt the decision-making process so as to consider economic as well as technical parameters in the investment decision valuation. This makes the whole process more complex and motivates this study.

In Section 3.1, the same selected technical solutions applicable to increase the flexibility of conventional power plants were considered. These technical solutions were separately discussed for the large thermal power plants and at the power system level. For each technical solution, the possible advantages of their use were individually presented (e.g. reduction of the minimum load, increase of the efficiency at part load or increase of the load gradient, etc.). Moreover, for the further economic analysis, the associated economic parameters (e.g. realization costs and construction times) were discussed.

Regarding the nonprofitable operation of the conventional power plant caused by the increased use of renewable energy technologies, possible solutions for the power plant owners can be either to disinvest or to invest in technical solutions in order to increase the flexibility of the conventional power plants. From this perspective, in the subsequent Section 3.2, the real options model for the disinvestment from a gas-fired power plant and the real options model for the flexible operation of an enhanced gas-fired power plant were discussed. For both models, the mathematical representation as well as the solution procedure have been introduced. The application of these models was presented in one case study, where a highly efficient and modern gas-fired power plant was analyzed.

For the real options model for evaluating the disinvestment from a gas-fired power plant, the solution is based on a binomial tree which was implemented in spreadsheets (Microsoft Excel®). The application of this solution method for real options analysis and the use of MS Excel® can be recommended as a decision support tool that is an alternative or complementary approach to the already existing and more traditional valuation methods. This model offers a simple use of real options analysis. Nevertheless, its strength lies in its ability to model uncertain parameters included in the model and the value inherent in flexibility (flexible option, disinvestment). This is well illustrated by using the changing volatility level of the capacity factor as an underlying asset. Moreover, the definition and inclusion of the “residual value” of the investment is an important parameter in the model construction as well as in the decision process.

In the case of the real options model for flexible operation of an enhanced gas-fired power plant, the mathematical representation was more complex and it was solved using dynamic programming (implemented in Python 2.7). The complexity of the proposed procedure began with the definition of the operation regime and the level of detail (hour level) of the analysis. The analysis was conducted for one specific technical improvement, but it illustrated the possible applications of this model for further flexibility measures.

Regarding the examination of current and possible future market designs to determine the most profitable markets for enhanced power plants, alternative market design implications were discussed in Section 3.3. Based on the literature study and the current design of the German electricity market, a methodology established on the fair price for a flexibility option that considers the costs was proposed. The “levelized cost of electricity” metric was used in the model as a fair remuneration of flexible electricity (flexible and non-flexible energy). As shown in the simple case study, the proposed approach results in reasonable prices compared to prices for balancing energy, which would otherwise have to be paid.

5 Further steps, future developments, and proposed actions

The real options models developed in this project give decision-makers additional insights to assess project valuations. Moreover, the proposed models can support, and complement already existing, traditional valuation approaches.

Even though the models implemented here were applied specifically for investment decisions in gas-fired power plants, their implementation is also possible for other technologies, with often only minor alterations. In further research, for instance, the introduced models can be implemented in a more elaborate software tool, where several conventional power generation technologies can be chosen from a portfolio of alternatives.

The further development of the real options disinvestment model can follow at least two paths. First, it can be adapted to consider different underlying assets, where for instance the electricity price or also the spark spread can be applied. Second, additional improvements can be made with respect to the definition of the “residual value” of the power plant. Additional research is needed to improve its estimation, a point that is already being discussed among industry practitioners and academics.

Considering the second model introduced in this project, on the value of enhanced flexibility of operation, further research is needed for the more realistic determination of the operation strategy. The approach proposed here was relatively simple, and additional complexity needs to be added for an improved modeling of the investment evaluation.

Furthermore, an improved decision support tool would also account for the possibility to systematically test variability of the difference economic and technical parameters included in the model, so as to facilitate sensitivity analyses of key decision variables and parameters.

Regarding the market design implications for an enhanced gas-fired power plant, further research should analyze the underlying risk and uncertainty structures in more detail. Moreover, in the approach adopted, we have argued from the point of view of a producer. An emphasis on the buyer or market side might lead to very different results, and should also be explored in the future.

