Investigating the Impact of Flexible Demand on Market-Based Generation Investment Planning

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Abstract

Demand flexibility has attracted significant interest given its potential to address techno-economic challenges associated with the decarbonisation of electricity systems. However, previous work has investigated its long-term impacts through centralized generation planning models which do not reflect the current deregulated environment. At the same time, existing market-based generation planning models are inherently unable to capture the demand flexibility potential since they neglect time-coupling effects and system reserve requirements in their representation of the electricity market. This paper investigates the long-term impacts of demand flexibility in the deregulated environment, by proposing a time-coupling, bi-level optimization model of a self-interested generation company's investment planning problem, which captures for the first time the energy shifting flexibility of the demand side and the operation of reserve markets with demand side participation. Case studies investigate different cases regarding the flexibility of the demand side and different market design options regarding the allocation of reserve payments. The obtained results demonstrate that, in contrast with previous centralised planning models, the proposed model can capture the dependency of generation investment decisions and the related impacts of demand flexibility on the electricity market design and the subsequent strategic response of the self-interested generation company.

Keywords—Bi-level optimization, electricity markets, flexible demand, generation investment planning.

NOMENCLATURE

Indices and Sets

$t \in T$	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

w_d	Weighting factor of day d
X_i^0	Existing capacity of generation technology i (MW)
C_i^{IN}	Investment cost of generation technology i (£/MW/year)
C_i^{EN}	Marginal energy cost of generation technology i (£/MWh)
C_i^{RU}	Marginal upward reserve cost of generation technology i (£/MWh)
C_i^{RD}	Marginal downward reserve cost of generation technology i (£/MWh)
$k_{i,d,t}^{RE}$	Normalized output of renewable generation technology i at day d and hour t
δ_i^{RE}	Standard deviation of output of renewable generation technology i
ε_i^{RE}	Forecasting error of output of renewable generation technology i
$d_{d,t}^{BA}$	Baseline demand at day d and hour t (MW)
α	Flexibility limit of the demand side
A	System adequacy coefficient
Γ	Percentage of reserve costs paid by renewable generation technologies

Variables

X_i	New capacity of generation technology i (MW)
$g_{i,d,t}$	Power output of new capacity of technology i at day d and hour t (MW)
$g_{i,d,t}^0$	Power output of existing capacity of technology i at day d and hour t (MW)
$g_{i,d,t}^{RU}$	Upward reserve provided by new capacity of technology i at day d and hour t (MW)
$g_{i,d,t}^{RU,0}$	Upward reserve provided by existing capacity of technology i at day d and hour t (MW)
$g_{i,d,t}^{RD}$	Downward reserve provided by new capacity of technology i at day d and hour t (MW)
$g_{i,d,t}^{RD,0}$	Downward reserve provided by existing capacity of technology i at day d and hour t (MW)
$d_{d,t}^{SH}$	Change of demand at day d and hour t due to load shifting (MW)
$d_{d,t}^{RU}$	Upward reserve provided by demand at day d and hour t (MW)
$d_{d,t}^{RD}$	Downward reserve provided by flexible demand at day d and hour t (MW)
$\lambda_{d,t}$	Energy clearing price at day d and hour t (£/MWh)
$\lambda_{d,t}^{RU}$	Upward reserve clearing price at day d and hour t (£/MWh)
$\lambda_{d,t}^{RD}$	Downward reserve clearing price at day d and hour t (£/MWh)

1 INTRODUCTION

1.1 Background and Motivation

Electricity systems are currently facing fundamental techno-economic challenges associated with the combined effects of decarbonization and deregulation. Environmental and energy security concerns have driven governments worldwide to take significant initiatives towards the decarbonization of electricity systems through the large-scale integration of renewable generation [1]. Nevertheless, the inherent variability and limited predictability and controllability of renewable generation create significant system balancing challenges since conventional generators need to remain in the system and operate in an economically inefficient fashion (part-loaded) to provide the required balancing services to the system.

In this setting, flexible demand technologies enabling temporal redistribution (shifting) of electricity demand, have attracted great interest by governments, industry and academia [2]-[4]. This is because demand flexibility can support system balancing, increase the absorption of renewable generation and reduce peak demand levels, overall contributing to a more cost-effective transition to the low-carbon future. A particularly relevant and fast developing area of research focuses on quantitatively investigating this role and value of flexible demand in the long-term development of the electricity system, through the employment of generation investment planning models.

However, existing studies in this area (e.g. [5]-[9]) have employed traditional centralized planning models inherited from the era of vertically integrated electricity utilities, optimising system objectives (i.e. minimising the long-term system cost) and assuming perfectly competitive behaviour by market participants. However, the recent worldwide deregulation of the electricity industry has driven unbundling of vertically integrated monopoly utilities and the introduction of competition in the generation sector [10]. This paradigm change means that such centralized models are not able to provide accurate insights anymore, since they neglect the fact that self-interested generation companies' actions are not generally aligned with system cost minimization but rather rely on profit-driven decisions. In this deregulated setting, new market-based generation investment planning models are required instead, capturing the effort of self-interested generation companies to maximize their long-term profits while accounting for the impact of their investment decisions on the competitive electricity market. Apart from assisting the decision making of generation companies, such models are also valuable for electricity market regulators, as they assist them in assessing the impact of alternative market design options on the long-term development of the system.

Numerous previous works [11]-[23] have developed such market-based generation investment planning models. Although the focus and assumptions of these papers differ, they all employ the same fundamental methodology, namely bi-level optimization. The popularity of this methodology lies in its ability to rigorously capture the interactions between the strategic investment decisions of self-interested generation companies (modeled in the upper level) and the competitive clearing of the electricity market at the operational timescale (modeled in the lower level).

Papers [15], [19]-[20] focus specifically on investments in renewable generation due to their increasing significance in the low-carbon future. Papers [15]-20], [22]-[23] incorporate transmission network constraints in the problem formulation in order to identify the optimal location of generation investments, considering potential network congestion effects. Apart from strategic investment decisions, papers [11]-[14], [16]-[18], [21]-[23] account for the potential exercise of market power by generation companies in the electricity market through strategic bidding. Finally, papers [14]-[23] model uncertainties that generation companies face in their investment decision making through stochastic, scenario-based approaches.

However, all the market-based planning models developed in these previous works exhibit two fundamental shortcomings. First of all, the operational timescale of these models (at which the electricity market clearing is performed) consists of a number of independent time periods and does not involve time-coupling effects. This assumption implies that these models are inherently unable to capture the energy shifting flexibility of the demand side and they can only encapsulate its (time-independent) self-price elasticity; however this elasticity is known to be generally limited with respect to the energy shifting potential, since consumers cannot greatly reduce their overall energy requirements but they are more likely to shift their energy requirements in time [24].

Secondly, these previous models consider solely the energy segment of the electricity market in their lower level problems and completely neglect the reserve requirements of the system and the related operation of reserve markets. This assumption implies that these models are inherently unable to capture the undeniable balancing challenges associated with the integration of renewable generation and subsequently the potential value of flexible demand in supporting system balancing.

