Impact of Demand Response Participation in Energy, Reserve and Capacity Markets

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Abstract

Demand response is capable of providing multiple services, including energy and reserve. As a consequence of providing energy, demand response is also inherently contributing to generation adequacy, and thus may be in entitled to avail of revenue from a capacity remuneration mechanism. Participation in multiple markets may result in a trade-off, thus necessitating simultaneous optimization of the demand response provision of such services. This paper uses Mixed Complementarity Problems to investigate these trade-offs and resulting market outcomes in the presence of load-shifting demand response. An approach to approximate the capacity value of the demand response resource, thereby permitting its participation in the capacity market, is also presented. It is found that, for the case study examined here, that demand response has its most significant impact on the energy market, with marginal and negligible impacts on the capacity and reserve market, respectively. The results also suggest that considerable cost savings are attainable by the DR aggregator through participation in the energy market, but that significant further cost savings are not forthcoming through participation in the reserve or capacity market.

Keywords: Demand Response, Load-Shifting, Mixed Complementarity Problem, Markets, Reserve, Capacity

1. Introduction

Demand Response (DR) can participate in multiple markets, including energy and ancillary services markets, as well as in capacity markets, thereby potentially availing of multiple revenue streams. It has been shown in the literature that DR is technically capable of operating in all electricity markets. DR is capable of participating in the energy market, by offering services such as load-shifting. Load-shifting programs can assist in reducing the need for expensive

Nomenclature

Abbreviations

CRM Capacity remuneration mechanism

CV Capacity Value

DR Demand Response

ELCC Effective Load Carrying Capability

KKT Karush-Kuhn-Tucker

MCP Mixed Complementarity Problem

UCED Unit Commitment and Economic Dispatch

Indices

$capacity$ Relates to capacity market

$energy$ Relates to energy market

i Firm

j Technology

$reserve$ Relates to reserve market

t Time in hours

Parameters

CAP Initial installed generating capacity

DEM Non-interruptible system demand

$DMAX$ Maximum capacity of demand response resource

$DREF$ Reference demand

E Elasticity of demand

$ICOST$ Investment cost

MC Marginal operating cost

$MCOST$ Maintenance cost

$RESERVE_{REQ}$ Reserve requirement

$TARGET$ Capacity market target

$WIND$ Wind generation

Variables

κ Capacity price

λ System marginal price

μ Reserve price

Π Profit

cap_{bid} Capacity market bid

cap_{dr} Capacity market bid of the demand response resource

dr_{down} Load-shifting downwards

dr_{up} Load-shifting upwards

$exit$ Market exit decision variable

gen Generator power output

$invest$ Generation capacity investment decision variable

$reserve_{dr}$ Reserve provision from the demand response resource

$reserve_{gen}$ Reserve provision from a generating unit

Sets

H Set containing the first hour of each day

peaking units and in flattening the load profile, by reducing demand at times of high prices and, in the case of load-shifting, by increasing load at times of lower electricity market prices. As a consequence of load-shifting, DR is also also inherently contributing to generation adequacy, thus DR can provide capacity and thus receive capacity payments or operate in capacity markets and ultimately contribute to generation adequacy [1]. Finally, it has been illustrated in the literature that DR is well-placed to provide some reserve services [2, 3, 4, 5], which we define as services which the system operator employs over various time-frames to maintain the supply-demand balance on a continuous basis [6].

The importance of valuing DR was highlighted in [7], where it was noted that undervaluing DR could leave a beneficial resource underexploited, while overvaluing could lead to a situation where there is considerable investment in a resource than cannot be effectively realized. The aim of this paper is to inform the discussion on the value of DR by exploring the impact of DR participation in various electricity markets, simultaneously.

Given that DR can contribute to generation adequacy, and thus has a capacity value (CV), as shown in [8, 9], albeit low in comparison to thermal generation, it is necessary to consider how DR would impact upon electricity markets and upon capacity remuneration mechanisms (CRM). While there has been considerable work reported in the literature in the area of DR participation in electricity markets, there has been little work exploring the impact of DR participating in all three electricity markets (energy, reserve and capacity) simultaneously. Participation of DR in multiple markets may necessitate in a trade-off between the services offered. Thus there is a need for consideration of simultaneous optimization of the DR provision of multiple services. This paper aims to inform the discussion on these topics.

It is acknowledged that there are many types of DR resources, many different programs to exploit these resources and multiple approaches to modeling them. In this paper, one type of DR resource is considered: electrical space and water heating. Such a resource is chosen because of the inherent thermal inertia associated with it, making it suitable for load-shifting, whilst still maintaining the ability to meet customers' heating demands.

This paper considers an electricity system with energy and reserve markets, as well as a capacity market in the form of a capacity auction. Multiple firms with different initial endowments of generating capacity compete with each other and participate in the three electricity markets in an effort to maximize their profits. Each firm decides the level of generation, reserve provision, capacity bid, investment and exit, subject to physical constraints, operating, maintenance and investment costs and the market clearing prices. A DR aggregator is also considered, responsible for scheduling the operation of a load-shifting DR resource capable of providing reserve, but also implicitly contributing to generation adequacy, whilst ensuring consumers' requirements are satisfied at all times. Similar to the generating firms, the DR aggregator seeks to maximize their profit subject to resource constraints and the market clearing prices. The type of DR resource considered is a load-shifting DR resource. Wind generation is also incorporated, however wind only contributes to the energy market and its sole function is to reduce net demand.

Five different models are developed in this paper, considering different combinations of DR market participation. These models are discussed in detail in section 2.4. A novel method for approximating the contribution of a DR resource to generation adequacy, and thus its ability to participate in a capacity auction, is also presented in this paper, permitting inclusion of the DR resource in the capacity market model. In order to model these different markets Mixed Complementarity Problems (MCPs) are employed. MCPs involve the definition of complementarity pairs for variables and equations [10]. This means that bounded variables must be mapped to complementarity inequality. An MCP with function F seeks to find vectors x and y such that:

$$0 \leq F_x(x,y) \quad \perp \quad x \geq 0, \tag{1a}$$

and

$$0 = F_y(x,y), \quad y \;\; \text{free}. \tag{1b}$$

Here x represents the nonnegatively constrained variables with associated nonnegative F components denoted F_x while y represents the free variables associated with components F_y that must equal zero exactly [11]. Note: the perb notation, $0 \leq a \perp b \geq 0$, is equivalent to $a \geq 0$, $b \geq 0$ and $ab = 0$.

MCPs are typically made up of the combination of Karush-Kuhn-Tucker (KKT) conditions for optimality from multiple interconnected optimization problems in addition to the market clearing conditions that connect the problems. Assuming the individual optimization problems are convex, the KKT conditions are both necessary and sufficient for optimality. Consequently, solving the MCP solves the different players' optimization problems simultaneously and in equilibrium. The benefits of the MCP approach include the ability to optimize the problems of multiple players simultaneously. Furthermore, MCPs allow primal and dual variables to be constrained together. For example, in the formulation presented in this paper, the output of all generators, with the output of the DR resource, and prices are constrained together via market clearing conditions. An MCP is a particularly useful method when computing a market equilibrium which cannot be represented by an optimization model [10].

Many economic problems can be expressed as MCPs and, consequently, MCPs have been widely deployed in the literature for electricity market analysis. Höschle *et al.* [12] employ an MCP to analyze the impact of a CRM on total system costs. Ventosa *et al.* [13] employ an MCP to represent the participation of hydro and thermal generation in a competitive market. A case study of the Spanish electric power system is used in Liang *et al.* [14] combining an energy and regulation reserve market model. Bushnell [15] presents a framework for studying the competition between multiple firms with hydrothermal generation portfolios. Haikel [16] compares three investment incentive mechanisms (1. capacity payment, 2. forward capacity market, 3. reliability options) and finds that market-based mechanisms would be the most cost-efficient way of ensuring long-term system adequacy and encouraging earlier and adequate new investments. Lynch and Devine [17] utilize a stochastic MCP to examine the effects of refurbishment on electricity prices and investment in generating technology.