Finally, another avenue for further research concerns the data used for our calculations. A broader base might again lead to deeper insights and might be worthwhile examining.

6 Literature

50Hertz (2015a). 50Hertz Transmission Gmbh. `http://www.50hertz.com/en/Grid-Data/Wind-power/Archive-Wind-power`. [2015-10-05].

50Hertz (2015b). Bilanzkreisabrechnung: reBAP im CSV-Format in EUR/MWh. `http://www.50hertz.com/de/Maerkte/Regelenergie/Bilanzkreisabrechnung`. [2015-04-27].

ABB (2009). Energy Efficient Design of Auxiliary Systems in Fossil-Fuel Power Plants. `https://library.e.abb.com/public/5e627b842a63d389c1257b2f002c7e77/Energy%20Efficiency%20for%20Power%20Plant%20Auxiliaries-V2_0.pdf`. [2015-10-05].

Agora (2013). 12 insights on Germany's Energiewende. `http://www.agora-energiewende.de/fileadmin/Projekte/2012/12-Thesen/Agora_12_Insights_on_Germanys_Energiewende_web.pdf`. [2015-08-05].

Alexander, R., Mo, M., and Stent, A. (2012). Arithmetic Brownian motion and real options. *European Journal of Operational Research*, 219(1):114–122.

Alstom (2013). Peak Power – Cost-Effective Thermal Energy Storage. `http://www.alstom.com/Global/Power/Resources/Documents/Brochures/peak-power-water-based-energy-storage-solution-for-steam-plants.pdf?epslanguage=en-GB`. [2015-08-19].

Ascend (2014). Independent Market Assessment on Southwest Power Pool Market, USA. `http://wartsila.prod.avaus.fi/docs/default-source/smartpowergeneration/content-center/spp-analysis-final_v2.pdf?sfvrsn=2`. [2015-08-19].

Bine Informationsdienst (2015). Energieforschung für die Praxis: Strom aus Gas und Kohle. `http://www.bine.info/publikationen/basisenergie/publikation/strom-aus-gas-und-kohle/`. [2015-10-01].

Black, F. and Scholes, M. (1973). The pricing of options and corporate liabilities. *The Journal of Political Economy*, 81(3):637–654.

BNetzA (2014). Monitoringbericht 2014. Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen, Bonn.

Brauner, G. (2012). *Erneuerbare Energie braucht flexible Kraftwerke – Szenarien bis 2020.* WEC-Workshop VDE ETG, TU Wien, November.

Buchholz, W., Frank, W., Karl, H., Pfeiffer, J., Pittel, K., Triebswetter, U., Habermann, J., Mauch, W., and Staudacher, T. (2012). *Die Zukunft der Energiemärkte: Ökonomische Analyse und Bewertung von Potenzialen und Handlungsmöglichkeiten.* Ifo Institut, München.

Clausen, T. (2015a). KWK Energiewende Energiemarktdesign. http://www.agora-energiewende.de/fileadmin/Projekte/2014/perspektiven-der-kwk/20150128_KWK_im_zukuenftigen_Energiemarktdesign.pdf. [2015-08-24].

Clausen, T. (2015b). Wie passt KWK ins künftige Strom- und Wärmesystem? http://www.agora-energiewende.de/fileadmin/Projekte/2014/perspektiven-der-kwk/20141112_Agora_TC_Gruene_KWK.pdf. [2015-08-24].

Cox, J., Ross, S., and Rubinstein, M. (1979). Option pricing: A simplified approach. *Journal of Financial Economics*, 7(3):229–263.

De Doncker R. (2011). Emissionsfreies Kraftwerk. European Patent 2 373 401 B1.

Deng, S.-J. and Oren, S. (2003). Incorporating operational characteristics and start-up costs in option-based valuation of power generation capacity. *Probability in the Engineering and Informational Sciences*, 17:155–181.

Diantonio, G., Hofer, D., and Parry, W. (2010). Überlastventile für eine Dampfturbine und zugehöriges Verfahren. Patent: DE102009026053 A1.