1.2 Scope and Contributions

This paper aims at rigorously investigating the impact of flexible demand on market-based generation investment planning by addressing the above shortcomings of previous modeling approaches. In order to achieve this, the paper proposes a time-coupling, bi-level optimization approach for modeling 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 the participation of the demand side in these markets.

Specifically, the upper level (UL) problem of the proposed bi-level optimization formulation optimizes the investment decisions of the examined generation company in different generation technologies (including renewable, must-run and flexible generation) so as to maximize its long-term profit. This UL problem is subject to the lower level (LL) which represents endogenously the daily market clearing process of a joint energy and reserve market. 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 payments 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 problem (MILP).

The proposed model is validated through case studies on a test system reflecting the general characteristics of the UK electricity system. These studies investigate different cases regarding the flexibility of the demand side and different market design options regarding the allocation of reserve payments. The obtained results demonstrate that, in contrast with previous centralised planning models, the proposed model can capture the dependency of generation investment decisions and the related impacts of demand flexibility on the electricity market design and the subsequent strategic response of the self-interested generation company. Furthermore, the case studies analyse the impacts of demand flexibility and the allocation of reserve payments on the long-term profits of the examined generation company.

1.3 Paper Structure

The rest of this paper is organized as follows. Section 2 details the proposed modelling approach. Case studies and quantitative results are presented in Section 3. Finally, Section 4 discusses conclusions and future extensions of this work.

2 MODEL FORMULATION

2.1 Assumptions

For clarity reasons, the main assumptions behind the proposed model are outlined below:

- The model expresses the investment planning problem of a single self-interested generation company, which aims at maximizing its long-term profit by optimizing its generation investment decisions. This company is allowed to invest in generation capacity of different conventional and renewable technologies, each characterized by different investment costs, operating costs, and operating constraints.
- Considering the focus of the paper on investigating the impacts of the energy shifting flexibility and reserve market participation of the demand side on market-based generation investment planning (which already introduce significant modelling complexity), and in order to avoid the additional complexity and computational requirements associated with the employment of a dynamic planning approach, the model assumes a static planning approach with a yearly operation horizon. In other words, the examined generation company optimizes its investment decisions considering a single, future target year. This yearly operation horizon is divided into a number of representative days. Both investment and operating costs and revenues are calculated at the same yearly basis.
- In contrast with unrealistic “greenfield” assumptions, the model assumes that generation capacity of different conventional and renewable technologies already exists in the system, but it does not belong to the examined company.

- An out-of-market generation adequacy constraint is imposed on the investment planning problem by the regulator, to ensure that the total firm generation capacity in the system (excluding renewable generation) is sufficiently higher (as determined by an adequacy coefficient A) than the peak demand and therefore long-term security of supply requirements are satisfied.
- The considered electricity market is a pool-based, joint energy and reserve market with a day-ahead horizon and hourly resolution, and is cleared by the market operator through the solution of a short-term cost minimization problem. We have decided to consider a market design involving joint (simultaneous) clearing of energy and reserve markets (adopted in most US markets [25]) instead of separate (sequential) clearing (adopted in most European markets [26]), since the latest scientific literature has clearly demonstrated that the former design is more efficient in terms of social welfare [26]-[28].
- Due to the focus of this work on a widely decarbonized energy setting, the upward and downward reserve requirements are assumed to be driven solely by the forecasting errors of renewable generation, neglecting similar forecasting errors of demand and generation plant outages.
- Although in most US [25] and European [26] markets, the reserve costs are allocated entirely to the demand side, some markets have started allocating part of these costs to renewable generation, considering that the latter is responsible for a significant part of the system's reserve requirements [26]. Therefore, the proposed model assumes that the reserve costs are allocated among the demand side and renewable generation, with the total percentage paid by renewable generation being determined by a market design parameter Γ.
- Both the examined generation company as well as the rest of the generation companies (owning the existing generation capacity) are assumed to bid in the electricity market according to the actual marginal costs of each generation technology, i.e. strategic bidding is not considered.

- A subset of the considered generation technologies are assumed “must-run” i.e. they must be operating at their full capacity during all times and they cannot provide reserves.
- Another subset of generation technologies includes renewable technologies, which are assumed to exhibit zero marginal costs, their output can be curtailed if required, and they cannot provide reserves.
- The rest of the generation technologies (excluding “must-run” and renewable technologies) are flexible technologies which can be flexibly dispatched and provide reserves.
- The demand side exhibits flexibility which can be used for both energy shifting and reserve provision, and is represented through a generic (technology-agnostic) time-coupling model [29]. According to this model, demand at each hour 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. Furthermore, 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.

2.2 Bi-Level Optimization Formulation

The proposed model is formulated as a bi-level optimization problem:

(Upper Level)

$$\max_{\{X_i,\forall i\}} \sum_d w_d \Big[\sum_{i,t}(\lambda_{d,t} - C_i^{EN}) g_{i,d,t} + \sum_{i\in I^{FL},t}\big((\lambda_{d,t}^{RU} - C_i^{RU}) g_{i,d,t}^{RU} + (\lambda_{d,t}^{RD} - C_i^{RD}) g_{i,d,t}^{RD}\big) - \Gamma\big(\sum_{i\in I^{RE},t}(\lambda_{d,t}^{RU} + \lambda_{d,t}^{RD})\delta_i^{RE}\varepsilon_i^{RE} k_{i,d,t}^{RE} X_i\big)\Big] - \sum_i C_i^{IN} X_i \quad (1a)$$

subject to:

$$X_i \geq 0 \qquad \forall i \quad (1b)$$

$$\sum_{i\notin I^{RE}}(X_i^0 + X_i) \geq A * (1-\alpha) d_{d,t}^{BA} \qquad \forall d, \forall t \quad (1c)$$

(Lower Level)

$$\min_{V^{LL}} \sum_{i,d,t}\big(C_i^{EN}(g_{i,d,t} + g_{i,d,t}^0)\big) + \sum_{i\in I^{FL},d,t}\big(C_i^{RU}(g_{i,d,t}^{RU} + g_{i,d,t}^{RU,0}) + C_i^{RD}(g_{i,d,t}^{RD} + g_{i,d,t}^{RD,0})\big) \quad (2a)$$

where:

$$V^{LL}=\left\{g_{i,d,t}, g^0_{i,d,t}, \forall i, \forall d, \forall t\right\} \cup \left\{g^{RU}_{i,d,t},\ g^{RU,0}_{i,d,t},\ g^{RD}_{i,d,t}, g^{RD,0}_{i,d,t}, \forall i \in I^{FL}, \forall d, \forall t\right\} \cup \left\{d^{SH}_{d,t}, d^{RU}_{d,t}, d^{RD}_{d,t}, \forall d, \forall t\right\} \quad (2b)$$

$$d^{BA}_{d,t} + d^{SH}_{d,t} - \sum_i (g_{i,d,t} + g^0_{i,d,t}) = 0 \quad : \lambda_{d,t},\ \forall d, \forall t \quad (3a)$$

