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Modelling and Analysing the impact of Flexible Technologies on Market-Based Generation Investment Planning

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I hereby declare that this thesis and the work reported herein was composed by and originated entirely from me. Information derived from the published and unpublished work of others has been acknowledged in the text and references are given in the list of sources.

Temitayo Oderinwale (2019)

This Thesis is dedicated:

To my teachers who have invested their knowledge in me over the years;

To my family for the love and support and for believing in me all the way;

To the good people of the Federal Republic of Nigeria.

Acknowledgement

The ungrateful person will not remember.
— Deji Adeyanju

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Abstract

In recent times, the value of flexibility potentials available at the demand side in addressing techno-economic challenges associated with the decarbonisation of power systems has attracted notable interest from governments, industry and academia. Notwithstanding these interests, its impacts on long-term power system planning has only been investigated using system cost minimisation models. Such models are inherited from the era of vertically integrated power utilities and cannot represent the profit-oriented decisions of the liberalised electricity industry. Available market-based generation investment planning models in technical literature neglect the time-coupling effects in their operational timescale and for this reason are inherently unable to integrate the operation of non-generating flexible technologies.

This thesis investigates the impacts of demand flexibility on the long-term investment decisions of a self-interested generation company under different market designs. The thesis proposes a novel time-coupling, bi-level optimisation model which accounts for the energy shifting flexibility of the demand side. This model is further enhanced to also incorporate the operation of reserve markets with demand side participation, thereby presenting a jointly cleared energy and reserves market. This model is solved using rigorous mathematical techniques involving the formulation of a Mathematical Program with Equilibrium Constraint (MPEC) problem and the transformation of the MPEC problem to a Mixed Integer Linear Program (MILP) problem.

Different case studies have been carried out to investigate the impact of demand flexibility participating in either only the energy market or in both the energy and reserves market. These case studies demonstrated the similarities in impact of different flexible technologies on the optimal generation investment decisions and enhancing the profit earned by the investing company. The thesis also investigates different scenarios regarding the flexibility of the demand side, market design options and strict carbon targets. The thesis findings show the dependence of the impact of demand flexibility on the optimal investment decisions of the examined generating company on: (i) the market(s) in which demand flexibility participates and (ii) the market design option considered.

Contents

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List of Publications

Some of the results presented in this thesis have also been peer-reviewed and presented in the following publications listed below.

Journal Publications

[1] **Temitayo Oderinwale**, Dimitrios Papadaskalopoulos, Yujian Ye and Goran Strbac, "Investigating the Impact of Flexible Demand on Market-Based Generation Investment Planning", International Journal of Electrical Power and Energy Systems, vol. 119, July 2020.

Conference Publications and Presentations

[1] **Temitayo Oderinwale**, Dimitrios Papadaskalopoulos, Yujian Ye and Goran Strbac, "Incorporating Demand Flexibility in Strategic Generation Investment Planning", 2018 15th International Conference on the European Energy Market (EEM), held in Lodz Poland June 27 - 29, 2018.

[2] **Temitayo Oderinwale**, Yujian Ye, Dimitrios Papadaskalopoulos and Goran Strbac, "Impact of Energy Storage on Market-Based Generation Investment Planning", 2019 IEEE Milan PowerTech Conference, June 23 - 27, 2019.

Nomenclature

Sets and Indices:

$t \in T$	Index and set of hours
$d \in D$	Index and set of Representative days
$i \in I$	Index and set of Generation Technologies
$I^{MR} \subseteq I$	Subset of Must-Run Generation Technologies
$I^{RE} \subseteq I$	Subset of Renewable Generation Technologies
$I^{FL} \subseteq I$	Subset of Flexible Generation Technologies
V^{LL}	Set of decision variables of Lower Level Problem
V^{MPEC}	Set of decision variables of MPEC Formulation
V^{CEN}	Set of decision variables of Centralized Planning Problem

Parameters:

wf_d	Weighting Factor for the day d
X_i^E	Existing Capacity of Generation Technology i (MW)
IC_i	Investment Cost of Generation Technology i (£/MW/year)
C_i^G	Energy Production Cost of Generation Technology i (£/MWh)
C_i^{RU}	Upward Reserve Cost of Generation Technology i (£/MWh)
C_i^{RD}	Downward Reserve Cost of Generation Technology i (£/MWh)
$k_{i,d,t}^{RE}$	Normalised Output of Renewable Generation Technology i in day d and hour t
Δ_i^{RE}	Standard Deviation of Output of Renewable Generation Technology i

ε_i^{RE}	Forecast Error of Output of Renewable Generation Technology i
$D_{d,t}^{BA}$	Baseline Demand in day d and hour t (MW)
s^{max}	Power Capacity of ES (MW)
E^{cap}	Energy Capacity of ES (MWh)
E^{max}	Maximum Energy Limit of ES (MWh)
E^{min}	Minimum Energy Limit of ES (MWh)
E_o	Initial Energy Level of ES (MWh)
τ	Temporal resolution (h)
η^c, η^d	Charging and Discharging Efficiency of ES
α	Flexibility Limit of the Demand Side
Υ	System Adequacy Coefficient
Γ	Reserve Costs allocation for Renewable Generation Technology
Λ^{MSG}	Minimum Stable Generation from the Must-Run Generation Technology
SEI	Carbon Emission Target
E_i^{CO}	Carbon Emission of Generation Technology i

Variables:

X_i	New Capacity of Generation Technology i (MW)
$g_{i,d,t}$	Energy Output of New Capacity of Technology i in day d and hour t (MW)
$g_{i,d,t}^{E}$	Energy Output of Existing Capacity of Technology i in day d and hour t (MW)
$g_{i,d,t}^{RD}$	Downward Reserve provided by New Capacity of Technology i in day d and hour t (MW)

$g_{i,d,t}^{RU}$ Upward Reserve provided by New Capacity of Technology i in day d and hour t (MW)

$g_{i,d,t}^{RD,E}$ Downward Reserve provided by Existing Capacity of Technology i in day d and hour t (MW)

$g_{i,d,t}^{RU,E}$ Upward reserve provided by Existing Capacity of Technology i in day d and hour t (MW)

$d_{d,t}^{e}$ Power consumed by demand in day d and hour t (MW)

$d_{d,t}^{sh}$ Change in demand in day d and hour t due to Flexible Demand used for energy arbitrage (MW)

$d_{d,t}^{RD}$ Upward Reserve provided by Flexible Demand in day d and hour t (MW)

$d_{d,t}^{RU}$ Downward Reserve provided by Flexible Demand in day d and hour t (MW)

$s_{d,t}^{c}$ Charging Power of ES in day d and hour t (MW)

$s_{d,t}^{d}$ Discharging Power of ES in day d and hour t (MW)

$E_{d,t}$ Energy Level of ES in day d and at the end of hour t (MWh)

Acronyms:

CCGT Combined Cycle Gas Turbines

ES Energy Storage

GENCO Generating ompany

KKT Karush-Kuhn-Tucker

LDC Load Duration Curve

LL Lower Level

MCP Mixed Complementarity Problem

MILP Mixed Integer Linear Program

MPEC Mathematical Program with Equilibrium Constraints

OCGT Open Cycle Gas Turbines

UL Upper Level

The beginning is the most important part of the work.

— *Plato*

What we call the beginning is often the end. And to make an end is to make a beginning. The end is where we start from.

— *T.S. Eliot*

Chapter 1

Introduction

1.1 Motivation

The need to protect the environment and address issues relating to climate change and air pollution prompted the introduction of policies and action plans by governments across the world with the aim to reduce carbon emissions. In this context, decarbonising the entire energy (including power, transport, heat) sector is receiving significant global attention because of its high carbon intensity.

This decarbonisation agenda has driven the increased penetration of renewable-based power generation in many countries including United Kingdom (UK), United States, Canada, Australia [1,2] as well as countries within the European Union (EU-27). On its part, the European Commission has set out a target for renewable-based generation to provide at least 32% of the total energy requirement in the European Union (EU) by 2030 [3].

The decarbonisation agenda has also engendered the rapidly increasing electrification of transport and heat sectors with the increased usage of electric vehicles (EV) and electric heaters to replace the traditional transport and heat technologies. In 2018, the governments of France and UK announced a plan to impose a ban on fossil fuel powered cars beginning from 2040.

The electrification of transport and heat sectors will increase electricity demand levels in the different time periods and more significantly the demand levels in peak time periods where their use occur simultaneously with the non-EV, non-heat peak demand levels. This will also increase the net demand variability and uncertainty. The increased demand levels in peak hours will necessitate an increase in investment and dispatch of fast ramping generating technologies generally referred to as peakers. Since peakers are carbon emitting technologies, an increase in investment and dispatch of peakers will increase carbon emissions in peak time-periods which will be counter-productive to the decarbonisation agenda.

On its part, the higher penetration of renewable-based generation introduces unique power system balancing challenges because of its inherent variability and limited predictability. This variability when combined with the hourly demand profile variations can increase the frequency of start-up and shut-down cycles for conventional generation technologies thereby increasing the power system flexibility requirements. On a different note, its limited predictability requires that power systems schedules sufficient reserves provision to cater for the possible forecast errors.

The envisaged challenges of increased variability underscore the importance of power system flexibility in the emerging low-carbon power systems. The reduced utilisation of the conventional generating units as they are displaced in the merit order by renewables reduces their capacity to provide the needed system flexibility. This realisation emphasises the need to explore flexibility potentials from the demand-side.

Power system flexibility refers to its ability to respond to changes or variations (expected or unexpected) in either supply or consumption. Traditionally, power system flexibility is provided by the conventional generating units, but the availability of smart technologies enables the demand side to actively provide this resource.

Power system flexibility can be provided by:

i. flexible generating units which make use of their ramping capabilities to increase output (ramp-up) or decrease output (ramp-down) as may be required;

ii. demand side flexibility which involve the readjustment of the time of use of different loads in response to market signals such as price;

iii. energy storage systems which can provide flexibility through its charging and discharging activities in off-peak and peak time periods respectively.

The potential value of non-generating flexible technologies to enable integration of renewable technologies as well as modify electricity consumption patterns thereby improving substantially the economic efficiency of low-carbon electricity systems is generating increasing interest from governments and industry [4–8] as well as academia [9–11]. Furthermore, the availability of smart technologies such as smart metering makes it easier for consumers to change their demand pattern in response to market signals thereby increasing the capacity of demand-side flexibility available in the system.

Power systems are operated to meet daily electricity demands. Its reliability and smooth functioning are required to provide indispensable services in modern-day society. To guarantee the security of supply, generation investment planning is a very important problem in power systems. This problem is aggravated with the liberalisation of electricity markets – which began in the 1980s in Chile, and soon after implemented in the United Kingdom – because the role and task of generation companies has been significantly complicated as individual generating companies (gencos) act in their best interest. Prior to this liberalisation, generation investment planning is carried out by a centralised planner who minimises the total costs including investment and operations costs to satisfy identified constraints.

The evolution and planning of future low carbon power systems will be impacted by the expected changes in the power system operations due to integration of renewable generation, electrification of the transport and heat sectors and the availability of technologies which facilitates demand-side flexibility. Therefore, long-term planning for generation investment in the competitive market framework requires the use of models which incorporate the dynamics of different power system flexibility sources as well as the reactions of the market to the investment decisions. This is very important as generation investment involves a large amount of capital and sub-optimal investment decisions have consequences for the power system, the environment and the investing company.

Available generation investment planning models in the competitive market framework employ a simplified representation of the demand side, ignoring the inter-temporal constraints that are essential to the representation of impact of flexible technologies. This thesis aims to contribute to fill this gap by proposing a novel market-based generation investment planning model which incorporates the operational flexibility of the demand-side and considers its participation in both the energy and the reserves market.

1.2 Research Objectives and Proposed Methodologies

The main aim of this thesis is to explore and analyse the impact of the participation of flexible technologies in electricity markets (energy and reserves) on the optimal generation investment strategy of a self-interested profit-maximising generation company. In addition, the impact of market design options on the investment strategy is also considered.

The thesis objectives are as follows:

1. Formulate novel multi-period bi-level optimisation models which can handle time-coupling constraints needed to represent the inter-temporal characteristics of non-generating flexible technologies. The consideration of time-coupling constraints introduces significant complexities to the

bi-level models and complicates the solution process. These models are solved using mathematically rigorous approach.

2. The developed bi-level models are applied in the following ways:

   2.1. To analyse the possible similarities and differences in impact of energy redistribution characteristics of demand flexibility and energy storage operations on the net system demand and generation investment strategies of generation companies operating in a competitive market environment.

   2.2. To represent the reserves market and analyse its influence on the investment decisions of the self-interested generating company.

   2.3. To analyse the impact of demand flexibility on the investment decisions of the self-interested generating company when participating only in the energy market (providing only energy redistribution flexibility) and when participating in both energy and reserves market (providing both energy redistribution flexibility and reserves).

   2.4. To investigate the dependence of the impact of demand flexibility on the market design options relating to the allocation of the reserves cost.

   2.5. To analyse the impact of demand flexibility considering strict carbon emissions targets.

   2.6. To understand the motivation of the generation company for investment in different technology options including conventional and renewable technologies, specifically wind.

1.3 Contribution to Knowledge

The research presented in this thesis analyses the impact of demand flexibility in generation investment planning within the liberalised electricity market framework. This thesis contributes to knowledge in the following ways:

- The development of a bi-level planning model which employs a chronological representation of demand. This allows the consideration of the time-coupling characteristics of demand which is essential to incorporate the time-shifting demand-flexibility and energy storage operations in the model. Such time-coupling characteristics cannot be considered using the discrete demand blocks employed in existing planning models because these demand blocks focus on the demand levels and neglects the time of demand.

- The modelling of an electricity market consisting of both energy and reserves market which is jointly cleared by the market operator. The joint energy and reserves market is represented in the lower level of the bi-level model presented. The consideration of reserves market is essential to adequately model low-carbon future power systems given the high level of variability anticipated. Furthermore, given the reduced competitiveness of conventional generation technologies in the energy market due to the higher penetration of renewables, the reserves market becomes an important revenue source for flexible conventional generation technologies. As a result, modelling both energy and reserves market allows the self-interested generation company to make a better informed and realistic decision.

- In addition to modelling both energy and reserves market, the demand flexibility is considered to participate in only the energy market (thereby providing energy arbitrage only) and to participate in both energy and reserves market (thereby providing reserves in addition to energy arbitrage).

- The investment options available to the self-interested genco includes both conventional technologies - nuclear, Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT) - and renewable technologies (wind). This allows a careful analysis of the self-interested genco's technology preference especially for baseload generation and the factors that drive this choice.

- An analysis of the dependence of the impact of demand flexibility on the investment decisions of the examined generation company on the market design with respect to the allocation of the reserves cost.
- A detailed study of the impact of demand flexibility on the investment decisions of the generation company under increasingly stringent carbon emissions limit.
- In contrast to previous work that has focused on either conventional or renewables, the investment options available to the investing company includes both conventional technologies - nuclear, Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT) - and renewable technologies (wind). This allows a careful analysis of the investing company's technology preference especially for baseload generation and the factors that drive this choice.

1.4 Thesis Structure

Chapter 1 presents the general background and motivation for the research presented in this thesis. This chapter also highlights the objective of the thesis and its contributions to knowledge.

Chapter 2 describes the evolution of the electricity market from the era of vertically integrated utilities to the introduction of competitive markets in the 1980s. The projected impact of ongoing efforts of energy systems decarbonisation in promoting increasing penetration of flexible technologies is also discussed. An overview of the operation of flexible technologies in future power systems is presented in the chapter. A review of various models developed to support investment planning under different electricity market structures is included with a focus on state-of-the-art models which express the decision making process for the generating companies in the liberalised electricity industry. Finally, a detailed review of the models considering the impact of flexible technologies in generation investment planning is included. The chapter concludes by clearly expressing the identified gaps in knowledge that this thesis address.

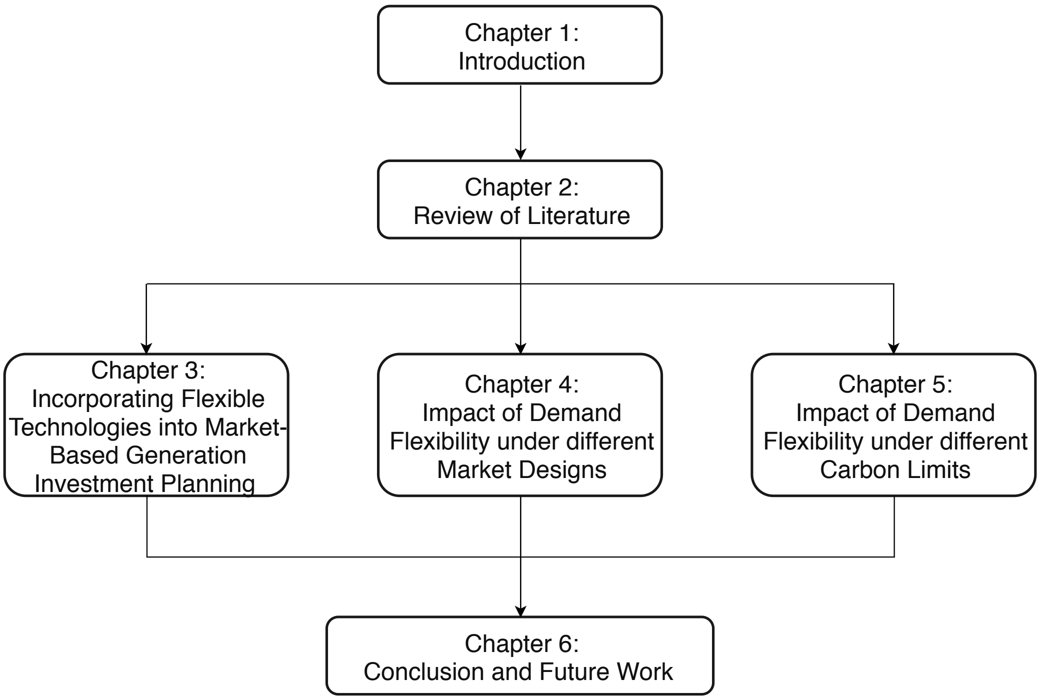

Figure 1.1: Thesis Structure

Chapter 3 presents a bi-level model to study the impact of the time-shifting flexibility of demand as well as operations of energy storage on market-based generation investment planning. A multi-period bi-level model is developed to allow the incorporation of the time coupling constraints associated with demand shifting and recovery and energy storage charging and discharging cycles. Separate case studies are carried out in this chapter on these respective technologies. The results of these case studies demonstrate the similarities in impacts of these technologies which can be summarised as limiting peak demand levels, reducing the variability of system demand profile and reducing the total capacity investment. These impacts are enhanced for higher levels of demand flexibility, ES energy capacity and ES power-to-energy ratio.

Chapter 4 presents a bi-level model which incorporates in its lower level problem the daily market clearing process of a co-optimised energy and reserve market. This model accounts for the energy shifting flexibility of the demand side, the dependency of the reserve requirements on the amount of renewable generation in the system, the ability of flexible generation and flexible demand to contribute to the provision of these required reserves, and alternative market design options regarding the allocation of the system cost of the required reserves. The optimal investment decisions under market-based planning approach are compared with those obtained using the centralised planning approach – inherited from the era of vertically integrated electricity utilities, and the differences are analysed.

Chapter 5 assesses the impacts of demand flexibility on market-based generation investment planning under different carbon emissions limit. The bi-level model presented in chapter 4 is enhanced with the introduction of yearly carbon emissions limit. The influence of the market participation for demand flexibility as well as market design with respect to reserve cost allocation on these investment decisions is analysed and discussed.

Chapter 6 outlines the main contributions of the research presented in this thesis and identifies the areas for further research.

The one who asks for the ancient paths from those who have gone ahead shall not miss the way.

— Yoruba Proverb

Chapter 2

Review of Literature

2.1 Introduction

Over the years, studies on power system operation and planning have been useful to aid the decision-making process of regulators and system operators and more recently those of profit-oriented market participants (such as generating companies, aggregators or merchant operators). In addition to the worldwide market liberalisation which took place over the last four decades, the increasing penetration of renewable technologies due to environmental concerns is affecting significantly power system operations and is now a vital consideration in the planning of future power systems.

Similarly, the increasing ability of the demand-side and other non-generating flexible technologies to actively participate in the electricity market brings a new dimension to the investment planning problems faced by generation companies. A major impact of these technologies is the resulting change in the temporal demand profile. Furthermore, these flexible technologies can also provide the highly required system flexibility for future power systems.

This chapter presents a review of some existing studies on electricity markets and power system operations and planning. It sets the context for the relevance of the work presented in the later chapters of this thesis.

The evolution of the electricity market is presented in section 2.2, studies discussing the impact of flexible technologies on power system operations is reviewed in section 2.3. Section 2.4 focuses on generation investment planning models applicable to the vertically integrated electricity era and the current liberalised electricity industry. Section 2.5 reviews the existing studies on flexible technologies and generation investment. The chapter concludes with section 2.6 which discusses the gap in knowledge that the thesis address.

2.2 Electricity Market Evolution: What was, What is, What is to come

The electricity market development has closely followed the growth and development of the entire electricity industry. When the electric power generation industry started, a single entity centrally controlled the planning and operation of generating utilities in a country or region. This entity also controlled the transmission network, and made necessary decisions with regards to its expansion. Such vertically integrated utilities were structured as public utilities concerned essentially with ensuring the reliability of electricity provision at minimum cost.

With the advancement in technology and a paradigm shift in philosophy supporting the introduction of competition among power producers, discussions on deregulating the electricity supply sector started in the mid-1970s. Proponents of this philosophy argued that the presence of competition will lead to more efficient decisions in investment and operations and consequently a lower electricity price for the consumers [12]. In 1981, Chile liberalised its electricity industry, the first country to do this, with the United Kingdom and the United States doing same a few years later.

Following this liberalisation, the vertically integrated electricity industry was restructured to involve numerous generating companies and a monopoly transmission network operator. In the liberalised electricity industry, each generating company operates for profit maximisation, therefore, to make optimal decision, each firm must analyse thoroughly, the market reaction to its strategy (investment and bidding).

The ongoing decarbonisation agenda arising from increasing concerns about protecting the environment is engendering the large-scale integration of renewable-based generation (such as wind and Solar PV) into the electricity generation mix in many countries worldwide. The use of these renewables introduces fundamental techno-economic challenges to both the operation and planning of power systems. The limited predictability on a sub-hourly scale of sunshine and wind speed increases the importance of reserves scheduling in power systems. This growing importance of reserves provision in operation of power systems emphasises its importance in the electricity market.

Furthermore, the electricity market is evolving to incorporate the participation of non-generating flexible technologies considering its significant potentials to ensure the smooth operations of low-carbon power systems.

Several electricity markets models have been developed to explore the operation of flexible technologies and its impact on different aspects of power system operation. Some relevant models are presented in section 2.3

2.3 Electricity Market Models incorporating Flexible Technologies

The output variability of renewable based generation is its major disadvantage. The large-scale integration of renewable based generation would require a higher amount of system flexibility to handle the potentially large power output variability. Flexible technologies cannot only handle this variability but also serve as a reserve resource to ensure smooth system operation thereby increasing the effectiveness of low-carbon power systems. Furthermore, as discussed in Chapter 1, its ability to engage in inter-temporal energy arbitrage thereby yielding a net demand flattening effect is beneficial to handle the rise in peak demand levels occasioned by the large-scale electrification of heat and transport sectors.

The value and potential of the two most widely used flexible technologies (flexible demand and energy storage) has for the aforementioned reasons attracted special interest from governments and industry [4–8] as well as academia [9–11].

New models have been proposed in literature to co-ordinate the participation of these individually owned flexible technologies in the electricity market. Authors of [13] developed a market mechanism based on Lagrangian relaxation (LR) principles which considers the decentralised participation of flexible technologies in electricity markets. The advantages of this model is demonstrated in the companion paper [14]. A similar LR-based mechanism is employed in [15] to coordinate in a decentralised fashion, an electricity microgrid under the participation of flexible technologies. An iterative control algorithm based on Nash Equilibrium principles is developed in [16]. This algorithm is deployed to coordinate efficiently, individually-owned price-responsive appliances, representing the interaction with each other and ensure convergence to a system configuration satisfactory to all involved agents.

2.3.1 Electricity Market Models incorporating use of Demand Flexibility for Energy Shifting

The impact of using inter-temporal energy shifting potential of flexible demand on power system operation has been analysed in literature using different models. The model presented in [17] explores the non-convexities associated with the participation of flexible demand in the electricity market and analyses the effects on the consumer surplus sub-optimality. Authors in [18] consider the flexibility of Thermostatically Controlled Loads (Refrigerators) using a stochastic unit commitment model. The paper evaluates the impact of this flexible load's participation in the energy only market and in the ancillary market.

A few studies [19–22] have modelled the energy shifting potential of flexible demand using price elasticities. The effects of peak demand reduction and average system price reduction arising from the use of demand flexibility for energy shifting in the electricity market have also been discussed in [19, 20]. Authors in [19] employ a unit commitment model to quantify its effect on various categories of market participants - generators, price responsive consumers and price-taking consumers. While a security-constrained unit commitment (SCUC) model is developed in [20] to analyse its impact on hourly operation and control of congested power system. Authors in [22] incorporate demand shifting into a unit commitment model of a power system with high wind integration. The paper also demonstrates the value of demand flexibility to support wind integration and reduce curtailment.

A different approach is used for modelling the energy shifting potential of flexible demand in [23, 24]. These papers consider the demand shifting as a variable dependent on the hourly baseline demand, assuming a technology-agnostic model. Authors of [23] discuss the impact of demand shifting on the exercise of market power by generation companies using both analytical and quantitative case studies. The potential economic value of industrial demand flexibility on the European power system is quantified and discussed in [24].

In [22], the results obtained using these two approaches for modelling demand flexibility are compared. The paper concludes that while the use of price elasticities to model demand shifting may lead to higher cost savings in peak hours, modelling demand shifting as dependent on hourly baseline demand leads to a higher overall cost savings and a higher usage of available demand shifting potentials. In view of this, demand flexibility is modelled in this thesis as a proportion of the hourly baseline demand.

2.3.2 Electricity Market Models incorporating operation of Energy Storage Facilities

Energy storage (ES) is another flexible technology which is widely used because of its very large potentials. The impact of the presence of ES in electricity systems on different aspects of power system operations has therefore received considerable attention in literature.

Studies have explored its value in systems with high wind penetration levels.

The demonstrated values include: enhancing the integration of wind [25, 26], managing the wind power variability, [27, 28], reducing system imbalances [29].

Authors in [30, 31] also established the benefits of ES to increase the capacity factor, increase the efficiency and reduce the cycling burden of conventional generators. The model presented in [32] explores the use of ES to mitigate the effects of wind forecast errors in power system operation while reference [33] demonstrates the ability of ES to reduce transmission congestion through charging and discharging at critical times to redirect energy flow.

It should be emphasised that these studies [25–33] considered ES as a facility owned by the system operator and operated to either minimise the system costs or maximise the total social welfare of the system.

In the liberalised electricity market, the ES facility is not necessarily owned by the network operator, profit-oriented merchant operators can also own ES facilities and operate them to access additional revenue streams. Another category of studies have focused on ES as a merchant owned facility operating independently in the electricity market and seek to maximise its profit. In this regard, different models have been proposed in literature.

In [34], a stochastic programming framework is presented which helps the independently operated ES to choose optimal energy and reserve bids considering unpredictability in market prices occasioned by wind power output variability. A multiple-service business model which maximises net profit of ES facility connected to distribution network is presented in [35]. The considered ES facility provides energy arbitrage, network congestion management and balancing services through both active and reactive power control. Authors of [36] developed a model for investor-owned battery storage to optimally bid in power markets (joint day-ahead energy, reserve, and regulation markets) implementing a Performance Based Regulation (PBR) mechanism.

Modelling of the bidding strategy for ES facilities owned by generation companies and jointly operated as part of an integrated wind-storage system is considered in [37, 38]. On its part, reference [37] employs a stochastic model to represent the uncertainties related to wind production and hourly prices in both the day ahead market and real-time market operation while it penalises the wind production deviation. In [38], the wind uncertainty is modelled using a probabilistic distribution.

In an endeavour to maximise profit, these merchant owned ES facilities also tend to exercise market power where possible. In literature, models to study the impact of this market power exercise employ the bi-level optimisation technique in representing the decision-making process of ES. This technique is widely used because of its ability to endogenously determine the market clearing price.

The market power potential of price-maker ES and the dependence of the extent of its market power exercise on its operational characteristics such as ES power rating and ES energy capacity is analysed in [39]. Authors in [40] demonstrate the advantage of locational diverse ownership of ES in a transmission-constrained energy market. The results obtained shows that transmission congestion can lead to a higher overall total profit for the merchant operator where it increases price differentials in multiple hours.

On its part, reference [41] explores the ability of ES units to exploit the ramping limitations of conventional generators to maximise self-profit. Authors of [42] compared the impacts of price-taking and price-making storage behaviours on energy market efficiency in a market involving multiple independent, strategic generation companies. The paper concludes that the presence of ES improves the market efficiency irrespective of network congestion, however, this is higher when the ES is a price-taker.

The impact of ES market power exercise on its capacity to provide system flexibility is studied in [43]. This paper also investigates the effect of different ownership arrangements of ES in electricity markets and the dependence of potential benefits of ES on the self-interested strategies of the ES owners. The loss in welfare is quantified using the price of anarchy metric. The analysis shows that the welfare lost due to selfish actions of ES merchants increases as network congestion becomes more intense.

The result of the case studies presented in these papers [39–43] indicates that when ES is owned by profit-oriented merchant operators, there exists a higher tendency for them to exploit the perceived limitations of network and generators for self interest rather than strengthen these perceived limitations. This profit-maximising behaviour reduces the potential benefits of ES to the power system operation and highlights the need for appropriate market design to facilitate competition among merchant operators and effectively reduce their exercise of market power.

The studies reviewed above evaluate and analyse the beneficial impacts of the penetration of flexible technologies on different aspects of power systems operations. These studies developed different models to achieve their different objectives. Studies focusing on the impact of flexible technologies on generation investment decisions are discussed in section 2.5 of this chapter. The next section focuses on generation investment planning paradigms and relevant applicable mathematical models.

2.4 Generation Investment Planning Models

Mathematical models are used to represent the most important parts of a system with mathematical equations and are applied to achieve a specific objective such as testing system changes, aiding decision making etc. The application of mathematical models specifically linear programming to investment planning began in the 1950s, the work of Masse [44] was one of the earliest applications.

The 1970s and 1980s witnessed the introduction of dynamic programming and decomposition techniques to investment planning [45]. These investment planning models focused on determining the size of the generation units to be built and when they should be built to achieve an aim of minimising the total cost involved. The advancement in computing technology and increasing availability of computing resources in the last two decades facilitated the development of more sophisticated algorithms and solvers to handle generation investment planning problems of higher complexity.

2.4.1 Centralised Planning Modelling Framework

In the early days of the electricity industry, a central electric power utility decides the generation investment to be carried out. The objective of the central planner is to minimise its total investment and production costs incurred while providing adequate supply of electric energy required to satisfy expected future demand within a pre-determined reliability and environmental criterion. Following the seminal work of Masse and Gibrat in [44], the application of mathematical models (linear programming) to generation investment planning gained traction; the work of Anderson [46] presents a comprehensive review of the early models.