In recent years there has been a move towards incorporating price responsive demand in MCP. Daoxin *et al.* [18] include both renewable energy generation and price responsive demand in their MCP. The inclusion of price responsive demand is achieved through the use of a control parameter which reflects the response of consumers to changes in price. However, constraints on the price responsive demand are not taken into account and reserve provision is not considered. While there has been research examining the interaction of DR with high levels of wind penetration, reserve markets with DR participation have only been incorporated through the use of a Unit Commitment and Economic Dispatch (UCED) algorithm [19, 20]. Both [19] and [20] examine the provision of both energy and reserve from DR using a UCED algorithm and assess the impact on operation and cost savings.

In the first case study in [20], demand is modeled as a constant value modified by a sinusoid. Additionally, the authors in [20] chose to only include two generation units in the portfolio; a base load unit and a peaking unit. Furthermore, they have assumed that DR is a fixed fraction of the total system demand at each point in time. In the second case study in [20], hourly demand and wind data is utilized and DR is assumed to be 5% of the system load in each hour. Rather than assume a percentage of the system load which is shiftable, this paper instead utilizes actual data for the demand-side resource requirements and the power system demand.

Conejo *et al.* [21] propose an hourly real-time DR model. The demand model seeks to minimize the cost of meeting the load minus the utility of the customers [21]. Unlike the model in [18], the model developed in [21] crucially includes physical constraints pertaining to the demand resource, including a minimum energy consumption constraint, and ramping limits on hourly load levels. However, again no consideration is given to reserve provision by the DR resource.

Nekouei *et al.*[22] provide a game-theoretic approach for DR. Interplay between aggregators and generators is formulated as a Stakelberg leader game, in which the aggregator influences the spot price of electricity. The consumer seeks to minimize its load curtailment costs, while the aggregator seeks to minimize the aggregate inconvenience of customers. They applied the Stackelberg game to analyze the profitability of DR in South Australia. Crucially, reserve provision by the demand-side is not considered in the model in [22].

The authors in [23] employ an MCP model to minimize costs and incorporate prices responsive demand. In their work on determining an optimal generation mix with DR and wind penetration, De Jonghe *et al.* [23] reviewed some of the literature and found that there have been no generation technology mix models that integrate energy efficiency programs, DR to hourly varying prices and dynamic operating constraints simultaneously. In their paper, they propose three methodologies for integrating short-term demand responsiveness into a technology mix optimization model, one of which is a complementarity programming method [23] and utilize the same DR models in each method. As regards the complementarity programming method employed in [23],the authors formulate a mixed linear complementarity problem, not dissimilar to what is presented in this paper. The key difference is the manner in which the DR is represented. A reference price and quantity demanded for each hour is considered in [23] and elasticity assumptions are utilized[23]. The reference price is the quantity weighted average of the hourly energy prices over the time horizon and the short-term demand function that expresses quantity demanded as a function of relative deviations from the reference price [23]. In this paper, a load-shifting DR resource is modeled, separate from elastic or price-responsive demand, with the ability to provide reserve and contribute to generation adequacy, complete with an energy limit constraint.

This paper is organized as follows: Section 2 introduces the MCP methodology employed and details the DR aggregator problem. Input data, case study information and a description of the different market models employed is discussed in Section 2.5. Section 3 presents the results of the various case studies and sensitivities, while Section 4 discusses the key findings.

2. Methodology

This section details the firms' and DR aggregator problems as well as the market clearing conditions, under competitive market conditions. The corresponding KKT conditions are also derived and presented in the Appendix. Throughout this section, parameters are denoted with capitals, primal variables are denoted with lower case lettering. Variables in parentheses, alongside constraints, are the Lagrange multipliers associated with the constraints and are denoted with lower-case Greek letters.

2.1. Generating Firm's Problem

Each generating firm may have multiple types of generating technologies. Its problem involves choosing the amount of generation ($gen^{t,i,j}$), reserve provision ($reserve^{t,i,j}_{gen}$) and capacity bid ($cap^{i,j}_{bid}$), as well as investment in new capacity ($invest^{i,j}$) and decommissioning of existing capacity ($exit^{i,j}$), for all of its generating units in order to maximize their profits, Π^i_{gen}. These profits consist of profit from the energy, reserve and capacity markets, Π^i_{Energy}, $\Pi^i_{Reserve}$ and $\Pi^i_{Capacity}$, respectively, where i is an index representing each different firm, j represents the generating technology and t is the time index, in this case 1-hour. Firm i's problem is:

$$\max_{\substack{gen\\exit\\invest\\cap}} \quad \Pi^i = \sum_j \Pi^{i,j}_{energy} + \sum_j \Pi^{i,j}_{reserve} + \sum_j \Pi^{i,j}_{capacity}, \tag{2a}$$

where

$$\Pi^{i,j}_{energy} = \sum_t (gen^{t,i,j}) \times (\lambda^t - MC^{i,j}), \tag{2b}$$

$$\Pi^{i,j}_{reserve} = \sum_t (reserve^{t,i,j}_{Gen}) \times \mu^t, \tag{2c}$$

$$\Pi^{i,j}_{capacity} = (cap^{i,j}_{bid}) \times (\kappa) - (invest^{i,j}) \times ICOST^j - (CAP^{i,j} - exit^{i,j}) \times MCOST^j, \tag{2d}$$

subject to:

$$gen^{t,i,j} + reserve^{t,i,j}_{Gen} \leq CAP^{i,j} - exit^{i,j} + invest^{i,j}, \quad (\theta_1^{t,j}), \quad \forall t, j, \tag{2e}$$

$$cap^{i,j}_{bid} \leq CAP^{i,j} - exit^{i,j} + invest^{i,j}, \quad (\theta_2^{i,j}), \quad \forall t, j, \tag{2f}$$

The variables λ_t, μ_t and κ represent the prices associated with the energy, reserve and capacity markets receptively. Each are exogenous to the firms' problems but are variables of the overall model determined via the market clearing conditions. All of the generating firm's primal variables are constrained to be non-negative.

The parameter $MC^{i,j}$ denotes the marginal cost of generating firm i technology j, $ICOST^j$ represents the investment cost of generating technology j, while $MCOST^j$ is the maintenance cost associated with technology j. The parameter $CAP^{i,j}$ represents the initial endowment of generating capacity for each firm i and for each technology j.

Equation (2a) is the objective function of the generating firm. Each generating firms choses how to participate in each market in order to maximize their profit. Equation (2b) represents the energy component profit of the generator and consists of the revenue obtained from the energy market less the marginal cost $MC^{i,j}$ of producing energy. Equation (2c) denotes the reserve component of the generator's profit. As can be seen, there is no cost component associated with providing reserve as it is assumed that the cost of providing reserve is the opportunity cost of not providing energy. Equation (2d) represents the revenue from the capacity market less investment costs and maintenance costs associated with providing capacity. Equation (2e) constrains the power and reserve provided by a generating unit to be strictly less than or equal to the installed capacity of the unit, taking any exit and investment decisions into account. Equation (2f) ensures the capacity bid of each generator does not exceed the installed capacity.

2.2. Demand Response Aggregator Problem - Energy, Reserve and Capacity Markets

The DR aggregator's problem is to choose DR in both the downward and upward direction, dr^t_{down} and dr^t_{up}, respectively, reserve provision, $reserve^t_{dr}$, and capacity market bids cap_{dr} so as to maximize profits from the energy, reserve and capacity markets. The total load-shifting performed by the DR resource is the net result of a combination of dr^t_{down} and dr^t_{up}, the upwards and downwards change in demand at each time, t. In this paper, DR can only provide reserve in the downward direction (from the DR point of view). This DR reserve is assumed to be analogous to a generator providing upward reserve, permitting the formulation of Equation (4c) to represent a reserve market.