$$\sum_{i\in I^{FL}} (g^{RU}_{i,d,t} + g^{RU,0}_{i,d,t}) + d^{RU}_{d,t} \geq \sum_{i\in I^{RE}} \delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^0_i) \quad : \lambda^{RU}_{d,t},\ \forall d, \forall t \quad (3b)$$

$$\sum_{i\in I^{FL}} (g^{RD}_{i,d,t} + g^{RD,0}_{i,d,t}) + d^{RD}_{d,t} \geq \sum_{i\in I^{RE}} \delta^{RE}_i \varepsilon^{RE}_i k^{RE}_{i,d,t} (X_i + X^0_i) \quad : \lambda^{RD}_{d,t},\ \forall d, \forall t \quad (3c)$$

$$g_{i,d,t} \geq 0 \quad : \mu_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4a)$$

$$g^0_{i,d,t} \geq 0 \quad : \mu^0_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4b)$$

$$g^{RU}_{i,d,t} \geq 0 \quad : \mu^{RU}_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4c)$$

$$g^{RU,0}_{i,d,t} \geq 0 \quad : \mu^{RU,0}_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4d)$$

$$g^{RD}_{i,d,t} \geq 0 \quad : \mu^{RD}_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4e)$$

$$g^{RD,0}_{i,d,t} \geq 0 \quad : \mu^{RD,0}_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4f)$$

$$g_{i,d,t} + g^{RU}_{i,d,t} \leq X_i \quad : \nu^{RU}_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4g)$$

$$g^0_{i,d,t} + g^{RU,0}_{i,d,t} \leq X^0_i \quad : \nu^{RU,0}_{i,d,t},\ \forall i \in I^{FL},\ \forall d,\ \forall t \quad (4h)$$

$$g^{RD}_{i,d,t} \leq g_{i,d,t} \quad : \nu^{RD}_{i,d,t},\ \forall i \in I^{FL}, \forall d,\ \forall t \quad (4i)$$

$$g^{RD,0}_{i,d,t} \leq g^0_{i,d,t} \quad : \nu^{RD,0}_{i,d,t},\ \forall i \in I^{FL}, \forall d,\ \forall t \quad (4j)$$

$$g_{i,d,t} = X_i \quad : \xi_{i,d,t},\ \forall i \in I^{MR}, \forall d,\ \forall t \quad (5a)$$

$$g^0_{i,d,t} = X^0_i \quad : \xi^0_{i,d,t},\ \forall i \in I^{MR}, \forall d,\ \forall t \quad (5b)$$

$$g_{i,d,t} \geq 0 \quad : \pi_{i,d,t},\ \forall i \in I^{RE},\ \forall d,\ \forall t \quad (6a)$$

$$g^0_{i,d,t} \geq 0 \quad : \pi^0_{i,d,t},\ \forall i \in I^{RE},\ \forall d,\ \forall t \quad (6b)$$

$$g_{i,d,t} \leq k^{RE}_{i,d,t} X_i \quad : \rho_{i,d,t},\ \forall i \in I^{RE}, \forall d, \forall t \quad (6c)$$

$$g^0_{i,d,t} \leq k^{RE}_{i,d,t} X^0_i \quad : \rho^0_{i,d,t},\ \forall i \in I^{RE}, \forall d, \forall t \quad (6d)$$

$$\sum_t d^{SH}_{d,t} = 0 \quad : \sigma_d, \forall d \quad (7a)$$

$$-\alpha d_{d,t}^{BA} \leq d_{d,t}^{SH} \leq \alpha d_{d,t}^{BA} \qquad : \varphi_{d,t}^{-}, \varphi_{d,t}^{+}, \forall d,\ \forall t \qquad (7b)$$

$$d_{d,t}^{RU} \geq 0 \qquad : \chi_{d,t}^{RU}, \forall d,\ \forall t \qquad (7c)$$

$$d_{d,t}^{RD} \geq 0 \qquad : \chi_{d,t}^{RD}, \forall d,\ \forall t \qquad (7d)$$

$$d_{d,t}^{RU} \leq \alpha d_{d,t}^{BA} + d_{d,t}^{SH} \qquad : \psi_{d,t}^{RU},\ \forall d, \forall t \qquad (7e)$$

$$d_{d,t}^{RD} \leq \alpha d_{d,t}^{BA} - d_{d,t}^{SH} \qquad : \psi_{d,t}^{RD},\ \forall d, \forall t \qquad (7f)$$

The objective function (1a) of the UL problem maximizes the profit of the examined strategic generation company across the yearly horizon, which includes the following components: i) its profit from selling energy in the market (first term), ii) its profit from providing (through its flexible generation) upward and downward reserves in the market (second term), iii) the upward and downward reserve payment allocated to its renewable generation (third term), and iv) its investment cost for procuring generation capacity (fourth term). This problem is subject to the natural positivity limits of the investment decisions (1b), as well as the out-of-market adequacy constraints (1c) which are imposed by the regulator to ensure that security of supply requirements are satisfied (Section 3.1).

The UL problem is also subject to the LL problem (2a)-(7f) which represents the joint energy and reserve market clearing process at each representative day, minimizing the short-term (operating) cost of energy and reserve provision (2a), and being subject to five distinct sets of constraints. The first set of constraints (3a)-(3c) involves system-wide constraints, including the demand-supply energy balance constraints (3a) (the Lagrangian multipliers of which constitute the energy clearing prices), and the upward and downward reserve constraints (3b) and (3c) (the Lagrangian multipliers of which constitute the upward and downward reserve clearing prices, respectively).

The second set of constraints (4a)-(4j) involves the operating constraints of flexible generation technologies, including the natural positivity limits of energy and reserve provision (4a)-(4f), capacity limits constraining the sum of energy production and upward reserve provision (4g)-(4h), and upper limits for the downward reserve provision (4i)-(4j). The third set of constraints (5a)-(5b) involves the operating constraints of “must-run” generation technologies, expressing the fact that they operate at their full capacity during all times. The fourth set of constraints (6a)-(6d) involves the operating constraints of renewable generation technologies, expressing the fact that their dispatch is constrained by their uncontrollable normalized output, and this output can be curtailed if required.

The fifth set of constraints (7a)-(7f) involves the operating constraints of the demand side. Its energy shifting flexibility is expressed by constraints (7a)-(7b). The variable $d_{d,t}^{SH}$ represents the change of demand with respect to the baseline level $d_{d,t}^{BA}$ at day d and hour t due to load shifting, taking negative / positive values when demand is moved away from / towards (d,t). Constraint (7a) ensures that demand shifting is energy neutral within the daily market horizon (Section 2.1). Constraint (7b) expresses the limits of demand change at each hour due to load shifting as a ratio α ($0\% \leq \alpha \leq 100\%$) of the baseline demand; $\alpha = 0\%$ implies that the demand does not exhibit any time-shifting flexibility, while $\alpha = 100\%$ implies that the whole demand can be shifted in time. Beyond energy shifting, demand flexibility can also be used for reserve provision, which is constrained by (7c)-(7f). Finally, it should be noted that the flexibility of the demand side can reduce the peak demand of the system, and is therefore factored in the adequacy constraint (1c).