However, this linear programming (LP) framework could only incorporate a few aspects of real-world power systems planning, leaving out many crucial aspects. The inclusion of additional constraints to represent these neglected aspects necessitated the development of different types of more complex mathematical model formulation such as non-linear programming [46, 47] and integer programming [48, 49]. Since both model formulation types have a higher mathematical difficulty, decomposition techniques were later developed and applied to simplify the solution process for these complex formulations through sub-dividing the problem into a master problem and a set of smaller, simpler subproblems. The generalised Bender's decomposition (GBD) algorithm has been applied in [50] and [51] to iteratively solve the master problem and subproblem until an optimum cost is found. In [50], the GBD algorithm is applied to a large-scale, non-linear, mixed integer program (MIP), the planning master problem is an integer programming problem while the operation subproblem is a non-linear programming problem. The GBD algorithm is also applied in [51], in which the subproblems are solved using the probabilistic simulation procedure and the master problem is solved as a linear program.

With the growing research interests in generation investment planning, models considering the joint planning of generation capacity investment and transmission expansion were also developed and presented in technical literature [49, 52]. These models represented the reality under the vertically integrated electricity industry structure; generation and transmission planning decisions are handled by the same utility company and are made with the objective of minimising the total system cost.

In [53], the GBD algorithm is applied to solve the joint generation and transmission planning problem in an iterative way. An heuristic approach is developed in [54] to solve this joint expansion problem which is formulated as a Mixed Integer Non-Linear Problem (MINLP). Reliability assessment was later incorporated into joint generation and transmission planning models of [55] and [56] which employed linear programming and mixed integer programming formulation respectively.

A more detailed review of the joint generation and transmission problem can be found in [57]. It should be noted that dedicated models focusing on transmission expansion planning have also been developed in technical literature. This is not within the scope of this thesis, but a comprehensive review can be found in [58] for interested readers.

Consideration for the environment introduced a new dimension into the generation investment planning problem, these environmental factors have been captured in literature using different modelling approaches. Environmental factors were introduced as uncertainty parameters in [59, 60] using a two-stage stochastic MIP model. Environmental costs and constraints are imposed in the Mixed Integer Non Linear Problem (MINLP) presented in [61]. The paper solves the problem using a combination of Genetic Algorithm and Bender's Decomposition methods. A least cost planning model incorporating carbon trading mechanisms, carbon reduction targets and emission penalty is proposed in [62]. In [63], a dynamic LP model incorporating CO_2 emission tax in the cost function while including annual emissions reduction rate as one of the constraints is presented. This model which also considers the gradual retirement of old inefficient generation plants was applied in a simplified 11-node representation of the US power system. In [64], a dynamic programming based model for generation investment planning is presented which incorporates the gaseous emissions associated with different generating units depending on quantity and quality of fuel burned.

Under the centralised planning framework, generation investment planning studies focusing on different aspects of the problem exist in literature. The introduction of competition into the electricity supply sector means that these models can no longer give accurate insights because they neglect the fact that the profit-driven decisions of self-interested generators are not generally aligned with decisions under system cost minimisation framework. For this reason, investment planning in the liberalised electricity market framework require a different set of models that can illustrate the relationship between investment decision and profit made by the investing company in the electricity market.

2.4.2 Generation Investment Planning Models under Liberalised Electricity Markets: Game Theoretic Model Framework

Following the liberalisation of the electricity industry and the introduction of the competitive electricity market, each generating company makes its investment decision with the aim of maximising profit. Investment planning models suitable for the restructured electricity industry should adequately represent and incorporate the market in the decision-making process, accounting for the impact of the market on the profit of the generating companies.

Naturally, the investment and dispatch decision takes place in two stages separated in time – in the first stage, the investment decision is made and in the second stage, dispatch decision is made subject to the capacity limits set by the decision in the first stage. This implies that the resulting market price in the second stage is dependent on the investment decision of the first stage. Many researchers have drawn a parallel between this sequential decision process and the Stackelberg game involving a leader, who takes the first action (investment decisions), and follower whose actions (dispatch decision) depends on that of the leader.

A game theory based hierarchical optimisation model (specifically, the bi-level model formulation) can be used to represent this interaction. In this bi-level model, investment decisions are made in the upper level and in the lower level, the market is cleared to determine prices and dispatch decisions. A graphical illustration of the bi-level model is shown in figure 2.1. For market-based decision making, game theory based models are useful not only because prices can be determined endogenously, but also because it is suitable to represent and analyse the strategic behaviour of market participants.

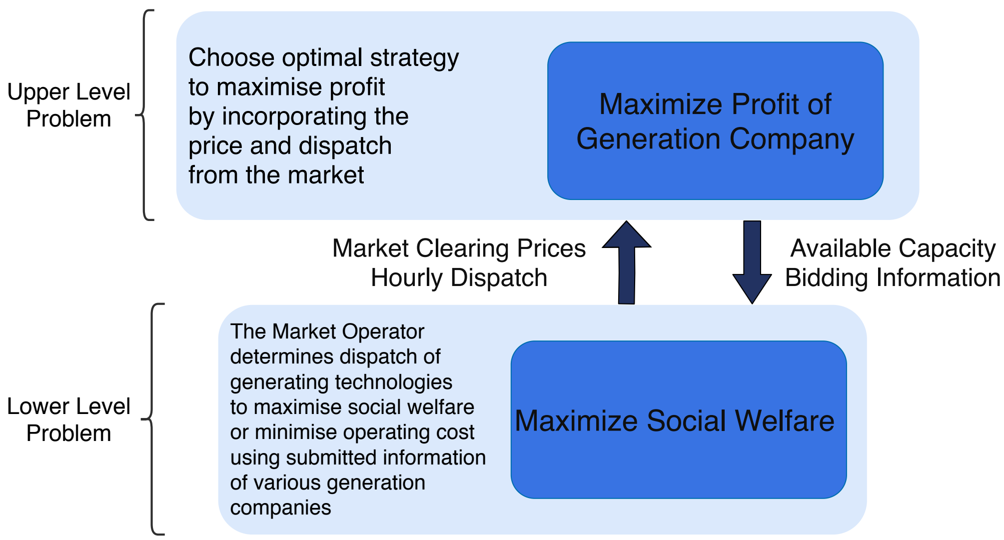

Figure 2.1: Bi-level Formulation showing interaction between the decision of Generation Company and the decisions from Market Clearing

Although the bi-level model is used in this thesis, it should be noted that the technical literature also features game theory based investment planning models involving single-level formulations where investment and dispatch decisions are made simultaneously. These one-level problems are formulated and solved mathematically as a Mixed Complementarity Problem (MCP). A brief review of relevant works on one-level investment models and bi-level models is presented in the following sub-sections.

2.4.2.1 Game Theory Optimisation Based One-Level Generation Investment Planning Models

Many studies have applied the one-level game theory based modelling approach, also referred to as the open loop approach, for generation investment planning models. This approach presents less computational difficulties compared to the bi-level modelling approach and can also be solved to obtain a Nash equilibrium among multiple market participants. The one-level problem is solved after reformulating same as a MCP which involves collecting the first-order Karush-Kuhn-Tucker (KKT) conditions for the constrained optimisation problem. The MCP is solved using the PATH solver [65].

In [66], the author presents a game theoretic framework involving multiple generating companies, elastic demand and a transmission system operator. The transmission network is represented using a DC approximation. The model is applied respectively to a case where there is no arbitrage between the different locations in the network and a second case in which arbitragers operate in the network to benefit from price differential at different network locations.

In [67], two varying approaches to determine the generation expansion in an electricity market is presented. In the first approach presented, investment and production decisions are made simultaneously yielding a MCP; while a stackelberg-based bi-level optimisation model is presented in the second approach considering that investment and production decisions are made separately. In a similar way, a theoretical analysis of the MCP formulation alongside two other formulations is presented in [68] considering a one year time horizon with two unique producers each investing in one distinct technology.

Oderinwale and Van der Weijde in [69] applied this approach to analyse the dependence of the policy effectiveness of introducing carbon taxation and feed-in tariffs on investment decision of generation companies in relation to technical properties of network and the market size. Authors of [70] analysed the impact of capacity mechanism on the earnings of different generation technologies, classifying them broadly as base, mid and peak technologies. The paper also analysed the interaction between earnings from the energy, flexibility and capacity markets. This model formulation was further employed in [71] to capture the interaction of market design and risk aversion and assess the impact of capacity mechanisms on risk-averse market participants.

Although this one-level model has been useful and widely applied to study the interaction between multiple investors in the electricity market, its simplistic consideration of investment and dispatch as concurrent decisions does not capture the fact that temporal difference between the timing for these decisions can be exploited by the generation companies to benefit from market reactions to investment decisions. The exploitation of this temporal difference in investment and dispatch decision timing is discussed in [72]. For this reason, the bi-level model formulation approach captures in a more realistic way, the interaction between the investment decision of the generating company and the dispatch decision in the market.

2.4.2.2 Game Theory Optimisation Based Bi-Level Generation Investment Planning Models

A few recent papers have applied the bi-level modelling approach to generation investment planning problems. As discussed earlier, the bi-level modelling approach adequately captures the inter-dependency of the investment and dispatch decisions. However, these models have a higher difficulty in comparison to the single-level models discussed earlier. Bi-level models were first discussed in the works of Bracken and McGill [73, 74], and they are generally classified as models in which an optimisation problem forms part of the constraints of another optimisation problem.

Bi-level models have been applied to analyse different sections of the power system, such as, strategic bidding of a large consumer [75], strategic offering of a conventional generator [76], [77] strategic investment in transmission network [78]. A comprehensive review of the application of bi-level models to power system is presented in [79]. The popularity of this methodology in market-based studies lies in its ability to comprehensively capture the interactions between the strategic decisions of the generation companies and the competitive clearing of the electricity market at the operational timescale.

To solve this bi-level model, its mathematical properties are exploited to transform it into a single-level Mathematical Program with Equilibrium Constraints (MPEC) problem. This transformation is carried out by replacing the lower level problem with a set of equivalent equations also referred to as optimality conditions (see fig. 2.2). The resulting MPEC problem is non-linear and very difficult to solve, therefore, linearization techniques are employed by the studies which employ this approach.

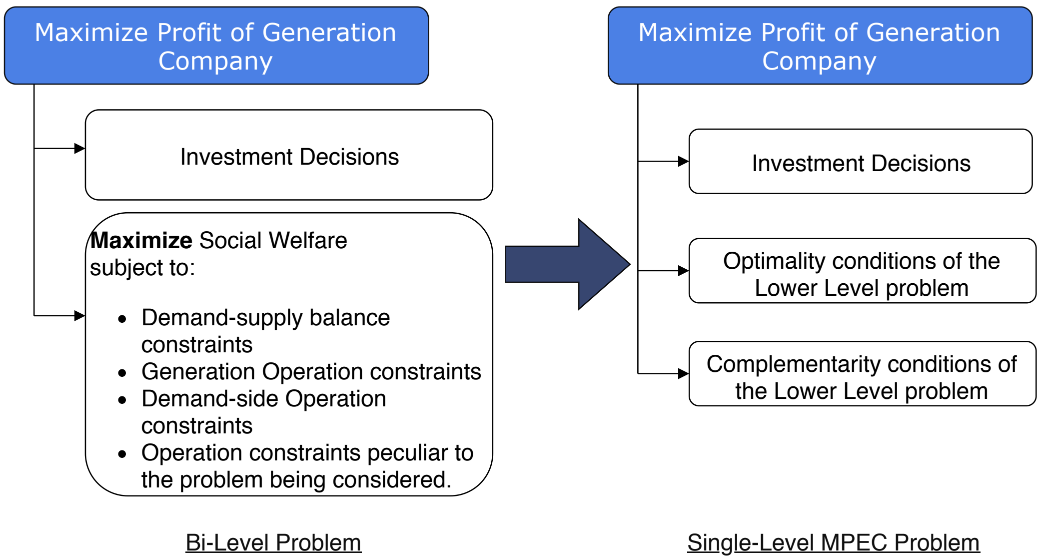

Figure 2.2: Transforming the Bi-level Problem into a Single-Level MPEC Problem

Relevant studies that have applied the bi-level modelling approach to generation investment planning have considered different assumptions of the market and network conditions. In [80], a stochastic bi-level model is presented considering uncertainty in future demand and rival investment decisions, but assuming a market with perfect competition in the lower level. Other studies have incorporated strategic bidding in the market by the generation company into the generation investment planning model. The study presented in [72] analyses the effect of strategic bidding on investment choices of the investing generating company (genco). The study demonstrates that the degree of market power available to the investing genco affects both the investment capacity and the preferred technology for investment. Similar conclusions were made in [81] where the effect of uncertainty was imbibed into the model. Both [72] and [81] present a dynamic model which determines the investment schedule over a number of years.

In addition to considering the effects of the strategic bidding and diverse uncertainties that generation companies face, authors in [82] also consider the transmission network constraints to identify the optimal location of generating investments under potential network congestion conditions. The analysis shows that the optimal location and optimal investment capacities are dependent on the number of possible scenarios considered by the genco. Furthermore, as the number of possible scenarios rises, the optimal investment levels reduces. This implies that under uncertainty, the investing genco acts more cautiously to prevent over-investing. Further work by the authors, [83], applied Bender's decomposition to handle the computational difficulties of using the direct MPEC approach. Both [82] and [83] considered a future target year. On the other hand, a dynamic MPEC model is developed in [84] and applied to obtain the investment schedule over five years.

The bi-level formulation has also been used in [85, 86] to model the investment in wind generation technology in a market environment by a profit-maximising generation company. These papers considered a future target year and a perfectly competitive market in which participants reveal their true costs.

While the aforementioned papers have only considered the day-ahead market, the generation investment models presented in [87,88] also considered futures market (alongside the day-ahead market). The futures market is becoming increasingly relevant in different european electricity markets [89] because it helps to hedge the volatility of the pool price. The model presented in [87] considers a cournot competition among players with no arbitrage between futures and day-ahead markets and no representation of the transmission network. In contrast, [88] considers an investor that can exercise market power though its strategic bidding. The futures market is divided into base and peak futures market and the paper also considers arbitrage between futures and day-ahead market.

These papers [72, 80–88] unanimously represent the electricity demand in an approximate fashion by using demand blocks to approximate the load-duration curve (LDC). The demand block is a non-chronological representation of demand which is inherently unable to capture temporal relationship among hours at the operational timescale. For the reason that market clearing is independently carried out in each demand block, these aforementioned papers do not consider the operation of flexible technologies, which require inter-temporal interaction in the operational timescale, in the electricity market.

In this thesis, the use of demand blocks is dropped, rather, the demand is modelled using a detailed multi-period representation capable of incorporating important time-coupling characteristics in the operational timescale.

For clarity, a summary of the features of the generation investment model presented in this thesis and those of relevant bi-level models (solved using MPEC approach) presented in technical literature is provided in Table 2.1.

Table 2.1: Relevant Features of Generation Investment Planning Bi-level (MPEC) Models presented in Technical Literature and the Bi-level Model presented in this Thesis

Paper	Type of Investment Technologies Considered	Demand Representation	Regulatory Constraint	Market Type
[72]	Conventional Technologies	Demand Block	No	Energy Only
[80]	Conventional Technologies	Demand Block	No	Energy Only
[81]	Conventional Technologies	Demand Block	No	Energy Only
[82]	Conventional Technologies	Demand Block	No	Energy Only
[83]	Conventional Technologies	Demand Block	No	Energy Only
[84]	Conventional Technologies	Demand Block	No	Energy Only
[85]	Renewable Technologies	Demand Block	No	Energy Only
[86]	Renewable Technologies	Demand Block	No	Energy Only
[88]	Conventional Technologies	Demand Block	Minimum Production Capacity	Energy Only
[87]	Conventional Technologies	Demand Block	No	Energy Only
This Thesis	Conventional and Renewable Technologies	Multi-period	Supply Adequacy	Energy and Reserves Market

2.4.3 Generation Investment Planning Models under Liberalised Electricity Markets: Non-MPEC Approaches

In this section, a review of some relevant generation investment planning studies which focus on liberalised electricity market framework which have employed other approaches aside the MPEC approach is presented. Such approaches include dynamic programming, reinforcement learning, iterative procedure, as well as specially developed heuristic algorithms.

A cournot-based generation expansion planning model considering multiple investors is presented in [90]. The developed model is solved using an iterative search procedure.

A dynamic programming based model is developed in [91] and applied to obtain the optimal investment for a generation company. The investment decisions under both the vertically integrated system, optimising system objectives, and the liberalised market environment with profit maximisation objectives are compared. The authors contend that differences in investment strategies in both planning approaches is not a definite indication of the presence of price manipulation and market failure. The model presented in [92] combines dynamic programming and game theory to study the impacts of regulatory interventions on the dynamic behaviour of investments in new generation capacity in electricity markets. Uncertainty in electric demand and fuel prices were modelled using Markov chains.

In [93], a robust optimisation-based model is presented to optimise profit for a risk-averse price-making generation investor under worst-case realisation of uncertain parameters, such as load and non-dispatchable generation. A game-theory based model for the generation investment planning is presented in [94]. This model incorporates the quasi-Newton optimisation method in determining the payoff values for different player strategies.

An heuristic approach which involves the solution of an equivalent optimisation problem is developed in [95] to solve the generation expansion planning problem. This heuristic approach involves 2 stages:

i) solve an equivalent optimisation problem whose KKTs are same with the relaxed equilibrium model.

ii) use the solution for (i) as starting point for the diagonalization technique.

A two-tier matrix game is developed in [96] to model the generation investment problem. The top tier game examines the generation investment, while the second tier game models the energy supply competition among generators. The impact of risk on the profit of investors is incorporated into the model. This model is solved using a reinforcement learning approach. Authors in [97] also employ a reinforcement learning based solution procedure to analyse the impact of CO2 cap-and-trade programs on restructured electricity markets and generators' investment decisions. Similarly, reference [98] makes use of a reinforcement learning based algorithm to determine the final expansion decisions of the respective investors. The study analysed the impact of electricity subsidies, carbon emission prices and possible gas revolution on the electricity market of Iberian Peninsula.

2.5 Flexible Technologies and Generation Investment Planning

Recent long term generation investment planning studies are beginning to consider the impact of different flexible technologies. Flexibility of the demand side have been modelled either using a generic approach or considering specific technologies such as Electric Vehicles (EVs). Similarly, while a few studies consider a generic energy storage facility, others explicitly consider Battery Storage, Pumped Hydro Storage (PHS) or Compressed Air Energy Storage (CAES). In this section, a review of relevant studies in technical literature which consider the impact of these flexible technologies in generation investment is presented.

Despite the significant potential and great interest in flexible demand, its incorporation into system planning has been scarcely investigated. In [99,100], a power generation expansion planning model incorporating flexible demand as a peak generator which operates for peak demand reduction is presented. The inter-temporal operational constraints are not considered. An integrated generation and transmission expansion planning model is presented in [101] which considers the time-shifting flexibility of the demand-side. The results obtained demonstrate that significant cost savings arise due to the reduced requirement for both generation and transmission expansion capacity. Authors of [102] analyses the impact of energy efficiency and demand response on optimal generation mix, modelling flexible demand using self and cross price elasticities. On their part, authors of [103] investigate the impact of demand shifting on generation investment at high wind penetration levels.

Technology-specific operational complexities of EVs are considered in [104]. Multi-objective model formulations are employed in [105, 106]. In [105], the impact of different EV charging patterns on generation investment planning is analysed. Additional work in [106] analyses the impact of electric vehicles operating as an energy storage in vehicle to grid (V2G) mode in the Croatian power system and also incorporates high penetration of renewable energy sources. Authors of [107] employed a MILP formulation to study impact of different penetration rates of Plug-in Hybrid EVs on optimal generation investment. Studies involving different scenarios for EV penetration and different values for EV flexibility enabling costs were carried out to demonstrate the value of EV under varying wind generation capacity levels assuming a test system similar to the UK. Authors in [108] proposed a MILP based algorithm to quantify the impact of EVs at different penetration levels, wind penetration level and CO_2 costs of electric vehicle penetration in five power systems namely those of: Electric Reliability Council of Texas (ERCOT), Finland, Germany, Ireland and Sweden.

Similarly, studies investigating the impact of ES on capacity investment decisions have made use of least cost planning models appropriate for the era of regulated utilities. In this regard, the impact of ES on evolution of the investment mix under increasingly strict carbon limits is analysed in [109] using numerous case studies.

References [110–112] co-optimise investment in different types of energy storage and generation technologies in an isolated grid. In [110], sensitivity analysis is carried out to exploit the impacts of different characteristics of multiple energy storage types, as well as the availability of different sources of renewable energy on investment planning results. In [111], the impact of unpredictability associated with renewable energy source is considered using a stochastic optimisation approach. In [112], a method based on discrete Fourier Transform for the coordinated sizing of ES and diesel generators in an isolated microgrid is proposed.

Studies presented in [113–115] also consider co-optimised investments in ES and generation technology. In [113], a partial equilibrium model is used to analyse the value of investment in ES considering different penetration levels for renewable energy. A generic representation of the ES is employed. The study findings show that the value of ES in supplying operational flexibility is enhanced at higher penetration levels for renewable energy. A similar model is presented in [114], considering pumped hydro storage and battery energy storage technologies. This study shows that pumped hydro storage and battery energy storage complement each other in providing flexibility to the power system. Authors in [115] develops a mixed integer nonlinear programming model which incorporates environmental pollution costs into the objective function. The model is solved using the particle swarm optimisation algorithm. The study shows the beneficial impacts of ES investment in reducing power system emissions due to reduced use of highly emitting generation technologies.

References [116–118] all consider whole system investment involving ES, generation and transmission, while [119] only considers investment in ES and conventional technology with available wind power considered as a stochastic variable. The model presented in [116] distinguishes between bulk and distributed storage applications, while considering the competition against other technologies, such as flexible generation, interconnection and demand-side response. Furthermore, system adequacy and security requirements as well as emission constraints are also considered within the same framework.

Authors of [117] proposed and applied a new chronological clustering technique in a capacity expansion model which determines whole system investment in conventional and renewable generation, intraday and interday energy storage technologies, and transmission facilities. Renewable portfolio standards are considered in [118], and the value of simultaneously optimising generation, transmission and ES investments is compared with optimising them sequentially.

However, these papers make use of the centralised planner's perspective, applicable to the regime of vertically integrated electricity utilities, optimising system objectives (i.e. minimising the long-term system cost).

2.6 Gap in Knowledge: What is not yet done?

Although numerous existing studies have shown the undeniable value of flexible technologies on power system operations, the impact of these technologies on the long-term power system planning have only been investigated using system cost minimisation models applicable to the era of vertically integrated power system. Such models do not represent the present realities of the liberalised electricity industry.

Available literature on market-based power system planning represents the demand side in a non-chronological way using demand blocks. Therefore, technologies which require inter-temporal interaction in the operational timescale have not been included in these studies. Clearly, the investigation of the impact of flexible technologies on investment planning in the liberalised electricity industry has been an unexplored research topic.

Considering the significant interest and impact of flexible technologies on power system operations, it is important to analyse and investigate their long-term impacts on generation investment planning of power systems.

This thesis investigates, using rigorous mathematical optimisation techniques, the impact of flexible technologies on market-based generation investment planning. The thesis develops a novel time-coupling bi-level optimisation formulation for modelling the investment planning problem of a self-interested generation company, which captures for the first time:

i) the energy shifting flexibility of the demand side through the incorporation of relevant time-coupling constraints in the market clearing process, and

ii) the operation of reserve markets for satisfying the reserve requirements of the system, and

iii) the participation of the demand side flexibility in both the energy markets (to provide inter-temporal energy redistribution) and in the reserves market (to provide reserves resource).

Always plan ahead, it was not raining when Noah built the ark.

— *Richard Cushing*

Chapter 3

Incorporating Flexible Technologies into Market-Based Generation Investment Planning

3.1 Introduction

Non-generating flexible technologies have become important in power system operations. As discussed in Chapter 2, many studies in literature have considered its beneficial impacts in this regard. However, the impact of these flexible technologies on generation investment planning has not received this same level of attention especially considering liberalised electricity markets. This chapter addresses this gap in knowledge by incorporating the operation of flexible technologies into a market-based generation investment planning model. Some of the results presented in this chapter have been published in [120, 121].

Two flexible technologies with the largest potential (flexible demand and energy storage) have been considered in this chapter:

1. Flexible demand also considered as time shifting demand flexibility which captures the ability of consumers to shift the time of use of certain electricity consumption e.g. operation of washing and drying machines, automated industrial processes, from periods of higher electricity prices to periods of lower electricity prices.

2. The Energy Storage (ES) is considered to operate on both sides of the electricity market both as a consumer and as a supplier. The ES units are charged in the low-price, low-demand hours and in such hours act as a consumer, while it discharges in the high-price, high-demand hours thereby acting as a supplier of electricity.

To adequately represent the operation of these flexible technologies, the time of electricity consumption is as important as the level of load consumption therefore a multi-period model is employed. The use of a multi-period model enables incorporating time-coupling constraint which links periods of demand shifting and demand recovery as well as periods of ES charging and ES discharging.

The remaining sections of this chapter are as follows: section 3.2 outlines the modelling assumptions employed in this chapter, section 3.3 presents the mathematical formulation of the bi-level optimization model. Section 3.4 explains the process of obtaining the optimality conditions to derive the equivalent MPEC formulation and identifies the non-linearities, section 3.5 explains the steps to linearize the problem. Section 3.6 – 3.8 presents the case studies and results obtained from analysing the respective impacts of time-shifting demand flexibility and ES operational characteristic. The chapter is concluded in section 3.9.

3.2 Modelling Assumptions

The main assumptions considered in the model and case studies presented in this chapter are summarised below.

1. The model expresses the investment planning problem faced by a self-interested generation investment company operating in a competitive market framework. This company aims to maximise its long-term yearly profits by optimising its generation investment decisions.

2. The model assumes a static planning approach and a yearly operation horizon. This means that the examined generation company optimises its investment decisions considering a future target year .

3. The examined generation company can invest in generation capacity of different conventional technologies, which are characterised by different investment costs, operating costs, and operating constraints.

4. There exists in the system, generation capacity of different conventional technologies, but this does not belong to the examined generation company.

5. An out-of-market adequacy constraint is imposed on the investment planning problem by the regulator, to ensure that the total firm generation capacity in the system is sufficiently higher (as determined by an adequacy coefficient Υ) than the peak demand and therefore security of supply requirements are satisfied.

6. A pool-based, day-ahead, energy-only wholesale electricity market with hourly resolution is considered. This market is cleared by the market operator through the solution of a short-term cost minimisation problem.

7. The presence and impact of the network or network congestion has not been considered in this model. Network-related constraints have not been included in the model. This assumption is very valid in a

well-meshed electricity network where there are no price differentials in the network.

8. Both the examined generation company as well as the rest of the generation companies (owning the existing generation capacity) are assumed to submit to the electricity market operator the actual production costs of each generation technology, i.e. strategic bidding is not considered.

9. A subset of the considered generation technologies is assumed “must-run” i.e. they must be operating at full capacity during all times.

10. Another subset of the considered generation technologies are flexible technologies, these technologies have no restraint on their times of operation.

11. A generic, technology-agnostic model is employed for the representation of the time-shifting flexibility of the demand side. According to this model, demand at each time period can be reduced / increased within certain limits, and demand shifting is energy neutral within the daily market horizon i.e. the total size of demand reductions is equal to the total size of demand increases (load recovery), assuming without loss of generality that demand shifting does not involve energy gains or losses.

12. The demand flexibility limit is considered to have the same proportion in each hour of the day. This can also be modelled using time-varying parameter, however, for ease of analysis, this approach is not used.

13. A generic, technology-agnostic model is also employed for the representation of the technical characteristics of ES, which includes charging and discharging efficiencies, energy balance constraints as well as minimum and maximum energy and power limits.

14. The considered ES is assumed to be already built and does not belong to the examined generation company.

15. The operation and maintenance costs of ES are assumed negligible, so it does not submit a price offer or bid to the market.

3.3 Multi-Period Bi-Level Optimisation Model

In order to capture the interaction between the investment decisions of the strategic investor and the revenue it makes from the market, a bi-level model is proposed in this chapter. This bi-level model consists of an upper level (UL) problem with an objective function to maximise the profit of the strategic investor subject to investment and regulatory constraints. The lower level (LL) problem represents the market clearing problem of the market operator. This market clearing is carried out to minimise the short-term operating cost for each day.

The mathematical formulation of the multi-period bi-level optimisation model used in this chapter is presented below. The upper level problem is presented.

3.3.1 Upper Level Problem

$$\underset{X_i}{Max} \sum_{d} wf_d \Bigg\{ \sum_{t,i} \left(\lambda_{d,t} - C_i^G\right) g_{i,d,t} \Bigg\} - \sum_{i} IC_i X_i \tag{3.1}$$

subject to

$$0 \leq X_i \qquad \forall i \tag{3.2}$$

$$\sum_{i} (X_i + X_i^E) \geq \Upsilon \Big((1-\alpha) D_{d,t}^{BA} - s^{max} \Big) \qquad \forall d,t \tag{3.3}$$

$$(3.4) - (3.16)$$

The objective function of the upper level problem (3.1) seeks to maximise the total annual profit which is expressed as the difference between the profit from the energy market (first term) and the investment cost (second term). The weighting factor (included in the first term) is multiplied by the daily operational profit to obtain yearly operational profit. The term $\lambda_{d,t}$ represents the hourly market clearing price obtained as the dual variable of the demand-supply balance constraint (3.5) in the lower level problem.

Constraint (3.2) represents the non-negativity of investment decisions. The investment decision of the generation company is modelled using a continuous variable X_i. After the optimal investment size is known, selecting the available investment size options to give the optimal investment size is a simple task. Another approach of modelling the investment decisions is to use specific sizes for the different investment technologies, but this approach also involves the use of integer variables which increases the difficulty of the problem.

Constraint (3.3) represents the supply adequacy constraint imposed by the market regulator to preserve the security of supply requirements. This constraint incorporates the peak limiting values of demand flexibility and ES. This upper level problem is also constrained by the lower level problem as defined by constraints (3.4) - (3.16).

3.3.2 Lower Level Problem

$$\underset{V^{LL}}{Min} \left\{ \sum_{t,i} C_i^G (g_{i,d,t} + g_{i,d,t}^E) \right\} \tag{3.4}$$

subject to

$$D_{d,t}^{BA} + d_{d,t}^{sh} + s_{d,t}^{c} = \sum_i (g_{i,d,t} + g_{i,d,t}^E) + s_{d,t}^{d} \qquad : \lambda_{d,t} \qquad \forall d,t \tag{3.5}$$

$$0 \leq g_{i,d,t} \leq X_i \qquad : \mu_{i,d,t}^{-}; \mu_{i,d,t}^{+} \qquad \forall i \in I^{FL}, d, t \tag{3.6}$$

$$0 \leq g_{i,d,t}^E \leq X_i^E \qquad : \mu_{i,d,t}^{E-}; \mu_{i,d,t}^{E+} \qquad \forall i \in I^{FL}, d, t \tag{3.7}$$

$$g_{i,d,t} = X_i \qquad : \xi_{i,d,t} \qquad \forall i \in I^{MR}, d, t, \tag{3.8}$$

$$g_{i,d,t}^E = X_i^E \qquad : \xi_{i,d,t}^E \qquad \forall i \in I^{MR}, d, t, \tag{3.9}$$

$$-\alpha D^{BA}_{d,t} \leq d^{sh}_{d,t} \leq \alpha D^{BA}_{d,t} \qquad : \pi^-_{d,t}, \pi^+_{d,t} \qquad \forall d,t \tag{3.10}$$

$$\sum_t d^{sh}_{d,t} = 0 \qquad : \varphi_d \qquad \forall d \tag{3.11}$$

$$E_{d,t} = E_{d,t-1} + \tau\eta^c s^c_{d,t} - \frac{\tau s^d_{d,t}}{\eta^d} \qquad : \varrho_{d,t} \qquad \forall d,t \tag{3.12}$$

$$E_o = E_{d,t} \qquad : \rho_{d,t} \qquad \forall d, t = N_T \tag{3.13}$$

$$E^{min} \leq E_{d,t} \leq E^{max} \qquad : \sigma^-_{d,t}; \sigma^+_{d,t} \qquad \forall d,t \tag{3.14}$$

$$0 \leq s^d_{d,t} \leq s^{max} \qquad : \chi^-_{d,t}; \chi^+_{d,t} \qquad \forall d,t \tag{3.15}$$

$$0 \leq s^c_{d,t} \leq s^{max} \qquad : \varphi^-_{d,t}; \varphi^+_{d,t} \qquad \forall d,t \tag{3.16}$$

The lower level problem represents the market clearing problem for each representative day incorporating constraints which represent both the time shifting flexibility of demand and ES operations. The demand-supply balance constraint is given by (3.5). The operational constraints of the flexible generation technologies are expressed by (3.6) and (3.7), while the operational constraints of the must-run generation technologies are expressed by (3.8) and (3.9).