As shown in [9, 24, 25], DR is capable of reducing peak demand thereby displacing a certain amount of peaking generating capacity. This capability is often referred to as the contribution to generation adequacy of the resource. Generation adequacy is defined as the existence of sufficient generating capacity on the power system to meet peak load and is usually expressed by capacity value metrics [26]. In [25] a new metric called the Equivalent Generation Capacity Substituted is proposed. The authors in [25] suggest that the Equivalent Generation Capacity Substituted metric indicates the amount of conventional generation capacity that can be displaced by DR without impacting upon the original level of generation adequacy. In [8], the Effective Load Carrying Capability (ELCC) is the metric used, which is the amount by which a system's load can increase when the generator is added to the system, while maintaining the system's adequacy [27]. It should be noted, as highlighted in [28], that there are a variety of possible definitions and calculation methods for capacity value metrics. Thus, there is not one single definite value for the capacity value of a resource.

Throughout an entire year, the period during which a lack of generation adequacy would be most apparent is the peak demand period. In the MCP models presented here, firms make investment and exit decisions based on the peak system demand and their profitability. Firms decide to invest in generation if there is a deficit during peak periods and there is scope for them to recoup their investment costs. On the other hand, firms will opt to exit the market if there is excess generating capacity, displacing their operation at the peak, thus impacting upon their profits. Thus it is plausible that a change in investment seen with the addition of a DR resource in an MCP model is representative of the contribution of the DR resource to generation adequacy. Consequently, it is proposed here that the change in generator investment due to the addition of the DR resource is an indication of the capacity value of the DR resource, and the DR resource is then in a position to participate in the capacity market.

It is assumed that, in future electricity markets, reference demands relating to DR resources will be knowable and obtainable by DR aggregators, and that reserve markets are non-discriminatory, permitting the participation of DR. It is also assumed that DR aggregators are capable of responding to wholesale electricity market prices. Assuming the DR resource is capable of providing a response (dr^t_{down} and dr^t_{up}) and providing reserve in the same period as well as the ability to participate in the capacity market, the DR aggregators problem is:

$$\max_{\substack{dr_{down} \\ dr_{up} \\ reserve_{dr} \\ cap_{dr}}} \quad \Pi_{dr} = \Pi_{energy} + \Pi_{reserve} + \Pi_{capacity}, \tag{3a}$$

where

$$\Pi_{energy} = \sum_t (dr^t_{down} - dr^t_{up} - DREF^t) \times \lambda^t, \tag{3b}$$

$$\Pi_{reserve} = \sum_t (reserve^t_{dr}) \times \mu^t, \tag{3c}$$

$$\Pi_{cap} = cap_{dr} \times \kappa - MC^{slack} \times slack, \tag{3d}$$

subject to:

$$dr^t_{down} + reserve^t_{DR} \leq DREF^t, \ \ (\gamma^t_1), \ \ \forall t, \tag{3e}$$

$$dr^t_{up} + DREF^t \leq DMAX, \ \ (\gamma^t_2), \ \ \forall t, \tag{3f}$$

$$\sum_{t=t'}^{t'+23} (dr^t_{down}) = \sum_{t=t'}^{t'+23} (dr^t_{up}), \ \ (\gamma^{t'}_3), \ \ \forall t' \in H = \{1, 25, 49, ...\}, \tag{3g}$$

$$cap_{dr} \leq \sum_{i,j} INVEST^{i,j}_{NoDR} - \sum_{i,j} invest^{i,j}_{DR} + slack, \ \ (\gamma_4). \tag{3h}$$

The parameter $DREF^t$ represents the amount of load end-users would wish to consume at a specific point in time, t, and thus represents the electrical demand in the absence of DR. The parameter $DMAX$ represents the total installed capacity of the DR resource. Equation (3a) is the objective function of the DR aggregator. The DR aggregator choses how to participate in each market in order to maximize their profit. Equation (3b) represents the energy component of the DR aggregator's profit and consists of the revenue obtained from the energy market due to load-shifting as well as the cost of meeting the consumers reference demand, $DREF^t$. Equation (3c) denotes the reserve component of the DR aggregator's profit, while Equation (3d) represents the capacity component. As can be seen, there is no cost component associated with providing reserve as it is assumed that the cost of providing reserve is the opportunity cost of not participating in the energy market. Constraint (3e) ensures that, in each time-step, t, the DR aggregator can only shift downwards and can only provide upward reserve (from the point of view of the power system) by an amount less than or equal to the reference demand. That is, there can only be downwards shifting load and reserve if the end-user appliances are on and available. Equation (3f) constraints the upward shifting of the resource to be less than the installed capacity of the end-user appliance, $DMAX$. Constraint 3g represents the energy limited nature of the DR resource and ensures that any shifting downwards is balanced by shifting upwards over a 24 hour period, where H is the set containing the first hour of each day. As is the case for the firms' problems, the prices λ^t, μ^t and κ are exogenous to the DR agregators problem and are determined via market clearing conditions. All of the DR aggregator's primal variables are constrained to be non-negative.

Load-shifting DR is chosen here and is modeled in a generic way in this study. It is intended that the model of the DR can be made resource-specific in future work by varying the values of the parameters relating the maximum installed capacity, $DMAX$, the reference demand, $DREF^t$, and whether or not the resource can provide reserve.

The authors in [20] model DR in a broadly similar way to the representation employed here, but DR reserve is modeled differently. DR reserve is taken to be the difference between the installed capacity of the DR resource and the DR output, in the same way reserve from a generator is modeled. However, in [20], the DR resource output can be positive or negative and so this would suggest that the reserve provided by the DR resource can be upward or downward reserve. However, it also suggests that the reserve provided by the resource can actually exceed the maximum capacity of the DR resource at that instant, which is not plausible in reality. In contrast, here reserve is modeled one direction only to avoid this problem.

Equations (3d) and (3h) represent the manner in which the DR resource is able to participate in the capacity market. The capacity bid, cap_{dr}, is equal to the change in investment from the 'no DR' case (the parameter $\sum_{i,j} INVEST^{i,j}_{noDR}$, see section 2.4) to the case 'with DR' case (the variable $\sum_{i,j} invest^{i,j}_{DR}$). The change in investment is an approximation for the generation adequacy contribution of the DR resource. The slack variable is included in order to ensure that there is no opportunity for the DR aggregator to over-estimate the generation adequacy contribution of the resource. This variable represents generation from an expensive generating unit, MC^{slack}, which would be required to make up any difference between the capacity bid of the DR and the actual, realized generation adequacy contribution of the resource. If the change in investment between the 'no DR' case and the 'with DR' case is zero, the high cost associated with the slack variable forces the variable cap_{dr} to be zero also. Thus, while the slack variable represents generation, its sole function is to ensure that the DR aggregator problem is feasible; there is no participation of this generator in any of the electricity markets.

2.3. Market Clearing Conditions

The different MCPs consider different types of market clearing conditions. These connect each of the firms problems and the DR aggregator problem. The first type of market clearing condition is associated with the energy market and when DR is not considered:

$$\sum_i Gen^{t,i} = DEM^t + E \times \lambda^t, \quad \forall t, \quad (\lambda^t), \tag{4a}$$

where the parameter DEM^t denotes the system demand in hour t and the parameter E represents the elasticity of load, which henceforth refers to elasticity associated with demand or price-responsive load. This price-responsive load is distinct from the DR resource's load shifting. When DR is included Equation (4a) becomes:

$$\sum_i gen^{t,i} = DEM^t - DREF^t + dr^t_{up} - dr^t_{down} + E \times \lambda^t, \;\; \forall t, \quad (\lambda^t). \tag{4b}$$

This type of DR is a load-shifting DR resource. The parameter $DREF^t$, as mentioned earlier, denotes the end-users requirements at each point in time. To avoid double counting this parameter is removed from the supply-demand equation as it is the demand which is satisfied by the load-shifting operation of the DR resource. Wind generation is also incorporated, however it is assumed that wind is a price-taker and does not provide any reserve or a contribution to the capacity market. Therefore wind only contributes to the energy market and its sole function is to reduce net demand. In the analysis which follows, when wind generation is considered it is included as net load. The reserve and capacity markets, with and without DR participation are shown below:

$$\sum_i reserve_{Gen}^{t,i} = RESERVE_{REQ}, \quad \forall t, \quad (\mu^t), \tag{4c}$$

$$\sum_i reserve_{Gen}^{t,i} + reserve_{DR}^{t} = RESERVE_{REQ}, \quad \forall t, \quad (\mu^t), \tag{4d}$$

$$\sum_i cap_{bid}^{i} = TARGET, \quad (\kappa), \tag{4e}$$

$$\sum_i cap_{bid}^{i} + cap_{dr} = TARGET, \quad (\kappa). \tag{4f}$$

Equations (4c) and (4d) represent the reserve market with and without DR participation, while including a reserve requirement, the parameter $RESERVE_{REQ}$. Similarly, the capacity market with and without DR is represented by Equations (4e) and (4f), respectively, where the parameter $TARGET$ represents the amount of generating capacity required.