2.3 Solution of Bi-Level Optimization Problem through MPEC Reformulation

In order to effectively solve the above bi-level optimization problem, the LL problem is replaced by its *Karush-Kuhn-Tucker* (KKT) optimality conditions, a transformation enabled by the continuity and convexity of the LL problem. This converts the bi-level problem to a single-level MPEC which is formulated as:

$$\max_{V^{MPEC}} \sum_d w_d \Big[\sum_{i,t}(\lambda_{d,t} - C_i^{EN}) g_{i,d,t} + \sum_{i \in I^{FL},t}\big((\lambda_{d,t}^{RU} - C_i^{RU}) g_{i,d,t}^{RU} + (\lambda_{d,t}^{RD} - C_i^{RD}) g_{i,d,t}^{RD}\big) - \Gamma\big(\sum_{i \in I^{RE},t}(\lambda_{d,t}^{RU} + \lambda_{d,t}^{RD})\delta_i^{RE}\varepsilon_i^{RE} k_{i,d,t}^{RE} X_i\big)\Big] - \sum_i C_i^{IN} X_i \tag{8a}$$

where:

$$V^{MPEC} = \{X_i, \forall i\} \cup V^{LL} \cup \{\lambda_{d,t}, \lambda_{d,t}^{RU}, \lambda_{d,t}^{RD}, \varphi_{d,t}^{-}, \varphi_{d,t}^{+}, \chi_{d,t}^{RU}, \chi_{d,t}^{RD}, \psi_{d,t}^{RU}, \psi_{d,t}^{RD} \forall d, \forall t\} \cup \{\mu_{i,d,t}, \mu_{i,d,t}^{0}, \mu_{i,d,t}^{RU}, \mu_{i,d,t}^{RU,0}, \mu_{i,d,t}^{RD}, \mu_{i,d,t}^{RD,0}, \nu_{i,d,t}^{RU}, \nu_{i,d,t}^{RU,0}, \nu_{i,d,t}^{RD}, \nu_{i,d,t}^{RD,0}, \forall i \in I^{FL}, \forall d, \forall t\} \cup \{\xi_{i,d,t}, \xi_{i,d,t}^{0}, \forall i \in I^{MR}, \forall d, \forall t\} \cup \{\pi_{i,d,t}, \pi_{i,d,t}^{0}, \rho_{i,d,t}, \rho_{i,d,t}^{0}, \forall i \in I^{RE}, \forall d, \forall t\} \cup \{\sigma_d, \forall d\} \tag{8b}$$

(1b) – (1c), (3a), (5a), (5b) (7a)

$$C_i^{EN} - \lambda_{d,t} - \mu_{i,d,t} + \nu_{i,d,t}^{RU} - \nu_{i,d,t}^{RD} = 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{9a}$$

$$C_i^{EN} - \lambda_{d,t} - \mu_{i,d,t}^{0} + \nu_{i,d,t}^{RU,0} - \nu_{i,d,t}^{RD,0} = 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{9b}$$

$$C_i^{RU} - \lambda_{d,t}^{RU} - \mu_{i,d,t}^{RU} + \nu_{i,d,t}^{RU} = 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{9c}$$

$$C_i^{RU} - \lambda_{d,t}^{RU} - \mu_{i,d,t}^{RU,0} + \nu_{i,d,t}^{RU,0} = 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{9d}$$

$$C_i^{RD} - \lambda_{d,t}^{RD} - \mu_{i,d,t}^{RD} + \nu_{i,d,t}^{RD} = 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{9e}$$

$$C_i^{RD} - \lambda_{d,t}^{RD} - \mu_{i,d,t}^{RD,0} + \nu_{i,d,t}^{RD,0} = 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{9f}$$

$$C_i^{EN} - \lambda_{d,t} - \xi_{i,d,t} = 0, \quad \forall i \in I^{MR}, \forall d, \forall t \tag{9g}$$

$$C_i^{EN} - \lambda_{d,t} - \xi_{i,d,t}^{0} = 0, \quad \forall i \in I^{MR}, \forall d, \forall t \tag{9h}$$

$$C_i^{EN} - \lambda_{d,t} - \pi_{i,d,t} + \rho_{i,d,t} = 0, \quad \forall i \in I^{RE}, \forall d, \forall t \tag{9i}$$

$$C_i^{EN} - \lambda_{d,t} - \pi_{i,d,t}^{0} + \rho_{i,d,t}^{0} = 0, \quad \forall i \in I^{RE}, \forall d, \forall t \tag{9j}$$

$$\lambda_{d,t} + \sigma_d - \varphi_{d,t}^{-} + \varphi_{d,t}^{+} - \psi_{d,t}^{RU} + \psi_{d,t}^{RD} = 0, \quad \forall d, \forall t \tag{9k}$$

$$-\lambda_{d,t}^{RU} - \chi_{d,t}^{RU} + \psi_{d,t}^{RU} = 0, \quad \forall d, \forall t \tag{9l}$$

$$-\lambda_{d,t}^{RD} - \chi_{d,t}^{RD} + \psi_{d,t}^{RD} = 0, \quad \forall d, \forall t \tag{9m}$$

$$0 \le \sum_{i \in I^{FL}} \left(g_{i,d,t}^{RU} + g_{i,d,t}^{RU,0} \right) + d_{d,t}^{RU} - \sum_{i \in I^{RE}} \delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} (X_i + X_i^0) \perp \lambda_{d,t}^{RU} \ge 0, \quad \forall d, \forall t \tag{10a}$$

$$0 \le \sum_{i \in I^{FL}} \left(g_{i,d,t}^{RD} + g_{i,d,t}^{RD,0} \right) + d_{d,t}^{RD} - \sum_{i \in I^{RE}} \delta_i^{RE} \varepsilon_i^{RE} k_{i,d,t}^{RE} (X_i + X_i^0) \perp \lambda_{d,t}^{RD} \ge 0, \quad \forall d, \forall t \tag{10b}$$

$$0 \le g_{i,d,t} \perp \mu_{i,d,t} \ge 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10c}$$

$$0 \le g_{i,d,t}^{0} \perp \mu_{i,d,t}^{0} \ge 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10d}$$

$$0 \le g_{i,d,t}^{RU} \perp \mu_{i,d,t}^{RU} \ge 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10e}$$

$$0 \le g_{i,d,t}^{RU,0} \perp \mu_{i,d,t}^{RU,0} \ge 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10f}$$

$$0 \le g_{i,d,t}^{RD} \perp \mu_{i,d,t}^{RD} \ge 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10g}$$

$$0 \leq g_{i,d,t}^{RD,0} \perp \mu_{i,d,t}^{RD,0} \geq 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10h}$$

$$0 \leq \left(X_i - g_{i,d,t} - g_{i,d,t}^{RU}\right) \perp \nu_{i,d,t}^{RU} \geq 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10i}$$

$$0 \leq \left(X_i^0 - g_{i,d,t}^0 - g_{i,d,t}^{RU,0}\right) \perp \nu_{i,d,t}^{RU,0} \geq 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10j}$$

$$0 \leq \left(g_{i,d,t} - g_{i,d,t}^{RD}\right) \perp \nu_{i,d,t}^{RD} \geq 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10k}$$