The operational constraints of the demand side are expressed by (3.10) – (3.11). The limits for the hourly change of demand as a proportion of the baseline demand is expressed using equation (3.10). $\alpha = 0\%$ implies that the demand does not exhibit any time-shifting flexibility, while $\alpha = 100\%$ implies that the whole demand can be shifted in time. This limit is considered to be of the same proportion in each hour. It is also possible to model the demand flexibility limits using time-varying parameter, but this will introduce further complications into the analysis. Constraint (3.11) ensures that demand shifting is energy neutral within the daily market horizon.

The ES constraints relating to its energy balance (3.12), energy neutrality assumption over the daily market horizon (3.13), and minimum and maximum energy and power limits (3.14)-(3.16) are included in the model.

V^{LL} refers to the set of all primal variables in the lower level problem.

$$V^{LL} = \left\{ g_{i,d,t}, g^{E}_{i,d,t}, d^{sh}_{d,t}, E_{d,t}, s^{d}_{d,t}, s^{c}_{d,t} \right\}$$

The dual variables of the lower level problem are expressed using the set V^{Dual}.

$$\begin{aligned} V^{Dual} = \Big\{ & \lambda_{d,t}, \mu^{-}_{i,d,t}, \mu^{+}_{i,d,t}, \xi_{i,d,t}, \mu^{E-}_{i,d,t}, \mu^{E+}_{i,d,t}, \xi^{E}_{i,d,t}, \pi^{-}_{d,t}, \\ & \pi^{+}_{d,t}, \varphi_{d}, \varrho_{d,t}; \rho_{d,t}, \sigma^{-}_{d,t}, \sigma^{+}_{d,t}, \chi^{-}_{d,t}, \chi^{+}_{d,t}, \varphi^{-}_{d,t}, \varphi^{+}_{d,t} \Big\} \end{aligned}$$

This lower level problem is convex and continuous, so its solution is equivalent to the solution obtained from solving a set of equations also referred to as Karush-Kuhn-Tucker (KKT) optimality conditions. This implies that this lower level problem can be replaced by these KKT optimality conditions. This replacement transforms the bi-level optimisation problem into a different problem called Mathematical Program with Equilibrium Constraints (MPEC) problem.

3.4 Obtaining the KKT Optimality Conditions

This begins with the derivation of the Lagrangian expression for the lower level problem. The Lagrangian is expressed below as:

$$
\begin{aligned}
\mathcal{L} = & \sum_{i,d,t} \Big(C_i^G (g_{i,d,t} + g_{i,d,t}^E) \Big) \\
& + \sum_{d,t} \lambda_{d,t} \Bigg(D_{d,t}^{BA} + d_{d,t}^{sh} + s_{d,t}^c - \sum_i (g_{i,d,t} + g_{i,d,t}^E) - s_{d,t}^d \Bigg) \\
& + \sum_{i \in I^{FL}, d,t} \mu_{i,d,t}^+ \Bigg(g_{i,d,t} - X_i \Bigg) - \sum_{i \in I^{FL}, d,t} \mu_{i,d,t}^- g_{i,d,t} \\
& - \sum_{i \in I^{MR}, d,t} \xi_{i,d,t} (g_{i,d,t} - X_i) \\
& + \sum_{i \in I^{FL}, d,t} \mu_{i,d,t}^{E+} \Bigg(g_{i,d,t}^E - X_i^E \Bigg) - \sum_{i \in I^{FL}, d,t} \mu_{i,d,t}^{E-} g_{i,d,t}^E \\
& - \sum_{i \in I^{MR}, d,t} \xi_{i,d,t}^E (g_{i,d,t}^E - X_i^E) \\
& + \sum_{d,t} \varrho_d \Bigg(E_{d,t} - E_{d,t-1} - \tau \eta^c s_c^{d,t} + \frac{\tau s_{d,t}^d}{\eta^d} \Bigg) + \sum_{d,t=N_T} \rho_{d,t} \Bigg(E_o - E_{d,t} \Bigg) \\
& - \sum_{d,t} \sigma_{d,t}^- \Bigg(E^{min} - E_{d,t} \Bigg) + \sum_{d,t} \sigma_{d,t}^+ \Bigg(E_{d,t} - E^{max} \Bigg) \\
& + \sum_{d,t} \varphi_{d,t}^+ \Bigg(s_{d,t}^c - s_{d,t}^{max} \Bigg) - \sum_{d,t} \varphi_{d,t}^- \Bigg(s_{d,t}^c \Bigg) \\
& + \sum_{d,t} \chi_{d,t}^+ \Bigg(s_{d,t}^d - s^{max} \Bigg) - \sum_{d,t} \chi_{d,t}^- \Bigg(s_{d,t}^d \Bigg) \\
& + \sum_{d,t} \varphi_d d_{d,t}^{sh} - \sum_{d,t} \pi_{d,t}^- (\alpha D_{d,t}^{BA} + d_{dt}^{sh}) \\
& + \sum_{d,t} \pi_{d,t}^+ (d_{d,t}^{sh} - \alpha D_{d,t}^{BA})
\end{aligned} \tag{3.17}
$$

3.4.1 KKT Conditions

Given the Lagrangian equation provided above, the KKT conditions associated with the lower-level problems are derived below.

$$
\frac{\delta \mathcal{L}}{\delta g_{i,d,t}} = C_i^G - \lambda_{d,t} + \mu_{i,d,t}^+ - \mu_{i,d,t}^- = 0 \qquad \forall i \in I^{FL}, d, t \tag{3.18}
$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}} = C_i^G - \lambda_{d,t} - \xi_{i,d,t} = 0 \qquad \forall i \in I^{MR}, d, t \qquad (3.19)$$

$$\frac{\delta \mathcal{L}}{\delta g^E_{i,d,t}} = C_i^G - \lambda_{d,t} + \mu^{E+}_{i,d,t} - \mu^{E-}_{i,d,t} = 0 \qquad \forall i \in I^{FL}, d, t \qquad (3.20)$$

$$\frac{\delta \mathcal{L}}{\delta g^E_{i,d,t}} = C_i^G - \lambda_{d,t} - \xi^E_{i,d,t} = 0 \qquad \forall i \in I^{MR}, d, t \qquad (3.21)$$

$$\frac{\delta \mathcal{L}}{\delta d^{sh}_{d,t}} = \lambda_{d,t} + \varphi_{d,t} - \pi^-_{d,t} + \pi^+_{d,t} = 0 \qquad \forall d, t \qquad (3.22)$$

$$\frac{\delta \mathcal{L}}{\delta E_{d,t}} = \sigma^+_{d,t} - \sigma^-_{d,t} + \varrho_{d,t} - \varrho_{d,t+1} = 0 \qquad \forall d, t < N_T \qquad (3.23)$$

$$\frac{\delta \mathcal{L}}{\delta E_{d,t}} = \sigma^+_{d,t} - \sigma^-_{d,t} + \varrho_{d,t} - \rho_{d,t} = 0 \qquad \forall d, t = N_T \qquad (3.24)$$

$$\frac{\delta \mathcal{L}}{\delta s^d_{d,t}} = -\lambda_{d,t} + \frac{\tau \varrho_{d,t}}{\eta^d} + \chi^+_{d,t} - \chi^-_{d,t} = 0 \qquad \forall d, t \qquad (3.25)$$

$$\frac{\delta \mathcal{L}}{\delta s^c_{d,t}} = \lambda_{d,t} - \tau \eta^c \varrho_{d,t} + \varphi^+_{d,t} - \varphi^-_{d,t} = 0 \qquad \forall d, t \qquad (3.26)$$

$$D^{BA}_{d,t} + d^{sh}_{d,t} + s^c_{d,t} - \sum_i g_{i,d,t} - s^d_{d,t} = 0 \qquad \forall d, t \qquad (3.27)$$

$$g_{i,d,t} = X_i \qquad \forall i \in I^{MR}, d, t \qquad (3.28)$$

$$E_{d,t} = E_{d,t-1} + \tau \eta^c s_c^{d,t} - \frac{\tau s^d_{d,t}}{\eta^d} \qquad \forall d, t \qquad (3.29)$$

$$E_o = E_{d,t} \qquad \forall d, t = N_T \qquad (3.30)$$

The complementarity constraints associated with the inequality constraints of the lower level problem are also part of the KKT conditions. They are expressed in a compact form as:

$$0 \leq (X_i - g_{i,d,t}) \perp \mu^+_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (3.31)$$

$$0 \leq g_{i,d,t} \perp \mu^-_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (3.32)$$

$$0 \leq (X^E_i - g^E_{i,d,t}) \perp \mu^{E+}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (3.33)$$

$$0 \leq g^E_{i,d,t} \perp \mu^{E-}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (3.34)$$

$$0 \leq (E_{d,t} - E^{min}) \perp \sigma^-_{d,t} \geq 0 \qquad \forall d, t \qquad (3.35)$$

$$0 \leq (E^{max} - E_{d,t}) \perp \sigma^+_{d,t} \geq 0 \qquad \forall d, t \qquad (3.36)$$

$$0 \leq s^c_{d,t} \perp \varphi^-_{d,t} \geq 0 \qquad \forall d,t \qquad (3.37)$$

$$0 \leq (s^{max} - s^c_{d,t}) \perp \varphi^+_{d,t} \geq 0 \qquad \forall d,t \qquad (3.38)$$

$$0 \leq s^d_{d,t} \perp \chi^-_{d,t} \geq 0 \qquad \forall d,t \qquad (3.39)$$

$$0 \leq (s^{max} - s^d_{d,t}) \perp \chi^+_{d,t} \geq 0 \qquad \forall d,t \qquad (3.40)$$

$$0 \leq (d^{sh}_{dt} + \alpha D^{BA}_{d,t}) \perp \pi^-_{d,t} \geq 0 \qquad \forall d,t \qquad (3.41)$$

$$0 \leq (\alpha D^{BA}_{d,t} - d^{sh}_{dt}) \perp \pi^+_{d,t} \geq 0 \qquad \forall d,t \qquad (3.42)$$

It is important to give a detailed expression of the compact equations (3.31) – (3.42). If this is represented in the generic form $0 \leq a \perp b \geq 0$, the detailed expression would be:

$$0 \leq a; \qquad 0 \leq b; \qquad ab = 0$$

3.5 The MPEC Formulation

The single level MPEC problem includes the upper level objective function, upper level constraints and the KKT conditions of the lower level. This MPEC problem can be succinctly described as:

$$\underset{V^{MPEC}}{Max} \sum_d wf_d \left\{ \sum_{i,t} \left(\lambda_{d,t} g_{i,d,t} - C^G_i g_{i,d,t} \right) \right\} - \sum_i IC_i X_i$$

subject to

(3.2) — (3.3)

(3.18) — (3.42)

where:

$$V^{MPEC} = \{X_i, \forall i\} \cup V^{LL} \cup V^{Dual}$$

The derived MPEC problem cannot be solved to global optimality because it contains non-linearities in the constraints defining the complementarity conditions as well as the upper level objective function. These non-linearities need to be linearised to guarantee the solution of this problem to global optimality. The process of linearising the constraints is explained in the next sub sections.

3.5.1 Linearising the Constraints of the Complementarity Conditions

The first source of non-linearity is the complementarity constraints (3.32) – (3.42) derived as part of the KKT conditions. They involve the multiplication of a dual variable with primal variable(s). Representing the respective complementarity constraints in a generic form, $0 \leq a \perp b \geq 0$.

This is linearised by introducing two disjunctive equations [122] as follows:

$$a \leq M * \varpi; \qquad b \leq M * (1 - \varpi)$$

where M is a large enough positive constant and $\varpi \in \{0, 1\}$.

This introduction of auxiliary binary variables increases the computational burden of the problem but enables its guaranteed solution to global optimality.

3.5.2 Linearising the Upper Level Objective Function

The revenue term in the UL objective function given as the product of the price and dispatch variables ($\sum_{i,d,t} \lambda_{d,t} g_{i,d,t}$) makes it non-linear.

To handle such linearisation, Pereira et.al. in [123] proposed a binary expansion approach involving the use of binary variables and discrete intervals. At best, this approach gives an approximation of the original non-linear objective function and its solution is highly dependent on the step-size of the discrete intervals.

On its part, Ruiz et.al in [77] proposed an exact linearisation approach to handle the non-linear revenue terms in the upper level objective function. This approach makes use of the strong duality theorem as well as some of the KKT conditions to obtain an exact linearised equivalent of the objective function. This approach makes no use of binary variables.

In this chapter, the non-linear terms in the objective function are linearised using the exact linearisation approach.

3.5.2.1 The Exact Linearisation Approach

To begin, the equality of the primal and dual objective functions for the lower level problem is expressed (3.43). This is based on the strong duality theorem which says that for a continuous and convex problem, the optimal value of the objective function for both the primal and dual problem is the same. This is presented in the equation below.

$$\begin{aligned}\sum_{i,d,t}\Big(C_i^G(g_{i,d,t}+g^E_{i,d,t})\Big) &= \sum_{d,t}\lambda_{d,t}D^{BA}_{d,t}-\sum_{i\in I^{FL},d,t}\mu^+_{i,d,t}X_i\\ &+\sum_{i\in I^{MR},d,t}\xi_{i,d,t}X_i-\sum_{i\in I^{FL},d,t}\mu^{E+}_{i,d,t}X^E_i+\sum_{i\in I^{MR},d,t}\xi^E_{i,d,t}X^E_i\\ &-\sum_{d,t=1}\varrho_{d,t}E_o+\sum_{d,t=N_T}\rho_{d,t}E_o+\sum_{d,t}\sigma^-_{d,t}E^{min}-\sum_{d,t}\sigma^+_{d,t}E^{max}\\ &-\sum_{d,t}\chi^+_{d,t}s^{max}-\sum_{d,t}\varphi^+_{d,t}s^{max}-\sum_{d,t}\Big(\pi^+_{d,t}+\pi^-_{d,t}\Big)D^{BA}_{d,t}\end{aligned}\tag{3.43}$$

The next step involves multiplying equations(3.18), (3.19) by $g_{i,d,t}$ we have:

$$\sum_{i\in I^{FL},d,t}\lambda_{d,t}g_{i,d,t}=\sum_{i\in I^{FL},d,t}\Big(C_i^G g_{i,d,t}+\mu^+_{i,d,t}g_{i,d,t}-\mu^-_{i,d,t}g_{i,d,t}\Big)\tag{3.44}$$

$$\sum_{i\in I^{MR},d,t}\lambda_{d,t}g_{i,d,t}=\sum_{i\in I^{MR},d,t}\Big(C_i^G g_{i,d,t}-\xi_{i,d,t}g_{i,d,t}\Big)\tag{3.45}$$

Adding equations (3.44), (3.45) yields:

$$\begin{aligned}\sum_{i,d,t}\lambda_{d,t}g_{i,d,t} &= \sum_{i,d,t}C_i^G g_{i,d,t}-\sum_{i\in I^{MR},d,t}\xi_{i,d,t}g_{i,d,t}\\ &+\sum_{i\in I^{FL},d,t}\Big(\mu^+_{i,d,t}g_{i,d,t}-\mu^-_{i,d,t}g_{i,d,t}\Big)\end{aligned}\tag{3.46}$$

Rearranging (3.46) and using the equations (3.28, 3.32, 3.33), the equation below results.

$$\sum_{i,d,t}(C_i^G g_{i,d,t}) = \sum_{i,d,t}\lambda_{d,t} g_{i,d,t} + \sum_{i\in I^{MR},d,t}\xi_{i,d,t}X_i - \sum_{i\in I^{FL},d,t}\mu^+_{i,d,t}X_i \tag{3.47}$$

Substituting the respective terms into equation (3.43),

$$\begin{aligned}&\sum_{i,d,t}\lambda_{d,t} g_{i,d,t} + \sum_{i\in I^{MR},d,t}\xi_{i,d,t}X_i - \sum_{i\in I^{FL},d,t}\mu^+_{i,d,t}X_i = \sum_{d,t}\lambda_{d,t}D^{BA}_{d,t}\\ &- \sum_{i\in I^{FL},d,t}\mu^+_{i,d,t}X_i + \sum_{i\in I^{MR},d,t}\xi_{i,d,t}X_i - \sum_{i\in I^{FL},d,t}\mu^{E+}_{i,d,t}X^E_i + \sum_{i\in I^{MR},d,t}\xi^E_{i,d,t}X^E_i\\ &- \sum_{d,t=1}\varrho_{d,t}E_o + \sum_{d,t=N_T}\rho_{d,t}E_o + \sum_{d,t}\sigma^-_{d,t}E^{min} - \sum_{d,t}\sigma^+_{d,t}E^{max}\\ &- \sum_{d,t}\chi^+_{d,t}s^{max} - \sum_{d,t}\varphi^+_{d,t}s^{max} - \sum_{d,t}\left(\pi^+_{d,t} + \pi^-_{d,t}\right)D^{BA}_{d,t} - \sum_{i,d,t}C^G_i g^E_{i,d,t}\end{aligned} \tag{3.48}$$

Then equation (3.48) can be rewritten as:

$$\begin{aligned}&\sum_{i,d,t}\lambda_{d,t} g_{i,d,t} = \sum_{d,t}\lambda_{d,t}D^{BA}_{d,t} - \sum_{i\in I^{FL},d,t}\mu^{E+}_{i,d,t}X^E_i + \sum_{i\in I^{MR},d,t}\xi^E_{i,d,t}X^E_i\\ &- \sum_{d,t=1}\varrho_{d,t}E_o + \sum_{d,t=N_T}\rho_{d,t}E_o + \sum_{d,t}\sigma^-_{d,t}E^{min} - \sum_{d,t}\sigma^+_{d,t}E^{max}\\ &- \sum_{d,t}\chi^+_{d,t}s^{max} - \sum_{d,t}\varphi^+_{d,t}s^{max} - \sum_{d,t}\left(\pi^+_{d,t} + \pi^-_{d,t}\right)D^{BA}_{d,t} - \sum_{i,d,t}C^G_i g^E_{i,d,t}\end{aligned} \tag{3.49}$$

The RHS of equation(3.49) is fully linear and this is equivalent to the LHS which is the bilinear product of price and dispatch. Therefore the UL objective function can be written in a fully linear form as:

$$\underset{V^{MPEC}}{Max}\sum_{d} wf_d\Bigg\{\sum_{d,t}\lambda_{d,t}D^{BA}_{d,t} - \sum_{i\in I^{FL},d,t}\mu^{E+}_{i,d,t}X^E_i + \sum_{i\in I^{MR},d,t}\xi^E_{i,d,t}X^E_i - \sum_{d,t=1}\varrho_{d,t}E_o$$

$$
\begin{aligned}
&+\sum_{d,t=N_T}\rho_{d,t}E_o+\sum_{d,t}\sigma^-_{d,t}E^{min}-\sum_{d,t}\sigma^+_{d,t}E^{max}-\sum_{d,t}\chi^+_{d,t}s^{max}\\
&-\sum_{d,t}\varphi^+_{d,t}s^{max}-\sum_{d,t}\left(\pi^+_{d,t}+\pi^-_{d,t}\right)D^{BA}_{d,t}-\sum_{i,d,t}C^G_i\left(g^E_{i,d,t}+g_{i,d,t}\right)\Bigg\}\\
&-\sum_{i}IC_iX_i \qquad (3.50)
\end{aligned}
$$

The linearisation of the UL objective function and the linerisation of the complementarity constraints converts the MPEC into a Mixed Integer Linear Program (MILP) which can be solved to global optimality using industry software such as CPLEX, GUROBI, XPRESS. The application of this developed model on case studies analysing the impact of demand flexibility and ES operations is presented in the next section.

3.6 Case Studies

The developed model is applied in two distinct studies to determine the optimal investment decision of a profit-maximising self-interested generation company operating in a competitive market framework. The first study focuses on the impact of time-shifting demand flexibility, while the second study focuses on the impact of ES operations and includes a sensitivity analysis on the effect of changing ES parameters.

The strategic generation company can invest in three different technologies, namely nuclear, combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). Nuclear generation is assumed “must-run”. Four typical days representing the four seasons of the year are used, and the respective baseline demand profiles are obtained from [104].

The assumed parameters common to these two distinct studies are presented in Tables 3.1 and 3.2. Table 3.1 provides the data for the existing capacity and incurred costs. Table 3.2 provides other parameters including the weighting factor for the representative days considered. The weighting factor is needed to calculate the yearly operational profit in the upper level objective function (3.1) since the lower level problem is cleared considering a daily horizon.

Table 3.1: Existing Capacity and Cost Parameters of Generation Technologies

Technology	Nuclear	CCGT	OCGT
Type	Must-run	Flexible	Flexible
Existing Capacity X_i^E (MW)	9200	17500	17500
Investment Cost IC_i (£/MW/year)	328210	52120	26460
Energy Cost C_i^G (£/MWh)	4.72	37.68	56.98

Table 3.2: General Parameters used in the Case Studies

Parameter	Value
Weighting Factor of winter day wf_{winter}	119
Weighting Factor of spring day wf_{spring}	64
Weighting Factor of summer day wf_{summer}	91
Weighting Factor of autumn day wf_{autumn}	91
System Adequacy Coefficient Υ	1.01

Table 3.3: ES Parameters

Parameter	E^{min}	E_0	s^{max}	$\eta^c = \eta^d$
Value	20% E^{max}	25% E^{max}	50% E^{max} / 1h	0.9

3.7 Analysing Impact of Time-Shifting Demand Flexibility

This study aims at quantitatively analysing the impacts of the flexibility of the demand side to shift its energy requirements on the investment decisions of a strategic generation company. In these studies, different scenarios are considered regarding the extent of available demand flexibility (as expressed by parameter α).

Fig. 3.1 presents the hourly net system demand corresponding to one of the representative days for the different flexibility scenarios considered. As seen in the figure, demand flexibility allows the optimal rescheduling of the demand towards the off-peak hours thereby reducing the net-demand variability and flattening the net-demand profile. The extent of the demand flattening is increased as the capacity of available demand flexibility (α) increases. Given the energy neutrality constraint (3.11), both demand reduction during the peak periods and demand increase in the off-peak periods are equal.

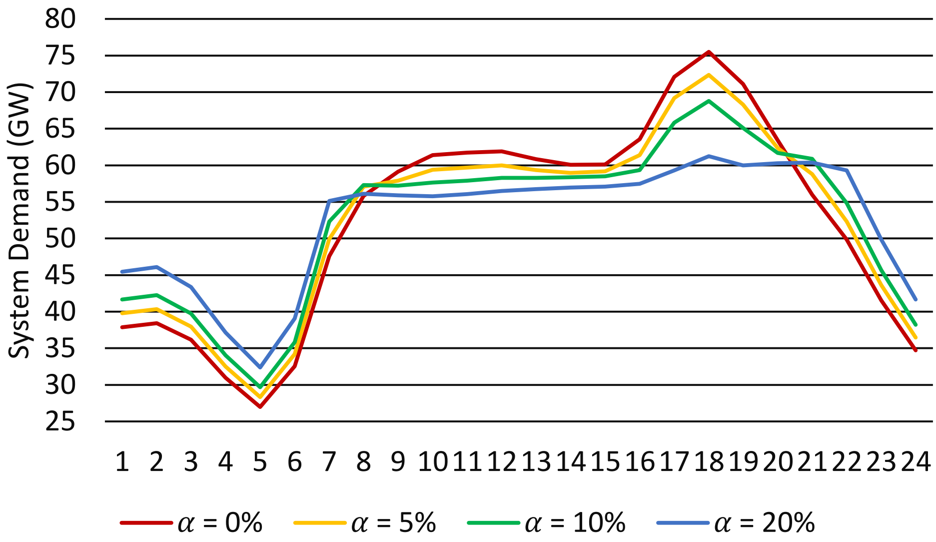

Figure 3.1: Hourly System Demand for different Demand Flexibility Scenarios

By reason of the reduction in the peak demand levels in the system (Fig. 3.1), demand flexibility brings about a reduction in the total capacity investment of the generation company. This can be seen in fig. 3.2 where the optimal investment decisions of the generation company for different demand flexibility scenarios is presented.

Furthermore, by flattening the demand profile, demand flexibility enhances the profitability of baseload nuclear generation. This translates to an increased investment in nuclear generation capacity by the generation company, while its investment in CCGT and OCGT generation capacity is reduced with respect to the inflexible demand scenario ($\alpha = 0\%$).

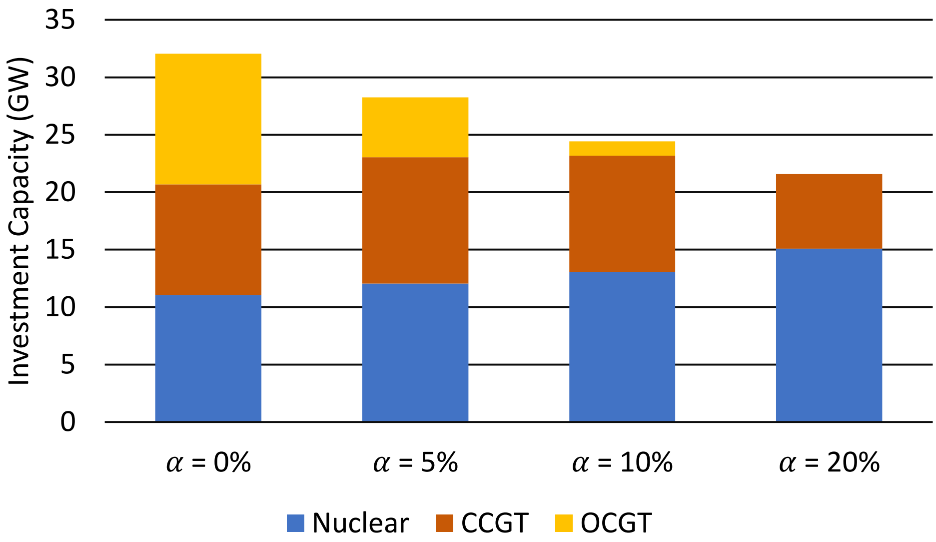

Figure 3.2: Investment decisions of Examined Generation Company for different Demand Flexibility Scenarios

In addition, the effect of demand flexibility on the total capacity investment and on the optimal investment mix is enhanced as the capacity of demand flexibility increases.

Tables 3.4 and 3.5 present the impact of demand flexibility on the yearly profit of the generation company with respect to the inflexible demand scenario ($\alpha = 0\%$). The increased investment in nuclear generation (as discussed earlier) enhances the energy profit due to the lower energy production costs of nuclear compared to CCGT and OCGT generation. On the other hand, the increased nuclear generation investment, due to its significantly higher investment costs, raises the investment cost incurred by the generation company. However, the energy profit increase is higher as shown in table 3.5. Therefore, the total profit of the investing generation company is increased in the considered demand flexibility scenarios.

Table 3.4: Long Term Profit of Examined Generation Company under different Demand Flexibility Levels (in billion £)

	$\alpha = 0\%$	$\alpha = 5\%$	$\alpha = 10\%$	$\alpha = 20\%$
Energy Profit	5.308	5.844	6.259	6.835
Investment Cost	4.425	4.664	4.846	5.288
Total Profit	0.884	1.180	1.413	1.547

Table 3.5: Comparison of the Energy Profit and Investment Cost Increments under different Demand Flexibility Levels with respect to the Case of $\alpha = 0\%$

	Energy Profit Increment		Investment Cost Increment	
	(bn £)	(%)	(bn £)	(%)
$\alpha = 5\%$	0.535	10.08%	0.239	5.41%
$\alpha = 10\%$	0.951	17.91%	0.421	9.51%
$\alpha = 20\%$	1.527	28.76%	0.863	19.50%

3.8 Analysing the Impact of ES Operational Characteristics

The set of study presented in this section quantitatively analyses the impacts which the presence and participation of ES in the energy market will have on the investment decisions of the considered strategic generation company. The case studies carried out involve different scenarios as regards the energy capacity of ES and its power to energy ratio.

In the first study, different scenarios regarding the energy capacity of ES are examined.

Fig. 3.3 presents the net demand of the system (accounting for the charging and discharging power of ES) corresponding to one of the considered representative days, for the different examined scenarios along with a scenario without ES in the system (No ES). The introduction of ES flattens the system demand profile by charging, thereby increasing net system demand, during off-peak periods and discharging, thereby reducing net system demand,

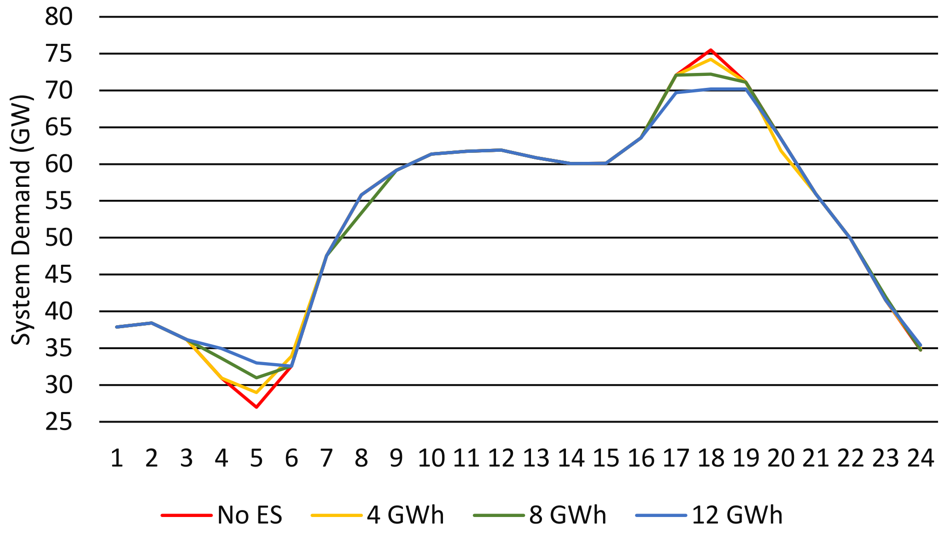

Figure 3.3: Net System Demand for different ES Energy Capacity Scenarios

during peak periods. Given the dependence of ES power output on its energy capacity, defined by the power-to-energy ratio, increasing the ES capacity affects both the total energy arbitrage and the hourly charge / discharge capacity. Owing to this, the impact of ES on flattening the demand profile is enhanced with its increased energy capacity.