2.4. MCP Models and Sensitivities

The authors in [23] suggest that since their MCP model minimizes costs and incorporates price-responsive demand, it can be viewed as a optimal generation technology mix model. Similarly, the models employed in this paper (see Figure 1) minimize costs, incorporate both elastic demand and DR, allow for investment and withdrawal of generation and include DR. Thus, these models may also be considered optimal generation technology mix models.

The MCP models are developed in the General Algebraic Modeling System (GAMS) and solved using the PATH solver [29]. Due to the considerable computation time, the MCP analysis is performed for the first 100 days of the year. The market clearing conditions presented in the previous section are utilized in conjunction with the firms problems and the DR aggregator problems in different combinations in order to produce a number of different MCP models, an explanation of these models is now provided:

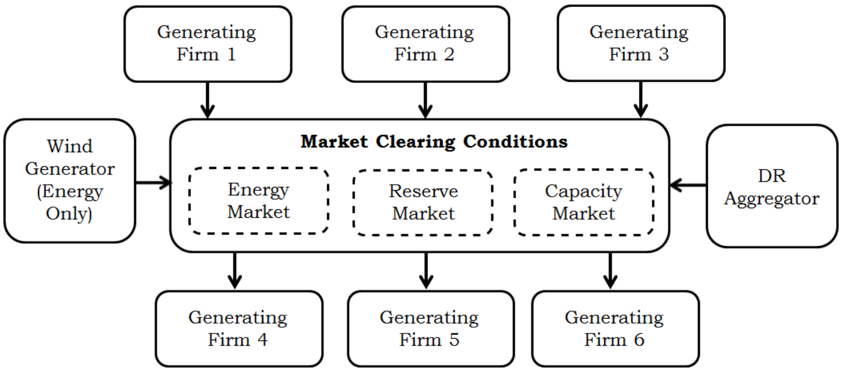

Figure 1: Overview of the methodology

1 **Without a DR resource** - in this model there is no load-shifting DR but there is price-responsive demand. The MCP consists of the generators' problems, KKT conditions (6a) through (6g), and market clearing conditions (4a), (4c), (4e). In order to solve models ii. and iv. below, it is necessary to first solve this model in order to determine the variable $\sum_{i,j} invest^{i,j}$, which becomes the parameter $\sum_{i,j} INVEST^{i,j}_{noDR}$ in Constraint 3h in models ii. and iv.

2 **With a DR resource** - for all of the following models, the MCP consists of the firms' problems, KKT conditions (6a) through (6g). However, the market clearing condition representations differ depending on what markets the DR resource is participating in.

i **DR in Energy Market Only** - the market clearing conditions in this model comprise Equations (4b), (4c) and (4e). The KKT conditions for the DR resource in this model are KKT conditions (7a),(7b), (7d), (7e), (7f) and (7g) with the variable $reserve^t_{DR}$ fixed to zero.

ii **DR in Energy & Capacity Market Only** - in this model DR only participates in the energy market and capacity market. The market clearing conditions in this model comprise Equations (4b), (4c) and (4f). The KKT conditions for the DR resource in this model are KKT conditions (7a),(7b), (7d), (7e), (7f), (7g) and (7h), with the variable $reserve^t_{DR}$ fixed to zero.

iii **DR in Energy & Reserve Market Only** - in this model DR only participates in the energy market and reserve market. The market clearing conditions in this model comprise Equations (4b), (4d) and (4e). The KKT conditions for the DR resource in this model are KKT conditions (7a),(7b), (7c), (7e), (7f) and (7g).

iv **DR in All Markets** - in this model DR participates in all available markets. The market clearing conditions in this model comprise Equations (4b), (4d) and (4f). The KKT conditions for the DR resource in this model are KKT conditions (7a) through (7h).

All of the models presented above are examined by varying the input parameters for the different peak load and wind penetration levels.

2.5. System Data

The initial endowment of generating capacity for each firm, $CAP^{i,j}$, is shown in Table 1 and the corresponding cost characteristics are presented in Tables 2 and 3. Three generating technologies are considered, baseload, mid-merit and peaking capacity. Firm 1 has baseload capacity only, firm 2 has baseload and mid-merit capacity only, firm 3 and 5 are integrated firms, with capacity in all three generation technologies. Firm 4 has baseload and peaking capacity, while firm 6 has peaking capacity only. The marginal costs, maintenance costs and investment costs are all based on the values employed in [17].

Table 1: Initial endowment of capacity $CAP^{i,j}$ for each firm (MW)

Technology	**f1**	**f2**	**f3**	**f4**	**f5**	**f6**
Baseload	1000	800	500	500	400	—
Mid-Merit	—	500	400	—	400	—
Peaking	—	—	200	300	200	200
Firm Total	1000	1300	1100	800	1000	200

From Table 1 it can be seen that the initial installed endowment of generating capacity is 5400 MW. Thus examining a peak load of 7500 MW represents the case where there is considerable under capacity, while examining a peak load of 2500 MW represents over capacity.

Table 2: Marginal Cost $MC^{i,j}$ for each firm (€/MW)

Technology	**f1**	**f2**	**f3**	**f4**	**f5**	**f6**
Baseload	30	45	55	55	65	—
Mid Merit	—	50	35	—	35	—
Peaking	—	—	93	83	93	93

Table 3: Generation Cost Characteristics (€/MW)

Technology	**Maintenance** $MCOST^j$	**Investment** $ICOST^j$
Baseload	25	100000
Mid Merit	12	65000
Peaking	7	45000

The reserve requirement, $RESERVE_{REQ}$, is 500 MW for all cases, unless otherwise stated. The capacity target, $TARGET$, is 1.2 times the system peak load for all cases. In all cases examined, all firms are assumed to be price-takers.

2.6. Demand Data

The reference DR data, denoted as $DREF^t$, utilized in this paper is the space and water heating demand profile for 100,000 apartments on the Irish system as determined by [30]. This data was obtained through the development of 'archetype models' by [30], which are representative of a group of dwellings and dwelling loads. A set of reference dwellings is modeled in detail by [30], using EnergyPlus, a deterministic building energy analysis and thermal load simulation program [31]. These models are converted into building performance simulation 'archetypes' by integrating high space and time resolution operational data. The set of dwelling archetypes is used to generate annual profiles for space and domestic hot water heat demands on a fifteen-minute basis. These consumer end-use heating time series are converted to hourly-resolution and scaled for use in this paper. The installed capacity of the resource, $DMAX$, is 556 MW, while the marginal cost associated with the slack variable, MC^{slack} is €10,000 /MWh.

An annual system demand profile from Ireland for the year 2009 [32] is examined, and scaled linearly as appropriate to produce the parameter DEM^t, with different peak load levels. For example, when peak load in the following sections is stated to be 7500 MW then, for each hourly timestep, DEM^t is 1.5 times that when peak load is stated to be 5000 MW. Actual wind data from Ireland, also for the year 2009, is employed. Elasticity of demand (E) is chosen to be -0.11 as this corresponds to the elasticity of demand on the Irish system as determined by Di Cosmo & Hyland [33].