$$0 \leq \left(g_{i,d,t}^0 - g_{i,d,t}^{RD,0}\right) \perp \nu_{i,d,t}^{RD,0} \geq 0, \quad \forall i \in I^{FL}, \forall d, \forall t \tag{10l}$$

$$0 \leq g_{i,d,t} \perp \pi_{i,d,t} \geq 0, \quad \forall i \in I^{RE}, \forall d, \forall t \tag{10m}$$

$$0 \leq g_{i,d,t}^0 \perp \pi_{i,d,t}^0 \geq 0, \quad \forall i \in I^{RE}, \forall d, \forall t \tag{10n}$$

$$0 \leq \left(k_{i,d,t}^{RE} X_i - g_{i,d,t}\right) \perp \rho_{i,d,t} \geq 0, \quad \forall i \in I^{RE}, \forall d, \forall t \tag{10o}$$

$$0 \leq \left(k_{i,d,t}^{RE} X_i^0 - g_{i,d,t}^0\right) \perp \rho_{i,d,t}^0 \geq 0, \quad \forall i \in I^{RE}, \forall d, \forall t \tag{10p}$$

$$0 \leq \left(d_{d,t}^{SH} + \alpha d_{d,t}^{BA}\right) \perp \varphi_{d,t}^{-} \geq 0, \quad \forall d, \forall t \tag{10q}$$

$$0 \leq \left(\alpha d_{d,t}^{BA} - d_{d,t}^{SH}\right) \perp \varphi_{d,t}^{+} \geq 0, \quad \forall d, \forall t \tag{10r}$$

$$0 \leq d_{d,t}^{RU} \perp \chi_{d,t}^{RU} \geq 0, \quad \forall d, \forall t \tag{10s}$$

$$0 \leq d_{d,t}^{RD} \perp \chi_{d,t}^{RD} \geq 0, \quad \forall d, \forall t \tag{10t}$$

$$0 \leq \left(\alpha d_{d,t}^{BA} + d_{d,t}^{SH} - d_{d,t}^{RU}\right) \perp \psi_{d,t}^{RU} \geq 0, \quad \forall d, \forall t \tag{10u}$$

$$0 \leq \left(\alpha d_{d,t}^{BA} - d_{d,t}^{SH} - d_{d,t}^{RD}\right) \perp \psi_{d,t}^{RD} \geq 0, \quad \forall d, \forall t \tag{10v}$$

The set of decision variables of the MPEC formulation (8b) includes the decision variables of the UL and the LL problem as well as the Lagrangian multipliers associated with the constraints of the LL problem. The KKT optimality conditions of the LL problem correspond to equations (9a)-(10v).

This MPEC formulation is characterized by several non-linearities, including bilinear terms in the objective function (8a) and the complementarity slackness conditions (10a)-(10v). In order to avoid global optimality issues associated with non-linear formulations, this MPEC is transformed to a *mixed-integer linear problem* (MILP), which can be efficiently solved to global optimality using commercial branch-and-cut solvers. For brevity reasons, this transformation is not presented here, but adopts the linearization approaches presented in previous bi-level optimization / MPEC works [29].

3 CASE STUDIES

3.1 Test Data and Implementation

The examined case studies aim at validating the proposed market-based generation investment planning model in a test system reflecting the general characteristics of the UK system. Four generation technologies are considered, namely wind (as a form of renewable generation), nuclear (as a form of "must-run" generation), combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) (as forms of flexible generation), since they constitute the most widely deployed generation technologies in the UK system [30].The type, existing capacity (derived from [30]) and assumed investment and operating costs of each technology are provided in Table I.

Table I: Assumed parameters of examined generation technologies

	Wind	Nuclear	CCGT	OCGT
Type	Renewable	Must-run	Flexible	Flexible
Existing capacity X_i^0 (MW)	17,600	9,200	17,500	17,500
Investment cost C_i^{IN} (£/MW/year)	93,140	328,210	52,120	26,460
Energy cost C_i^{EN} (£/MWh)	0	4.72	37.68	56.98
Reserve cost $C_i^{RU} = C_i^{RD}$ (£/MWh)	-	-	9.42	14.25

Four typical days, representing the four seasons of the year, are used, and the respective profiles of the normalized output of wind generation and the baseline demand are obtained from [9]. The assumed values of the remaining parameters are presented in Table II.

As discussed in Section 1, the main contribution of the proposed model lies in capturing the flexibility of the demand to shift its energy requirements in time and provide reserves in market-based generation investment planning. In this context, three different cases are examined regarding the flexibility of the demand side:

a) **Base case**: The demand side does not exhibit any flexibility, implying that $\alpha = 0\%$,

b) **Case 1**: The demand side exhibits a flexibility of $\alpha = 10\%$, but this flexibility can be used only for energy shifting, implying that the demand side does not participate in the reserve segment of the market and thus constraints (7c)-(7f) are removed from the formulation of the proposed model, and

c) **Case 2**: The demand side exhibits a flexibility of $\alpha = 10\%$, and this flexibility can be used for both energy shifting and reserve provision, implying that the demand side participates in both energy and reserve segments of the market.

Table II: Assumed parameters in the case studies

Parameter	Value
Weighting factor of winter day w_{winter}	119
Weighting factor of spring day w_{spring}	64
Weighting factor of summer day w_{summer}	91
Weighting factor of autumn day w_{autumn}	91
Standard deviation of wind generation output δ_i^{RE}	3.5
Forecasting error of wind generation output ε_i^{RE}	7%
Flexibility limit of the demand side α	0% and 10%
System adequacy coefficient A	1.01
Percentage of reserve costs paid by wind generation Γ	0% and 100%

Furthermore, as discussed in Section 1, these two flexibility potentials of the demand side (energy shifting and reserve provision) have only been incorporated by the existing literature in centralized planning problems -inherited from the era of vertically integrated electricity utilities- but not in market-based planning problems which reflect the current reality of deregulated electricity systems. In this context, in order to demonstrate the value of the paper's contribution, the optimal generation investment decisions under each of the above three cases (base case, case 1 and case 2) are determined for both the centralized planning and the market-based planning approach. Regarding the latter, as previously discussed, the investment decisions are made by a self-interested generation company, which aims at maximizing its overall profit by employing the proposed model. Regarding the centralized planning approach, the investment decisions are made by a regulated electricity utility, which aims at minimizing the overall system cost. The optimization problem we have employed for modelling this approach follows the standard structure adopted in relevant works [5]-[9]. Specifically, it is a single-level problem with i) the objective function given by equation (11a), minimizing the long-term system cost (given by the sum of the energy, reserve and investment costs), and ii) the constraints (1b)-(1c) and (3a)-(7f).

$$\min_{V^{CEN}} \sum_d w_d \left[\sum_{i,t} C_i^{EN} (g_{i,d,t} + g_{i,d,t}^0) + \sum_{i \in I^{FL},t} \left(C_i^{RU} (g_{i,d,t}^{RU} + g_{i,d,t}^{RU,0}) + C_i^{RD} (g_{i,d,t}^{RD} + g_{i,d,t}^{RD,0}) \right) \right] + \sum_i C_i^{IN} X_i \tag{11a}$$

where:

$$V^{CEN} = \{X_i, \forall i\} \cup V^{LL} \tag{11b}$$

Finally, in contrast with centralised planning models, market-based planning models enable the valuable assessment of the impact of alternative market design options on generation investment planning decisions (Section 1). One important market design aspect lies in the allocation of the payments for the required reserves in the system. In this context, the proposed market-based planning model is executed for two scenarios regarding this allocation: i) a scenario where the reserve payments are allocated exclusively to renewable generation ($\Gamma = 100\%$) and ii) a scenario where the reserve payments are exclusively allocated to the demand side ($\Gamma = 0\%$).