The resulting flattening of the demand profile influences the optimal investment decisions. Fig. 3.4 shows the investment decision of the strategic generation company for the examined scenarios. Since the required generating capacity is a decision based on the peak demand levels, the reduction of peak demand levels by ES operations drives a reduction in the total capacity investment levels. Furthermore, the resulting flattening of the demand profile enhances the competitiveness of "must-run" nuclear generation in the system while the amount of CCGT and OCGT capacity is reduced with respect to the case with No ES.

Following the above discussion, the participation of ES for charging and discharging yields a total profit increase for the generation company in the considered scenarios with respect to the scenario with No ES in the system. This is presented in Table 3.6 below. The total profit increase is driven

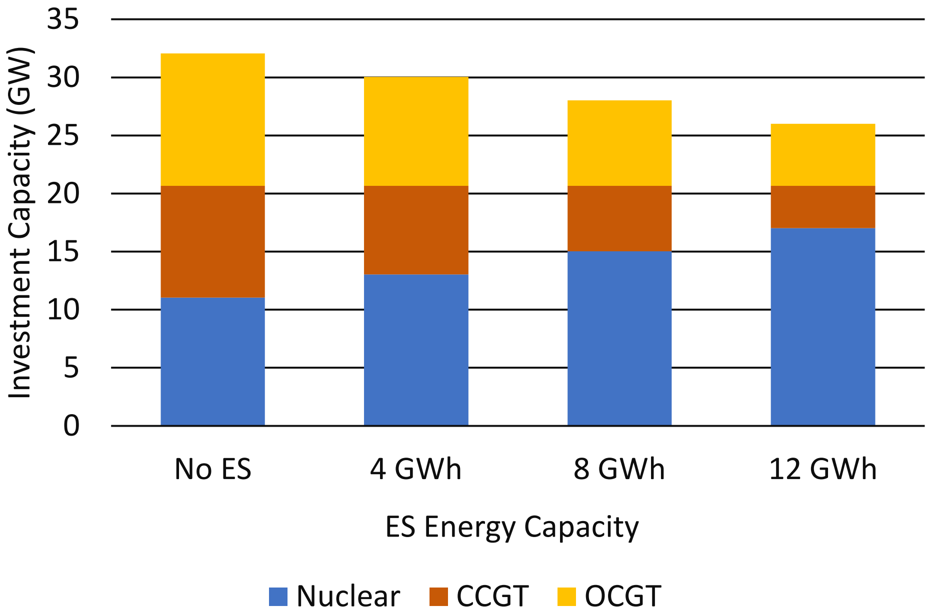

Figure 3.4: Investment Decisions of Examined Generation Company for different ES Energy Capacity Scenarios

primarily by the positive impact of ES charging and discharging on the energy profit, which lies in increasing the amount of energy produced by low-cost nuclear generation over high-cost CCGT and OCGT generation and therefore enhancing the energy revenues of nuclear generation. It should be mentioned that this total profit increase occurs despite the increased investment in nuclear generation which exhibit high investment costs.

Table 3.6: Long Term Profit of Examined Generation Company under different ES Capacity Levels (in billion £)

ES Capacity	No ES	4 GWh	8 GWh	12 GWh
Energy Profit	5.308	5.886	6.463	7.041
Investment Cost	4.424	4.923	5.422	5.921
Total Profit	0.884	0.963	1.041	1.120

Table 3.7: Comparison of the Increment in Energy Profit, Investment Cost and Total Profit under different ES Capacity Levels with respect to the respective values at No ES

ES Capacity	Energy Profit Increment		Investment Cost Increment		Total Profit Increment	
	(bn £)	(%)	(bn £)	(%)	(bn £)	(%)
4 GWh	0.577	10.88%	0.499	11.27%	0.079	8.90%
8 GWh	1.155	21.76%	0.998	22.55%	0.157	17.79%
12 GWh	1.732	32.64%	1.496	33.82%	0.236	26.69%

3.8.1 Sensitivity Analysis on Impact of Power-to-Energy (PTE) Ratios

This section explores the value of different duration of ES capacity on the impacts made on the optimal investment decisions. The set of study compares the different scenarios regarding the ratio (50% and 20%) between the power capacity and the energy capacity of ES (known as power-to-energy ratio). The 50% PTE scenario implies that if the ES facility operates at its maximum discharge/charge capacity, it will be fully discharged/charged at the end of 2 hours. This also means that the ES facility can charge or discharge up to half of its capacity within an hour. Similarly, the 20% PTE scenario implies that the ES can charge or discharge up to one-fifth of its capacity within an hour.

The hourly power charge or discharge of the ES is dependent on the PTE ratio. A lower power-to-energy ratio reduces the ability of ES to charge / discharge during critical off-peak / peak periods. Therefore, at lower PTE ratios, the generation company invests in more total capacity and reduces its investment in nuclear generation. This is shown in fig. 3.5 where the optimal investment decisions under both PTE ratios considered is compared.

Table 3.8 presents the long-term profit of the generation company under both PTE ratios. The reduced investment in nuclear generation which has a lower operations cost reduces the energy profits of the generation company. Though the investment cost incurred is also reduced, the reduction in energy profits has a more prominent effect on the long-term profit of the generation company. Consequently, the generation company has a lower long-term profit at lower PTE ratios.

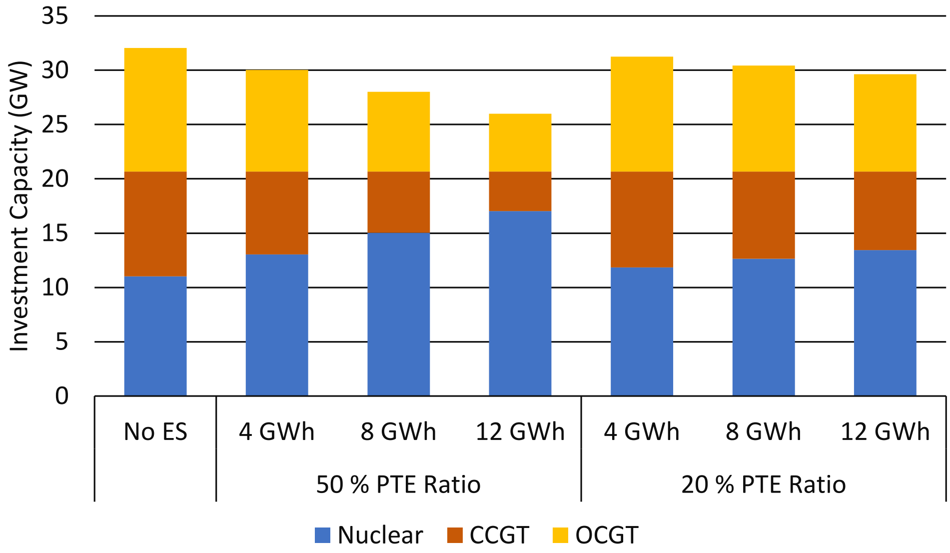

Figure 3.5: Investment decisions of Examined Generation Company for different ES Energy Capacity scenarios under different ES PTE Ratios

Table 3.8: Long Term Profit of Examined Generation Company under different ES PTE ratios (in billion £)

		50% PTE ratio			20% PTE ratio		
ES Capacity	No ES	4 GWh	8 GWh	12 GWh	4 GWh	8 GWh	12 GWh
Energy Profit	5.308	5.886	6.463	7.041	5.539	5.770	6.001
Investment Cost	4.424	4.923	5.422	5.921	4.624	4.823	5.023
Total Profit	0.884	0.963	1.041	1.120	0.915	0.947	0.978

3.9 Conclusion

The results in this chapter have shown the similarities in the impacts of time-shifting flexibility of the demand side and ES operations on the optimal investment decisions of a profit-maximising self-interested generation company. These impacts can be summarised as limiting peak demand levels and reducing the variability of system demand profile, reduction of the total capacity investment and enhancing the profit earned by the investing company. These impacts are enhanced for higher levels of demand flexibility, ES energy capacity and power-to-energy ratio.

Given the similarities in impacts, going forward the models and analysis presented in the next chapters of this thesis will focus on demand flexibility. Furthermore, this chapter considered only the energy markets and focused solely on investments in conventional generation technologies. With the increasing penetration of renewable generation technologies to satisfy environmental constraints, the impact of demand flexibility on the integration of renewable technologies in the electricity market and the investment in same also needs to be analysed.

Every enterprise is built by wise planning, becomes strong through common sense, and profits wonderfully by keeping abreast of the facts.

— King Solomon

Chapter 4

Impact of Demand Flexibility on Market-Based Generation Investment Planning under different Market Designs

4.1 Introduction

The previous chapter analysed the influence of non-generating flexible technologies including demand-side flexibility and energy storage on the optimal investment decisions of a generation company operating in the competitive market environment. To do this, a bi-level model was developed which maximises the annual long-term profit of the investing company in the upper level problem and clears the market in the lower level through the solution of a short-term operating cost minimisation problem.

However, the technology options available for investment were limited to conventional technologies. Furthermore, the presence of renewable technology capacity is not considered in the developed model. Following the growing efforts to decarbonise electricity production, generation companies in recent times actively consider renewable technology options in their investment portfolio.

In this chapter, an enhanced multi-period bi-level model is presented. This model optimises the investment decision of a generation company competing with rival companies in a market environment and includes both conventional and renewable technologies as investment options available to the generation company.

This enhanced bi-level model has a lower level problem which represents endogenously the daily market clearing process of a co-optimised energy and reserve market [1].

This market clearing problem accounts for the energy shifting flexibility of the demand side, the dependency of the reserve requirements on the amount of renewable generation in the system, the ability of flexible generation and flexible demand to contribute to the provision of these required reserves, and alternative market design options regarding the allocation of the system costs for the required reserves.

This bi-level problem is solved after converting it to a Mathematical Program with Equilibrium Constraints (MPEC), and subsequently to a Mixed-Integer Linear Program (MILP).

It should be noted that in view of the similarities in impacts of both demand-side flexibility and energy storage on the optimal investment decisions of a generation company as presented in chapter 3, the model and analysis

[1] The joint optimisation of energy and reserves market is a market design prevalent in North American electricity markets such as: Pennysylvania, Jersey, Maryland power pool (PJM); ISO-New England (ISO-NE); Midcontinent Independent System Operator (MISO); New York ISO (NYISO); California Independent System Operator (CAISO) [124]. In European markets, a different approach is taken in which the energy and reserves market are independently traded [125].

Different research works [126–128] have demonstrated that co-optimising energy and reserves yields a more efficient dispatch when compared with trading energy and reserves independently. The EU recently released the electricity balancing guideline with an aim to ensure that the reserves is procured close to the day ahead market. This shows that the EU is moving towards the joint optimisation of energy and reserves market.

presented in this chapter selects only flexibility of the demand side. Some of the results presented in this chapter have been published in [129].

4.2 Modelling Assumptions

The model presented in this chapter makes use of a number of assumptions. This is summarised below:

1. The model expresses the investment planning problem faced by a self-interested generation investment company operating in a competitive market framework. This company aims to maximise its long-term yearly profits by optimising its generation investment decisions.

2. The model assumes a static planning approach and a yearly operation horizon. This means that the examined generation company optimises its investment decisions considering a future target year. The yearly operation horizon is divided into a number of representative days.

3. The examined generation company can invest in generation capacity of different conventional and renewable technologies, which are characterised by different investment costs, operating costs, and operating constraints.

4. There exists in the system, generation capacity of different conventional and renewable technologies, but this does not belong to the examined generation company.

5. The presence and impact of the network or network congestion has not been considered in this model. Network-related constraints have not been included in the model. This assumption is very valid in a well-meshed electricity network where there are no price differentials in the network.

6. An out-of-market adequacy constraint is imposed on the investment planning problem by the regulator, to ensure that the total firm generation capacity in the system is sufficiently higher (as determined by an adequacy coefficient Υ) than the peak demand and therefore security of supply requirements are satisfied.

7. The considered electricity market is a pool-based, joint energy and reserve market with a day-ahead horizon and hourly resolution. This market is cleared by the market operator through the solution of a short-term cost minimisation problem.

8. The upward and downward reserve requirements are assumed to be entirely dependent on the forecasting errors of renewable generation, thereby neglecting similar forecasting errors due to demand and generation plant outages.

9. The reserve costs are assumed to be paid (at the reserve clearing prices) by renewable generation technologies and / or the demand side. The total percentage paid by renewable generation technologies is determined by the market design parameter Γ.

10. Both the examined generation company as well as the rest of the generation companies (owning the existing generation capacity) are assumed to submit to the electricity market operator the actual production costs of each generation technology, i.e. strategic bidding is not considered.

11. A subset of the considered set of generation technologies is assumed "must-run" i.e. they must be operating at near full capacity during all times and they cannot provide reserves.

12. Another subset of the considered set of generation technologies includes renewable technologies, which are assumed to exhibit zero production costs, their output can be curtailed if required, and they cannot provide reserves.

13. Another subset of the considered generation technologies are flexible technologies. These generation technologies can provide both energy and reserves.

14. The demand side exhibits flexibility which can be used for energy arbitrage as well as reserves provision thereby participating in both energy and reserves markets.

15. A generic, technology-agnostic model is employed for the representation of the time-shifting flexibility of the demand side.

16. The demand flexibility limit is considered to have the same proportion in each hour of the day. This can also be modelled using time-varying parameter, however, for ease of analysis, this approach is not used.

17. It is assumed that deployment of this flexibility does not compromise the satisfaction and comfort of the consumers and is offered to the market operator at zero cost.

4.3 Multi-Period Bi-level Optimisation Model

The mathematical formulation of the multi-period bi-level optimisation model used in this chapter is presented below. The upper level (UL) problem is presented first.

4.3.1 Upper Level Problem

$$\begin{aligned}
&\underset{X_i}{Max} \sum_{d} wf_d \Bigg\{ \sum_{i,d,t} \Big(\lambda_{d,t} - C_i^G\Big) g_{i,d,t} + \sum_{i \in I^{FL},t} \Big(\lambda_{d,t}^{RD} - C_i^{RD}\Big) g_{i,d,t}^{RD} + \\
&\sum_{i \in I^{FL},t} \Big(\lambda_{d,t}^{RU} - C_i^{RU}\Big) g_{i,d,t}^{RU} - \Gamma\Bigg(\sum_{i \in I^{RE},t} (\lambda_{d,t}^{RU} + \lambda_{d,t}^{RD}) \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} X_i \Bigg) \Bigg\} \\
&- \sum_{i} IC_i X_i
\end{aligned} \tag{4.1}$$

subject to

$$0 \leq X_i \qquad \forall i \qquad (4.2)$$

$$\sum_{i \notin I^{RE}} (X_i + X_i^E) \geq \Upsilon(1-\alpha) D_{d,t}^{BA} \qquad \forall d,t \qquad (4.3)$$

$$\sum_{d,t} wf_d g_{i,d,t} \geq \Psi \sum_{d} wf_d X_i \qquad \forall i \in I^{MR} \qquad (4.4)$$

$$\sum_{d,t} wf_d g_{i,d,t}^E \geq \Psi \sum_{d} wf_d X_i^E \qquad \forall i \in I^{MR} \qquad (4.5)$$

$$(4.6) - (4.25)$$

The objective function (4.1) of the UL problem maximises the profit of the strategic generation company across the yearly horizon. This total profit is made up of five component terms.

i. The operational profit obtained from the energy market (first term);

ii. The operational profit obtained from the up and down reserves market (second and third terms);

iii. The proportion of the reserve costs incurred by the renewable generation technology of the investing company (fourth term);

iv. The investment cost incurred for procuring the generation capacity (fifth term).

This problem is subject to the positivity limits of the investment decisions (4.2). The investment decision of the generation company is modelled using a continuous variable X_i, this is to avoid the increased computational burden associated with the use of integer variables to model investment size options. It should be noted that though generation companies have limited investment size options, it is a simple task to combine the investment size options to give the optimal value as obtained using this model. For this reason, the use of continuous variable for X_i does not erode either the applicability of the model or the validity of the obtained solution.

The adequacy constraints (4.3) are imposed by the regulator to ensure that enough firm capacity is built in order to satisfy demand at all times. Constraints (4.4) and (4.5) define respectively, the minimum yearly load factor for the must-run technologies belonging to the investing generation companies and other rival generation companies. The upper level problem is also subject to the lower level problem defined by the equations (4.6) – (4.25).

4.3.2 Lower Level Problem

The lower level problem depicts the day-ahead market clearing process. The pool-based joint energy and reserves market is cleared through the solution of a short-term operating cost minimisation problem (4.6).

$$\underset{V^{LL}}{Min}\left\{\sum_{i,d,t} C_i^G(g_{i,d,t}+g_{i,d,t}^E)+\sum_{i\in I^{FL},d,t}\Big(C_i^{RD}(g_{i,d,t}^{RD}+g_{i,d,t}^{RD,E})+C_i^{RU}(g_{i,d,t}^{RU}+g_{i,d,t}^{RU,E})\Big)\right\} \tag{4.6}$$

The lower level objective function is subject to different sets of constraints which are detailed below.

i) System-wide constraints:

$$D_{d,t}^{BA}+d_{d,t}^{sh}-\sum_i(g_{i,d,t}+g_{i,d,t}^E)=0 \qquad :\lambda_{d,t} \qquad \forall d,t \tag{4.7}$$

$$\sum_{i\in I^{FL}}(g_{i,d,t}^{RU}+g_{i,d,t}^{RU,E})+d_{d,t}^{RU} \geq \sum_{i\in I^{RE}}\Delta_i^{RE}\varepsilon_i^{RE}k_{i,d,t}^{RE}(X_i+X_i^E) \qquad :\lambda_{d,t}^{RU} \qquad \forall d,t \tag{4.8}$$

$$\sum_{i\in I^{FL}}(g_{i,d,t}^{RD}+g_{i,d,t}^{RD,E})+d_{d,t}^{RD} \geq \sum_{i\in I^{RE}}\Delta_i^{RE}\varepsilon_i^{RE}k_{i,d,t}^{RE}(X_i+X_i^E) \qquad :\lambda_{d,t}^{RD} \qquad \forall d,t \tag{4.9}$$

The system-wide constraints impose restrictions over several components of the power system. These constraints include: the demand-supply energy balance constraints (4.7); the dual variable of this constraint gives the energy clearing price; and the upward and downward reserve constraints (4.8) and (4.9), the dual variables of which constitute the upward and downward reserve clearing prices respectively. The demand-supply energy balance constraint ensures that the total generation from all technologies is sufficient to meet the hourly demand accounting for the effect of energy shifting and recovery.

ii) Operating constraints of flexible generation technologies:

$$0 \leq g_{i,d,t}^{RU} \qquad : \mu_{i,d,t}^{RU} \qquad \forall i \in I^{FL}, d, t \tag{4.10}$$

$$0 \leq g_{i,d,t}^{RU,E} \qquad : \mu_{i,d,t}^{RU,E} \qquad \forall i \in I^{FL}, d, t \tag{4.11}$$

$$0 \leq g_{i,d,t}^{RD} \leq g_{i,d,t} \qquad : \vartheta_{i,d,t}^{-}, \vartheta_{i,d,t}^{+} \qquad \forall i \in I^{FL}, d, t \tag{4.12}$$

$$0 \leq g_{i,d,t}^{RD,E} \leq g_{i,d,t}^{E} \qquad : \vartheta_{i,d,t}^{E,-}, \vartheta_{i,d,t}^{E,+} \qquad \forall i \in I^{FL}, d, t \tag{4.13}$$

$$g_{i,d,t} + g_{i,d,t}^{RU} \leq X_i \qquad : \mu_{i,d,t}^{+} \qquad \forall i \in I^{FL}, d, t \tag{4.14}$$

$$g_{i,d,t}^{E} + g_{i,d,t}^{RU,E} \leq X_i^{E} \qquad : \mu_{i,d,t}^{E,+} \qquad \forall i \in I^{FL}, d, t \tag{4.15}$$

The second set of constraints impose the limits for the hourly energy and reserves provision of the flexible generation technologies available in the system. Constraints (4.10) and (4.11) impose the non-negativity of upward reserve dispatch of the generation technologies. Constraint (4.12) and (4.13) impose the limits for the downward reserves provision. Constraints (4.14) and (4.15) impose the capacity limits for the sum of energy production and upward reserve provision.

iii) Operating constraints of must-run generation technologies:

$$\Lambda^{MSG} X_i \leq g_{i,d,t} \leq X_i \qquad : \xi_{i,d,t}^{-}, \xi_{i,d,t}^{+} \qquad \forall i \in I^{MR}, d, t \tag{4.16}$$

$$\Lambda^{MSG} X_i^{E} \leq g_{i,d,t}^{E} \leq X_i^{E} \qquad : \xi_{i,d,t}^{E,-}, \xi_{i,d,t}^{E,+} \qquad \forall i \in I^{MR}, d, t \tag{4.17}$$

This set of constraints relates to the operation of generation technologies which are classified as must-run. These technologies are always online and have a high minimum stable generation.

iv) Operating constraints of renewable generation technologies:

$$0 \leq g_{i,d,t} \leq k^{RE}_{i,d,t} X_i \qquad : \beta^{-}_{i,d,t}; \beta^{+}_{i,d,t} \qquad \forall i \in I^{RE}, d, t \tag{4.18}$$

$$0 \leq g^{E}_{i,d,t} \leq k^{RE}_{i,d,t} X^{E}_i \qquad : \beta^{E,-}_{i,d,t}; \beta^{E,+}_{i,d,t} \qquad \forall i \in I^{RE}, d, t \tag{4.19}$$

This set of constraints relates to the renewable generation technologies, depicting the hourly variation in available capacity. If necessary, the hourly wind production can be curtailed.

v) Operating constraints of demand side flexibility

$$\sum_t d^{sh}_{d,t} = 0 \qquad : \varphi_d \qquad \forall d \tag{4.20}$$

$$-\alpha D^{BA}_{d,t} \leq d^{sh}_{d,t} \leq \alpha D^{BA}_{d,t} \qquad : \pi^{-}_{d,t}; \pi^{+}_{d,t} \qquad \forall d, t \tag{4.21}$$

$$0 \leq d^{RU}_{d,t} \qquad : \zeta^{RU}_{d,t} \qquad \forall d, t \tag{4.22}$$

$$0 \leq d^{RD}_{d,t} \qquad : \zeta^{RD}_{d,t} \qquad \forall d, t \tag{4.23}$$

$$d^{RD}_{d,t} \leq d^{sh}_{d,t} + \alpha D^{BA}_{d,t} \qquad : \nu^{RD}_{d,t} \qquad \forall d, t \tag{4.24}$$

$$d^{RU}_{d,t} \leq \alpha D^{BA}_{d,t} - d^{sh}_{d,t} \qquad : \nu^{RU}_{d,t} \qquad \forall d, t \tag{4.25}$$

The constraints (4.20) and (4.21) relate to the use of demand flexibility for load redistribution i.e. shifting and recovery of demand. Constraint (4.20) ensures that this load redistribution is energy neutral, that is, not involving energy loss or gains. Constraint (4.21) expresses the limit for the demand change possible in each hour as a ratio α, $(0\% \leq \alpha \leq 100\%)$ of the baseline demand $D^{BA}_{d,t}$ where $\alpha = 0\%$ implies that the demand does not exhibit any time-shifting flexibility, while $\alpha = 100\%$ implies that the whole demand can be shifted in time.

Constraints (4.22) – (4.25) relate to the participation of demand flexibility in the reserves market. The positivity limits of the provision of downward and upward reserves are expressed in constraints (4.22) and

(4.23), while the upper limits are expressed in constraints (4.24) and (4.25).

The term V^{LL} is the set of all primal variables in the lower level problem.

$$V^{LL} = \left\{ g_{i,d,t}, g^{E}_{i,d,t}, g^{RU}_{i,d,t}, g^{RU,E}_{i,d,t}, g^{RD}_{i,d,t}, g^{RD,E}_{i,d,t}, d^{sh}_{d,t}, d^{RD}_{d,t}, d^{RU}_{d,t} \right\}$$

The dual variables of the lower level problem can be expressed using a variable set V^{Dual}.

$$\begin{aligned} V^{Dual} = \Big\{ & \lambda_{d,t}, \lambda^{RU}_{d,t}, \lambda^{RD}_{d,t}, \mu^{RU}_{i,d,t}, \mu^{RU,E}_{i,d,t}, \vartheta^{+}_{i,d,t}, \vartheta^{-}_{i,d,t}, \vartheta^{E,+}_{i,d,t}, \vartheta^{E,-}_{i,d,t}, \mu^{+}_{i,d,t}, \\ & \mu^{E,+}_{i,d,t}, \xi^{+}_{i,d,t}, \xi^{-}_{i,d,t}, \xi^{E,+}_{i,d,t}, \xi^{E,-}_{i,d,t}, \beta^{+}_{i,d,t} \beta^{-}_{i,d,t}, \beta^{E,+}_{i,d,t} \beta^{E,-}_{i,d,t}, \varphi_{d}, \pi^{-}_{d,t}, \\ & \pi^{+}_{d,t}, \zeta^{RU}_{d,t}, \zeta^{RD}_{d,t}, \nu^{RD}_{d,t}, \nu^{RU}_{d,t} \Big\} \end{aligned}$$

4.4 Obtaining the KKT Optimality conditions

To solve the bi-level optimisation problem defined above, it is important to convert it into a single-level optimisation problem often referred to as Mathematical Problem with Equality Constraints (MPEC). This conversion involves the replacement of LL problem by a set of equations known as the optimality conditions. The optimality conditions are formulated in this chapter using the Karush-Kuhn-Tucker approach and are hereafter referred to as KKT optimality conditions. This conversion is enabled by the continuity and convexity of the LL problem.

4.4.1 Lagrangian Equation

To obtain the KKT conditions, the lagrangian equation of the lower level problem is first defined. This is expressed below:

$\mathcal{L} =$

$$
\begin{aligned}
&\sum_{i,d,t} C_i^G(g_{i,d,t}+g_{i,d,t}^E)+\sum_{i\in I^{FL},d,t}\Big(C_i^{RD}(g_{i,d,t}^{RD}+g_{i,d,t}^{RD,E})+C_i^{RU}(g_{i,d,t}^{RU}+g_{i,d,t}^{RU,E})\Big)\\
&+\sum_{d,t}\lambda_{d,t}\Big(D_{d,t}^{BA}+d_{d,t}^{sh}-\sum_i(g_{i,d,t}+g_{i,d,t}^E)\Big)\\
&+\sum_{d,t}\lambda_{d,t}^{RU}\Big(\sum_{i\in I^{RE}}\Delta_i^{RE}\varepsilon_i^{RE}k_{i,d,t}^{RE}(X_i+X_i^E)-\sum_{i\in I^{FL}}(g_{i,d,t}^{RU}+g_{i,d,t}^{RU,E})-d_{d,t}^{RU}\Big)\\
&+\sum_{d,t}\lambda_{d,t}^{RD}\Big(\sum_{i\in I^{RE}}\Delta_i^{RE}\varepsilon_i^{RE}k_{i,d,t}^{RE}(X_i+X_i^E)-\sum_{i\in I^{FL}}(g_{i,d,t}^{RD}+g_{i,d,t}^{RD,E})-d_{d,t}^{RD}\Big)\\
&-\sum_{i\in I^{FL},d,t}\mu_{i,d,t}^{RU}g_{i,d,t}^{RU}-\sum_{i\in I^{FL},d,t}\mu_{i,d,t}^{RU,E}g_{i,d,t}^{RU,E}\\
&-\sum_{i\in I^{FL},d,t}\vartheta_{i,d,t}^{-}g_{i,d,t}^{RD}-\sum_{i\in I^{FL},d,t}\vartheta_{i,d,t}^{E,-}g_{i,d,t}^{RD,E}\\
&+\sum_{i\in I^{FL},d,t}\vartheta_{i,d,t}^{+}\Big(g_{i,d,t}^{RD}-g_{i,d,t}\Big)+\sum_{i\in I^{FL},d,t}\vartheta_{i,d,t}^{E,+}\Big(g_{i,d,t}^{RD,E}-g_{i,d,t}^E\Big)\\
&+\sum_{i\in I^{FL},d,t}\mu_{i,d,t}^{+}\Big(g_{i,d,t}+g_{i,d,t}^{RU}-X_i\Big)+\sum_{i\in I^{FL},d,t}\mu_{i,d,t}^{E,+}\Big(g_{i,d,t}^E+g_{i,d,t}^{RU,E}-X_i^E\Big)\\
&+\sum_{i\in I^{MR},d,t}\xi_{i,d,t}^{-}\Big(\Lambda^{MSG}X_i-g_{i,d,t}\Big)+\sum_{i\in I^{MR},d,t}\xi_{i,d,t}^{+}\Big(g_{i,d,t}-X_i\Big)\\
&+\sum_{i\in I^{MR},d,t}\xi_{i,d,t}^{E,-}\Big(\Lambda^{MSG}X_i^E-g_{i,d,t}^E\Big)+\sum_{i\in I^{MR},d,t}\xi_{i,d,t}^{E,+}\Big(g_{i,d,t}^E-X_i^E\Big)\\
&-\sum_{i\in I^{RE},d,t}\beta_{i,d,t}^{-}g_{i,d,t}+\sum_{i\in I^{RE},d,t}\beta_{i,d,t}^{+}\Big(g_{i,d,t}-k_{i,d,t}^{RE}X_i\Big)\\
&-\sum_{i\in I^{RE},d,t}\beta_{i,d,t}^{E,-}g_{i,d,t}^E+\sum_{i\in I^{RE},d,t}\beta_{i,d,t}^{E,+}\Big(g_{i,d,t}^E-k_{i,d,t}^{RE}X_i^E\Big)\\
&+\sum_{d,t}\varphi_d d_{d,t}^{sh}-\sum_{d,t}\pi_{d,t}^{-}\Big(\alpha D_{d,t}^{BA}+d_{d,t}^{sh}\Big)+\sum_{d,t}\pi_{d,t}^{+}\Big(d_{d,t}^{sh}-\alpha D_{d,t}^{BA}\Big)\\
&-\sum_{d,t}\zeta_{d,t}^{RU}d_{d,t}^{RU}-\sum_{d,t}\zeta_{d,t}^{RD}d_{d,t}^{RD}-\sum_{d,t}\nu_{d,t}^{RD}\Big(d_{d,t}^{sh}+\alpha D_{d,t}^{BA}-d_{d,t}^{RD}\Big)\\
&+\sum_{d,t}\nu_{d,t}^{RU}\Big(d_{d,t}^{sh}+d_{d,t}^{RU}-\alpha D_{d,t}^{BA}\Big) \qquad (4.26)
\end{aligned}
$$

4.4.2 KKT Condition

The KKT conditions associated with the lower-level problems are made up of different group of constraints including:

i) a set of equality constraints derived by differentiating the lagrangian equation with each primal variable of the lower level problem,

ii) a set of primal equality constraints present in the lower level problem,

iii) a set of complementarity conditions related to the inequality constraints of the lower level problem.

The set of equality constraints derived by differentiating the lagrangian equation with each primal variable of the lower level problem are presented first.