3. Results

3.1. Impact Demand Response on Energy Markets

The effect of including load-shifting DR can be seen in Figure 2. It is found that the impact on the system marginal price (SMP) profile of adding in the DR resource diminishes with increasing peak load, with the largest impact on SMP occurring in the case with a peak load of 2500 MW. Correspondingly, the system demand profile is altered with the addition of the DR resource, though this effect reduces with increasing peak load. An understanding of the impact of DR on the system demand profile is obtained from examining Figure 3: the DR resource succeeds in reducing system peaks and increasing in system demand at the troughs. As a result of the ability to load-shift, addition of the DR resource results in slight SMP reductions during peak hours, but increased prices during off-peak hours. Figure 2 clearly illustrates this leveling of the SMP during off peak hours.

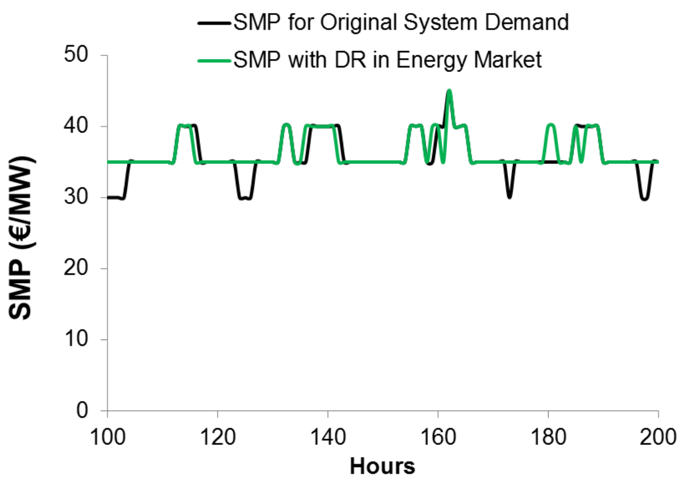

Figure 2: SMP with and without demand response for a peak load of **2500 MW** and no wind generation

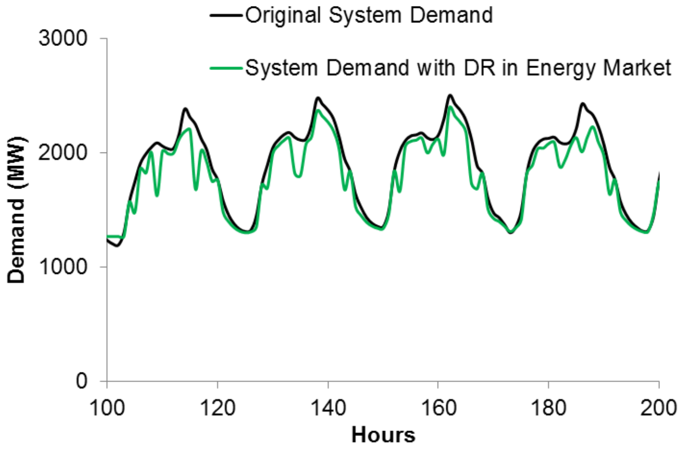

Figure 3: Change in system demand with the addition of demand response for a peak load of **2500 MW** with no wind generation

The reduction in impact on the demand profiles, and by extension, on the SMP profile, is expected given that the size of the DR resource relative to the system demand is decreasing with increasing peak load. The DR resource represents 22%, 11% and 7.4% for peak load levels of 2500 MW, 5000 MW and 7500 MW, respectively. Thus, with increasing load, the impact the DR resource has on the system load profile decreases.

The addition of DR in markets other than the energy market has very little impact on the SMP. This is because the price variations in the energy market is the key driver of the operational decisions of the DR resource. Furthermore, as will be discussed in the following section, for the majority of cases examined the reserve price is zero at all times and thus there is little incentive for the DR to drastically change its operational decisions in order to provide reserve as there is little revenue to be gained. Additionally, the energy limitation constraint placed on the DR resource, in order to ensure consumers' needs are satisfied, restricts how the DR resource can operate. Thus, permitting DR to participate in more than one electricity market simultaneously does not severely impact upon the aggregator's operational decision on how to operate the resource.

When the reserve requirement is low, in this case 500 MW, it is found that the participation of DR in both the energy and reserve markets has a negligible impact on the SMP profile. The following section includes an examination of the impact an increase in the system reserve requirement can have on the capacity and reserve markets.

3.2. Impact of Demand Response on the Reserve Market and on the Capacity Auction

We now consider the impact of the load-shifting DR resource on the reserve market and the capacity auction. When there is low reserve requirements ($RESERVE_{REQ} = 500MW$), the reserve price (μ^t) is €0 in every timestep, with and without DR inclusion in the reserve market. This is because, at such a low reserve requirement level, the generating firms are investing to meet the capacity target, which far exceeds the reserve requirement, and thus the firms are investing to receive capacity payments rather than to receive revenue from the reserve markets.

The capacity price is linked to the Lagrange multiplier of Equation (2f). When $cap_{bid}^{i,j}$ is positive, that is when the firm chooses to participate in the capacity market, $\theta_2^{i,j}$ for firm i and each technology j is equal to the price at which the capacity market clears, κ. Examining the KKT conditions for the generator problem shows that $\theta_2^{i,j}$ is related to both the cost of investment, $ICOST^j$, and the cost of maintenance, $MCOST^j$ for each firm, as well as to $\theta_1^{t,i,j}$ through both Equation (6d) and (6e). In turn, $\theta_1^{t,i,j}$ is dependent on the marginal cost and the SMP λ, through Equation (6a), as well as the reserve price μ through Equation (6b). Essentially the decision for each firm i and each technology j, i.e each unit, to participate in the capacity market is dependent upon the investment, maintenance and marginal costs and the revenue earned from the electricity markets. Any firm and technology whose revenue does not cover costs does not participate in the capacity market. Thus, the price at which the capacity market clears, κ, is the value of the Lagrange multiplier $\theta_2^{i,j}$ for the firm and technology whose revenue exactly equals the costs. These marginal units often do not participate in the energy or reserve markets and so the only costs they incur are maintenance costs. Thus it will be seen that the capacity prices are regularly equivalent to the marginal costs of the different technologies (see Table 3).

Table 4 illustrates that the capacity price (κ), associated with different peak loads and with 0 MW of wind, does not change following the addition of DR. It is found that at a peak load of 2500 MW, there is a slight increase in the installed capacity of peaking plants in the system generating portfolio from the initial endowment of capacity. Thus, it is not surprising that the capacity price is €7 per MW, as this equates to the maintenance cost of the peaking units.

At a peak load level of 5000 MW, the capacity price increases to €25 per MW for all scenarios and all wind levels examined, with and without DR. Such a capacity price is to be expected given that €25 is the maintenance cost of baseload units and baseload generation dominates the generating portfolio and there is no change in mid-merit or peaking capacity following the addition of DR.

At a peak load level of 7500 MW, the capacity price remains at €25 per MW for all scenarios, except at a wind penetration of 1500 MW, when the capacity prices increase dramatically, as can be seen in Table 5. For the case of 1500 MW of wind, the capacity price is €110.

As will be seen in the next section 3.2.2, the capacity bids of the DR resource for all cases are low relative to the capacity target, $TARGET$. DR participation in the capacity market results in only very marginal changes to the generating firms' investment and exit decisions, and accordingly only minor changes to the capacity bids of the different firms. As the marginal unit in the capacity market does not change following the addition of DR, the capacity price also does not change, which is what is seen for the vast majority of cases examined (Tables 4 and 5). However, at a peak load of 7500 MW and with an installed wind capacity of 1500 MW there are considerable changes in capacity price. The addition of DR in the energy market only and in both the energy and reserve markets results in dramatic increases in the capacity price. As might be expected, DR participation in the capacity market reduces these capacity prices by a factor of 5 or more. The capacity price in this case, for all different DR market participation scenarios is equivalent to the value of the Lagrange multiple of Constraint (2f) for Firm 1's baseload unit, $\theta_2^{2,bl}$.