The proposed model has been implemented and solved using the optimization software FICO™ Xpress [31] on a computer with a 6-core 3.50 GHz Intel(R) Xeon(R) E5-1650 processor and 32 GB of RAM. The average computational time required for solving this model across all the examined scenarios was around 7500s.

3.2 Impact of Demand Flexibility under Centralized Planning

The aim of the first set of studies lies in analyzing the impact of demand flexibility under the traditional centralized planning approach, where investment decisions are made by a regulated electricity utility, aiming at minimizing the overall system cost. As discussed in Section 3.1, although this approach does not reflect the current reality of deregulated electricity systems, it provides valuable insights for the subsequent analysis of the market-based planning approach.

Fig. 1 and Table III present the system demand profile corresponding to the representative day of the winter season (which is the season with the peak demand of the year), and the optimal investment decisions of the regulated utility, respectively, for each of the three examined cases regarding the flexibility of the demand side. Under all three cases, these decisions involve: i) significant investment in wind generation, reflecting the effort of the regulated utility to reduce the operating costs of the system, followed by ii) investment in flexible generation (CCGT and OCGT) in order to deal with the net demand variability (i.e. cover the system demand during periods with high demand and low wind generation) and provide the required reserves. It should be noted that wind generation is preferred to nuclear generation for covering the base load of the system, due to the very high investment cost of nuclear generation (Table I) and despite the increase of reserve requirements driven by the integration of new wind generation.

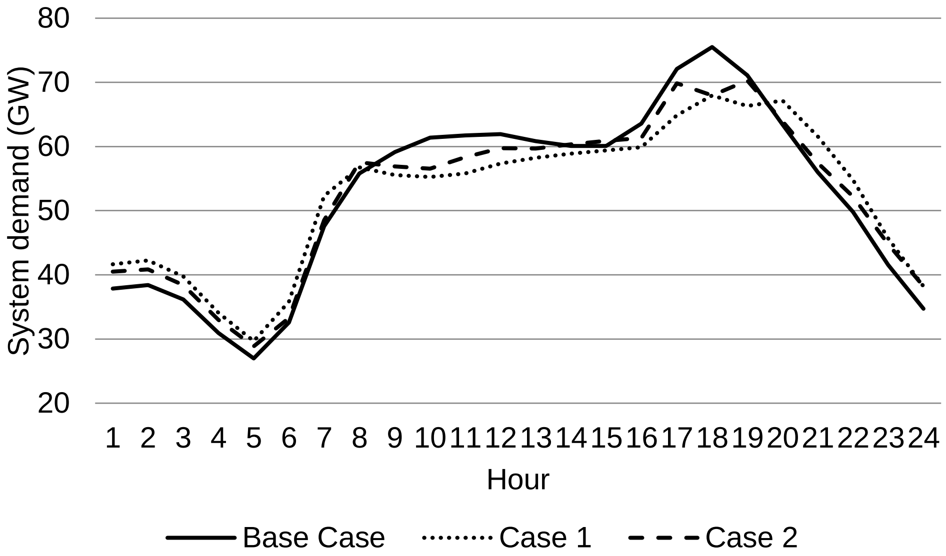

Figure 1: System demand profile under centralized planning and different demand flexibility cases

Table III: Optimal investment decisions under centralized planning and different demand flexibility cases (in GW)

	Base case	Case 1	Case 2
Wind	28.33	33.87	36.24
Nuclear	0	0	0
CCGT	20.16	14.54	15.13
OCGT	11.90	9.89	9.30

In case 1, where the available demand flexibility can be used only for energy shifting, the system demand profile is flattened i.e. the demand is reduced during peak hours and increased during off-peak hours, since demand flexibility is exploited in the market clearing process to reduce the system energy costs (Fig. 1). This effect enhances the cost efficiency of wind generation and thus yields higher investment in wind generation, despite the increase of reserve requirements, while it reduces investments in flexible CCGT and OCGT generation, compared to the base case (Table III).

In case 2, where the available demand flexibility can be used for both energy shifting and reserve provision, the flattening effect on the system demand profile is reduced compared to case 1 (Fig. 1), as the market clearing process retains part of the available flexibility for reserve provision, given that the reserve costs of flexible demand are (zero and therefore) lower than the respective costs of flexible CCGT and OCGT generation. Nevertheless, the cost efficiency of wind generation and consequently investment in wind generation is further increased compared to case 1, due to the reduction of the reserve costs, driven by the zero-cost reserve provision by the demand side. Furthermore, this effect reduces the cost efficiency of flexible generation in providing reserves and consequently investments in flexible generation, compared to the base case (Table III).

Table IV presents the long-term system cost along with its various components for each of the three examined cases regarding the flexibility of the demand side. Following the above discussion, it can be observed that demand flexibility yields a substantial total cost reduction in case 1 with respect to the base case (3.28%). These total cost benefits are driven by the positive impact of energy demand shifting on energy cost, which lies in increasing the wind generation capacity and subsequently the amount of energy produced by zero-cost wind generation, and reducing the amount of energy produced by CCGT and OCGT generation which exhibits high energy costs (Table I). These total cost benefits are achieved despite the increase in the investment cost (driven by the impact of energy demand shifting in increasing investment in wind generation which exhibits high investment cost, Table I) and in the reserve cost (driven by the higher reserve requirements as a result of higher wind generation in the system).

The total cost benefits of demand flexibility are further enhanced in case 2; specifically they are approximately 2 times higher than the benefits achieved in case 1 (6.98% lower cost with respect to the base case). These higher total cost benefits are driven by two correlated positive impacts of demand flexibility: i) the reserve cost is significantly reduced with respect to both the base case and case 1, as the demand side provides part of the required reserves at zero cost, avoiding the high reserve costs of CCGT and OCGT generation, and ii) the energy cost is further reduced with respect to case 1, since the wind generation capacity and subsequently the amount of energy produced by zero-cost wind generation is further increased with respect to case 1 (Table III), and despite the lower flattening effect of demand flexibility in case 2 (Fig. 1). These total cost benefits are achieved despite the further increase in the investment cost with respect to case 1 (driven by the impact of demand flexibility in further increasing investment in wind generation which exhibits high investment cost, Table I).