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}} = C_i^G - \lambda_{d,t} + \mu_{i,d,t}^{+} - \vartheta_{i,d,t}^{+} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.27}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{E}} = C_i^G - \lambda_{d,t} + \mu_{i,d,t}^{E,+} - \vartheta_{i,d,t}^{E,+} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.28}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{RU}} = C_i^{RU} + \mu_{i,d,t}^{+} - \mu_{i,d,t}^{RU} - \lambda_{d,t}^{RU} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.29}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{RU,E}} = C_i^{RU} + \mu_{i,d,t}^{E,+} - \mu_{i,d,t}^{RU,E} - \lambda_{d,t}^{RU} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.30}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{RD}} = C_i^{RD} + \vartheta_{i,d,t}^{+} - \vartheta_{i,d,t}^{-} - \lambda_{d,t}^{RD} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.31}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{RD,E}} = C_i^{RD} + \vartheta_{i,d,t}^{E,+} - \vartheta_{i,d,t}^{E,-} - \lambda_{d,t}^{RD} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.32}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}} = C_i^G - \lambda_{d,t} + \xi_{i,d,t}^{+} - \xi_{i,d,t}^{-} = 0 \qquad \forall i \in I^{MR}, d, t \tag{4.33}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{E}} = C_i^G - \lambda_{d,t} + \xi_{i,d,t}^{E,+} - \xi_{i,d,t}^{E,-} = 0 \qquad \forall i \in I^{MR}, d, t \tag{4.34}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}} = C_i^G - \lambda_{d,t} - \beta_{i,d,t}^{-} + \beta_{i,d,t}^{+} = 0 \qquad \forall i \in I^{RE}, d, t \tag{4.35}$$

$$\frac{\delta \mathcal{L}}{\delta g_{i,d,t}^{E}} = C_i^G - \lambda_{d,t} - \beta_{i,d,t}^{E,-} + \beta_{i,d,t}^{E,+} = 0 \qquad \forall i \in I^{RE}, d, t \tag{4.36}$$

$$\frac{\delta \mathcal{L}}{\delta d^{sh}_{d,t}} = \lambda_{d,t} - \pi^{-}_{d,t} + \pi^{+}_{d,t} + \varphi_d$$

$$- \nu^{RD}_{d,t} + \nu^{RU}_{d,t} = 0 \qquad \forall d,t \qquad (4.37)$$

$$\frac{\delta \mathcal{L}}{\delta d^{RU}_{d,t}} = -\lambda^{RU}_{d,t} - \zeta^{RU}_{d,t} + \nu^{RU}_{d,t} = 0 \qquad \forall d,t \qquad (4.38)$$

$$\frac{\delta \mathcal{L}}{\delta d^{RD}_{d,t}} = -\lambda^{RD}_{d,t} - \zeta^{RD}_{d,t} + \nu^{RD}_{d,t} = 0 \qquad \forall d,t \qquad (4.39)$$

The primal equality constraints of the lower level problem included in the KKT conditions are presented below:

$$D^{BA}_{d,t} + d^{sh}_{d,t} - \sum_i (g_{i,d,t} - g^{E}_{i,d,t}) = 0 \qquad \forall d,t \qquad (4.40)$$

$$\sum_t d^{sh}_{d,t} = 0 \qquad \forall d \qquad (4.41)$$

The complementarity constraints associated with the inequality constraints of the lower level problem are presented below:

$$0 \leq \Big(\sum_{i \in I^{FL}} (g^{RU}_{i,d,t} + g^{RU,E}_{i,d,t}) + d^{RU}_{d,t}$$

$$- \sum_{i \in I^{RE}} \Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^{E}_i) \Big) \perp \lambda^{RU}_{d,t} \geq 0 \qquad \forall d,t \qquad (4.42)$$

$$0 \leq \Big(\sum_{i \in I^{FL}} (g^{RD}_{i,d,t} + g^{RD,E}_{i,d,t}) + d^{RD}_{d,t}$$

$$- \sum_{i \in I^{RE}} \Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^{E}_i) \Big) \perp \lambda^{RD}_{d,t} \geq 0 \qquad \forall d,t \qquad (4.43)$$

$$0 \leq g^{RU}_{i,d,t} \perp \mu^{RU}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (4.44)$$

$$0 \leq g^{RU,E}_{i,d,t} \perp \mu^{RU,E}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (4.45)$$

$$0 \leq g^{RD}_{i,d,t} \perp \vartheta^{-}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (4.46)$$

$$0 \leq g^{RD,E}_{i,d,t} \perp \vartheta^{E,-}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (4.47)$$

$$0 \leq (g_{i,d,t} - g^{RD}_{i,d,t}) \perp \vartheta^{+}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (4.48)$$

$$0 \leq (g_{i,d,t} - g^{RD,E}_{i,d,t}) \perp \vartheta^{E,+}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \qquad (4.49)$$

$$0 \leq (X_i - g_{i,d,t} - g^{RU}_{i,d,t}) \perp \mu^{+}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \tag{4.50}$$

$$0 \leq (X_i - g^{E}_{i,d,t} - g^{RU,E}_{i,d,t}) \perp \mu^{E,+}_{i,d,t} \geq 0 \qquad \forall i \in I^{FL}, d, t \tag{4.51}$$

$$0 \leq (g_{i,d,t} - \Lambda^{MSG} X_i) \perp \xi^{-}_{i,d,t} \geq 0 \qquad \forall i \in I^{MR}, d, t \tag{4.52}$$

$$0 \leq (g^{E}_{i,d,t} - \Lambda^{MSG} X^{E}_i) \perp \xi^{E,-}_{i,d,t} \geq 0 \qquad \forall i \in I^{MR}, d, t \tag{4.53}$$

$$0 \leq (X_i - g_{i,d,t}) \perp \xi^{+}_{i,d,t} \geq 0 \qquad \forall i \in I^{MR}, d, t \tag{4.54}$$

$$0 \leq (X_i - g^{E}_{i,d,t}) \perp \xi^{E,+}_{i,d,t} \geq 0 \qquad \forall i \in I^{MR}, d, t \tag{4.55}$$

$$0 \leq g_{i,d,t} \perp \beta^{-}_{i,d,t} \geq 0 \qquad \forall i \in I^{RE}, d, t \tag{4.56}$$

$$0 \leq g^{E}_{i,d,t} \perp \beta^{E,-}_{i,d,t} \geq 0 \qquad \forall i \in I^{RE}, d, t \tag{4.57}$$

$$0 \leq (k^{W}_{d,t} X_i - g_{i,d,t}) \perp \beta^{+}_{i,d,t} \geq 0 \qquad \forall i \in I^{RE}, d, t \tag{4.58}$$

$$0 \leq (k^{W}_{d,t} X^{E}_i - g^{E}_{i,d,t}) \perp \beta^{E,+}_{i,d,t} \geq 0 \qquad \forall i \in I^{RE}, d, t \tag{4.59}$$

$$0 \leq (d^{sh}_{d,t} + \alpha D^{BA}_{d,t}) \perp \pi^{-}_{d,t} \geq 0 \qquad \forall d, t \tag{4.60}$$

$$0 \leq (\alpha D^{BA}_{d,t} - d^{sh}_{d,t}) \perp \pi^{+}_{d,t} \geq 0 \qquad \forall d, t \tag{4.61}$$

$$0 \leq d^{RU}_{d,t} \perp \zeta^{RU}_{d,t} \geq 0 \qquad \forall d, t \tag{4.62}$$

$$0 \leq d^{RD}_{d,t} \perp \zeta^{RD}_{d,t} \geq 0 \qquad \forall d, t \tag{4.63}$$

$$0 \leq (d^{sh}_{d,t} + \alpha D^{BA}_{d,t} - d^{RD}_{d,t}) \perp \nu^{RD}_{d,t} \geq 0 \qquad \forall d, t \tag{4.64}$$

$$0 \leq (\alpha D^{BA}_{d,t} - d^{sh}_{d,t} - d^{RU}_{d,t}) \perp \nu^{RU}_{d,t} \geq 0 \qquad \forall d, t \tag{4.65}$$

$$\lambda_{d,t} : \qquad \text{free} \tag{4.66}$$

It is important to give a detailed expression of the compact equations (4.42) – (4.43). If this is represented in the generic form $0 \leq a \perp b \geq 0$, the detailed expression would be:

$$0 \leq a; \qquad 0 \leq b; \qquad ab = 0$$

4.5 The MPEC Formulation

The single level MPEC problem includes the upper level objective function, upper level constraints and the KKT optimality conditions of the lower level problem. This MPEC formulation can be expressed in a concise form as:

$$\underset{V^{MPEC}}{Max} \sum_{d} wf_d \Bigg\{ \sum_{i,t} \Big(\lambda_{d,t} - C_i^G\Big) g_{i,d,t} + \sum_{i \in I^{FL},t} \Big(\lambda_{d,t}^{RD} - C_i^{RD}\Big) g_{i,d,t}^{RD} +$$
$$\sum_{i \in I^{FL},t} \Big(\lambda_{d,t}^{RU} - C_i^{RU}\Big) g_{i,d,t}^{RU} - \Gamma \Bigg(\sum_{i \in I^{RE},t} (\lambda_{d,t}^{RU} + \lambda_{d,t}^{RD}) \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} X_i \Bigg) \Bigg\}$$
$$- \sum_{i} IC_i X_i$$

subject to

(4.2) — (4.5)

(4.27) — (4.66)

The variables in the single level MPEC problem consists of the upper level primal variables, the lower level primal variables and the lower level dual variables.

$$V^{MPEC} = \Big\{ X_i, V^{LL}, V^{Dual} \Big\}$$

This MPEC problem however contains non-linearities in the constraints associated with the complementarity conditions and the bi-linear terms in the objective function. These non-linearities are handled using different approaches which are detailed below.

4.5.1 Linearising the Complementarity Constraints

The first source of non-linearity is the complementarity constraints which form part of the KKT conditions. They involve the multiplication of a dual variable with primal variable(s). Representing the respective complementarity constraints in a generic form, $0 \leq a \perp b \geq 0$.

This is linearised by introducing two disjunctive equations [122] as follows:

$$a \leq M * \varpi; \qquad b \leq M * (1 - \varpi)$$

where M is a large enough positive constant and $\varpi \in \{0,1\}$.

This introduction of auxiliary binary variables increases the computational burden and difficulty of the problem.

4.5.2 Linearising the Bi-linear Revenue Terms in the Objective Function

The bi-linear revenue terms ($\lambda_{d,t} g_{i,d,t}$, $\lambda^{RU}_{d,t} g^{RU}_{i,d,t}$, $\lambda^{RD}_{d,t} g^{RD}_{i,d,t}$) in the objective function include the product of prices (dual variables) and dispatch (primal variables). These terms are linearised using the exact linearisation approach presented in [77]. This approach employs the strong duality theorem and some of the KKT conditions to obtain an exact linearised equivalent of the objective function.

First, the strong duality equality for the lower level problem is derived. This is based on the strong duality theorem which says that for a continuous and convex problem, the optimal value of the objective function for both the primal and dual problem is the same. This is presented in the equation below.

$$\begin{aligned}
&\sum_{i,d,t} C^G_i (g_{i,d,t} + g^E_{i,d,t}) + \sum_{i \in I^{FL},d,t} \Big(C^{RD}_i (g^{RD}_{i,d,t} + g^{RD,E}_{i,d,t}) + C^{RU}_i (g^{RU}_{i,d,t} + g^{RU,E}_{i,d,t}) \Big) \\
&= \sum_{d,t} \lambda_{d,t} D^{BA}_{d,t} + \sum_{i \in I^{RE},d,t} \lambda^{RU}_{d,t} \Big(\Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^E_i) \Big) \\
&+ \sum_{i \in I^{RE},d,t} \lambda^{RD}_{d,t} \Big(\Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^E_i) \Big) - \sum_{i \in I^{FL},d,t} \mu^+_{i,d,t} X_i \\
&- \sum_{i \in I^{FL},d,t} \mu^{E,+}_{i,d,t} X^E_i + \sum_{i \in I^{MR},d,t} \xi^-_{i,d,t} \Lambda^{MSG} X_i + \sum_{i \in I^{MR},d,t} \xi^{E,-}_{i,d,t} \Lambda^{MSG} X^E_i \\
&- \sum_{i \in I^{MR},d,t} \xi^+_{i,d,t} X_i - \sum_{i \in I^{MR},d,t} \xi^{E,+}_{i,d,t} X^E_i - \sum_{i \in I^{RE},d,t} \beta^+_{i,d,t} k^{RE}_{i,d,t} X_i \\
&- \sum_{i \in I^{RE},d,t} \beta^{E,+}_{i,d,t} k^{RE}_{i,d,t} X^E_i - \sum_{d,t} \pi^-_{d,t} \alpha D^{BA}_{d,t} - \sum_{d,t} \pi^+_{d,t} \alpha D^{BA}_{d,t} \\
&- \sum_{d,t} \nu^{RD}_{d,t} \alpha D^{BA}_{d,t} - \sum_{d,t} \nu^{RU}_{d,t} \alpha D^{BA}_{d,t}
\end{aligned} \tag{4.67}$$

This equation can be rewritten as:

$$
\begin{aligned}
&\sum_{i,d,t} C_i^G g_{i,d,t} + \sum_{i\in I^{FL},d,t} \left(C_i^{RD} g_{i,d,t}^{RD} + C_i^{RU} g_{i,d,t}^{RU} \right) \\
&= \sum_{d,t} \lambda_{d,t} D_{d,t}^{BA} + \sum_{i\in I^{RE},d,t} \lambda_{d,t}^{RU} \left(\Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} (X_i + X_i^E) \right) \\
&+ \sum_{i\in I^{RE},d,t} \lambda_{d,t}^{RD} \left(\Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} (X_i + X_i^E) \right) - \sum_{i\in I^{FL},d,t} \mu_{i,d,t}^{+} X_i \\
&- \sum_{i\in I^{FL},d,t} \mu_{i,d,t}^{E,+} X_i^E + \sum_{i\in I^{MR},d,t} \xi_{i,d,t}^{-} \Lambda^{MSG} X_i + \sum_{i\in I^{MR},d,t} \xi_{i,d,t}^{E,-} \Lambda^{MSG} X_i^E \\
&- \sum_{i\in I^{MR},d,t} \xi_{i,d,t}^{+} X_i - \sum_{i\in I^{MR},d,t} \xi_{i,d,t}^{E,+} X_i^E - \sum_{i\in I^{RE},d,t} \beta_{i,d,t}^{+} k_{i,d,t}^{RE} X_i \\
&- \sum_{i\in I^{RE},d,t} \beta_{i,d,t}^{E,+} k_{i,d,t}^{RE} X_i^E - \sum_{d,t} \pi_{d,t}^{-} \alpha D_{d,t}^{BA} - \sum_{d,t} \pi_{d,t}^{+} \alpha D_{d,t}^{BA} \\
&- \sum_{d,t} \nu_{d,t}^{RD} \alpha D_{d,t}^{BA} - \sum_{d,t} \nu_{d,t}^{RU} \alpha D_{d,t}^{BA} - \sum_{i,d,t} C_i^G g_{i,d,t}^E \\
&- \sum_{i\in I^{FL},d,t} \left(C_i^{RD} g_{i,d,t}^{RD,E} + C_i^{RU} g_{i,d,t}^{RU,E} \right)
\end{aligned}
\tag{4.68}
$$

In the next step, the KKT equations (4.27), (4.33) and (4.35) are multiplied with $g_{i,d,t}$, the following equations result.

$$
\sum_{i\in I^{FL},d,t} \lambda_{d,t} g_{i,d,t} = \sum_{i\in I^{FL},d,t} \left(C_i^G g_{i,d,t} + \mu_{i,d,t}^{+} g_{i,d,t} - \vartheta_{i,d,t}^{+} g_{i,d,t} \right) \tag{4.69}
$$

$$
\sum_{i\in I^{MR},d,t} \lambda_{d,t} g_{i,d,t} = \sum_{i\in I^{MR},d,t} \left(C_i^G g_{i,d,t} + \xi_{i,d,t}^{+} g_{i,d,t} - \xi_{i,d,t}^{-} g_{i,d,t} \right) \tag{4.70}
$$

$$
\sum_{i\in I^{RE},d,t} \lambda_{d,t} g_{i,d,t} = \sum_{i\in I^{RE},d,t} \left(C_i^G g_{i,d,t} + \beta_{i,d,t}^{+} g_{i,d,t} - \beta_{i,d,t}^{-} g_{i,d,t} \right) \tag{4.71}
$$

These three equations add up to give:

$$
\begin{aligned}
\sum_{i,d,t} \lambda_{d,t} g_{i,d,t} = \sum_{i,d,t} C_i^G g_{i,d,t} &+ \sum_{i\in I^{MR},d,t} \left(\xi_{i,d,t}^{+} g_{i,d,t} - \xi_{i,d,t}^{-} g_{i,d,t} \right) \\
&+ \sum_{i\in I^{FL},d,t} \left(\mu_{i,d,t}^{+} g_{i,d,t} - \vartheta_{i,d,t}^{+} g_{i,d,t} \right)
\end{aligned}
$$

$$+\sum_{i\in I^{RE},d,t}\left(\beta^{+}_{i,d,t}g_{i,d,t}-\beta^{-}_{i,d,t}g_{i,d,t}\right) \tag{4.72}$$

Similarly multiplying equations (4.29) and (4.31) by $g^{RU}_{i,d,t}$ and $g^{RD}_{i,d,t}$ respectively, we have:

$$\sum_{i\in I^{FL},d,t}\lambda^{RU}_{d,t}g^{RU}_{i,d,t}=\sum_{i\in I^{FL},d,t}\left(C^{RU}_{i}g^{RU}_{i,d,t}+\mu^{+}_{i,d,t}g^{RU}_{i,d,t}-\mu^{RU}_{i,d,t}g^{RU}_{i,d,t}\right) \tag{4.73}$$

$$\sum_{i\in I^{FL},d,t}\lambda^{RD}_{d,t}g^{RD}_{i,d,t}=\sum_{i\in I^{FL},d,t}\left(C^{RD}_{i}g^{RD}_{i,d,t}+\vartheta^{+}_{i,d,t}g^{RD}_{i,d,t}-\vartheta^{-}_{i,d,t}g^{RD}_{i,d,t}\right) \tag{4.74}$$

Adding the equations (4.72), (4.73) and (4.74) yields:

$$\begin{aligned}
&\sum_{i,d,t}\lambda_{d,t}g_{i,d,t}+\sum_{i\in I^{FL},d,t}\lambda^{RD}_{d,t}g^{RD}_{i,d,t}+\sum_{i\in I^{FL},d,t}\lambda^{RU}_{d,t}g^{RU}_{i,d,t}=\sum_{i,d,t}C^{G}_{i}g_{i,d,t}\\
&+\sum_{i\in I^{MR},d,t}\left(\xi^{+}_{i,d,t}g_{i,d,t}-\xi^{-}_{i,d,t}g_{i,d,t}\right)+\sum_{i\in I^{FL},d,t}\left(\mu^{+}_{i,d,t}g_{i,d,t}-\vartheta^{+}_{i,d,t}g_{i,d,t}\right)\\
&+\sum_{i\in I^{RE},d,t}\beta^{+}_{i,d,t}g_{i,d,t}-\sum_{i\in I^{RE},d,t}\beta^{-}_{i,d,t}g_{i,d,t}+\sum_{i\in I^{FL},d,t}\Big(C^{RU}_{i}g^{RU}_{i,d,t}+\mu^{+}_{i,d,t}g^{RU}_{i,d,t}\\
&-\mu^{RU}_{i,d,t}g^{RU}_{i,d,t}\Big)+\sum_{i\in I^{FL},d,t}\left(C^{RD}_{i}g^{RD}_{i,d,t}+\vartheta^{+}_{i,d,t}g^{RD}_{i,d,t}-\vartheta^{-}_{i,d,t}g^{RD}_{i,d,t}\right)
\end{aligned} \tag{4.75}$$

The next step involves the use of some of the complementarity constraints defined earlier. The complementarity constraints (4.44, 4.46, 4.48, 4.50, 4.52, 4.54, 4.56, 4.58), can be rewritten to give the following expressions.

$$\sum_{i\in I^{FL},d,t}\mu^{RU}_{i,d,t}g^{RU}_{i,d,t}=0$$

$$\sum_{i\in I^{FL},d,t}\vartheta^{-}_{i,d,t}g^{RD}_{i,d,t}=0$$

$$\sum_{i\in I^{FL},d,t}\vartheta^{+}_{i,d,t}g_{i,d,t}=\sum_{i\in I^{FL},d,t}\vartheta^{+}_{i,d,t}g^{RD}_{i,d,t}$$

$$\sum_{i\in I^{FL},d,t}\mu^{+}_{i,d,t}(g_{i,d,t}+g^{RU}_{i,d,t})=\sum_{i\in I^{FL},d,t}\mu^{+}_{i,d,t}X_{i}$$

$$\sum_{i\in I^{MR},d,t} \xi^{-}_{i,d,t} g_{i,d,t} = \sum_{i\in I^{MR},d,t} \xi^{-}_{i,d,t} \Lambda^{MSG} X_i$$
$$\sum_{i\in I^{MR},d,t} \xi^{+}_{i,d,t} g_{i,d,t} = \sum_{i\in I^{MR},d,t} \xi^{+}_{i,d,t} X_i$$
$$\sum_{i\in I^{RE},d,t} \beta^{-}_{i,d,t} g_{i,d,t} = 0$$
$$\sum_{i\in I^{RE},d,t} \beta^{+}_{i,d,t} g_{i,d,t} = \sum_{i\in I^{RE},d,t} \beta^{+}_{i,d,t} k^{RE}_{i,d,t} X_i$$

By replacing the terms in (4.75) with the equivalent terms as defined above, the equation becomes:

$$\begin{aligned}
&\sum_{i,d,t} \lambda_{d,t} g_{i,d,t} + \sum_{i\in I^{FL},d,t} \lambda^{RD}_{d,t} g^{RD}_{i,d,t} + \sum_{i\in I^{FL},d,t} \lambda^{RU}_{d,t} g^{RU}_{i,d,t} = \\
&\sum_{i,d,t} C^{G}_{i} g_{i,d,t} + \sum_{i\in I^{FL},d,t} \left(C^{RU}_{i} g^{RU}_{i,d,t} + C^{RD}_{i} g^{RD}_{i,d,t}\right) + \sum_{i\in I^{MR},d,t} \xi^{+}_{i,d,t} X_i \\
&- \sum_{i\in I^{MR},d,t} \xi_{i,d,t} \Lambda^{MSG} X_i + \sum_{i\in I^{FL},d,t} \mu^{+}_{i,d,t} X_i + \sum_{i\in I^{RE},d,t} \beta^{+}_{i,d,t} k^{RE}_{i,d,t} X_i
\end{aligned} \tag{4.76}$$

Substituting the RHS of equation (4.68) into (4.76), the equation becomes:

$$\begin{aligned}
&\sum_{i,d,t} \lambda_{d,t} g_{i,d,t} + \sum_{i\in I^{FL},d,t} \lambda^{RD}_{d,t} g^{RD}_{i,d,t} + \sum_{i\in I^{FL},d,t} \lambda^{RU}_{d,t} g^{RU}_{i,d,t} = \sum_{d,t} \lambda_{d,t} D^{BA}_{d,t} \\
&+ \sum_{i\in I^{RE},d,t} \lambda^{RU}_{d,t} \left(\Delta^{RE}_{i} \varepsilon^{RE}_{i} k^{RE}_{i,d,t} (X_i + X^{E}_{i})\right) + \sum_{i\in I^{RE},d,t} \lambda^{RD}_{d,t} \left(\Delta^{RE}_{i} \varepsilon^{RE}_{i} k^{RE}_{i,d,t} (X_i + X^{E}_{i})\right) \\
&- \sum_{i\in I^{FL},d,t} \mu^{+}_{i,d,t} X_i - \sum_{i\in I^{FL},d,t} \mu^{E,+}_{i,d,t} X^{E}_{i} + \sum_{i\in I^{MR},d,t} \xi^{-}_{i,d,t} \Lambda^{MSG} X_i \\
&+ \sum_{i\in I^{MR},d,t} \xi^{E,-}_{i,d,t} \Lambda^{MSG} X^{E}_{i} - \sum_{i\in I^{MR},d,t} \xi^{+}_{i,d,t} X_i - \sum_{i\in I^{MR},d,t} \xi^{E,+}_{i,d,t} X^{E}_{i} \\
&- \sum_{i\in I^{RE},d,t} \beta^{+}_{i,d,t} k^{RE}_{i,d,t} X_i - \sum_{i\in I^{RE},d,t} \beta^{E,+}_{i,d,t} k^{RE}_{i,d,t} X^{E}_{i} - \sum_{d,t} \pi^{-}_{d,t} \alpha D^{BA}_{d,t} \\
&- \sum_{d,t} \pi^{+}_{d,t} \alpha D^{BA}_{d,t} - \sum_{d,t} \nu^{RD}_{d,t} \alpha D^{BA}_{d,t} - \sum_{d,t} \nu^{RU}_{d,t} \alpha D^{BA}_{d,t} \\
&- \sum_{i,d,t} C^{G}_{i} g^{E}_{i,d,t} - \sum_{i\in I^{FL},d,t} \left(C^{RD}_{i} g^{RD,E}_{i,d,t} + C^{RU}_{i} g^{RU,E}_{i,d,t}\right) + \sum_{i\in I^{MR},d,t} \xi^{+}_{i,d,t} X_i
\end{aligned}$$

$$- \sum_{i \in I^{MR},d,t} \xi_{i,d,t} \Lambda^{MSG} X_i + \sum_{i \in I^{FL},d,t} \mu^{+}_{i,d,t} X_i + \sum_{i \in I^{RE},d,t} \beta^{+}_{i,d,t} k^{RE}_{i,d,t} X_i \tag{4.77}$$

This can be compactly written as:

$$\sum_{i,d,t} \lambda_{d,t} g_{i,d,t} + \sum_{i \in I^{FL},d,t} \lambda^{RD}_{d,t} g^{RD}_{i,d,t} + \sum_{i \in I^{FL},d,t} \lambda^{RU}_{d,t} g^{RU}_{i,d,t} = \sum_{d,t} \lambda_{d,t} D^{BA}_{d,t} +$$
$$\sum_{i \in I^{RE},d,t} \lambda^{RU}_{d,t} \left(\Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^E_i) \right) + \sum_{i \in I^{RE},d,t} \lambda^{RD}_{d,t} \left(\Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^E_i) \right)$$
$$+ \mathrm{K}^{Lin} \tag{4.78}$$

For ease of reference and compactness, the term K^{Lin} is used to replace an addition of terms which is expressed below.

$$\begin{aligned} K^{Lin} = & \sum_{i \in I^{MR},d,t} \xi^{E,-}_{i,d,t} \Lambda^{MSG} X^E_i - \sum_{i \in I^{MR},d,t} \xi^{E,+}_{i,d,t} X^E_i \\ & - \sum_{i \in I^{FL},d,t} \mu^{E,+}_{i,d,t} X^E_i - \sum_{i \in I^{RE},d,t} \beta^{E,+}_{i,d,t} k^{RE}_{i,d,t} X^E_i \\ & - \sum_{d,t} \alpha D^{BA}_{d,t} \left(\pi^{-}_{d,t} + \pi^{+}_{d,t} + \nu^{RD}_{d,t} + \nu^{RU}_{d,t} \right) - \sum_{i,d,t} C^G_i g^E_{i,d,t} - \\ & \sum_{i \in I^{FL},d,t} \left(C^{RD}_i g^{RD,E}_{i,d,t} + C^{RU}_i g^{RU,E}_{i,d,t} \right) \end{aligned} \tag{4.79}$$

Therefore the upper level objective function can be rewritten in the equivalent form as:

$$\underset{V^{MPEC}}{Max} \sum_d wf_d \Bigg\{ \sum_{d,t} \lambda_{d,t} D^{BA}_{d,t} + \sum_{i \in I^{RE},d,t} \underline{\left(\boldsymbol{\lambda^{RU}_{d,t}} + \boldsymbol{\lambda^{RD}_{d,t}} \right)} \left(\Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (\underline{\boldsymbol{X_i}} + X^E_i) \right)$$
$$+ \mathrm{K}^{\mathrm{Lin}} - \sum_{i,t} C^G_i g_{i,d,t} - \sum_{i \in I^{FL},t} \left(C^{RU}_i g^{RU}_{i,d,t} + C^{RD}_i g^{RD}_{i,d,t} \right)$$
$$- \Gamma \Bigg(\sum_t \underline{\left(\boldsymbol{\lambda^{RU}_{d,t}} + \boldsymbol{\lambda^{RD}_{d,t}} \right) \boldsymbol{\Delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} X_i}} \Bigg) \Bigg\} - \sum_i IC_i X_i \tag{4.80}$$

This reformulated upper level objective function is not fully linearised owing to the presence of the bi-linear terms involving the product of reserve prices and variable representing the wind investment. These terms have been highlighted in bold fonts and underlined. These bi-linear terms are the products $\lambda_{d,t}^{RU} X_i$ and $\lambda_{d,t}^{RD} X_i$.

4.5.3 Linearising some Terms in the Objective Function using Binary Expansion

The bi-linear terms in equation (4.81a) are approximately linearised using the binary expansion method presented in [123]. The steps involved are described below:

The following steps are involved in linearising the terms $\lambda_{d,t}^{RU} X_i$, $\lambda_{d,t}^{RD} X_i$.

1. The primal variable X_i is selected to be discretised since this term is present in both bi-linear terms.

2. The number of discrete points used in approximating the term is represented with Z. The step size for the discretisation is represented with the constant term ∇.

3. To select the closest approximation of the original variable, we make use of the following equation:

$$X_i - \frac{\nabla}{2} \leq \sum_{s=0}^{S} 2^s \nabla \varphi_{d,t,s} \leq X_i + \frac{\nabla}{2}$$

   where $S = log_2 Z - 1$. The term $\varphi_{d,t,s}$ is an auxiliary binary variable.

4. Two dummy variables $r_{d,t}^{RU}$ and $r_{d,t}^{RD}$ are introduced and the following constraints are added to the problem:

$$\begin{aligned} 0 \leq \lambda_{d,t}^{RU} - r_{d,t}^{RU} &\leq M\varphi_{d,t,s} \qquad && \forall d,t,s \\ 0 \leq r_{d,t}^{RU} &\leq M(1-\varphi_{d,t,s}) \qquad && \forall d,t,s \\ 0 \leq \lambda_{d,t}^{RD} - r_{d,t}^{RD} &\leq M\varphi_{d,t,s} \qquad && \forall d,t,s \\ 0 \leq r_{d,t}^{RD} &\leq M(1-\varphi_{d,t,s}) \qquad && \forall d,t,s \end{aligned}$$

where M is a large enough positive term.