Diermann, C. (2015). Die Rolle der Kraft-Wärme-Kopplung in der Energiewende. http://www.agora-energiewende.de/fileadmin/Projekte/2014/perspektiven-der-kwk/Agora_KWK_web.pdf. [2015-08-24].

Dixit, A. and Pindyck, R. (1994). *Investment under Uncertainty.* Princeton University Press, Princeton, New Jersey.

E.ON (2013). *Annual Report 2013.* E.ON SE Düsseldorf.

E.ON (2014). Kraftwerk Irsching, Daten und Fakten. http://www.eon.com/de/ueber-uns/struktur/asset-finder/irsching.html. [2014-07-10].

Erdmann, G. and Zweifel, P. (2010). *Energieökonomik. Theorie and Anwendungen.* 1st ed. Springer-Verlag, Berlin/Heidelberg.

FDBR Fachverband Anlagenbau Energie. Umwelt. Prozessindustrie (2013). Feste Marktrahmen gefordert. Flexibilisierung thermischer Kraftwerke. *BWK*, 65(4):31–32.

Feil, J.-H. and Musshoff, O. (2013). Investment, disinvestment and policy impact analysis in the dairy sector: a real options approach. *SiAg-Working Paper 16, DFG-Forschergruppe 986, Humboldt-Universität zu Berlin.*

Fernandes, B., Cunha, J., and Ferreira, P. (2011). The use of real options approach in energy sector investments. *Renewable and Sustainable Energy Reviews*, 15(9):4491–4497.

Fleten, S.-E. and Näsäkkälä, E. (2010). Gas-fired power plants: Investment timing, operating flexibility and CO_2 capture. *Energy Economics*, 32:805–816.

Fontes, D. (2008). Fixed versus flexible production systems: A real options analysis. *European Journal of Operational Research*, 188(1):169–184.

Freund, O., Ernst, B., and Seume, J. (2012). Anforderungen an konventionelle Kraftwerke für die Transformation des Energiesystems. Ringvorlesung "Transformation des Energiesystems", Hannover. 9. Mai 2012.

Glensk, B. and Madlener, R. (2015). Real Options Analysis of the Flexible Operation of an Enhanced Gas-Fired Power Plant. *FCN Working Paper No.11/2015*. Institute for Future Energy Consumer Needs and Behavior, School of Business and Economics/E.ON ERC, RWTH Aachen University, August.

Glensk, B., Rosen, C., and Madlener, R. (2015). A Real Options Model for the Disinvestment in Conventional Power Plants. *FCN Working Paper No.9/2015*. Institute for Future Energy Consumer Needs and Behavior, School of Business and Economics/E.ON ERC, RWTH Aachen University, August.

Glensk, B., Rosen, C., and Madlener, R. (2016). A Real Options Model for the Disinvestment in Conventional Power Plants. In *Operations Research Proceedings 2014*. in: M. Lübbecke, A.M.C.A. Koster, P. Letmathe, R. Madlener, B. Peis, G. Walther (Eds.) (2016), Selected Papers of the International Annual Conference of the German Operations Research Society (GOR), RWTH Aachen University, Germany, September 2-5, 2014, Springer-Verlag, Berlin/Heidelberg/New York, pp.xx-yy (in press).

Götz, P., Henkel, J., Lenck, T., and Lenz, K. (2014). *Negative Strompreise: Ursachen und Wirkungen. Eine Analyse der aktuellen Entwicklung – und ein Vorschlag für ein Flexibilitätsgesetz*. Agora Energiewende, Berlin.

Guthrie, G. (2009). *Real Options in Theory and Practice*. Oxford University Press, New York.

Hille, M. (2012). *Technische und wirtschaftliche Situation konventioneller Kraftwerke in Deutschland*. BDEW - Bundesverband der Energie- und Wasserwirtschaft e.V., dena- Dialogforum - Retrofit und Flexibilisierung konventioneller Kraftwerke, Berlin.

IEA (2010). Projected costs of generating electricity. OECD, Paris, France.