Table IV: Long-term system cost under centralized planning and different demand flexibility cases (in billion £)

	Base case	Case 1	Case 2
Investment cost	4.004	4.174	4.410
Energy cost	8.848	8.220	8.032
Reserve cost	0.611	0.627	0.081
Total cost	13.463	13.021	12.523

3.3 Impact of Demand Flexibility under Market-Based Planning

The aim of the second (and main) set of studies lies in analyzing the impact of demand flexibility under the market-based planning approach, which reflects the current reality of deregulated electricity systems and constitutes the very focus of this paper. As discussed in Section 3.1, the proposed market-based planning model is executed for two market design scenarios regarding the allocation of payments for the required system reserves: i) a scenario where the reserve payments are allocated exclusively to wind generation ($\Gamma = 100\%$) and ii) a scenario where the reserve payments are exclusively allocated to the demand side ($\Gamma = 0\%$). It should be noted that the centralised planning approach is inherently unable to differentiate between these market design options, since it addresses the planning problem from a societal perspective, completely neglecting the way in which reserve payments (and market payments in general) are allocated (and this is the reason why such scenarios are not examined in Section 3.2).

Table V presents the optimal investment decisions of the examined self-interested generation company for each of the three examined cases regarding the flexibility of the demand side, and each of the two examined scenarios regarding the allocation of the reserve payments. It should be noted that for both reserve payments allocation scenarios the impact of demand flexibility on the system demand profile in case 1 and case 2 are similar to the trends observed under centralized planning (Fig. 1), and thus relevant graphs presenting the system demand profile under market-based planning are not presented here for brevity reasons.

Table V: Optimal investment decisions under market-based generation planning, different demand flexibility cases and different reserve payment allocation scenarios (in GW)

	$\Gamma = 100\%$			$\Gamma = 0\%$		
	Base case	Case 1	Case 2	Base case	Case 1	Case 2
Wind	0	2.22	4.53	13.62	18.33	7.16
Nuclear	7.41	8.79	7.37	0	0	5.76
CCGT	12.13	10.65	11.38	17.37	14.56	11.74
OCGT	12.51	4.99	5.68	14.66	9.83	6.93

We start our analysis by focusing on the scenario where the reserve payments are allocated exclusively to wind generation ($\Gamma = 100\%$). Under all three demand flexibility cases, in contrast with the investment decisions of the regulated utility under centralized planning (Table III), the baseload generation investment decisions of the self-interested generation company involve substantial investment in nuclear generation and lower (in cases 1 and 2) or even zero (in the base case) investment in wind generation (Table V), despite the very high investment cost of nuclear generation (Table I). This result is driven by two effects:

i) A higher wind generation capacity increases the amount of energy produced by zero-cost wind generation and therefore reduces the energy prices which greatly affect the profit of the self-interested generation company. In other words, this company acts strategically by avoiding investment in wind generation and maintaining the energy prices and thus its profits at higher levels. On the other hand, it should be noted that a higher wind generation capacity also increases the amount of required reserves in the system and subsequently the reserve prices; however, the reserve prices and revenues have a significantly lower impact on the company's profit than the energy prices and revenues.

ii) In this specific scenario, since the reserve payments are allocated to wind generation and their size depends proportionally to the amount of wind generation in the system (Section 3.1), the self-interested generation company avoids investment in wind generation and subsequently reserve payments which reduce its profits.

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 (Table V).

In case 1, where the available demand flexibility can be used only for energy shifting, the investments in both baseload generation technologies (wind and nuclear) are increased, while investments in flexible CCGT and OCGT generation are reduced, compared to the base case (Table V). This trend is driven by two correlated effects of energy demand shifting: i) in a similar fashion with centralized planning, energy demand shifting flattens the system demand profile and thus enhances the cost efficiency of baseload generation over flexible generation, and ii) this flattening effect on the system demand profile drives a similar flattening effect on the energy price profile, increasing the energy prices during off-peak hours and therefore enhancing the energy revenues of baseload generation.

In case 2, where the available demand flexibility can be used for both energy shifting and reserve provision, in a similar fashion with centralized planning (Fig. 1), the flattening effect of demand flexibility on the system demand profile, and subsequently on the energy price profile, is reduced, as the market clearing process retains part of the available flexibility for reserve provision. As a result, investment in nuclear generation is reduced compared to case 1 (Table V). On the other hand and despite this reduced flattening effect, investment in wind generation is further increased compared to case 1. This result is driven by the zero-cost reserve provision by the demand side, which reduces the overall reserve costs and subsequently the reserve payments that the generation company needs to incur for its wind generation. Furthermore, this effect reduces the profitability of flexible generation in providing reserves and consequently investments in flexible generation, compared to the base case (Table V).

Table VI presents the long-term profit of the generation company along with its various components for each demand flexibility case. Following the above discussion, it can be observed that demand flexibility yields a significant total profit increase in case 1 with respect to the base case (76.82%). These total profit benefits are driven primarily by the positive impact of energy demand shifting on the energy profit, which lies in increasing the amount of energy produced by zero-cost wind generation and low-cost nuclear generation over high-cost flexible generation, as well as increasing the energy prices during off-peak hours and therefore enhancing the energy revenues of wind and nuclear generation. These total profit benefits are achieved despite the increase in the investment cost (driven by the impact of energy demand shifting in increasing investment in wind and nuclear generation which exhibit high investment costs, Table I) and in the reserve payments (driven by the investment in wind generation).

The total profit benefits of demand flexibility are slightly reduced in case 2 (71.01% higher profit with respect to the base case). This trend is driven primarily by the reduction of the flattening effect of demand flexibility on the energy price profile and consequently the reduction of the energy revenues of baseload generation, despite the reduction in the investment cost (driven by the reduced investment in nuclear generation) and in the reserve payments (driven by the zero-cost reserve provision by the demand side).

Table VI: Long-term profit of examined generation company under different demand flexibility cases and different reserve payment 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 payment	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

We now move our focus on the scenario where the reserve payments are allocated exclusively to the demand side ($\Gamma = 0\%$). In contrast with the scenario $\Gamma = 100\%$, the baseload generation investment decisions of the self-interested generation company involve substantial investment in wind generation and lower (in case 2) or even zero (in the base case and case 1) investment in nuclear generation (Table V). This result is a direct consequence of the market design in this scenario; since wind generation does not incur reserve payments, it becomes a more competitive technology with respect to nuclear generation which exhibits a very high investment cost (Table I). However, the wind generation investment is still lower compared to centralized planning, since it reduces the energy prices and therefore the profit of the generation company. Following this increased investment in wind generation compared to the scenario $\varGamma = 100\%$, the reserve requirements are increased and therefore investments in flexible CCGT and OCGT generation are also increased.

In case 1, demand flexibility has a similar impact on the investment decisions with the scenario $\varGamma = 100\%$. The investment in wind generation is increased, while investments in flexible CCGT and OCGT generation are reduced, compared to the base case (Table V), due to the flattening effects of energy demand shifting on the system demand profile and the energy price profile.