5. The bilinear terms $\lambda_{d,t}^{RU}X_i$, $\lambda_{d,t}^{RD}X_i$, in the objective function are respectively replaced with the following approximate terms:

$$\lambda_{d,t}^{RU}X_i = \sum_{s=0}^{S} 2^s \nabla\lambda_{d,t}^{RU}$$
$$\lambda_{d,t}^{RD}X_i = \sum_{s=0}^{S} 2^s \nabla\lambda_{d,t}^{RD}$$

4.6 MILP Formulation

Following the use of different linearisation techniques on the MPEC problem as expressed in sections 4.5.1, 4.5.2 and 4.5.3. A mixed integer linear programming (MILP) problem results. This is presented below:

$$\begin{aligned}
\underset{V^{MPEC}}{Max} \sum_{d} wf_d \Bigg\{ & \sum_{d,t} \lambda_{d,t} D_{d,t}^{BA} + \sum_{i \in I^{RE},d,t} \Bigg(\Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} X_i^E \\
& + \sum_{i \in I^{RE},d,t} \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} \Big(\sum_{s=0}^{S} 2^s \nabla\lambda_{d,t}^{RU} + \sum_{s=0}^{S} 2^s \nabla\lambda_{d,t}^{RD} \Big) \Bigg) \\
& + \mathrm{K}^{Lin} - \sum_{i,t} C_i^G g_{i,d,t} - \sum_{i \in I^{FL},t} \Big(C_i^{RU} g_{i,d,t}^{RU} + C_i^{RD} g_{i,d,t}^{RD} \Big) \\
& - \Gamma \sum_{i \in I^{RE},d,t} \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} \Big(\sum_{s=0}^{S} 2^s \nabla\lambda_{d,t}^{RU} + \sum_{s=0}^{S} 2^s \nabla\lambda_{d,t}^{RD} \Big) \Bigg\} - \sum_{i} IC_i X_i
\end{aligned} \tag{4.81a}$$

1. The term K^{Lin} is expressed below:

$$\begin{aligned}
K^{Lin} = & \sum_{i \in I^{MR},d,t} \xi_{i,d,t}^{E,-} \Lambda^{MSG} X_i^E - \sum_{i \in I^{MR},d,t} \xi_{i,d,t}^{E,+} X_i^E \\
& - \sum_{i \in I^{FL},d,t} \mu_{i,d,t}^{E,+} X_i^E - \sum_{i \in I^{RE},d,t} \beta_{i,d,t}^{E,+} k_{i,d,t}^{RE} X_i^E
\end{aligned}$$

$$-\sum_{d,t}\alpha D^{BA}_{d,t}\Big(\pi^{-}_{d,t}+\pi^{+}_{d,t}+\nu^{RD}_{d,t}+\nu^{RU}_{d,t}\Big)-\sum_{i,d,t}C^{G}_{i}g^{E}_{i,d,t}-$$
$$\sum_{i\in I^{FL},d,t}\Big(C^{RD}_{i}g^{RD,E}_{i,d,t}+C^{RU}_{i}g^{RU,E}_{i,d,t}\Big) \tag{4.82}$$

2. The upper level constraints:

$$0\leq X_i \qquad \forall i \tag{4.83a}$$
$$\sum_{i\notin I^{RE}}(X_i+X^{E}_{i})\geq \Upsilon(1-\alpha)D^{BA}_{d,t} \qquad \forall d,t \tag{4.83b}$$
$$\sum_{d} wf_d g_{i,d,t}\geq \Psi\sum_{d} wf_d X_i \qquad \forall i\in I^{MR} \tag{4.83c}$$
$$\sum_{d} wf_d g^{E}_{i,d,t}\geq \Psi\sum_{d} wf_d X^{E}_i \qquad \forall i\in I^{MR} \tag{4.83d}$$
$$X_i-\frac{\nabla}{2}\leq\sum_{s=0}^{S}2^{s}\nabla\varphi_{d,t,s}\leq X_i+\frac{\nabla}{2} \qquad \forall i\in I^{RE} \tag{4.83e}$$

3. The constraints introduced from the binary expansion process.

$$0\leq\lambda^{RU}_{d,t}-r^{RU}_{d,t}\leq\varphi^{RU}_{d,t,s}M^{D} \qquad \forall d,t,s \tag{4.84a}$$
$$0\leq r^{RU}_{d,t}\leq(1-\varphi^{RU}_{d,t,s})M^{P} \qquad \forall d,t,s \tag{4.84b}$$
$$0\leq\lambda^{RD}_{d,t}-r^{RD}_{d,t}\leq\varphi^{RD}_{d,t,s}M^{D} \qquad \forall d,t,s \tag{4.84c}$$
$$0\leq r^{RD}_{d,t}\leq(1-\varphi^{RD}_{d,t,s})M^{P} \qquad \forall d,t,s \tag{4.84d}$$

where the terms M^P, M^D are large enough positive constants and the terms $\varphi^{RD}_{d,t,s}$ and $\varphi^{RU}_{d,t,s}$ are binary variables.

4. The equality constraints included in the KKT conditions including the first order equations and the primal equality constraints:

$$C^{G}_{i}-\lambda_{d,t}+\mu^{+}_{i,d,t}-\vartheta^{+}_{i,d,t}=0 \qquad \forall i\in I^{FL},d,t \tag{4.85a}$$
$$C^{G}_{i}-\lambda_{d,t}+\mu^{E,+}_{i,d,t}-\vartheta^{E,+}_{i,d,t}=0 \qquad \forall i\in I^{FL},d,t \tag{4.85b}$$
$$C^{RU}_{i}+\mu^{+}_{i,d,t}-\mu^{RU}_{i,d,t}-\lambda^{RU}_{d,t}=0 \qquad \forall i\in I^{FL},d,t \tag{4.85c}$$
$$C^{RU}_{i}+\mu^{E,+}_{i,d,t}-\mu^{RU,E}_{i,d,t}-\lambda^{RU}_{d,t}=0 \qquad \forall i\in I^{FL},d,t \tag{4.85d}$$

$$C_i^{RD} + \vartheta_{i,d,t}^{+} - \vartheta_{i,d,t}^{-} - \lambda_{d,t}^{RD} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.85e}$$

$$C_i^{RD} + \vartheta_{i,d,t}^{E,+} - \vartheta_{i,d,t}^{E,-} - \lambda_{d,t}^{RD} = 0 \qquad \forall i \in I^{FL}, d, t \tag{4.85f}$$

$$C_i^{G} - \lambda_{d,t} + \xi_{i,d,t}^{+} - \xi_{i,d,t}^{-} = 0 \qquad \forall i \in I^{MR}, d, t \tag{4.85g}$$

$$C_i^{G} - \lambda_{d,t} + \xi_{i,d,t}^{E,+} - \xi_{i,d,t}^{E,-} = 0 \qquad \forall i \in I^{MR}, d, t \tag{4.85h}$$

$$C_i^{G} - \lambda_{d,t} - \beta_{i,d,t}^{-} + \beta_{i,d,t}^{+} = 0 \qquad \forall i \in I^{RE}, d, t \tag{4.85i}$$

$$C_i^{G} - \lambda_{d,t} - \beta_{i,d,t}^{E,-} + \beta_{i,d,t}^{E,+} = 0 \qquad \forall i \in I^{RE}, d, t \tag{4.85j}$$

$$\lambda_{d,t} - \pi_{d,t}^{-} + \pi_{d,t}^{+} + \varphi_d - \nu_{d,t}^{RD} + \nu_{d,t}^{RU} = 0 \qquad \forall d, t \tag{4.85k}$$

$$-\lambda_{d,t}^{RU} - \zeta_{d,t}^{RU} + \nu_{d,t}^{RU} = 0 \qquad \forall d, t \tag{4.85l}$$

$$-\lambda_{d,t}^{RD} - \zeta_{d,t}^{RD} + \nu_{d,t}^{RD} = 0 \qquad \forall d, t \tag{4.85m}$$

$$D_{d,t}^{BA} + d_{d,t}^{sh} - \sum_i (g_{i,d,t} - g_{i,d,t}^{E}) = 0 \qquad \forall d, t \tag{4.85n}$$

$$\sum_t d_{d,t}^{sh} = 0 \qquad \forall d \tag{4.85o}$$

5. The dual variables of the MPEC problem which are free variables:

$$\lambda_{d,t} : \qquad \text{free} \tag{4.86a}$$

6. The equations showing the linearisation of the complementarity constraints of system wide constraints using disjunctive integer equivalents

$$0 \le \Big(\sum_{i \in I^{FL}} (g_{i,d,t}^{RU} + g_{i,d,t}^{RU,E}) + d_{d,t}^{RU} - \sum_{i \in I^{RE}} \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} (X_i + X_i^{E}) \Big) \le (1 - \varpi_{d,t}^{\lambda^{RU}}) M^P \qquad \forall d, t \tag{4.87a}$$

$$0 \le \lambda_{d,t}^{RU} \le \varpi_{d,t}^{\lambda^{RU}} M^D \qquad \forall d, t \tag{4.87b}$$

$$0 \le \Big(\sum_{i \in I^{FL}} (g_{i,d,t}^{RD} + g_{i,d,t}^{RD,E}) + d_{d,t}^{RD} - \sum_{i \in I^{RE}} \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} (X_i + X_i^{E}) \Big) \le (1 - \varpi_{d,t}^{\lambda^{RD}}) M^P \qquad \forall d, t \tag{4.87c}$$

$$0 \le \lambda_{d,t}^{RD} \le \varpi_{d,t}^{\lambda^{RD}} M^D \qquad \forall d, t \tag{4.87d}$$

7. The equations showing the linearisation of the complementarity con-

straints of flexible generation technologies using disjunctive integer equivalents

$$0 \leq g^{RU}_{i,d,t} \leq (1 - \varpi^{\mu^{RU}}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88a}$$

$$0 \leq \mu^{RU}_{i,d,t} \leq \varpi^{\mu^{RU}}_{i,d,t} M^D \qquad \forall i \in I^{FL}, d, t \tag{4.88b}$$

$$0 \leq g^{RU,E}_{i,d,t} \leq (1 - \varpi^{\mu^{RU,E}}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88c}$$

$$0 \leq \mu^{RU,E}_{i,d,t} \leq \varpi^{\mu^{RU,E}}_{i,d,t} M^D \qquad \forall i \in I^{FL}, d, t \tag{4.88d}$$

$$0 \leq g^{RD}_{i,d,t} \leq (1 - \varpi^{\vartheta^-}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88e}$$

$$0 \leq \vartheta^-_{i,d,t} \leq \varpi^{\vartheta^-}_{i,d,t} M^D \qquad \forall i \in I^{FL}, d, t \tag{4.88f}$$

$$0 \leq g^{RD,E}_{i,d,t} \leq (1 - \varpi^{\vartheta^{E,-}}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88g}$$

$$0 \leq \vartheta^{E,-}_{i,d,t} \leq \varpi^{\vartheta^{E,-}}_{i,d,t} M^D \qquad \forall i \in I^{FL}, d, t \tag{4.88h}$$

$$0 \leq (g_{i,d,t} - g^{RD}_{i,d,t}) \leq (1 - \varpi^{\vartheta^+}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88i}$$

$$0 \leq \vartheta^+_{i,d,t} \leq \varpi^{\vartheta^+}_{i,d,t} M^D \qquad \forall i \in I^{FL}, d, t \tag{4.88j}$$

$$0 \leq (g_{i,d,t} - g^{RD,E}_{i,d,t}) \leq (1 - \varpi^{\vartheta^{E,+}}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88k}$$

$$0 \leq \vartheta^{E,+}_{i,d,t} \leq \varpi^{\vartheta^{E,+}}_{i,d,t} M^D \qquad \forall i \in I^{FL}, d, t \tag{4.88l}$$

$$0 \leq (X_i - g_{i,d,t} - g^{RU}_{i,d,t}) \leq (1 - \varpi^{\mu^+}_{i,d,t})M^P \qquad \forall i \in I^{FL}, d, t \tag{4.88m}$$

$$0 \leq \mu^{+}_{i,d,t} \leq \varpi^{\mu^{+}}_{i,d,t} M^{D} \qquad \forall i \in I^{FL}, d, t \tag{4.88n}$$

$$0 \leq (X^{E}_{i} - g^{E}_{i,d,t} - g^{RU,E}_{i,d,t}) \leq (1 - \varpi^{\mu^{E,+}}_{i,d,t}) M^{P} \qquad \forall i \in I^{FL}, d, t \tag{4.88o}$$

$$0 \leq \mu^{E,+}_{i,d,t} \leq \varpi^{\mu^{E,+}}_{i,d,t} M^{D} \qquad \forall i \in I^{FL}, d, t \tag{4.88p}$$

8. The equations showing the linearisation of the complementarity constraints of must-run generation technologies using disjunctive integer equivalents:

$$0 \leq (g_{i,d,t} - \Lambda^{MSG} X_{i}) \leq (1 - \varpi^{\xi^{-}}_{i,d,t}) M^{P} \qquad \forall i \in I^{MR}, d, t \tag{4.89a}$$

$$0 \leq \xi^{-}_{i,d,t} \leq \varpi^{\xi^{-}}_{i,d,t} M^{D} \qquad \forall i \in I^{MR}, d, t \tag{4.89b}$$

$$0 \leq (g^{E}_{i,d,t} - \Lambda^{MSG} X^{E}_{i}) \leq (1 - \varpi^{\xi^{E,-}}_{i,d,t}) M^{P} \qquad \forall i \in I^{MR}, d, t \tag{4.89c}$$

$$0 \leq \xi^{E,-}_{i,d,t} \leq \varpi^{\xi^{E,-}}_{i,d,t} M^{D} \qquad \forall i \in I^{MR}, d, t \tag{4.89d}$$

$$0 \leq (X_{i} - g_{i,d,t}) \leq (1 - \varpi^{\xi^{+}}_{i,d,t}) M^{P} \qquad \forall i \in I^{MR}, d, t \tag{4.89e}$$

$$0 \leq \xi^{+}_{i,d,t} \leq \varpi^{\xi^{+}}_{i,d,t} M^{D} \qquad \forall i \in I^{MR}, d, t \tag{4.89f}$$

$$0 \leq (X^{E}_{i} - g^{E}_{i,d,t}) \leq (1 - \varpi^{\xi^{E,+}}_{i,d,t}) M^{P} \qquad \forall i \in I^{MR}, d, t \tag{4.89g}$$

$$0 \leq \xi^{E,+}_{i,d,t} \leq \varpi^{\xi^{E,+}}_{i,d,t} M^{D} \qquad \forall i \in I^{MR}, d, t \tag{4.89h}$$

9. The equations showing the linearisation of the complementarity constraints of renewable generation technologies using disjunctive integer equivalents:

$$0 \leq g_{i,d,t} \leq (1 - \varpi^{\beta^{-}}_{i,d,t}) M^{P} \qquad \forall i \in I^{RE}, d, t \tag{4.90a}$$

$$0 \leq \beta^{-}_{i,d,t} \leq \varpi^{\beta^{-}}_{i,d,t} M^{D} \qquad \forall i \in I^{RE}, d, t \tag{4.90b}$$

$$0 \leq g^{E}_{i,d,t} \leq (1 - \varpi^{\beta^{E,-}}_{i,d,t}) M^{P} \qquad \forall i \in I^{RE}, d, t \tag{4.90c}$$

$$0 \leq \beta^{E,-}_{i,d,t} \leq \varpi^{\beta^{E,-}}_{i,d,t} M^{D} \qquad \forall i \in I^{RE}, d, t \tag{4.90d}$$

$$0 \leq (k^{W}_{d,t} X_{i} - g_{i,d,t}) \leq (1 - \varpi^{\beta^{+}}_{i,d,t}) M^{P} \qquad \forall i \in I^{RE}, d, t \tag{4.90e}$$

$$0 \leq \beta^{+}_{i,d,t} \leq \varpi^{\beta^{+}}_{i,d,t} M^{D} \qquad \forall i \in I^{RE}, d, t \tag{4.90f}$$

$$0 \leq (k^{W}_{d,t} X^{E}_{i} - g^{E}_{i,d,t}) \leq (1 - \varpi^{\beta^{E,+}}_{i,d,t}) M^{P} \qquad \forall i \in I^{RE}, d, t \tag{4.90g}$$

$$0 \leq \beta^{E,+}_{i,d,t} \leq \varpi^{\beta^{E,+}}_{i,d,t} M^D \qquad \forall i \in I^{RE}, d, t \quad (4.90h)$$

10. The equations showing the linearisation of the complementarity constraints associated with the demand side flexibility using disjunctive integer equivalents:

$$0 \leq (d^{sh}_{d,t} + \alpha D^{BA}_{d,t}) \leq (1 - \varpi^{\pi^-}_{d,t}) M^P \qquad \forall d, t \quad (4.91a)$$

$$0 \leq \pi^-_{d,t} \leq \varpi^{\pi^-}_{d,t} M^D \qquad \forall d, t \quad (4.91b)$$

$$0 \leq (\alpha D^{BA}_{d,t} - d^{sh}_{d,t}) \leq (1 - \varpi^{\pi^+}_{d,t}) M^P \qquad \forall d, t \quad (4.91c)$$

$$0 \leq \pi^+_{d,t} \leq \varpi^{\pi^+}_{d,t} M^D \qquad \forall d, t \quad (4.91d)$$

$$0 \leq d^{RU}_{d,t} \leq (1 - \varpi^{\zeta^{RU}}_{d,t}) M^P \qquad \forall d, t \quad (4.91e)$$

$$0 \leq \zeta^{RU}_{d,t} \leq \varpi^{\zeta^{RU}}_{d,t} M^D \qquad \forall d, t \quad (4.91f)$$

$$0 \leq d^{RD}_{d,t} \leq (1 - \varpi^{\zeta^{RD}}_{d,t}) M^P \qquad \forall d, t \quad (4.91g)$$

$$0 \leq \zeta^{RD}_{d,t} \leq \varpi^{\zeta^{RD}}_{d,t} M^D \qquad \forall d, t \quad (4.91h)$$

$$0 \leq (d^{sh}_{d,t} + \alpha D^{BA}_{d,t} - d^{RD}_{d,t}) \leq (1 - \varpi^{\nu^{RD}}_{d,t}) M^P \qquad \forall d, t \quad (4.91i)$$

$$0 \leq \nu^{RD}_{d,t} \leq \varpi^{\nu^{RD}}_{d,t} M^D \qquad \forall d, t \quad (4.91j)$$

$$0 \leq (\alpha D^{BA}_{d,t} - d^{sh}_{d,t} - d^{RU}_{d,t}) \leq (1 - \varpi^{\nu^{RU}}_{d,t}) M^P \qquad \forall d, t \quad (4.91k)$$

$$0 \leq \nu^{RU}_{d,t}) \leq \varpi^{\nu^{RU}}_{d,t} M^D \qquad \forall d, t \quad (4.91l)$$

The terms M^P and M^D are large enough positive constraints. While all the terms denoted as ϖ^{**}_{***} are binary variables.

4.7 Case Studies

The impact of the demand side flexibility on the evolution of generation investments in future low-carbon power systems is analysed through a set of case studies. The various set of studies analyses using different perspectives, the impact of demand flexibility on generation investment evolution.

First, the impact of demand flexibility on generation investment decision is analysed using the perspective of a centralised planner who is interested in minimising the total operation and investment costs (mathematical formulation is presented in Appendix A). Next, the impact of demand flexibility on generation investment decision is analysed using the market-based planning model presented in section 4.6 above. Within each set of case studies, the differences in investment decisions by the self-interested generation company and the regulated utility are analysed.

The technology options considered available to the investing generation company include wind (renewable generation), nuclear (must-run generation), combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) - both considered as flexible generation technologies. Although wind technology is the only renewable technology considered as an investment option, the model developed in this chapter can also support the consideration of other renewable technologies (e.g solar) as technology options for investment.

The assumed values of the investment and operating costs of these technologies are presented in Table 4.1. Four typical days representing the four seasons of the year are used, the respective profiles for the baseline demand and the normalised output of wind generation technology are obtained from [104]. The remaining parameters used in the case studies are summarised in Table 4.2.

Table 4.1: Investment and Operating Costs of Generation Technologies

Technology	Wind	Nuclear	CCGT	OCGT
Type	Renewable	Must-run	Flexible	Flexible
Existing Capacity X_i^E (MW)	17600	9200	17500	17500
Investment Cost IC_i (£/MW/year)	93140	328210	52120	26460
Energy Cost C_i^G (£/MWh)	0	4.72	37.68	56.98
Reserve Cost $C_i^{rdn} = C_i^{rup}$ (£/MWh)	-	-	9.42	14.245

Table 4.2: General Parameters

Parameter	Value
Weighting Factor of winter day wf_{winter}	119
Weighting Factor of spring day wf_{spring}	64
Weighting Factor of summer day wf_{summer}	91
Weighting Factor of autumn day wf_{autumn}	91
System Adequacy Coefficient Υ	1.01
Standard deviation of wind generation output Δ_i^{RE}	3.5
Forecasting error of wind generation output ε_i^{RE}	7%

4.7.1 Case Study Definition

Three different cases regarding the level (α) and participation of the flexibility of the demand side in the energy and reserves market are examined. The cases are:

Base Case: The demand side does not exhibit any flexibility ($\alpha = 0\%$).

Case 1: The available demand side flexibility participates only in the energy market (providing inter-temporal energy redistribution only), and

Case 2: The available demand side flexibility participates in both energy and reserve markets and can be used in providing both inter-temporal energy redistribution and reserves.

The optimal generation investment decisions under each of the three cases listed above (base case, case 1 and case 2) have been determined using both the centralised planning approach – inherited from the era of vertically integrated electricity utilities – and the market-based planning approach – appropriate for the current deregulated market environment.

One major strength of the market-based planning approach is its ability to support the analysis of the impact of different market designs on generation investment decisions. In many US and European electricity markets, the reserve costs is allocated to the demand-side, however, due to the increasing penetration of intermittent renewable-based generation, electricity markets are beginning to allocate the reserve costs to the responsible renewable generation company. In this work, the impacts of reserve costs allocation as a market design is explored. To do this, the proposed market-based planning model has been applied in two scenarios regarding this allocation:

i) a scenario where the payment of reserve costs are entirely allocated to renewable generation ($\Gamma = 100\%$) and

ii) a scenario where the payment of reserve costs are entirely allocated to the demand side ($\Gamma = 0\%$).

4.7.2 Impact of Demand Flexibility on System Demand Profile in the Cases Considered

The participation of demand flexibility in different markets affects uniquely, the system demand profile. For the three cases examined, the system demand profile (obtained using the centralised planning model) corresponding to one of the representative days considered is presented in fig. 4.1 below.

In this figure, the demand variability between the peak and off-peak time period is most conspicuous in the base case that is, the peak demand is highest, and the off-peak demand is lowest. In case 1, where the available demand flexibility participates only in the energy market, the demand is reduced in the peak hours and increased in the off-peak hours thereby yielding a flatter system demand profile. Given the energy neutrality constraint, both demand reduction in the peak periods and demand increase in the off-peak periods are equal.

However, with the participation of demand flexibility in both energy and reserves markets (Case 2), its flattening effect on the system demand profile is reduced – the system demand is higher in the peak hours and lower in the off-peak hours – in comparison to case 1. This is because a portion of the available demand flexibility capacity is scheduled for reserves provision as the reserve costs of flexible demand are (zero and therefore) lower than the respective reserve costs of flexible CCGT and OCGT generation. To summarise, the participation of demand flexibility in reserves provision reduces its use for inter-temporal energy arbitrage as shown in fig. 4.2.

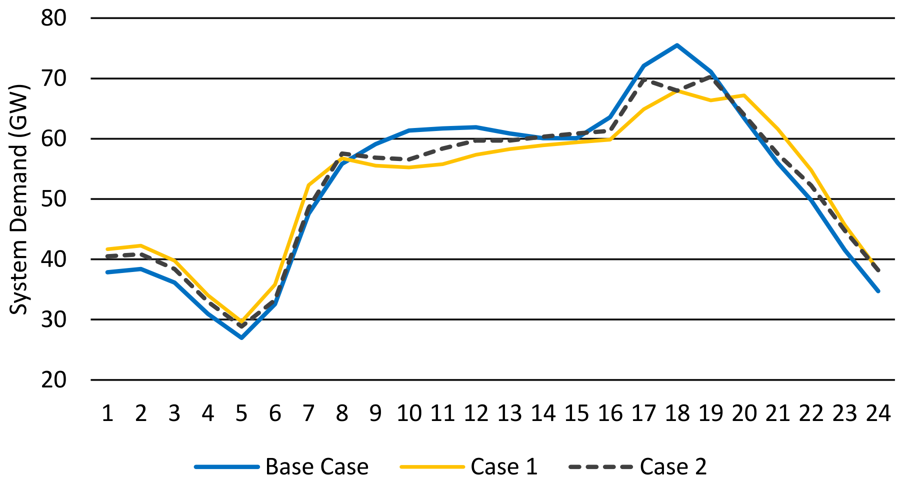

Figure 4.1: System Demand Profile for the different Demand Flexibility Cases under Centralised Planning

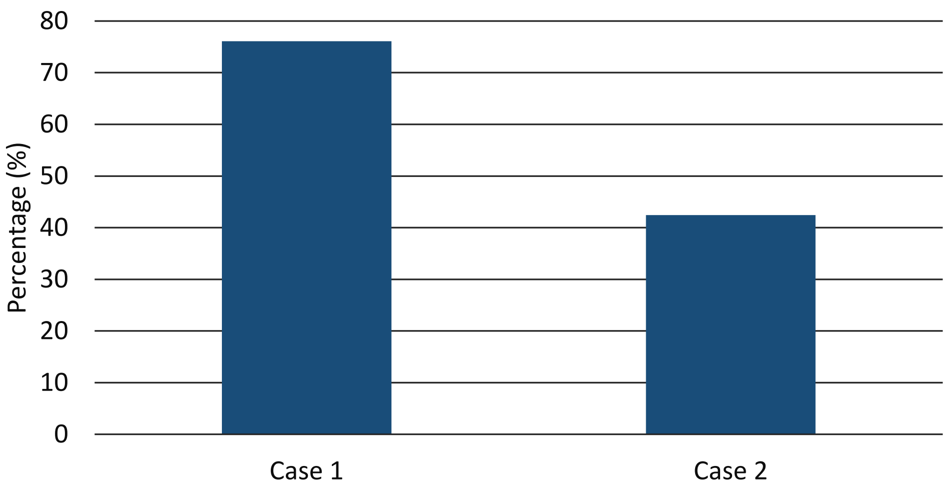

Figure 4.2: Energy Arbitrage Utilisation of Demand Flexibility for the respective cases under Centralised Planning

Although the graphs presented above are those obtained under the centralised planning model, the impact of demand flexibility on system demand profile and energy arbitrage utilisation in case 1 and case 2 under market-based planning are similar to those observed here. Therefore, additional graphs showing these under the market-based planning model are not presented here.

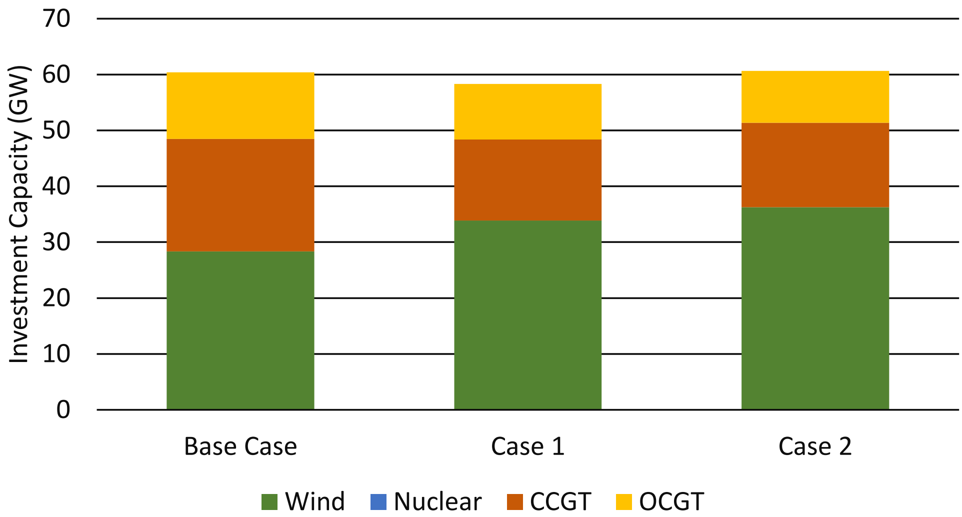

Figure 4.3: Investment Decision under Centralised Planning for the different Demand Flexibility Cases

4.7.3 Impact of Demand Flexibility on Generation Investment under Centralised Planning

This section analyses the impact of demand flexibility on the investment decisions made under the traditional centralised approach. Figure 4.3 presents the optimal investment decisions for the three cases examined regarding the flexibility of the demand side. Across all three cases, there is a substantial investment in wind generation with zero production cost – this helps to lower the operating costs of the central planner. The central planner also invests significantly in flexible CCGT and OCGT technologies which can provide the reserve requirements induced by the substantial wind investment. The very high investment cost of nuclear technology makes it a non-competitive cost option for the central planner, therefore, though wind investment increases the reserve requirement, it remains a preferred option over the nuclear technology in covering the baseload of the system.

In case 1, where the available demand flexibility participates only in the energy market, the increased demand in the off-peak hours (fig. 4.1) enhances the cost efficiency of wind generation and prompts an increase in the investment in wind generation with respect to the base case. On the other hand, given the reduction in the peak demand and the flattening of the demand profile, the investment in flexible CCGT and OCGT technologies is reduced compared to the base case.

Although the off-peak demand reduces in case 2 where the available demand flexibility participates in both the energy and reserves market, the investment in wind generation is further increased compared to case 1. This is owing to the fact that the total reserve costs is reduced as demand flexibility can provide reserves at zero cost. In contrast, the investment in flexible technologies is reduced with respect to the base case.

4.7.4 Impact of Demand Flexibility on Generation Investment under Market Based Planning

The focus of this section is to analyse the impact of demand flexibility on generation investment under the market-based planning framework. This approach is suited for the liberalised electricity system which currently operates in different countries across the world.

As mentioned in section 4.7.1, two market designs regarding the allocation of the system cost for reserves have been considered:

i) A scenario where the reserve costs are entirely allocated to responsible renewable generation ($\Gamma = 100\%$). This market design follows the philosophy that the system cost of providing reserves should be paid for by the responsible market agent based on their contribution to the need for reserves,

ii) A scenario where the reserve costs are entirely allocated to the demand side ($\Gamma = 0\%$). This market design follows the philosophy that the system cost of providing reserves should be paid for by the least responsive market participant.

Reserve Costs entirely allocated to Renewable Generation ($\Gamma = 100\%$)

The first analysis considers the market design scenario ($\Gamma = 100\%$) where the renewable generation fully pays for the entire system cost required to provide the reserves. This market design is considered because one of the model assumptions highlighted in section 4.2 is that the reserve requirements are entirely driven by the forecast errors of renewable generation.

The investment decisions are presented in fig. 4.4 below. In comparison to the investment decisions of the regulated utility under the centralised planning approach (fig. 4.3), the generation investment decisions by the strategic generation company involve a significantly lower wind capacity investment as well as a substantial investment in nuclear generation under all demand flexibility cases considered.

The wind capacity investment of the self-interested generation company is lower in this scenario because of the negative impacts which a higher wind investment capacity will have on its overall long-term profit. The negative profit impacts are due to a combination of the following factors:

i) A higher wind generation capacity increases the amount of energy produced by zero-cost wind generation and therefore reduces the energy prices which affects negatively the profit of the self-interested generation company. For this reason, this company acts strategically through a minimal investment in wind generation thereby maintaining the energy prices and thus its profits at higher levels. Furthermore, it should be noted that although a higher wind generation capacity increases the amount of required reserves in the system and subsequently the reserve prices; the reserve prices and revenues have a significantly lower impact on the company's total profit than the energy prices and revenues as will be shown later.

ii) In this specific scenario, since the incurred reserve costs are allocated to wind generation and the reserves size is proportionally dependent on the amount of wind generation in the system (section 4.2), the

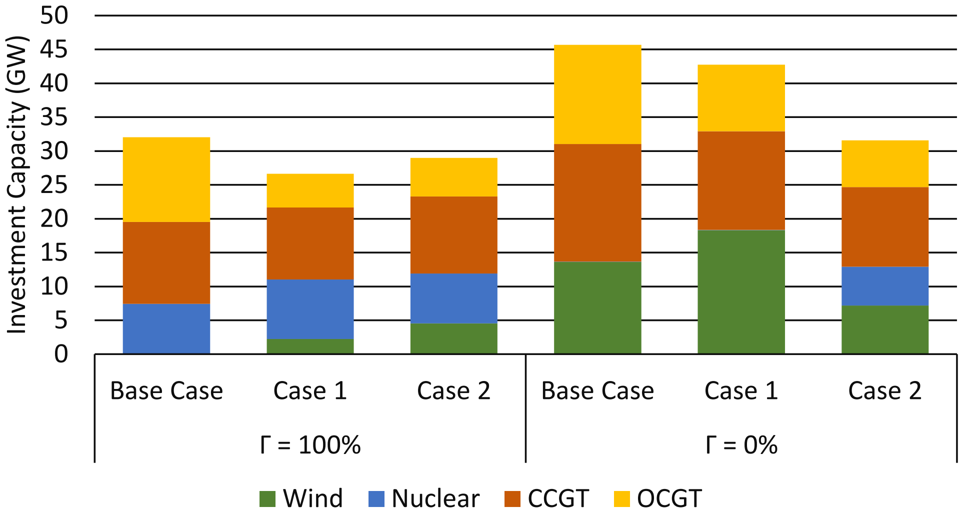

Figure 4.4: Optimal Investment Decision under Market-Based Planning for the different Demand Flexibility Cases and different Reserve Cost Allocation Scenarios

self-interested generation company engages in minimal investment in wind generation and subsequently minimises its reserve costs incurred.