IEEE (2003). Std. 958-2003 – Guide for the Application of AC Adjustable-Speed Drives on 2,400 - 16,800 V Auxiliary Systems in Electric Power Generating Stations. `http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=1304102`. [2015-08-10].

Klimstra, J. (2014). Power Supply Challenges – Solutions for Integrating Renewables. `http://www.wartsila.com/energy`. [2015-08-10].

Konstantin, P. (2009). *Praxisbuch Energiewirtschaft*. Springer-Verlag, Berlin/Heidelberg.

Litau, I. (2015). Simulation-based economic analysis of selected measures to increase the flexibility of conventional power plants. Master's Thesis, Chair of Energy Economics and Management, Institute for Future Energy Consumer Needs and Behavior (FCN), RWTH Aachen University.

Maaß, R. (2013). *Anpassung thermische Kraftwerke an künftige Herausforderungen im Strommarkt: Maßnahmenkatalog*. FDBR Fachverband Anlagenbau Energie. Umwelt. Prozessindustrie, Düsseldorf.

Mainova Press Releases (2010). Hocheffizientes Gas- und Dampfturbinenkraftwerk setzt neue Maßstäbe. `http://www.mainova.de/unternehmen/press/2835.html`. [2014-04-28].

Merton, R. (1973). Theory of rational option pricing. *The Bell Journal of Economics and Management Science*, 4(1):141–183.

Mun, J. (2006). *Real Options Analysis – Tools and Techniques for Valuing Strategic Investments and Decisions*. John Wiley & Sons, Hoboken, New Jersey.

Mura, F., De Doncker, R.W., Persigehl, B., Jeschke, P., and Hamayer, K. (2011). Analysis of a Gearless Medium-Voltage Variable Speed Gas Turbine. *VGB PowerTech*, 91(4):39–44.

Musshoff, O., Odening, M., Schade, C., Maart-Noelck, S., and Sandri, S. (2012). Inertia in disinvestment decisions: experimental evidence. *European Review of Agricultural Economics*, 40(3):463–485.

Näsäkkälä, E. and Fleten, S.-E. (2005). Flexibility and technology choice in gas fired power plant investments. *Review of Financial Economics*, 14(3-4):371–393.

Pickard, A. and Meinecke, G. (2011). The Future Role of Fossil Power Generation. Siemens AG, Erlangen, Germany.

Plewnia, M. (2014). Impact of Flexibility Measures on Conventional Power Plants. Master's Thesis, Chair of Energy Economics and Management, Institute for Future Energy Consumer Needs and Behavior (FCN), RWTH Aachen University.

Rautkivi, M. and Kruisdijk, M. (2013). Future market design for reliable electricity systems in Europe. POWERGEN Europe, 4-6 June 2013, Vienna.

Rohlfs, W. and Madlener, R. (2011). Valuation of CCS-Ready Coal-Fired Power Plants: A Multi-Dimensional Real Options Approach. *Energy Systems*, 2(3-4):243–261.

Rohlfs, W. and Madlener, R. (2013). Assessment of Clean-Coal Strategies: The Questionable Merits of Carbon Capture-Readiness. *Energy*, 52:27–52.

Rohlfs, W. and Madlener, R. (2014a). Multi-Commodity Real Options Analysis of Power Plant Investments: Discounting Endogenous Risk Structures. *Energy Systems*, 5(3):423–447.

Rohlfs, W. and Madlener, R. (2014b). Optimal Investment Strategies in Power Generation Assets: The Role of Technological Choice and Existing Portfolios in the Deployment of Low-carbon Technologies. *International Journal of Greenhouse Gas Control*, 28(September):114–125.

Roques, F., Newbery, D., and Nuttall, W. (2007). Fuel mix diversification in liberalized electricity markets: A mean-variance portfolio theory approach. *Energy Economics*, 30(4):1831–1849.

Rosen, C. and Madlener, R. (2015). An Option-Based Approach for the Fair Pricing of Flexible Electricity Supply. *FCN Working Paper No.10/2015*. Institute for Future Energy Consumer Needs and Behavior, School of Business and Economics/E.ON ERC, RWTH Aachen University, August.