Table 4: Capacity Prices for different peak load levels, a reserve requirement of **500 MW** and wind 0 MW of wind generation

Load Level	No DR	Energy Only	Energy & Res	Energy & Cap	All Markets
2500 MW	€7	€7	€7	€7	€7
5000 MW	€25	€25	€25	€25	€25
7500 MW	€25	€25	€25	€25	€25

Table 5: Capacity Prices for different peak load levels, a reserve requirement of **500 MW** and wind 1500 MW of wind generation

Load Level	No DR	Energy Only	Energy & Res	Energy & Cap	All Markets
2500 MW	€7	€7	€7	€7	€7
5000 MW	€25	€25	€25	€25	€25
7500 MW	€110	€1402	€1402	€272	€272

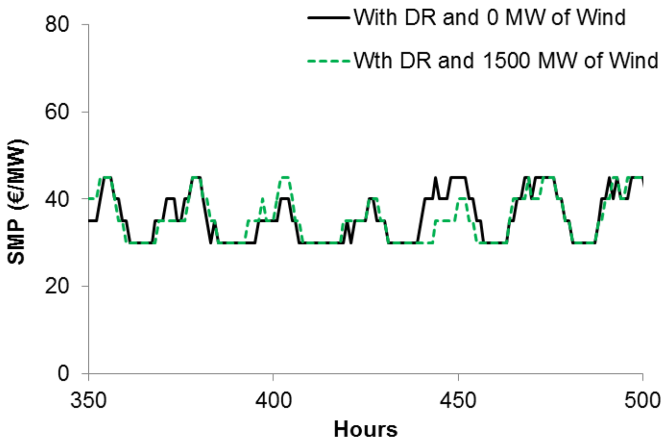

Figure 4: SMP suppression at a peak load of 7500 MW with high wind generation

This large increase in capacity price at both high peak load levels and high wind penetration levels is an interesting result. It is driven by the suppression in SMPs, which can be seen in Figure 4, as a result of high wind generation and DR participation. This suppression in SMPs would result in a reduction in generator revenue. However, the firms' problem seeks to maximize profits. Consequently, higher prices are needed to clear the capacity auction in order to cover the costs associated with the high investment at high peak load levels and to maximize their profits. Crucially, system operating costs do not increase drastically for this particular scenario, as shown in Table 13.

3.2.1. Increasing the Reserve Requirement

We now consider the impact of increasing the reserve requirement. At the highest load level, 7500 MW, there is, initially, considerable under-capacity, as mentioned earlier. Thus, increasing the reserve requirement to 1500 MW has no impact on the reserve price, which remains at €0, as the generating firms are continuing to invest in order to meet the capacity target.

At lower peak load levels 2500 MW and 5000 MW, however, increasing the reserve requirement to 1500 MW impacts upon both the reserve price (at the peak hour only) and on the capacity price. At these lower peak load levels, the necessity to meet the more stringent reserve requirement dominants investment decisions, that is the reserve market constraint becomes binding, and thus firms invest in order to meet the reserve requirement, not the capacity target. This results in capacity prices of €0 for all cases, while the reserve price is extremely low at all hours, except at the peak hour where the reserve price is €25. Figure 5 highlights that the increased reserve requirement at a peak load of 2500 MW incentives greater levels of investment in mid-merit and peaking generation.

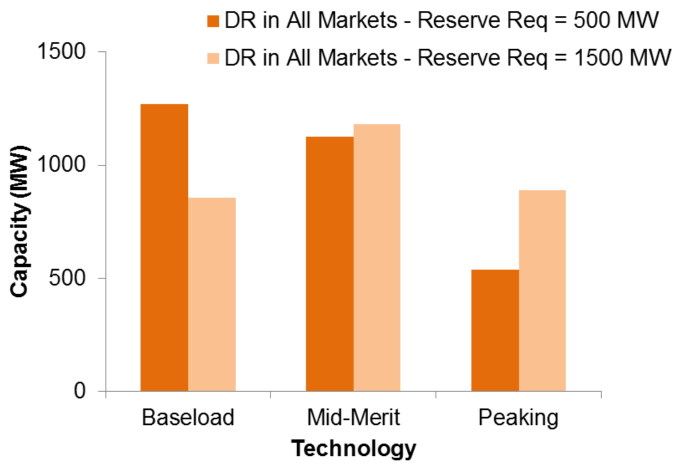

Figure 5: Change in Installed Generating Capacity with increasing reserve requirement with no wind generation - **2500 MW**

While the same change in technology is not noted at peak load levels of 5000 MW or 7500 MW, there is a change in the installed capacity of each firm, with a tendency towards greater levels of installed capacity for firms with more expensive baseload units, particularly firm 5. However, as will be shown in section 3.3, particularly in Table 9, this increase in the capacity of the most expensive baseload unit results in only a very marginal increase in the system operating costs (an increase less than 0.053%).

At a peak load of 7500 MW however, there are capacity prices greater than €0, but it is noted that there is a dependency on whether DR is participating in the capacity market. In the cases were DR is not participating in the capacity market, the capacity price is €25, while it is €0 when DR does provide capacity.

3.2.2. Capacity Bids of the DR Resources

The estimated capacity bids for the DR resource with different peak load and wind generation levels are now considered. Table 6 compares the capacity bid estimations of the DR resources, cap_{dr}, with the Effective Load Carrying Capability (ELCC) estimations obtained from the methodology developed and presented in [8]. Both metrics are then expressed as a percentage of the installed capacity of the DR resource. Interestingly, the magnitude of the net change in generating capacity does not change with the different scenarios, irrespective of whether there is wind participation, unless load-shifting DR is participating in the capacity market. This is as expected. The initial total endowment of capacity is 5400 MW and the peak system load is typically similar or higher than this. The $TARGET$ parameter for the capacity market is set to be 1.2 times the peak system load, which results in a target for capacity exceeding the initial endowment. In order to reach this target there is a requirement for additional generating capacity, and as wind does not participate in the capacity market in these case studies, this need for additional capacity results in investment in generation. When load-shifting DR does participate in the capacity market, the net change in generating capacity is less than the case without DR, as would be expected. It is found here that there is no change in the capacity bid estimates of the DR resource, irrespective of whether or not reserve is provided. This is a result of the fact that exit and investment decisions are incorporated.

Table 6: Comparison of the capacity bid estimation, cap_{dr}, of the DR resource with the Effective Load Carrying Capability estimation at a peak load of 7500 MW and with 0 MW of wind generation

Metric	**MW Estimate**	**CV**
cap_{dr}	126 MW	23%
ELCC	132 MW	24%

Table 7: Capacity bids of DR, cap_{dr}, with and without reserve provision, with a system reserve requirement of 500 MW

Peak Load	**Wind Level**	**With reserve**	**Without reserve**
2500 MW	0 MW	71 MW	71 MW
	1500 MW	0 MW	0 MW
5000 MW	0 MW	123 MW	123 MW
	1500 MW	110 MW	110 MW
7500 MW	0 MW	126 MW	126 MW
	1500 MW	114 MW	118 MW

3.3. Impact of Demand Response on System Operating Costs

In order to determine the system operating costs, Equation (5a) is utilized for the model without DR, while Equation (5b) is employed for all MCP models with DR. These system costs are the total costs paid by consumers, rather than fuel, carbon and other costs incurred by the generating firms. These equation represents the cost incurred by the system in meeting demand, reserve and capacity requirements. The energy cost associated with wind participation in the energy market is also considered.

$$Cost^{noDR}_{System} = \sum_t \sum_i \sum_j (Gen^{t,i,j} \times \lambda^t + Reserve^{t,i,ij}_{Gen} \times \mu^t) + \sum_i \sum_j (Cap^{i,j}_{Bid}) \times \kappa + WIND^t \times \lambda^t \quad (5a)$$

$$\begin{aligned} Cost^{withDR}_{System} = & \sum_t \sum_i \sum_j (Gen^{t,i,j} \times \lambda^t + Reserve^{t,i,ij}_{Gen} \times \mu^t) + \\ & \sum_i \sum_j (Cap^{i,j}_{Bid}) \times \kappa + \sum_t (Reserve^t_{DR} \times \mu^t) + Cap_{DR} \times \kappa + WIND^t \times \lambda^t \quad (5b) \end{aligned}$$

The analysis here shows that the increase in system costs with increasing peak load is roughly commensurate with the magnitude of the increase in peak load. For example, the system costs at 5000 MW are effectively two times the system costs at 2500 MW. Similarly, the system costs at 7500 MW are a factor of 1.5 greater than the corresponding costs at a peak load of 5000 MW. The percentage change in system costs with the addition of DR is 5%, 2.8% and 3.9%, for peak load levels of 2500 MW, 5000 MW and 7500 MW, respectively.