Following this reduced investment in wind generation compared to centralized planning, the reserve requirements are reduced and therefore investments in flexible CCGT and OCGT generation are also reduced (fig. 4.4).

In case 1, in a similar fashion to what obtains under the centralised planning model, energy arbitrage of demand flexibility enhances demand level in the off-peak hours. As a result, the self-interested generation company increases investment in wind and nuclear generation to provide the increased baseload demand and maximise energy profits in the off-peak hours. On the other hand, investment in flexible CCGT and OCGT capacity are reduced since the peak demand levels are reduced.

With the participation of demand flexibility in the reserves market in case 2, the zero-cost reserve provision of the demand side reduces the overall reserve costs and subsequently the reserve costs incurred by the strategic generation company for its wind generation. This reduction implies that the self-interested generation company can increase its investment in wind generation without a corresponding increase in its reserve costs incurred. In this specific study, it can be observed, (Table 4.3), that despite the increased investment in case 2, the reserve costs incurred by the self-interested generation company is 63% lower than in case 1 where the entire reserve requirement is provided by conventional generators.

Following the increased investment in wind generation and reduced energy demand in off-peak hours, in a similar fashion to fig. 4.1, the self-interested generation company reduces its investment in must-run nuclear generation which has a high investment cost. The self-interested generation company also increases slightly its investment in CCGT and OCGT generation compared to case 1, however this is still lower than what obtains under the base case.

Table 4.3 presents the long-term profit of the generation company along with its various components for each demand flexibility case. Although the total investment cost incurred by the generation company is higher in case 1, its total profit increases with respect to the base case. The reason is that both the increased energy production from zero-cost wind and low-cost nuclear generation to provide the increased off-peak demand as well as the increased energy prices in the off-peak hours combine to enhance the energy revenues of wind and nuclear generation.

Table 4.3: Long Term Profit of Examined Generation Company under different Demand Flexibility Cases and different Reserve Cost Allocation Scenarios (in billion £)

	$\Gamma = 100\%$			$\Gamma = 0\%$		
	Base Case	Case 1	Case 2	Base Case	Case 1	Case 2
Energy Profit	4.042	4.950	4.702	3.355	4.017	4.473
Reserve Profit	0	0.002	0	0.0125	0.013	0
Reserve Cost	0	0.033	0.012	0	0	0
Investment cost	3.396	3.778	3.585	2.569	2.738	3.353
Total Profit	0.646	1.142	1.104	0.799	1.292	1.121

In case 2, the total profit of the self-interested generation company is lower than in case 1, this is despite the reduction in both the investment cost (driven by the reduced investment in nuclear generation) and reserves costs (driven by the zero-cost reserve provision by the demand side). The reason for the decrease in total profit is the reduction in energy arbitrage and the reduced off-peak prices which translates to a reduction in the energy revenue and profits.

Reserve Costs entirely allocated to the demand side ($\Gamma = 0\%$)
The second analysis considers the scenario $\Gamma = 0\%$ where the reserve costs is entirely allocated to the demand side.

In view of the fact that the generation company does not incur additional costs due to reserve, its investment in wind capacity is higher in all the three cases considered with respect to the scenario $\Gamma = 100\%$ as shown in fig. 4.4. Consequently, its investment in nuclear generation, with a very high investment cost, is zero in the base case and case 1 and is lower in case 2. Furthermore, the investment in flexible CCGT and OCGT generation is increased as these technologies are needed to provide the necessary reserve requirements.

However, to maintain high energy prices and profitability for the investing generation company, its wind capacity investment remains lower than the respective investment levels under the centralized planning (fig 4.3).

In case 1, energy arbitrage, resulting from the participation of demand flexibility in energy markets increases the off-peak demand and this increases the baseload generation that the system can absorb. To provide this increased baseload generation, the self-interested generation company increases its investment in wind technology with respect to the base case. Its investment in CCGT and OCGT is however reduced because of the reduction in peak demand levels.

In contrast to the investment trends observed under both the centralised planning and the market-based planning with $\Gamma = 100\%$, the self-interested generation company reduces its investment in wind generation in case 2 where demand flexibility participates in the reserves market. The following factors combine to give this observed result:

- The zero-cost reserves provision of the demand-side makes the generation technologies to be less competitive in the reserves market. This is because the the system reserve cost is fully paid by the demand side, therefore reserves provision by demand flexibility does not enhance the profitability of the self-interested generation company.

- As discussed earlier, the energy arbitrage leads to an increase in off-peak energy market prices, but the use of demand flexibility for reserves provision limits it use for energy arbitrage (fig. 4.2).

For these reasons, the self-interested generation company acts strategically by reducing its investment in wind which effectively reduces the overall system reserves requirement and thereby facilitates use of demand flexibility for energy arbitrage for the purpose of increasing off-peak energy market prices.

Following this reduction in wind investment, the self-interested generation company invests in nuclear technology as it can make more revenue and profit in the energy market compared with CCGT and OCGT technologies in which the self-interested generation company reduces its investment.

In this scenario, as shown in Table 3.4, the impact of demand flexibility on the long-term profit of the generation company is similar to its impact in the scenario with $\Gamma = 100\%$. Specifically, the total profit is increased in case 1 with respect to the base case. Similarly, in case 2, the total profit of the generation company is reduced compared to case 1. This reduction of total profit is driven primarily by the increase in the investment cost due to the strategic investment in nuclear generation, which has been discussed above.

The magnitude of the total long-term profit of the generation company are higher in this scenario ($\Gamma = 0\%$) than in the earlier scenario discussed ($\Gamma = 100\%$). This is caused by the higher total investment cost incurred by the generation company under $\Gamma = 100\%$ which is attributable to the higher investment in nuclear generation.

4.8 Impact of increasing Demand Flexibility Capacity under different Market Designs

In this section, additional studies with demand flexibility levels at $\alpha = 20\%, 30\%$ are carried out under both market design options considered ($\Gamma = 0\%$ and $\Gamma = 100\%$). The increased demand flexibility level increases its capacity to participate in the markets (energy only markets in case 1 and energy and reserves market in case 2).

The first analysis considers the results obtained under the $\Gamma = 100\%$ market design. Fig. 4.6 presents the optimal investment decision of the generation company. This figure shows that irrespective of the specific market in which demand flexibility participates (energy only market in case 1, energy and reserves market in case 2), the generation company increases its investment in wind generation as the demand flexibility level α increases.

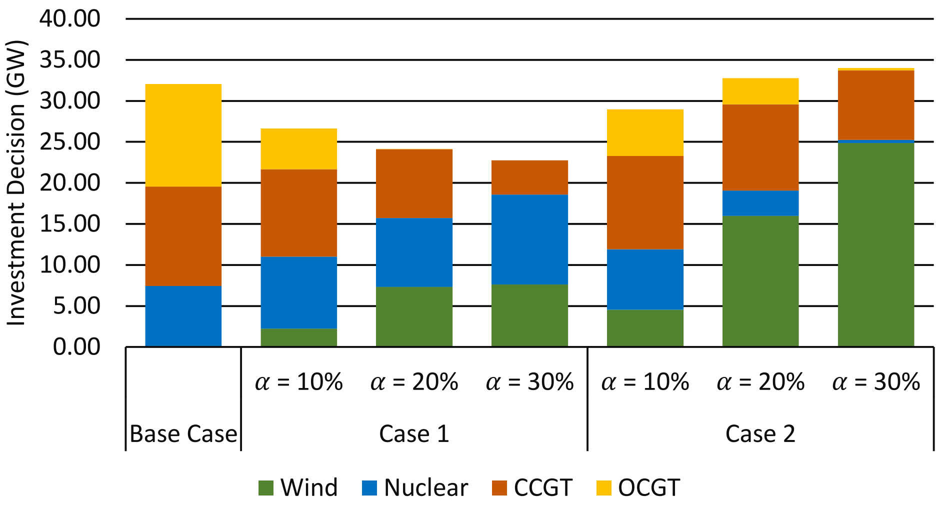

Figure 4.5: Optimal Investment Decision at different Demand Flexibility Levels under $\Gamma = 100\%$ Market Design

In case 1, the increase in off-peak demand resulting from increased energy shifting capacity of demand flexibility requires a higher baseload generation. Since the generation company incurs the system reserve costs, its investment in wind generation increases slightly; for this reason, investment in nuclear generation is sustained at high levels by the generation company. On the other hand, due to the reduction in peak demand levels, the investment in CCGT and OCGT generation is reduced.

In case 2 where demand flexibility also participates in the reserve market, similar to case 1 but with a higher magnitude, the self-interested generation company increases its wind capacity investment. Its investment in nuclear capacity is however reduced because of the substantial increase in wind as well as the limited flexibility and high investment cost of nuclear. Conversely, investment in CCGT and OCGT technologies are reduced because of the reduction in peak demand level.

Comparing both cases, the magnitude of increase in wind investment is higher in case 2 as the self-interested generation company can substantially increase its wind investment without incurring a corresponding substantial increase in reserves costs. On the other hand, the lower increase in wind investment under case 1 is attributable to its higher impact on the amount of system reserve costs incurred since the required reserves are solely provided by generators in this case. The values of the reserve cost as well as other terms which combine to give the long term profits are presented in Table 4.4.

The increased investment in wind and the high investment in nuclear generation capacity by the generation company culminates in an enhancement of the energy profits as the demand flexibility capacity increases. For this reason, the total profits of the generation company are increased despite the increase in investment costs incurred. In contrast, the energy profits of the generation company are reduced in case 2 as demand flexibility increases, because of the reduced investment in nuclear which can make a higher profit in the markets than the flexible CCGT and OCGT capacity. Despite the reduction in energy profits, the total profit is increased because of the reduction in the investment costs.

Table 4.4: Long Term Profit of Examined Generation Company at different Demand Flexibility Levels considering different Reserve Cost Allocation Scenarios (in billion £) under the $\Gamma = 100\%$ Market Design

	Base Case	Case 1			Case 2		
	$\alpha = 0\%$	$\alpha = 10\%$	$\alpha = 20\%$	$\alpha = 30\%$	$\alpha = 10\%$	$\alpha = 20\%$	$\alpha = 30\%$
Energy Profit	4.042	4.950	5.404	6.093	4.702	4.661	4.616
Reserve Profit	0	0.0023	0	0.0015	0	0	0
Reserve Cost	0	0.033	0.109	0.114	0.012	0.038	0.056
Investment Cost	3.396	3.778	3.878	4.527	3.585	3.137	2.893
Total Profit	0.646	1.142	1.417	1.454	1.104	1.486	1.666

The second analysis considers the results under the $\Gamma = 0\%$ market design option. The optimal investment decision of the generation company is presented in fig 4.6.

Similar to the investment decisions under the $\Gamma = 100\%$ market design, the self-interested generation company increases its investment in the wind generation compared to the base case with no demand flexibility $\alpha = 0\%$. The wind capacity investment is however higher under this market design because all reserve costs is allocated to the demand side. In a similar way, the investment in CCGT and OCGT generation is reduced because of the reduced peak demand levels.

Despite the similarities which increasing the demand flexibility has on the investment decisions of the self-interested generation company, its impact on the different profit component terms are not always similar. This can be seen in Table 4.5 which shows the different profit component terms. While the increasing participation of demand flexibility in the market leads to a progressive reduction in the energy profit under the $\Gamma = 100\%$ market design, this energy profits increase under the $\Gamma = 0\%$ market design. Although the total profit of the generation company increases in both market design.

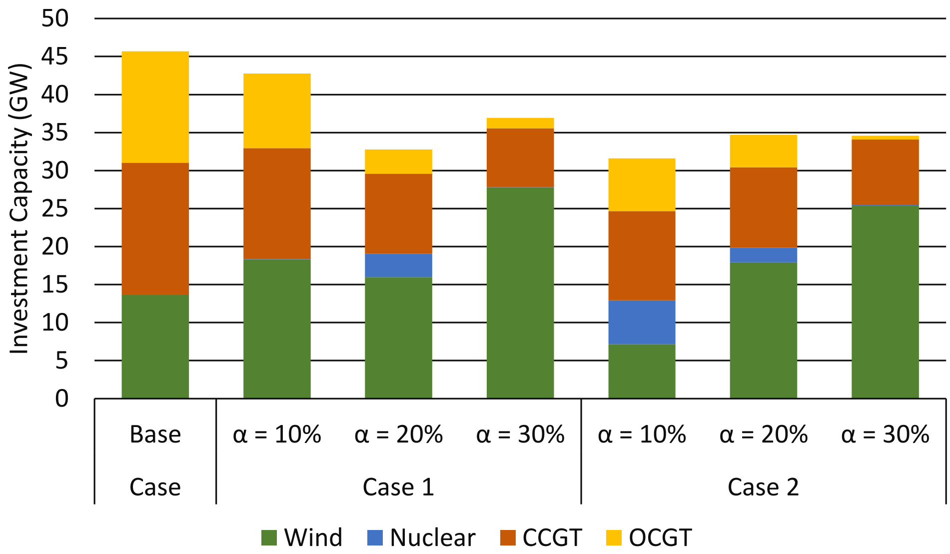

Figure 4.6: Optimal Investment Decision at different Demand Flexibility Levels under $\Gamma = 0\%$ Market Design

Table 4.5: Long Term Profit of Examined Generation Company at different Demand Flexibility Levels considering different Reserve Cost Allocation Scenarios (in billion £) under the $\Gamma = 0\%$ Market Design

	Base Case	Case 1			Case 2		
	$\alpha = 0\%$	$\alpha = 10\%$	$\alpha = 20\%$	$\alpha = 30\%$	$\alpha = 10\%$	$\alpha = 20\%$	$\alpha = 30\%$
Energy Profit	3.355	4.017	4.716	4.856	4.473	4.480	4.569
Reserve Profit	0.0125	0.0133	0	0.001	0	0	0
Reserve Cost	0	0	0	0	0	0	0
Investment Cost	2.569	2.738	3.137	3.043	3.353	2.960	2.846
Total Profit	0.799	1.292	1.578	1.814	1.121	1.520	1.724

4.9 Conclusion

This chapter investigates the impact of demand flexibility on the generation investment decisions.

The generation investment decisions under two different planning approaches – the traditional least-cost centralised planning approach and the profit maximizing market-based planning approach representative of the current deregulated environment – are compared. In both approaches, different case studies regarding the participation of the demand flexibility in the market are carried out: demand side exhibits no flexibility (base case), demand flexibility participates only in the energy market (case 1) and an additional case where the demand flexibility participates in both the energy and reserves market (case 2). For the market-based planning approach, the impact of reserve costs allocation as a market design is also considered.

The following conclusions are made from the results presented in this chapter:

1. The traditional centralised planning approach is unable to support the assessment of the impact of market design options on the investment decisions since it focuses on obtaining the least cost investment mix.

2. The investment decisions under the traditional least cost centralised planning approach are not aligned with those obtained under the market-based planning approach. This is because the centralised planning approach overestimates the investment in renewable generation and assumes that this renewable generation investment is always increased as a result of both the energy shifting and reserve provision capabilities of the demand side.

3. The results obtained demonstrate that both the generation investment decisions made by the self-interested generation companies and the related impacts of demand flexibility on same are dependent on the electricity market design considered.

4. The participation of demand flexibility in the market(s) enhances the total profit of the self-interested generation company with respect to the base case (with no demand flexibility) given its impact on increasing the investment, dispatch and subsequently the revenues earned from baseload wind and nuclear generation.

5. The effects of increasing the demand flexibility level on the investment mix of the generation company is similar under both market design options considered. Specifically, the investment in wind generation is increased while the investment in flexible CCGT and OCGT generation reduces. However the magnitude of these investment levels differ in both market designs.

A future that is certain, you prepare for it.
— Yoruba Proverb

Chapter 5

Impact of Demand Flexibility under different Carbon Limits

5.1 Introduction

Due to the high carbon intensity of the electricity sector, its decarbonisation to significantly lower carbon emission levels is considered to be an important step towards mitigating the worst impacts of climate change. This decarbonisation agenda has driven the integration of renewable-based power generation.

Previous studies [4, 5, 10] have identified the important role of demand side flexibility in improving the economic efficiency of low-carbon electricity systems. However, these studies only assess the short-run value of demand flexibility and ignore the long-run capacity expansion decisions.

In this chapter, the impact of demand flexibility on the optimal generation investment decisions is analysed considering stringent CO_2 emissions targets. The influence of the market participation for demand flexibility as well as market design with respect to reserve cost allocation on these investment decisions is analysed carefully and discussed.

To achieve this aim, the bi-level model presented in chapter 4 is extended to include yearly carbon emission constraint. The developed bi-level model is solved after conversion into a MPEC and finally a MILP optimisation problem.

The assumptions for the model used in this chapter is presented in the next section.

5.2 Modelling Assumptions

The model presented in this chapter makes use of a number of assumptions. This is summarised below:

1. The model expresses the investment planning problem faced by a self-interested generation investment company operating in a competitive market framework. This company aims to maximise its long-term yearly profits by optimising its generation investment decisions.

2. The model assumes a static planning approach and a yearly operation horizon. This means that the examined generation company optimises its investment decisions considering a future target year. The yearly operation horizon is divided into a number of representative days.

3. Carbon emission limits are imposed at 50 gCO2/kWh and 100 gCO2/kWh.

4. The examined generation company can invest in generation capacity of different conventional and renewable technologies, which are characterised by different investment costs, operating costs, and operating constraints.

5. There exists in the system, generation capacity of different conventional and renewable technologies, but this does not belong to the examined generation company.

6. The presence and impact of the network or network congestion has not been considered in this model. Network-related constraints have not been included in the model. This assumption is very valid in a

well-meshed electricity network where there are no price differentials in the network.

7. An out-of-market adequacy constraint is imposed on the investment planning problem by the regulator, to ensure that the total firm generation capacity in the system is sufficiently higher (as determined by an adequacy coefficient Υ) than the peak demand and therefore security of supply requirements are satisfied.

8. The considered electricity market is a pool-based, joint energy and reserve market with a day-ahead horizon and hourly resolution. This market is cleared by the market operator through the solution of a short-term cost minimisation problem.

9. The upward and downward reserve requirements are assumed to be entirely dependent on the forecasting errors of renewable generation, thereby neglecting similar forecasting errors due to demand and generation plant outages.

10. The reserve costs are assumed to be paid (at the reserve clearing prices) by renewable generation technologies and / or the demand side. The total percentage paid by renewable generation technologies is determined by the market design parameter Γ.

11. Both the examined generation company as well as the rest of the generation companies (owning the existing generation capacity) are assumed to submit to the electricity market operator the actual production costs of each generation technology, i.e. strategic bidding is not considered.

12. A subset of the considered generation technologies is assumed "must-run" i.e. they must be operating at near full capacity during all times and they cannot provide reserves.

13. Another subset of the considered generation technologies includes renewable technologies, which are assumed to exhibit zero production

costs, their output can be curtailed if required, and they cannot provide reserves.

14. Another subset of the considered generation technologies are flexible technologies. These generation technologies can provide both energy and reserves.

15. The demand side exhibits flexibility which can be used for energy arbitrage as well as reserves provision thereby participating in both energy and reserves markets.

16. A generic, technology-agnostic model is employed for the representation of the time-shifting flexibility of the demand side.

17. The demand flexibility limit is considered to have the same proportion in each hour of the day. This can also be modelled using time-varying parameter, however, for ease of analysis, this approach is not used.

18. It is assumed that deployment of this flexibility does not compromise the satisfaction and comfort of the consumers and is offered to the market operator at zero cost.

5.3 Multi-period Bi-level Optimisation Model

The mathematical formulation of the multi-period bi-level optimisation model used in this chapter is presented below. As mentioned earlier, the carbon constraint (5.6) is added to UL problem of the bi-level model of chapter 4. The UL problem is presented below.

5.3.1 Upper Level Problem

$$\underset{X_i}{Max} \sum_{d} wf_d \Bigg\{ \sum_{i,d,t} \left(\lambda_{d,t} - C_i^G\right) g_{i,d,t} + \sum_{i \in I^{FL},t} \left(\lambda_{d,t}^{RD} - C_i^{RD}\right) g_{i,d,t}^{RD} +$$

$$\sum_{i \in I^{FL},t} \Big(\lambda_{d,t}^{RU} - C_i^{RU}\Big) g_{i,d,t}^{RU} - \Gamma\bigg(\sum_{i \in I^{RE},t} (\lambda_{d,t}^{RU} + \lambda_{d,t}^{RD}) \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} X_i \bigg) \Bigg\}$$
$$- \sum_i IC_i X_i \tag{5.1}$$

subject to

$$0 \leq X_i \qquad \forall i \tag{5.2}$$

$$\sum_{i \notin I^{RE}} (X_i + X_i^E) \geq \Upsilon(1-\alpha) D_{d,t}^{BA} \qquad \forall d,t \tag{5.3}$$

$$\sum_{d,t} wf_d g_{i,d,t} \geq \Psi \sum_d wf_d X_i \qquad \forall i \in I^{MR} \tag{5.4}$$

$$\sum_{d,t} wf_d g_{i,d,t}^E \geq \Psi \sum_d wf_d X_i^E \qquad \forall i \in I^{MR} \tag{5.5}$$

$$\sum_d wf_d \bigg(\sum_{i,t} E_i^{CO} (g_{i,d,t} + g_{i,d,t}^E) \bigg) \leq SEI \sum_d wf_d \bigg(\sum_{i,t} (g_{i,d,t} + g_{i,d,t}^E) \bigg) \tag{5.6}$$

$$(5.7) - (5.26)$$

The objective function (5.1) of the UL problem maximises the profit of the self-interested generation company across the yearly horizon. This is given by the difference between its combined operational profit and the investment costs. The combined operational profit includes adding the profit in the energy market (first term) and reserves market (second and third term) subtracting the proportion of the reserve costs paid by renewable generation technology (fourth term). This operational profit is multiplied with the weighting factor for each representative day to obtain the annual value. The investment cost for procuring generation capacity is given in the fifth term.

This problem is subject to the positivity limits of the investment decisions (5.2), the adequacy constraints (5.3), which are imposed by the regulator to ensure that consumers' security of supply requirements are preserved. Constraints (5.4) and (5.5) define respectively the minimum yearly load factor for the must-run generation technologies belonging to the investing generation companies and other rival generation companies. Constraint (5.6) represents the yearly carbon emissions limit.

The UL problem is also subject to the LL problem defined by the equations (5.7) – (5.26).

5.3.2 Lower Level Problem

The lower level problem depicts the day-ahead market clearing process. The pool-based joint energy and reserves market is cleared through the solution of a short-term operating cost minimisation problem (5.7). The lower level problem of this bi-level model is the same with that of the bi-level model presented in chapter 4. For model completeness, the lower level problem is reproduced below.

$$\underset{V^{LL}}{Min}\left\{ \sum_{i,d,t} C_i^G(g_{i,d,t} + g_{i,d,t}^E) + \sum_{i\in I^{FL},d,t} \Big(C_i^{RD}(g_{i,d,t}^{RD} + g_{i,d,t}^{RD,E}) + C_i^{RU}(g_{i,d,t}^{RU} + g_{i,d,t}^{RU,E}) \Big) \right\} \tag{5.7}$$

The lower level objective function is subject to different sets of constraints which are detailed below.

i) System-wide constraints:

$$D_{d,t}^{BA} + d_{d,t}^{sh} - \sum_i (g_{i,d,t} + g_{i,d,t}^E) = 0 \qquad : \lambda_{d,t} \qquad \forall d,t \tag{5.8}$$

$$\sum_{i\in I^{FL}} (g_{i,d,t}^{RU} + g_{i,d,t}^{RU,E}) + d_{d,t}^{RU} \geq \sum_{i\in I^{RE}} \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE}(X_i + X_i^E) \qquad : \lambda_{d,t}^{RU} \qquad \forall d,t \tag{5.9}$$

$$\sum_{i\in I^{FL}} (g_{i,d,t}^{RD} + g_{i,d,t}^{RD,E}) + d_{d,t}^{RD} \geq \sum_{i\in I^{RE}} \Delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE}(X_i + X_i^E) \qquad : \lambda_{d,t}^{RD} \qquad \forall d,t \tag{5.10}$$

The system-wide constraints impose restrictions over several components of the power system. These constraints include: the demand-supply energy balance constraints (5.8), the dual variable of this constraint gives the energy clearing price; and the upward and downward reserve constraints (5.9) and (5.10), the dual variables of which constitute the upward and downward reserve clearing prices respectively. The demand-supply energy balance constraint ensures that the total generation from all technologies is sufficient to meet the hourly demand accounting for the effect of energy shifting and recovery.

ii) Operating constraints of flexible generation technologies:

$$0 \leq g_{i,d,t}^{RU} \qquad : \mu_{i,d,t}^{RU} \qquad \forall i \in I^{FL}, d, t \tag{5.11}$$
$$0 \leq g_{i,d,t}^{RU,E} \qquad : \mu_{i,d,t}^{RU,E} \qquad \forall i \in I^{FL}, d, t \tag{5.12}$$
$$0 \leq g_{i,d,t}^{RD} \leq g_{i,d,t} \qquad : \vartheta_{i,d,t}^{+}, \vartheta_{i,d,t}^{-} \qquad \forall i \in I^{FL}, d, t \tag{5.13}$$
$$0 \leq g_{i,d,t}^{RD,E} \leq g_{i,d,t}^{E} \qquad : \vartheta_{i,d,t}^{E,+}, \vartheta_{i,d,t}^{E,-} \qquad \forall i \in I^{FL}, d, t \tag{5.14}$$
$$g_{i,d,t} + g_{i,d,t}^{RU} \leq X_i \qquad : \mu_{i,d,t}^{+} \qquad \forall i \in I^{FL}, d, t \tag{5.15}$$
$$g_{i,d,t}^{E} + g_{i,d,t}^{RU,E} \leq X_i^{E} \qquad : \mu_{i,d,t}^{E,+} \qquad \forall i \in I^{FL}, d, t \tag{5.16}$$

The second set of constraints impose the limits for the hourly energy and reserves provision of the flexible generation technologies available in the system. Constraints (5.11) and (5.12) imposes the non-negativity of upward reserve dispatch of the generation technologies. Constraint (5.13) and (5.14) imposes the limits for the downward reserves provision. Constraints (5.15) and (5.16) imposes the capacity limits for the sum of energy production and upward reserve provision.

iii) Operating constraints of must-run generation technologies:

$$\Lambda^{MSG} X_i \leq g_{i,d,t} \leq X_i \qquad : \xi_{i,d,t}^{-}, \xi_{i,d,t}^{+} \qquad \forall i \in I^{MR}, d, t \tag{5.17}$$
$$\Lambda^{MSG} X_i^{E} \leq g_{i,d,t}^{E} \leq X_i^{E} \qquad : \xi_{i,d,t}^{E,-}, \xi_{i,d,t}^{E,+} \qquad \forall i \in I^{MR}, d, t \tag{5.18}$$

This set of constraints relates to the operation of generation technologies which are classified as must-run. These technologies are always online and have a high minimum stable generation.

iv) Operating constraints of renewable generation technologies:

$$0 \leq g_{i,d,t} \leq k_{i,d,t}^{RE} X_i \qquad : \beta_{i,d,t}^{-}; \beta_{i,d,t}^{+} \qquad \forall i \in I^{RE}, d, t \tag{5.19}$$

$$0 \leq g_{i,d,t}^{E} \leq k_{i,d,t}^{RE} X_i^{E} \qquad : \beta_{i,d,t}^{E,-}; \beta_{i,d,t}^{E,+} \qquad \forall i \in I^{RE}, d, t \tag{5.20}$$

This set of constraints relate to the renewable generation technologies, depicting the hourly variation in available capacity. If necessary, the hourly wind production can be curtailed.

v) Operating constraints of demand side flexibility

$$\sum_t d_{dt}^{sh} = 0 \qquad : \varphi_d \qquad \forall d \tag{5.21}$$

$$-\alpha D_{d,t}^{BA} \leq d_{dt}^{sh} \leq \alpha D_{d,t}^{BA} \qquad : \pi_{d,t}^{-}; \pi_{d,t}^{+} \qquad \forall d, t \tag{5.22}$$

$$0 \leq d_{d,t}^{RU} \qquad : \zeta_{d,t}^{RU} \qquad \forall d, t \tag{5.23}$$

$$0 \leq d_{d,t}^{RD} \qquad : \zeta_{d,t}^{RD} \qquad \forall d, t \tag{5.24}$$

$$d_{d,t}^{RD} \leq d_{d,t}^{sh} + \alpha D_{d,t}^{BA} \qquad : \nu_{d,t}^{RD} \qquad \forall d, t \tag{5.25}$$

$$d_{d,t}^{RU} \leq \alpha D_{d,t}^{BA} - d_{dt}^{sh} \qquad : \nu_{d,t}^{RU} \qquad \forall d, t \tag{5.26}$$

The constraints (5.21) and (5.22) relate to the use of demand flexibility for load redistribution i.e. shifting and recovery of demand. constraint (5.21) ensures that this load redistribution is energy neutral, that is, not involving energy loss or gains. Constraint (5.22) expresses the limit for the demand change possible in each hour as a ratio α, ($0\% \leq \alpha \leq 100\%$) of the baseline demand $D_{d,t}^{BA}$ where $\alpha = 0\%$ implies that the demand does not exhibit any time-shifting flexibility, while $\alpha = 100\%$ implies that the whole demand can be shifted in time.

Constraints (5.23) – (5.26) relate to the participation of demand flexibility in the reserves market. The positivity limits of the provision of downward and upward reserves are expressed in constraints (5.23) and (5.24), while the upper limits are expressed in constraints (5.25) and (5.26).

The term V^{LL} is the set of all primal variables in the lower level problem.

$$V^{LL} = \left\{ g_{i,d,t}, g^{E}_{i,d,t}, g^{RD}_{i,d,t}, g^{RD,E}_{i,d,t}, g^{RU}_{i,d,t}, g^{RU,E}_{i,d,t}, d^{sh}_{d,t}, d^{RD}_{d,t}, d^{RU}_{d,t} \right\}$$

The dual variables of the lower level problem can be expressed using a variable set V^{Dual}.

$$V^{Dual} = \Big\{ \lambda_{d,t}, \lambda^{RU}_{d,t}, \lambda^{RD}_{d,t}, \mu^{RU}_{i,d,t}, \mu^{RU,E}_{i,d,t}, \vartheta^{+}_{i,d,t}, \vartheta^{-}_{i,d,t}, \vartheta^{E,+}_{i,d,t}, \vartheta^{E,-}_{i,d,t}, \mu^{+}_{i,d,t}, \mu^{E,+}_{i,d,t}, \xi^{+}_{i,d,t}, \xi^{-}_{i,d,t}, \xi^{E,+}_{i,d,t}, \xi^{E,-}_{i,d,t}, \beta^{+}_{i,d,t} \beta^{-}_{i,d,t}, \beta^{E,+}_{i,d,t} \beta^{E,-}_{i,d,t}, \varphi_{d}, \pi^{-}_{d,t}, \pi^{+}_{d,t}, \zeta^{RU}_{d,t}, \zeta^{RD}_{d,t}, \nu^{RD}_{d,t}, \nu^{RU}_{d,t} \Big\}$$

Since the lower level problem in this chapter is not different from the lower level problem in chapter 4, the process of obtaining the MPEC formulation, the linearization process is as presented in sections 4.4, 4.5 and 4.6. Therefore, this process is not outlined again in this chapter.