Schimkat, A. (2013). Massnahmen zur Erhöhung der Flexibilität von Dampfkraftwerken. [2015-10-05].

Schwartz, E. and Trigeorgis, L. (2001). *Real Options and Investment under Uncertainty: Classical Readings and Recent Contributions*. The MIT Press, Cambridge, Massachusetts.

Stromklar (2014). Gaskraftwerk Irsching 5 bleibt am Netz. `http://www.stromklar.de/gaskraftwer-irsching-5-bleibt-am-netz-2169.htm`. [2014-03-20].

Trigeorgis, L. (1996). *Real Options: Managerial Flexibility and Strategy in Resource Allocation*. The MIT Press: Cambridge, Massachusetts/London, England.

Tseng, C.-L. and Lin, K. (2007). A Framework Using Two-Factor Price Lattices for Generation Asset Valuation. *Operations Research*, 55(2):234–251.

VDE (2012a). Energiespeicher für die Energiewende – Speicherungsbedarf und Auswirkungen auf das Übertragungsnetz für Szenarien bis 2050. Frankfurt am Main.

VDE (2012b). Erneuerbare Energie braucht flexible Kraftwerke – Szenarien bis 2020. Energietechnische Gessellschaft im VDE, Frankfurt am Main.

Wärtsilä (2014). Delivering flexibility in the German electricity markets: are current arrangements fit for the purpose? Helsinki, Finland.

Wärtsilä (2015). Technical Comparison Article Series – Combustion Engines vs. Gas Turbines. `http://www.wartsila.com/energy/learning-center/technical-comparisons`. [2015-07-29].

Westner, G. and Madlener, R. (2011). Development of Cogeneration in Germany: A Mean-Variance Portfolio Analysis of Individual Technology's Prospects in View of the New Regulatory Framework. *Energy*, 36(8):5301–5313.

Westner, G. and Madlener, R. (2012a). Investment in New Power Generation under Uncertainty: Benefits of CHP vs Condensing Plants in a Copula-Based Analysis. *Energy Economics*, 33(1):31–44.

Westner, G. and Madlener, R. (2012b). The Impact of Modified EU ETS Allocation Principles on the Economics of CHP-based District Heating Systems. *Journal of Cleaner Production*, 20(1):47–60.

7 Attachments

7.1 List of Figures

7.2 List of Tables

7.3 Publications

- Glensk B., Madlener R. (2015). Real Options Analysis of the Flexible Operation of an Enhanced Gas-Fired Power Plant. FCN Working Paper 11/2015, RWTH Aachen University, August.
- Glensk B., Rosen C., Madlener R. A Real Options Model for the Disinvestment in Conventional Power Plants. In: Operations Research Proceedings 2014, in: M. Lübbecke, A.M.C.A. Koster, P. Letmathe, R. Madlener, B. Peis, G. Walther (Eds.) (2016), Selected Papers of the International Annual Conference of the German Operations Research Society (GOR), RWTH Aachen University, Germany, September 2-5, 2014, Springer-Verlag, Berlin/Heidelberg/New York, pp.xx-yy (in press).
- Glensk B., Rosen C., Madlener R. (2015). A Real Options Model for the Disinvestment in Conventional Power Plants. FCN Working Paper 9/2015, RWTH Aachen University, August.
- Rosen C., Madlener R. (2015). An Option-Based Approach for the Fair Pricing of Flexible Electricity Supply. FCN Working Paper 10/2015, RWTH Aachen University, August.

7.4 Short CVs of scientists involved in the project

Prof. Dr. rer. soc. oec. Reinhard Madlener studied Commerce and Finance as well as Pedagogics at the Vienna University of Economics and Business Administration (WU Wien) and then (post-graduate) also Economics at the Institute for Advanced Studies Vienna (IHS). He received his PhD in 1996 from WU Wien in the Economics and Social Sciences (Dr. rer. soc. oec.), specializing in