Table 8 presents the system cost savings attainable for the different peak load levels and different wind penetrations, following the introduction of DR, with savings up to 7.4% possible. The final row, which shows the results for the case with a peak load of 7500 MW and with 1500 MW of wind, includes two values. The first corresponds to the case where the DR resource does not participate in the capacity market, and the second for when it does. The reason for the large increase in system operating cost savings for this scenario is a result of the decrease in capacity price, κ, following the introduction of the DR resource in the capacity market, see Table 5.

Table 8: Percentage reduction in system operating costs, including wind costs, following inclusion of Demand Response

Peak Load	**Wind Level**	**Percentage Reduction**
2500 MW	0 MW	5.9%
	1500 MW	7.4%
5000 MW	0 MW	2.8%
	1500 MW	2.8%
7500 MW	0 MW	1.1%
	1500 MW	0.8% or 2.1%

The system operating costs for a range of different scenarios are presented in Table 13. It is found that, for the majority of cases, there is no change between the cases with DR participation in different combinations of energy markets. Once DR is added, the only change to the system is participation of DR in the reserve and capacity markets, which, as seen earlier, does not result in changes to either the reserve price or the capacity prices. As noted in the previous section, at low levels of reserve requirement (in this case, 500 MW) the reserve price is zero at all times, and participation of DR in the capacity market, which as was noted earlier, for the most part, does not change with the addition DR.

The only scenario examined in which the system operating costs change with varying DR market participation is the case with under-capacity and high wind penetration, i.e the case with a peak load of 7500 MW and an installed wind capacity of 1500 MW. This is not surprising given that this was the only case which experienced differing capacity prices with changing DR participation.

Table 9: System costs with DR participating in all markets with different reserve requirements - no wind generation

Peak Load	**Reserve 500 MW**	**Reserve 1500 MW**
2500 MW	€130,249,339	€130,296,961
5000 MW	€271,405,604	€271,415,101
7500 MW	€412,907,825	€413,126,622

As mentioned earlier, increasing the reserve requirement has an impact on both the reserve price and the capacity price. Thus it is conceivable that there would be a similar impact on the system operating costs. Table 9 compares the system operating costs with two different levels of reserve requirement and illustrates that, as expected, the higher reserve requirement results in increased system operating costs.

3.3.1. Generating firms' Profits

Unlike the case with system operating costs, generator profit is not dramatically impacted by the participation of DR in the various electricity markets. In fact, in some cases, firms' profit actually increases slightly with the introduction of the DR resource. Crucially, it appears that generator profit is more heavily affected by the increasing penetration of wind generation than it is by the participation of DR. These results differs from the work presented in [34], where it was found that the introduction of more flexible demand generally reduces the profits of generators. However, in this paper, the profit of the generator includes consideration of the cost of investing in new generator technology as per Equation 2a, while in the work in [34], generator investment decisions, and associated costs, were not included. Consequently, here it is seen that the profit of generatoring firm increases slightly due to the fact that the introduction of DR results in less generator investment. Generator profit, not accounting for investment costs, however, reveals that there is indeed a reduction following the introduction of DR, thus confirming the results in [34], albeit for a different system using a different method.

At a low load level, where the capacity of the DR resource represents 22% of the system peak demand, the inclusion of DR in the energy market and in the energy and reserve markets has an impact on the profit of Firms 3 and 5 (firms with both mid-merit and peaking technologies), with these firms receiving considerably less profit. At higher load levels, the impact of DR on the profit of these firms becomes less pronounced. This is a result of the fact that the size of the DR resource relative to the system load is reducing and thus its ability to impact upon energy prices is also reducing.

Interestingly, at a peak load of 7500 MW, with an installed wind capacity of 1500 MW there is a spike in the profit of Firms 2, 3 and 5 (the only firms with mid-merit generation), particularly when the DR resource is not participating in the capacity market, which is not evident at other load levels. The key reason for this spike in generator profit is due to the large increase in capacity price seen at this wind level, as illustrated in Table 5. Furthermore, Firms 2,3 and 5 are profiting from the absence of the DR resource in the capacity auction.

3.4. Demand Response Aggregator Costs and Optimal Demand Response Portfolio

Tables 10, 11 and 12 indicate that the costs incurred by the DR aggregator decrease following the inclusion of the resource in electricity markets. The aggregator cost savings as a result of market participation are between 4% and 12%. However, for the different scenarios examined, and for the chosen test system, it is found that there is only a very marginal reduction in aggregator costs, and thus benefit to the consumers, as a result of participating in all three markets, compared to participating in the energy market only. This suggests that there is no simple formula for optimal DR participation - it is a case by case consideration.

As discussed in [7], savings on customers' electricity bills may not be sufficient enough to warrant investment in equipment and to compensate for the inconvenience [35] associated with engaging in a DR program. This does indeed seem to be the case here.

The capacity payments earned by the DR resource varies depending on the peak load level, since, as discussed earlier, the capacity price varies considerably with peak load level. In general, however, the capacity payment acquired by the DR resource is less than €3,000, except at a peak load level of 7500 MW and with a wind penetration of 1500 MW. The increase in capacity payment in this scenario is not driven by a change in operating decisions on the part of the DR aggregator. Rather it is a result of significantly higher capacity prices (see final row in Table 5).

From the results presented here it is difficult to ascertain the optimal DR portfolio. It is found from Tables 10, 11 and 12 that the DR aggregator savings increase with increasing peak load level. However, varying the marginal cost inputs, and thus the generating portfolio, it is found that the DR aggregator savings remain relatively constant with increasing peak load level.

Again, this hints at the optimal portfolio for DR being highly system dependent, as was the case with the CV estimates presented in section 3.2.2.

In [36], it is discovered that system cost savings increase with increasing load participation rates but do not grow at the same rate as load participation does. A similar trend in system operational cost savings was noted here. Interestingly, aggregator cost savings have been found to decrease with increasing participation rates. Furthermore, it is discovered that considerable additional savings, over and above the savings as a result of participating in the energy only market, are not awarded to the DR aggregator following the participation in the reserve market. This is because it was found that reserve prices for this particular case study were effectively zero at all times. Therefore, it could be argued that, for this particular stylized system and for this specific DR resource, there is no benefit for the DR aggregator to participate in the reserve market as there is little revenue to be earned. A slight increase in cost savings is achieved through participation in the energy and capacity market, savings which increase at high peak load levels and high installed wind levels. This a result of the fact that, as can be seen in Table 5, the capacity prices increase dramatically for this case. However, at lower wind levels and at lower peak load levels, the optimal portfolio for the load-shifting resource examined here is found to be participation in the energy market only.

The results here suggest that load-shifting resources, such as the type of DR resource considered here, do not benefit from participation in markets other than the energy market. Choosing to participate in the reserve market may not result in considerable reward and may in fact put consumers at a risk of inconvenience, in the form of their load requirements not being met during emergency operating periods, that is periods when the DR resource is called upon to provide reserve. This risk stems from the assumptions employed that any inconvenience placed on customers as a result of failure to meet their heating requirements during emergency operation is compensated by the revenue they receive by permitting their devices to be committed to providing reserve. It has been shown here that the reserve market may not in fact be particularly lucrative for load-shifting DR resources, which concurs with the concerns stated in [35] that the cost savings associated with DR may not justify the inconvenience placed on consumers.

While this assumption may be a misrepresentation of a load-shifting DR resource's ability to participation in the reserve market without inconveniencing the end-user, this is, in effect, captured within in the MCP results. The DR resource chooses to provide limited reserve, with maximum reserve provision of between 7% and 13% of the installed capacity of the DR resource, for all peak load levels and wind levels examined, for a reserve requirement of 500 MW. At the higher level of reserve requirement, 1500 MW, it is found that the DR resource does opt to provide slightly more reserve capacity, but this is a result of the fact that reserve prices at the peak are now higher and the capacity prices are often zero, as discussed in Section 3.2.1. It is acknowledged that some systems do not have reserve markets, but they do have reserve payments. In such a system it may still be worthwhile for a DR resource, such as the type of resource described here, to provide reserve.