5.4 Case Study Definition

In the following study, various levels of carbon emissions limit are imposed on the power system being considered. The impact of demand flexibility, market participation of demand flexibility and market design with respect to reserves cost allocation on the generation investment decision under the stringent carbon limits imposed is analysed using the bi-level model presented in 5.3.

Three different cases regarding the level (α) and participation of the flexibility of the demand side in the energy and reserves market are examined. The cases are:

Base Case: The demand side does not exhibit any flexibility ($\alpha = 0\%$).

Case 1: The available demand side flexibility ($\alpha = 10\%$) participates only in the energy market (providing inter-temporal energy redistribution only), and

Case 2: The available demand side flexibility ($\alpha = 10\%$) participates in both energy and reserve markets and can be used in providing both inter-temporal energy redistribution and reserves.

The optimal generation investment decisions under each of the three cases listed above (base case, case 1 and case 2) have been determined using both the centralized planning approach – inherited from the era of vertically integrated electricity utilities – and the market-based planning approach – appropriate for the current deregulated market environment.

The technology options considered available to the examined generation company include wind (renewable generation), nuclear (must-run generation), combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) - both considered as flexible generation technologies. Although wind technology is the only renewable technology considered as an investment option, the model developed in this thesis can also support the consideration of other renewable technologies (e.g solar) as technology options for investment.

The assumed values of the investment and operating costs of these technologies are presented in Table 5.1. Four typical days representing the four seasons of the year are used, the respective profiles for the baseline demand and the normalized output of wind generation technology are obtained from [104]. The remaining parameters used in the case studies are summarized in Table 5.2.

Table 5.1: Investment and Operating Costs of Generation Technologies

Technology	Wind	Nuclear	CCGT	OCGT
Type	Renewable	Must-run	Flexible	Flexible
Existing Capacity X_i^E (MW)	17600	9200	17500	17500
Investment Cost IC_i (£/MW/year)	93140	328210	52120	26460
Energy Cost C_i^G (£/MWh)	0	4.72	37.68	56.98
Reserve Cost $C_i^{rdn} = C_i^{rup}$ (£/MWh)	-	-	9.42	14.245
Carbon Emissions E_i^{CO} ($tonneCO_2/MWh$)	-	-	0.3398	0.5151

Table 5.2: General Parameters

Parameter	Value
Weighting Factor of winter day wf_{winter}	119
Weighting Factor of spring day wf_{spring}	64
Weighting Factor of summer day wf_{summer}	91
Weighting Factor of autumn day wf_{autumn}	91
System Adequacy Coefficient Υ	1.01
Standard deviation of wind generation output Δ_i^{RE}	3.5
Forecasting error of wind generation output ε_i^{RE}	7%
Demand Flexibility Level considered (α)	0% and 10%
Minimum hourly generation factor for must-run technology (Λ^{MSG})	0.5
Minimum yearly capacity factor for must-run technology (Ψ)	0.80

5.5 Results

5.5.1 Investment decision under Centralised Planning

The first set of studies analyses the investment decisions in the three cases mentioned under increasingly stricter carbon emissions limit using the traditional centralised planning approach. The results obtained using the centralised planning approach provide a benchmark to analyse the results under the market-based planning approach.

Fig. 5.1 presents the optimal investment decision of the centralised planner for each demand flexibility case under the carbon limits considered. In all the three cases considered, as the carbon emissions limit tightens, the investment in nuclear generation increases as it plays an increasingly important role in providing carbon-free generation. The investment in CCGT is however reduced.

In the base case, the investment in wind becomes increased at 100 gC02/kWh compared to the no carbon limit scenario. However, since the wind investment will necessitate the operation of flexible CCGT and OCGT to provide reserves, this is reduced at 50 gCO2/kWh, while the investment in Nuclear is significantly increased.

In case 1, the increase in off-peak demand and reduction in peak demand

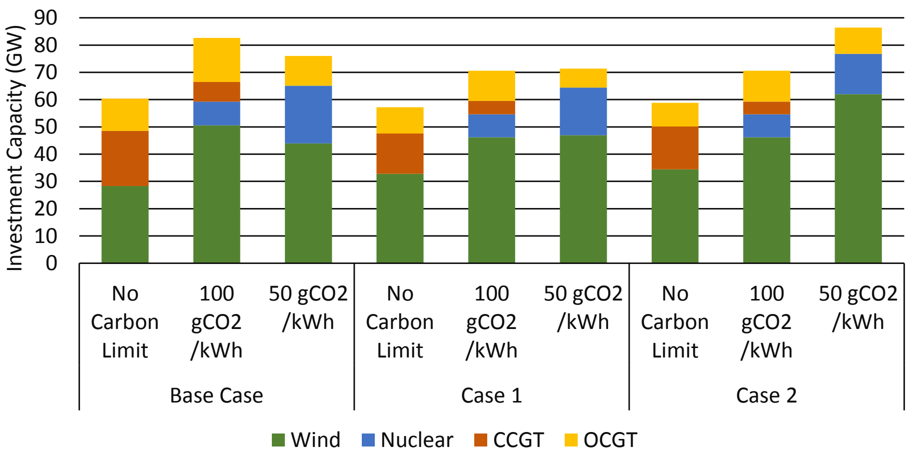

Figure 5.1: Optimal Investment Decision under Centralised Planning for the different Demand Flexibility cases under different Carbon Limit Scenarios

enhances the cost-efficiency of wind generation in the no carbon limit scenario with respect to the base case. This wind investment is enhanced as the carbon limit becomes more stringent. The off-peak demand increase also ensures that more wind can be absorbed in the low-demand hours, therefore less investment in nuclear generation with high investment cost is needed.

In case 2, demand flexibility also provides reserves but at zero-cost. This reduces the reserves cost incurred by the planner and enhances the cost-efficiency of wind generation so the investment in wind is increased (more significantly in the 50 gCO2/kWh scenario) compared to case 1.

5.5.2 Investment decision under Market-Based Planning

The first analysis considers the market design scenario ($\Gamma = 100\%$) where the renewable generation fully pays for the entire system cost required to provide the reserves. Fig. 5.2 presents the optimal investment decisions for the three cases examined under the carbon limits considered.

In all the three cases considered, as the carbon emissions limit tightens, nuclear generation plays an increasingly important role because it provides carbon-free generation. For this reason, the generation company increases its investment in nuclear, while the combined investment in carbon emitting but flexible CCGT and OCGT technologies reduces.

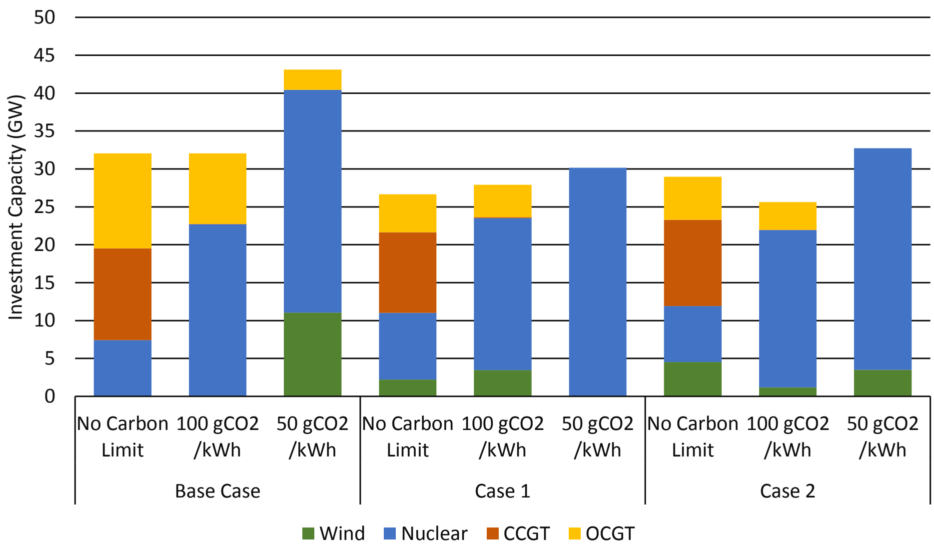

Figure 5.2: Optimal Investment Decision under Market-Based Planning (Γ = 100% Market Design) for the different Demand Flexibility Levels considered at different Carbon Limits

In the base case, it is only at 50 gCO2/kWh that the generation company invests in wind. This is to avoid violating the hourly minimum operational constraint of nuclear generation. For this reason, investment in wind is necessary and important to satisfy the strict carbon limit imposed.

In case 1, the off-peak demand levels are increased as a result of the energy arbitrage effects of demand flexibility. This translates to an increased investment in wind generation under the scenarios involving no carbon limit and carbon limit of 100 gCO2/kWh compared to the results under the base case. In contrast, there is no wind investment under the carbon limit of 50 gCO2/kWh because the increased off-peak demand ensures that the hourly minimum operational constraint of nuclear generation will not be violated in any hour.

In case 2, except for the increased investment in nuclear generation as the carbon limits becomes stricter, a comparison of the investment trends in case 2 and case 1 reveals no consistent trends. However, the investment in flexible CCGT and OCGT generation investments remain lower than their respective investment level in the base case.

For each demand flexibility case under the imposed carbon limits discussed above, the different component terms which combine to give the long-term total profit of the generation company is presented in Table 5.3. below. In all cases considered, the total profit reduces while the investment cost increases as the carbon limits becomes more stringent. The increase in the investment cost incurred by the generation company at lower carbon emission limits is because of the increased investment in nuclear generation which has a high investment cost.

In comparison with the base case, the energy operational profit of the generation company is higher in case 1 because of the increased off-peak demand as well as the combined increase in investment and dispatch of nuclear and wind generation (with a lower energy production cost). The system reserve costs which is dependent on the wind investment is higher in case 1 at both the no carbon limit and 100 gCO2/kWh carbon limit scenarios. However, at 50 gCO2/kWh, since there is no wind investment in case 1, this is higher in the base case compared to case 1.

In case 2, the energy operational profit of the generation company is higher in both 50 gCO2/kWh and 100 gCO2/kWh compared to case 1, because of the significantly higher investment in, and dispatch of zero-cost wind generation. However, under the no carbon limit scenario, the energy profit is lower in case 2 compared with case 1. This results from a combination of factors. First, the difference in wind investment is lower than the previous carbon scenarios.

In addition, the higher investment in and dispatch of CCGT and OCGT generation which make lower profit in the energy market reduces the energy profit. However, the total reserves cost is lower in case 2, because of the zero-cost reserve provision available from demand flexibility.

Table 5.3: Long Term Profit of Examined Generation Company for different Demand Flexibility Cases considering different Carbon Limits at $\Gamma = 100\%$ Market Design (in billion £)

	Base Case			Case 1			Case 2		
	No Carbon Limit	100 gCO2/ kWh	50 gCO2/ kWh	No Carbon Limit	100 gCO2/ kWh	50 gCO2/ kWh	No Carbon Limit	100 gCO2/ kWh	50 gCO2/ kWh
Energy Profit	4.042	6.181	5.798	4.950	6.538	6.014	4.702	6.300	6.113
Reserve Profit	0	0.0002	0	0.002	0	0	0	0.0002	0
Reserve Cost	0	0	0.254	0.033	0.070	0	0.012	0.0095	0.028
Investment Cost	3.396	7.703	10.746	3.778	7.017	9.902	3.585	7.014	9.917
Total Profit	0.646	-1.522	-5.203	1.142	-0.548	-3.888	1.104	-0.723	-3.833

In all cases, with the introduction of carbon limits, the energy profits from energy production is not sufficient to recover the investment and reserve costs incurred by the generation company. The long-term profit is negative under the carbon limit scenarios.

Reserve costs entirely allocated to the demand side ($\Gamma = 0\%$)
The investment mix for the three cases considered at different carbon limits is presented in fig. 5.3 below. For the three cases considered as the carbon limit becomes stricter, must-run nuclear generation becomes increasing preferred to the wind generation to meet the base load demand. This is because of the dependence of reserves requirement on the wind investment level; these reserve requirements will necessitate the operation of carbon emitting CCGT and OCGT generation in base case and case 1. The investment in nuclear generation capacity does not have the disadvantage of increasing reserve requirements.

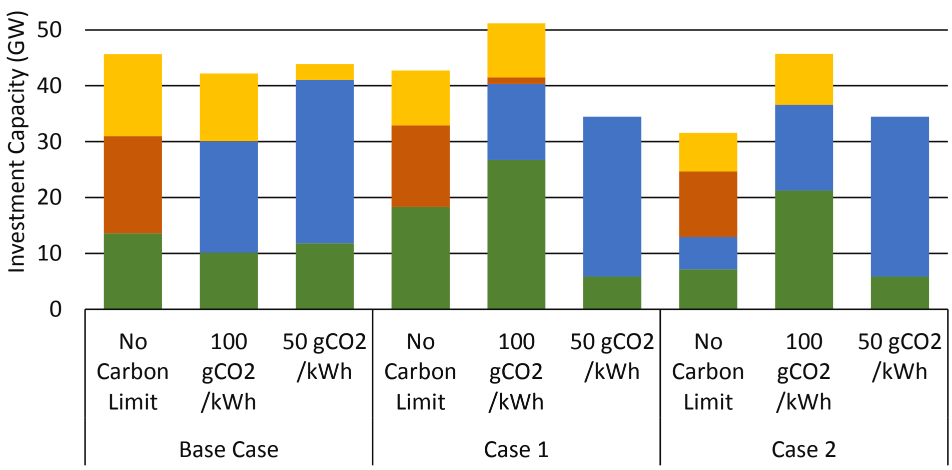

Figure 5.3: Optimal Investment Decision under Market-Based Planning ($\Gamma = 0\%$ Market Design) for the different Demand Flexibility Levels considered at different Carbon Limits

In comparison to the base case, the increased off-peak demand due to the energy arbitrage effects of demand flexibility in case 1 translates to an increased investment in wind under both no carbon limits and 100 gCO2/kWh carbon limits. The investment in CCGT and OCGT generation capacity are however reduced due to the reduction in the peak demand levels.

Conversely, under the 50 gCO2/kWh carbon limit, the wind investment is reduced in case 1.

In case 2, the investment in wind technology is lower than (under both no carbon limits and 100 gCO2/kWh carbon limits) or equal to (at 50 gCO2/kWh) the respective investment values in case 1. In contrast, there is a higher investment in nuclear generation capacity under both no carbon limits and 100 gCO2/kWh carbon limits to enhance the energy profit of the strategic generator. The investment in nuclear generation remains unchanged with respect to case 1.

Table 5.4 presents the long-term profit of the generation company for each demand flexibility case under the carbon limits considered. Similar to the results obtained under the $\Gamma = 100\%$ market design, in all cases considered, the total profit reduces while the investment cost increases as the carbon limits becomes more stringent. On the contrary, the generation company makes more profit in all the cases considered under this market design than it does in the $\Gamma = 100\%$ market design.

A comparison of the investment mix under both market designs ($\Gamma = 0\%$ and $\Gamma = 100\%$) presented in fig. 5.2 and 5.3 respectively, reveals some common observations in all the three cases considered. These are as follows:

- Since all reserve provision costs are allocated to the demand side, the investment in wind generation by the generation company is higher under the $\Gamma = 0\%$ market design than the respective investment values in the $\Gamma = 100\%$ market design.

Table 5.4: Long Term Profit of Examined Generation Company for different Demand Flexibility Cases considering different Carbon Limits at $\Gamma = 0\%$ Market Design (in billion £)

	Base Case			Case 1			Case 2		
	No Carbon Limit	100 gCO2/ kWh	50 gCO2/ kWh	No Carbon Limit	100 gCO2/ kWh	50 gCO2/ kWh	No Carbon Limit	100 gCO2/ kWh	50 gCO2/ kWh
Energy Profit	3.355	6.381	5.814	4.017	6.932	6.110	4.473	6.777	6.146
Reserve Profit	0.013	0.001	0	0.013	0.006	0	0	0.0001	0
Reserve Cost	0	0	0	0	0	0	0	0	0
Investment Cost	2.569	7.797	10.761	2.738	7.267	9.928	3.353	7.251	9.928
Total Profit	0.799	-1.415	-4.947	1.292	-0.329	-3.818	1.121	-0.475	-3.783

- The investment in nuclear generation is increased as the carbon limits become more stringent. However, the investment levels in nuclear generation is lower across the three cases under the $\Gamma = 0\%$ market design.

- The investment in flexible CCGT and OCGT generation is higher under the $\Gamma = 0\%$ market design. This is because of the reduced investment in nuclear as well as the higher reserves requirements associated with the higher investment in wind generation.

5.6 Determining the Carbon Threshold for Profitability

In both market designs considered, the long-term profits of the examined generation company are negative under the 50 gCO2/kWh and 100 gCO2/kWh carbon limits. These negative profits imply that remuneration for only energy and reserves provision is insufficient to give an economically feasible result at low carbon emissions level.

Further tests have therefore been carried out to determine the strictest carbon limit where the profit of the generation company is non-negative. This is referred to as the carbon threshold for profitability. Table 5.5 below shows the results obtained for the three cases under both market designs. The demand flexibility reduces this threshold in both case 1 and case 2 with respect to the base case.

Table 5.5: Carbon Emission Threshold for Profitability of the Generation Company in the Cases Considered

Market Design	Base Case	Case 1	Case 2
$\Gamma = 0\%$	138 gCO2/kWh	108 gCO2/kWh	109 gCO2/kWh
$\Gamma = 100\%$	140 gCO2/kWh	108 gCO2/kWh	109 gCO2/kWh

5.7 Conclusion

This chapter analyses the impact of demand flexibility on optimal investment decisions considering increasingly stricter carbon limits.

The results presented in this chapter explores the role and value of demand flexibility in decarbonising electricity systems. The result shows the increasing role of zero-carbon firm nuclear generation in meeting stricter emission limits. The investment in zero-carbon renewable (wind) generation reduces since this increases the reserve requirements which are provided by carbon emitting technologies.

More importantly, the inability of the market revenues to provide full recovery of costs incurred by the generation company when carbon limits are imposed highlights the failure of the energy and reserves market to solely stimulate desirable investment in low-carbon generation. With this market configuration, out of market payments are required by the generation company to fully recover costs.

The chapter also determines the carbon threshold for profitability of the generation company and shows the impact of demand flexibility in reducing this carbon threshold under the different market designs considered.

Now, let us hear the conclusion of the whole matter ...

— King Solomon

Chapter 6

Conclusions and Future Work

6.1 Summary and Conclusions

The emerging low-carbon power systems will feature a higher level of renewables-based generation compared to what currently exists. This will increase variability and need for system flexibility while also reducing the capacity of conventional generation technologies to provide this flexibility. Therefore, there is the need to explore flexibility options available in the demand side to ensure smooth operation of low-carbon power systems. Furthermore, the availability of technologies such as smart metering makes it easier for consumers to change their demand pattern in response to market signals thereby increasing the capacity of demand-side flexibility available in the system.

On this note, newer and better power system planning models are required to adequately integrate the envisaged changes in power system operations and the enhanced participation of demand side especially with regards to its flexibility potential. A particularly relevant and fast developing area of research has involved quantitatively investigating the impacts of demand flexibility in the long-term development of the electricity system.

These long-term impacts of demand flexibility have however only been investigated using the traditional centralised generation planning models which are inherited from the era of vertically integrated electricity utilities. As discussed in chapter 2, the state-of-the-art investment planning models which incorporate the competitive market framework have employed a simplified representation of the demand side which focus on the level of electricity consumption and ignores essential information about its chronology. This implies that these models are intrinsically unable to analyse the impact of flexible technologies (which involve time-coupling) on investment planning. For this reason, the investigation of the impact of these flexible technologies on investment planning in the liberalised electricity industry remains largely unexplored. To address this issue, novel time-coupling market-based generation investment planning models have been developed and presented in this thesis.

The investment planning problem faced by a self-interested generation company has been modelled in this thesis using bi-level optimisation formulations. The bi-level formulation approach has been employed in this thesis because it endogenously represents the interaction between the decisions made by the generation company and the resulting market prices. Since this thesis is focused on analysing the impact of flexible technologies on generation investment planning, the bi-level formulation developed incorporates time coupling constraints necessary to model the operations of flexible technologies.

The first model is developed and presented in chapter 3. This model considers the participation of these flexible technologies in the energy markets for energy arbitrage. Results obtained from case studies involving different types of flexible technologies show a similarity in their respective impacts on the generation investment planning decisions of the generation company. These impacts include: limiting peak demand levels, reducing the total capacity investment and reducing the variability of systems demand profile.

An enhanced bi-level model is presented in chapter 4 which allows investment in renewable technologies. This model also introduces the reserves market which is jointly optimised with the energy market and incorporates the participation of demand flexibility in both energy and reserves markets.

Different cases regarding the flexibility of the demand side and different market design options regarding the allocation of system costs for reserve are investigated in the case studies presented.

The value of demand flexibility in decarbonising the electricity systems is discussed in chapter 5 using strict carbon targets. More importantly, the results obtained in this chapter shows its value in reducing the carbon threshold for profitability of the generation company operating in a competitive market environment. The case studies involving the participation of demand flexibility in energy only markets as well as energy and reserves market are carried out under different market design options.

The findings of this thesis are relevant to both the market regulator and the self-interested generating company.

- For the market regulator, the thesis findings aid understanding of the impacts of demand flexibility in the long-term development of electricity system under the competitive market environment and the effect of alternative market designs in this regard.

- For the self-interested generating company, the thesis findings show the ability of the proposed model to determine optimum investment strategy to maximise its long-term profit with the market participation of demand flexibility under different market designs.

The main conclusions from this thesis can be summarised as:

1. Flexible technologies of different types have similar impact on the system demand profile as well as on the optimal investment decisions of the examined company and the evolution of its investment mix at higher capacity levels.

2. The investment decisions under the traditional cost minimisation centralised planning approach are not aligned with those obtained under the market-based planning approach. While the centralised planner makes the decisions considering societal perspectives, the self-interested

generation company is aware that its investment decision influences the market outcomes and strategically exploits this to obtain maximum profit. An example of this difference can be seen in chapter 4, where the centralised planner overestimates the investment in renewable generation and assumes that this renewable generation investment is always increased as a result of demand flexibility participating in both energy and reserve markets.

3. The electricity market design in operation influences the strategic investment decisions of generation companies in the competitive market framework. Furthermore, the related impacts of demand flexibility on these investment decisions are also reliant on the market design.

4. The participation of demand flexibility in the market(s) enhances the total profit of the self-interested generation company with respect to the base case (with no demand flexibility) given its impact on increasing the investment, dispatch and subsequently the revenues earned from baseload wind and nuclear generation.

5. The electricity market design in operation influences the profitability of the generation company. However, this profitability deteriorates when the market design places the burden of paying the system reserve costs on the generation side rather than the demand side.

6. Out of market side payments (make-whole payments) are required by the generation company to recover its costs when strict carbon limits are imposed. Demand flexibility helps to reduce the amount of make-whole payments required.

6.2 Contribution to Knowledge

The following contributions to knowledge have been made by the research presented in this thesis:

- The development of a bi-level planning model which employs a chronological representation of demand. This allows the consideration of the time-coupling characteristics of demand which is essential to incorporate the operations of flexible technologies (including demand-flexibility and energy storage) in the model. Such time-coupling characteristics cannot be considered using the discrete demand blocks employed in existing planning models because these demand blocks focus on the demand levels and neglects the time of demand.

- The modelling of an electricity market consisting of both energy and reserves market which is jointly cleared by the market operator. This joint energy and reserves market is represented in the lower level of the developed bi-level model. The consideration of reserves market is essential to adequately model low-carbon future power systems given the high level of variability anticipated. Furthermore, given the reduced competitiveness of conventional technologies in the energy market due to the higher penetration of renewables, the reserves market becomes an important revenue source for flexible conventional generation technologies. As a result, modelling both energy and reserves market allows the self-interested generation company to make a better informed and realistic decision.

- In addition to modelling both energy and reserves market, demand flexibility is considered to participate in only the energy market (thereby providing energy arbitrage) and to participate in both energy and reserves market (thereby providing reserves in addition to energy arbitrage).

- An analysis of the dependence of the impact of demand flexibility on the investment decisions of the examined generation company on the market design with respect to the allocation of the reserves cost.

- A detailed study of the impact of demand flexibility on the investment decisions of the generation company under increasingly stringent carbon emissions limit.

- In contrast to previous work that has focused on either conventional or renewables, the investment options available to the investing company includes both conventional technologies - nuclear, Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine (OCGT) - and renewable technologies (wind). This allows a careful analysis of the investing company's technology preference especially for baseload generation and the factors that drive this choice.

It is important to note that the case studies and results presented in chapters 3, 4 and 5 have been carried out considering an investing company with no existing generating facilities. The investment decisions will potentially differ for an investing company with existing assets depending on the technology composition of its assets. It is however expected that the impact of demand flexibility on the investment decisions will remain as discussed in this thesis.

6.3 Future Work

The research presented in this thesis can be improved on and enriched in a number of directions. Some relevant suggestions for the future research include:

1. The use of specific flexible technologies:
   The model presented in this thesis assumes a technology-agnostic representation for the respective flexible technologies considered. To improve on this work, more detailed modelling which accounts for the technology-specific operational constraints of respective flexible technologies such

as: time-shiftable domestic appliances, electric heaters, electric vehicles etc will be carried out. This will enable a detailed assessment of the diverse impacts of each technology and the favourable market designs for each of them. Although it should be mentioned that a consideration of numerous technologies will be at a cost of increased computational complexity.

2. Ownership and investment in flexible technologies by the generation companies:
In this thesis, the respective flexible technologies are assumed to be already in existence and not owned by the generation company. It will be interesting to explore how the ownership of these flexible technologies by the investing generation company can influence its optimal investment decisions. Furthermore, studies can also analyse how the investment in these flexible technologies by the generation company will affect its investment decisions in different generation technologies.

3. Strategic bidding in the market by generators:
The models presented in this thesis make the assumption that all generation companies bid at the marginal production costs of their respective technologies. For these companies to increase their profits, there is strong motivation for them to inflate their price bids in certain crucial hours in the market through strategic bidding. The possibility of strategic market bidding may change both the optimal investment decisions as well as the profit earned by the investing generation company. For this reason, further work will aim at allowing strategic market bidding by the generation companies and analyse the impacts that demand flexibility will have under these conditions.

4. Transmission Network:
Expanding the model to include the transmission network will be useful to study how the location of flexible demand technologies within the network can affect its impact on the optimal investment decisions. In

addition, the impact of the transmission congestion on the utilization of demand-side flexibility and the evolution of the investment mix can also be assessed.

5. Uncertainty:
   The inclusion of uncertainty in the model is another direction for future work. While the uncertainties relating to renewable generation is handled in this thesis through the scheduling of reserves, other uncertainties relating to the bidding strategy of competitors in the market as well as the long term uncertainties relating to their investment strategy can also be incorporated. This will require the use of stochastic optimization techniques to obtain a solution.

6. Multiple Investing Generation Companies:
   The modelling of the interaction between multiple investing generation companies through an equilibrium programming approach. In this context, different companies are determining their optimal investment decisions accounting for the impact of their respective decisions on the market. The equilibrium solution is achieved when no individual company can improve its profitability by changing its investment decision

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Appendix A: Centralised Planning Model

This appendix presents the cost minimization model used for the centralized planning approach. The results obtained usng the centralized planning approach is included in the discussions of chapters 4 and 5.

$$
\begin{aligned}
\underset{V^{CEN}}{Min} \Bigg\{ \sum_{i,d,t} C_i^G (g_{i,d,t} + g^E_{i,d,t}) + \sum_{i \in I^{FL},d,t} \Big(C_i^{RD} (g^{RD}_{i,d,t} + g^{RD,E}_{i,d,t}) \\
+ C_i^{RU} (g^{RU}_{i,d,t} + g^{RU,E}_{i,d,t}) \Big) \Bigg\} + \sum_i IC_i X_i
\end{aligned}
$$

subject to

$$
\begin{gathered}
(4.2) - (4.25) \\
(5.6)
\end{gathered}
$$

The term V^{CEN} is the set of all primal variables in the optimization problem.

$$
V^{CEN} = \Big\{ X_i, g_{i,d,t}, g^E_{i,d,t}, g^{RD}_{i,d,t}, g^{RD,E}_{i,d,t}, g^{RU}_{i,d,t}, g^{RU,E}_{i,d,t}, d^{sh}_{d,t}, d^{RD}_{d,t}, d^{RU}_{d,t} \Big\}
$$

Appendix B:
Data

This appendix presents using Tables, the hourly demand data and the normalised hourly wind output factor for the representative days used for the different seasons of the year.

Table B.1: Hourly Demand (in GW) for the representative day of each season

	Winter	Summer	Spring	Autumn
1	37.88	30.42	35.32	33.64
2	38.41	27.66	32.46	30.80
3	36.15	27.23	31.61	30.07
4	30.96	24.72	28.98	27.41
5	26.98	20.23	28.22	27.11
6	32.56	26.84	30.55	29.65
7	47.57	41.00	45.33	44.09
8	55.82	45.65	48.83	47.37
9	59.13	50.75	53.56	52.15
10	61.38	54.09	57.02	56.17
11	61.73	55.62	58.62	58.15
12	61.91	56.16	59.21	59.02
13	60.85	54.84	57.99	58.38
14	60.08	53.28	56.22	56.95
15	60.10	52.72	55.35	56.40
16	63.57	53.35	55.66	57.62
17	72.10	53.69	56.23	60.76
18	75.50	52.45	56.18	63.31
19	71.12	50.54	56.58	62.33
20	63.44	50.33	57.98	59.73
21	55.99	48.25	54.29	53.33
22	49.83	44.04	48.07	46.70
23	41.53	35.70	39.87	38.72
24	34.73	29.28	33.17	31.78

Table B.2: Hourly Wind Capacity Factor for the representative day in each season

	Winter	Summer	Spring	Autumn
1	0.50	0.15	0.16	0.55
2	0.49	0.12	0.17	0.54
3	0.46	0.12	0.16	0.53
4	0.40	0.13	0.15	0.49
5	0.36	0.13	0.13	0.46
6	0.31	0.15	0.11	0.38
7	0.30	0.18	0.10	0.31
8	0.30	0.20	0.10	0.30
9	0.28	0.20	0.12	0.31
10	0.27	0.20	0.15	0.33
11	0.28	0.19	0.20	0.36
12	0.31	0.21	0.24	0.38
13	0.33	0.23	0.29	0.40
14	0.34	0.25	0.30	0.40
15	0.35	0.28	0.32	0.39
16	0.36	0.28	0.36	0.39
17	0.39	0.24	0.39	0.40
18	0.43	0.20	0.38	0.41
19	0.49	0.15	0.33	0.40
20	0.54	0.11	0.26	0.38
21	0.55	0.08	0.19	0.36
22	0.58	0.07	0.15	0.35
23	0.58	0.07	0.15	0.32
24	0.58	0.07	0.18	0.32