In case 2 however, the impacts of demand flexibility on the investment decisions are reversed compared to the scenario $\varGamma = 100\%$. Specifically, investment in wind generation is reduced compared to both case 1 and the base case, and, in contrast with these two cases, the generation company invests in nuclear generation (Table V). From a first glance, this result seems peculiar, since the previous insights from the centralized planning model and the market-based planning model with $\varGamma = 100\%$ indicate that the zero-cost reserve provision of the demand side is expected to increase the competitiveness of wind generation. However, this peculiar result is associated with the strategic behaviour of the examined generation company, which is captured through the proposed model. Specifically, it is driven by two correlated factors:

i) In this scenario ($\varGamma = 0\%$), the generation company does not incur reserve payments, irrespectively of its investment decisions. Therefore, the zero-cost reserve provision of the demand side does not have a positive impact on the company's profitability. On the contrary, it has a negative impact since it renders the high-cost reserve capability of the company's CCGT and OCGT generation less competitive in the reserve market. In other words, in this scenario the reserve provision capability of flexible demand enhances the competing position of the latter with respect to the generation company.

ii) As previously discussed, the deployment of available demand flexibility for reserve provision limits its deployment in the energy market and therefore reduces its flattening effect on the system demand profile and the energy price profile. However, this flattening effect enhances the profitability of the company's baseload generation in the energy market.

Driven by these two factors, the self-interested company acts strategically by limiting investment in wind generation in order to reduce the size of the reserve market which does not offer significant profits to the company (due to the lower competitiveness of its CCGT and OCGT generation in this market with respect to the demand side) and at the same time increase the deployment of available demand flexibility in the energy market and increase the energy profits of the company's baseload generation (which now includes nuclear generation given the strategic reduction of wind generation). Following this reduced investment in wind generation compared to the base case and case 1, the reserve requirements are reduced and therefore investments in flexible CCGT and OCGT generation are also reduced (Table V).

Regarding the long-term profit of the generation company (Table VI), following the above discussion, demand flexibility in case 1 has a similar impact with the scenario $\Gamma = 100\%$. Specifically, it yields a significant total profit increase with respect to the base case (61.83%), driven primarily by the positive impact of energy demand shifting on the energy profit of baseload generation, despite the increase in the investment cost (driven by the impact of energy demand shifting in increasing investment in wind generation).

In case 2 however, the impacts of demand flexibility on the generation company's profit are distinctively different compared to the scenario $\Gamma = 100\%$. Although the total profit benefits of demand flexibility are still reduced compared to case 1 (40.31% higher profit with respect to the base case), this relative reduction in this scenario (61.83%-40.31%=21.52%) is much more significant than the respective reduction in the scenario $\Gamma = 100\%$ (76.82%-71.01%=5.81%), since the competing position of flexible demand with respect to the generation company is enhanced. Furthermore, this reduction of total profit benefits is now driven primarily by the increase in the investment cost due to the strategic investment in nuclear generation, which has been discussed above.

Finally, when comparing the long-term profit of the generation company under the two examined reserve payment allocation scenarios, we observe that it is substantially lower when the reserve payments are allocated exclusively to wind generation ($\Gamma = 100\%$) than when they are allocated exclusively to the demand side ($\Gamma = 0\%$), for all demand flexibility cases (Table VI). This result is driven primarily by the increase in the investment cost, due to the higher investment in nuclear generation in the scenario $\Gamma = 100\%$. From a higher-level perspective, this result implies (rather intuitively) that the profitability of the generation company deteriorates when the market design puts the burden of reserve payments on the generation side rather than the demand side.

4 CONCLUSIONS AND FUTURE WORK

Previous work has investigated the long-term impacts of demand flexibility in the era of vertically integrated electricity utilities, by adopting traditional centralized generation planning models. On the other hand, its respective impacts in the current era of deregulated electricity systems have not been investigated yet, since existing market-based generation planning models neglect time-coupling effects and system reserve requirements in their representation of the electricity market, rendering them unable to capture the energy shifting and reserve provision capabilities of flexible demand.

This paper has addressed this knowledge gap by proposing a time-coupling, bi-level optimization approach for modeling the investment planning problem of a self-interested generation company in the deregulated environment, 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 renewables-dependent reserve requirements of the system, and the participation of the demand side in these markets.

Case studies in a test system reflecting the general characteristics of the UK system have investigated different cases regarding the flexibility of the demand side (no flexibility, flexibility used only for energy shifting and flexibility used for both energy shifting and reserve provision) and different market design options regarding the allocation of reserve payments (exclusive allocation to renewable generation and exclusive allocation to the demand side).

The first important conclusion stemming from the obtained results is that generation investment decisions and the related impacts of demand flexibility in the current deregulated environment are highly dependent on the electricity market design and the subsequent strategic response of the self-interested generation companies. Specifically, when the reserve payments are allocated to renewable generation, the baseload generation investment decisions of a self-interested generation company involve mainly nuclear generation (despite its very high investment cost) and less renewable generation, while this trend is reversed when the reserve payments are allocated to the demand side. In the case where demand flexibility is used only for energy shifting, similar trends are observed under both market design options, involving higher investment in baseload generation and lower investment in flexible gas generation with respect to a case without demand flexibility. However, in the case where demand flexibility is used for both energy shifting and reserve provision, these two market design options trigger fundamentally different investment decisions, driven by the strategic response of the self-interested generation company. Specifically, when the reserve payments are allocated to renewable generation, the reserve provision capability of the demand side results in higher renewable generation and lower nuclear generation investments, while this trend is reversed when the reserve payments are allocated to the demand side.

A relevant second key conclusion is that, in contrast with the proposed model, this dependency of generation investment decisions and the related impacts of demand flexibility on the electricity market design and the subsequent strategic response of self-interested generation companies cannot be captured by previous centralised planning models, since they address the planning problem from a societal perspective and they completely neglect the way in which market payments are allocated. Specifically, in the examined studies, this centralised approach misleadingly indicates that: i) baseload generation investment decisions involve solely renewable (and never nuclear) generation, ii) this renewable generation investment is much higher than the one envisaged by the proposed market-based planning model, and iii) this renewable generation investment is always increased as a result of both the energy shifting and reserve provision capabilities of the demand side.

Finally, the results of the proposed model indicate that demand flexibility yields significant profit benefits for the examined generation company, driven primarily by the positive impact of energy demand shifting in increasing the amount of energy produced by low-cost baseload generation and the energy prices during off-peak hours. These profit benefits are reduced when flexible demand can also provide reserves, as part of its flexibility is retained for reserve provision and the above positive impacts of energy demand shifting are reduced, and this profit reduction is much more significant when the reserve payments are allocated to the demand side, since the competing position of flexible demand with respect to the generation company is enhanced. Finally, for all demand flexibility cases, the generation company's profit is substantially lower when the reserve payments are allocated to renewable generation, since the market design is less favourable for the generation company.

Future work aims at enhancing the proposed model in two directions. The first one lies in capturing the strategic interactions between the investment decisions of multiple generation companies by extending the proposed model to an equilibrium programming model determining long-term generation planning equilibria stemming from these interactions, and analysing the impacts of flexible demand on such equilibria. The second one lies in incorporating the operation of capacity markets, which have recently emerged as a market mechanism to preserve generation adequacy and address the "missing money" problem of generation companies [32]-[33], in the proposed model and representing the participation of the demand side in such markets.

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