As previously alluded to, load-shifting DR resources have an inherent contribution to generation adequacy as a result of their operation. Thus, given that the ability of the DR resource to participate the capacity market is, in effect, a consequence of the operation of the resource in the energy market, there does not appear to be any indication that participation in both the energy and capacity markets results in a trade-off. Thus, in conclusion, the optimal portfolio for the type of DR resource examined here is participation in the energy and capacity markets only.

Table 10: DR Aggregator Costs - peak load 2500 MW

DR Case	**Wind Level**	**Energy Costs**	**Savings**
No DR	0 MW	€7,268,961	—
Energy Only		€6,992,656	3.8%
Energy & Reserve		€6,992,614	3.8%
Energy & Capacity		€6,992,332	3.8%
All Markets		€6,992,118	3.8%
No DR	1500 MW	€7,113,773	—
Energy Only		€6,538,263	8.1%
Energy & Reserve		€6,538,263	8.1%
Energy & Capacity		€6,538,263	8.1%
All Markets		€6,538,263	8.1%

Table 11: DR Aggregator Costs - peak load 5000 MW

DR Case	Wind Level	Energy Costs	Savings
No DR	0 MW	€7,174,783	—
Energy Only		€6,530,838	9%
Energy & Reserve		€6,530,013	9%
Energy & Capacity		€6,527,760	9%
All Markets		€6,526,908	9%
No DR	1500 MW	€7,192,125	—
Energy Only		€6,643,309	7.6%
Energy & Reserve		€6,643,563	7.6%
Energy & Capacity		€6,640,156	7.7%
All Markets		€6,640,284	7.7%

Table 12: DR Aggregator Costs - peak load 7500 MW

DR Case	Wind Level	Energy Costs	Savings
No DR	0 MW	€7,193,387	—
Energy Only		€6,526,963	9.3%
Energy & Reserve		€6,528,960	9.3%
Energy & Capacity		€6,523,612	9.3%
All Markets		€6,525,829	9.3%
No DR	1500 MW	€7,191,498	—
Energy Only		€6,528,872	9.2%
Energy & Reserve		€6,529,387	9.2%
Energy & Capacity		€6,497,859	9.7%
All Markets		€6,361,990	11.5%

4. Conclusion

This paper examined the participation of a load-shifting DR resource in energy, reserve and capacity markets in order to inform the discussion on the impact of DR. Five different models considering different combinations of DR market participation are developed. These markets are modeled as MCPs, permitting optimization of six different generating firms' problems and a DR aggregator's problem simultaneously. An approach to approximate the contribution of the DR resource to generation adequacy is also presented, permitting DR participation in the capacity market.

The results indicate that, in general, the DR resource can have a positive impact on electricity markets. However, this impact is largely limited to the energy market. The participation of DR in the energy market does succeed in reducing variability in SMP, whilst increasing prices at off-peak hours and decreasing peak prices. There are significant system operating cost savings to be obtained following the introduction of DR into electricity markets, mainly driven by the impact of the DR resource on the energy market. It is found that there is minimal impact on generating firms' profits following the addition of DR in the various electricity markets.

In general, there are no major increases in DR aggregator savings as a result of DR participation in more than one market simultaneously, even at high peak load levels. It appears that the 'optimal DR portfolio' is very much a case by case, system by system, consideration.

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Appendix

KKT conditions for firm providing energy, reserve and capacity

The KKT optimality conditions for all firms are given below:

$$0 \leq \quad gen^{t,i,j} \quad \perp \quad -\lambda^t + \theta_1^{t,i,j} + MC^{i,j} \quad \geq 0, \forall t, i, j, \tag{6a}$$

$$0 \leq \quad reserve_{Gen}^{t,i,j} \quad \perp \quad -\mu^t + \theta_1^{t,i,j} \quad \geq 0, \forall t, i, j, \tag{6b}$$

$$0 \leq \quad cap_{bid}^{i,j} \quad \perp \quad -\kappa + \theta_2^{i,j} \quad \geq 0, \forall t, i, j, \tag{6c}$$

$$0 \leq \quad invest^{i,j} \quad \perp \quad ICOST_{i,j} - \sum_t \theta_1^{t,i,j} - \theta_2^{i,j} \quad \geq 0, \forall t, i, j, \tag{6d}$$

$$0 \leq \quad exit^{i,j} \quad \perp \quad -MCOST_{i,j} + \sum_t \theta_1^{t,i,j} + \theta_2^{i,j} \quad \geq 0, \forall t, i, j, \tag{6e}$$

$$0 \leq \quad \theta_1^{t,i,j} \quad \perp \quad CAP_{i,j} - exit^{i,j} + invest^{i,j} - gen^{t,i,j} - reserve_{Gen}^{t,i,j} \quad \geq 0, \forall t, i, j, \tag{6f}$$

$$0 \leq \quad \theta_2^{i,j} \quad \perp \quad CAP^{i,j} - exit^{i,j} + invest^{i,j} - cap_{bid}^{i,j} \quad \geq 0, \forall t, i, j. \tag{6g}$$

As firm i's problem is convex, the KKT conditions are both necessary and sufficient for optimality [11].

KKT conditions for DR providing energy, reserve and capacity

The KKT conditions for the DR aggregator are shown below.

$$0 \leq \quad dr_{down}^t \quad \perp \quad -\lambda^t + \gamma_1^t + \gamma_3^{t'} \quad \geq 0, \ \ \forall t, t' \in H, \tag{7a}$$

$$0 \leq \quad dr_{up}^t \quad \perp \quad \lambda^t + \gamma_2^t - \gamma_3^{t'} \quad \geq 0, \ \ \forall t, t' \in H, \tag{7b}$$

$$0 \leq \quad reserve_{DR}^t \quad \perp \quad -\mu^t + \gamma_1 \quad \geq 0, \ \ \forall t, \tag{7c}$$

$$0 \leq \quad CV_{DR} \quad \perp \quad -\kappa + \gamma_4 \quad \geq 0, \ \ \forall t, \tag{7d}$$

$$0 \leq \quad \gamma_1^t \quad \perp \quad DREF^t - dr_{down}^t - reserve_{DR}^t \quad \geq 0, \ \ \forall t, \tag{7e}$$

$$0 \leq \quad \gamma_2^t \quad \perp \quad DMAX - dr_{up}^t - DREF^t \quad \geq 0, \ \ \forall t, \tag{7f}$$

$$0 = \sum_{t=t'}^{t'+23} (dr_{down}^t) - \sum_{t=t'}^{t'+23} (dr_{up}^t), \ \ \gamma_3^{t'} \ \text{free}, \ \ \forall t' \in H, \tag{7g}$$

$$0 \leq \quad \gamma_4 \quad \perp \quad \sum_i INVEST_{NoDR}^i - \sum_i invest_{DR}^i + slack \quad \geq 0. \tag{7h}$$

As above, since the DR aggregator problem is convex, the KKT conditions are both necessary and sufficient for optimality [11].

Table 13: System operating costs, including wind costs, with different DR market participation combinations

Peak Load	Wind Level	No DR	Energy Only	Energy & Capacity	Energy & Reserve	All Markets
2500 MW	0 MW	€138,338,447	€130,249,339	€130,249,340	€130,249,340	€130,249,339
2500 MW	1500 MW	€135,567,215	€125,590,205	€125,590,205	€125,590,205	€125,590,205
5000 MW	0 MW	€279,132,776	€271,405,604	€271,405,605	€271,405,605	€271,405,604
5000 MW	1500 MW	€278,979,306	€271,142,327	€271,142,327	€271,142,327	€271,142,327
7500 MW	0 MW	€420,624,322	€412,907,825	€412,907,825	€412,907,825	€412,907,825
7500 MW	1500 MW	€421,068,019	€417,519,853	€412,535,101	€417,519,853	€412,328,448