General Economics, Environmental Economics, and Statistics. Before taking up his current position at RWTH Aachen University in June 2007, he was Managing Director of the Institute for Advanced Studies Carinthia (1999-2000), Assistant Professor at the Centre for Energy Policy and Economics (CEPE), ETH Zurich (2001-2007), Lecturer at the Faculty of Economics, University of Zurich (2003-2010), and Senior Researcher at the German Institute of Economic Research / DIW Berlin (2007). Among others, he was Visiting Fellow at the University of Illinois (Urbana-Champaign), the European University Institute (Florence, Italy), and the University of Warwick (Coventry, UK). Prof. Madlener is one of five full professors of the E.ON Energy Research Center (E.ON ERC), established at RWTH Aachen University at the end of 2006, Director of the Institute for Future Energy Consumer Needs and Behavior (FCN), founded by himself in June 2007, Co-Editor of *Energy Policy*, and President of the Swiss Association for Energy Economics (SAEE).

Prof. Dr. ir. Dr. h.c. Rik W. De Doncker received his PhD in Electrical Engineering from the Katholieke Universiteit Leuven, Belgium, in 1986. In 1987, he was appointed a Visiting Associate Professor at the University of Wisconsin, Madison, where he lectured and conducted research on field-oriented controllers for high-performance induction motor drives. In 1988, he was a General Electric Company Fellow in the Microelectronic Center, IMEC, Leuven, Belgium. In December 1988, he joined the General Electric Company Corporate Research and Development Center, Schenectady, NY, where he led research on drives and high-power soft-switching converters, ranging from 100 kW to 4 MW, for aerospace, industrial, and traction applications. In 1994, he joined Silicon Power Corporation (formerly GE-SPCO) as Vice President, Technology. He worked on high-power converter systems and MTO devices and was responsible for the development and production of 15 kV medium-voltage transfer switch. Since October 1996, he has been Professor at RWTH Aachen University, Aachen, Germany, where he leads the Institute for Power Electronics and Electrical Devices. He has published over 180 technical papers and is holder of 20 patents, with several pending. Prof. De Doncker was a member of the IEEE IAS Executive Board and is Past President of IEEE Power Electronics Society (PELS). He is a member of the EPE Executive Council. He was founding Chairman of the German IEEE IAS-PELS Joint Chapter. Prof. De Doncker is also the recipient of the IAS Outstanding Achievement Award and the PES Custom Power Award. In 2006, he was appointed Director of the E.ON Energy Research Center. In 2010, he became a member of the German National Platform for E-Mobility (NPE) and led the VDE/ETG Task Force Study on E-Mobility.

Dr. rer. oec. Barbara Glensk studied Econometrics and Statistics at the Karol-Adamiecki University of Economics in Katowice, Poland. She worked at that university as a Research Associate with the Chair of Operations Research, receiving her PhD in Economics (Dr. rer. oec.) from there in 2002. Since 2008, Dr. Glensk has been working as a Research Associate with the Institute for Future Energy Consumer Needs and Behavior (FCN) at the E.ON Energy Research Center at RWTH Aachen University, Germany.

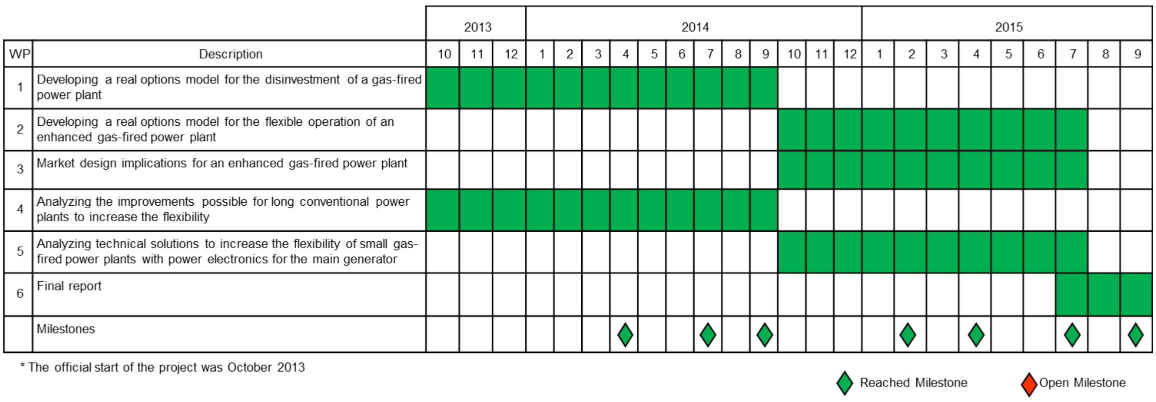
Dr. rer. pol. Christiane Rosen studied Economics (B.Sc.), Mathematical Economics and Infonomics

(M.Sc.) in the Netherlands (Maastricht University), China, and Belgium. In August 2009, she joined the Institute for Future Energy Consumer Needs and Behavior (FCN) at the E.ON Energy Research Center, where she focused on auction theory and energy markets, especially ancillary services markets. In 2014, she received her PhD from the School of Business and Economics at RWTH Aachen University, Germany. Her dissertation introduces a local reserve energy market for residential prosumers and evaluates the design theoretically, experimentally, and through the help of a simulation study. Since May 2015, she has been working with ProCom GmbH as a consultant and coach for solutions in the field of energy trading, power plant operation, and portfolio optimization.

Sedigheh Rabiee M.Sc. gained a B.Sc. in Electrical Engineering and Information Technology from Shiraz University, Shiraz, Iran, in 2008, and gained an M.Sc. in Electrical Power Engineering from the Technical University of Darmstadt, Germany, in 2012. Her master's thesis deals with the implementation of modular multilevel converters in a multiterminal HVDC system. Since February 2013, she has been with the Institute for Power Generation and Storage Systems (PGS), E.ON Energy Research Center, RWTH Aachen University, as a Research Associate. Her research interests include the application of power electronic devices in medium-voltage DC grids.

Ralf Bachmann Schiavo M.Sc. gained an B.Sc. in Electrical Engineer from the State University of Santa Catarina, Brazil, in 2009, and gained an M.Sc. in Electrical Power Engineering from the Technical University of Darmstadt, Germany, in 2012. From 2012 to 2015 he was with the Excitation Systems and Synchronizing Equipment, ABB Switzerland Ltd., as a System Development Engineer. Since March 2013, he has been with the Institute of Power Generation and Storage Systems, E.ON Energy Research Center, RWTH Aachen University, Germany, as a Research Associate. His research interests include the control of power electronic systems and electrical power systems.

7.5 Project timeline



7.6 Activities within the scope of the project

Progress made within the project has been presented at a variety of national and international scientific conferences, including the following:

Glensk B., Madlener R. (2015). Investments in Flexibility Measures for Gas-Fired Power Plants: A Real Options Approach. International Conference on Operations Research: "Optimal Decisions and Big Data" (OR 2015), Vienna, Austria, September 1-4, 2015.

Glensk B., Rosen C., Madlener R. (2014). A Real Options Model for the Disinvestment in Conventional Power Plants. International Conference on Operations Research "Business Analytics and Optimization" (OR 2014), Aachen, Germany, September 2-5, 2014.

Glensk B., Rosen C., Madlener R. (2015). Real Options Analysis of the Flexible Operation of an Enhanced Gas-fired Power Plant. Nordic Environmental Social Science Conference (NESS 2015), Trondheim, Norway, June 9-11, 2015.

Madlener R., Glensk B., Rosen C. (2015). Real Options Analysis of Investments in Flexibility Measures for Gas-fired Power Plants. INFORMS Annual Meeting 2015, Philadelphia, USA, November 1-4, 2015.

Rosen C., Glensk B., Madlener R. (2015). Market Analysis for Energy Provision by Flexible Power Plants. Nordic Environmental Social Science Conference (NESS 2015), Trondheim, Norway, June 9-11, 2015.



E.ON Energy Research Center Series

ISSN: 1868-7415
First Edition: Aachen, November 2015

E.ON Energy Research Center,
RWTH Aachen University

Mathieustraße 10
52074 Aachen
Germany

T +49 241 80 49667
F +49 241 80 49669
post_erc@eonerc.rwth-aachen.de
www.eonerc.rwth-aachen.de