Demand Response and Battery Energy Storage Systems in Electricity Markets: Frameworks & Models

by

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I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

I understand that my thesis may be made electronically available to the public.

Abstract

Ensuring a balance between the generation and demand is one of the most challenging tasks in power systems because of contingencies, sudden load changes, forecasting errors and other disturbances, occurring from time to time. The peak demand, which occurs only for a short duration, has always been a concern for independent system operators (ISOs), as it leads to high market prices and reliability concerns. Furthermore, in recent years there have been significant increase in the penetration of renewable energy sources (RES) to address the challenge of significantly reducing carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions and the system's dependence on fossil fuels based generation resources. However, the high penetration of RES, because of their intermittency and uncertainty, poses operational and reliability issues and thus necessitates an increase in the procurement and deployment of primary and secondary regulation reserves, as well as spinning and non-spinning reserves.

In recent years, demand response (DR) and battery energy storage systems (BESS), because of their characteristic features such as fast response time, high ramp rate, and the ability to provide flexible upward and downward response as compared to conventional generators, have been considered as promising and viable options by the ISO to reduce the peak demand, facilitate RES integration and for the provision of ancillary services, such as regulation and spinning reserves.

Despite the benefits and the growth opportunities of DR and BESS, there are still many challenges associated with their market participation. To address the challenges pertaining to DR and BESS participation in electricity markets, this thesis proposes appropriate models and frameworks, which can efficiently integrate these resources into the day-ahead and real-time electricity markets, and at the same time effectively address the aforementioned challenges of ISOs.

This thesis first presents a new bid/offer structure for DR provisions, simultaneously through price responsive demand (PRD) based bids and load curtailment based DR offers from customers. Thereafter, incorporating the DR offer structure, a novel day-ahead, co-optimizing market auction framework and mathematical model for DR-energy-spinning reserve market, based on LMPs, which includes transmission loss representation within the dc power flow constraints is proposed. The impact of DR on both energy and spinning reserve market prices, market dispatch, line congestions, and other economic indicators, is studied using the IEEE Reliability Test System (RTS), by considering various scenarios and cases.

In the next stage, the thesis considers the BESS participation in the day-ahead markets. First, a novel BESS cost function model, considering Degradation Cost, based on depth of

discharge (DOD) and discharge rate, and Flexibility Cost, in terms of the battery power-to-energy (P/E) ratio, is presented. A detailed bid/offer structure based on the proposed cost functions is formulated. Thereafter, a new framework and mathematical model for BESS participation in an LMP-based, co-optimized, day-ahead energy and spinning reserve market, have been developed. Three case studies are presented to investigate the impact of BESS participation on system operation and market settlement. The proposed model is validated on the IEEE RTS to demonstrate its functionalities.

Finally, the thesis considers BESS participation in the real-time operations. Firstly, a novel framework for simultaneously procuring primary and secondary regulation reserves alongside energy, in a BESS integrated electricity market, by taking into account probabilistic scenarios of contingencies, is proposed. Thereafter, an appropriate mathematical model is developed considering BESS alongside conventional generators to determine the optimal real-time primary and secondary regulation reserves and energy market clearing, in a co-optimized, LMP based market, taking into consideration the *a priori* cleared day-ahead market schedules. Lastly, the impact of participation of BESS in day-ahead and real-time energy and reserve markets on prices, market clearing dispatch, and other economic indicators are investigated using the IEEE RTS, for various scenarios and cases.

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List of Acronyms

AGC	Automatic Generation Control
BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CPP	Critical Peak Pricing
DADRP	Day-Ahead Demand Response Program
DLC	Direct Load Control
DOD	Depth of Discharge
DR	Demand Response
DRR	Demand Response Resource
DSM	Demand-Side Management
ERCOT	Electric Reliability Council of Texas
ESS	Energy Storage System
FERC	Federal Energy Regulatory Commission
genco	Generation company
GAMS	General Algebraic Modelling System
GHG	Green House Gas
IBP	Incentive Based Program
IESO	Independent Electricity System Operator
ISO	Independent System Operator
ISO-NE	Independent System Operator New England

LDC	Local Distribution Company
LMP	Locational Marginal Price
LR	Load Resources
LRP	Load Resource Participation
MIP	Mixed Integer Programming
MISO	Mid-continent Independent System Operator
NERC	North American Electric Reliability Council
NYISO	New York Independent System Operator
OPF	Optimal Power Flow
P/E	Power to Energy
PBP	Price Based Program
PDR	Proxy Demand Response
PHS	Pumped Hydro Storage
PRD	Price Responsive Demand
RDRR	Reliability Demand Response Resource
RES	Renewable Energy Source
RTDRP	Real-Time Demand Response Program
RTP	Real Time Pricing
RTS	Reliability Test System
SOC	State of Charge
TOU	Time of Use
UC	Unit Commitment

Chapter 1

Introduction

1.1 Motivation

Ensuring a balance between the generation and demand is one of the most challenging tasks in power systems because of contingencies, sudden load changes, forecasting errors and other disturbances, occurring from time to time. The peak demand, which occurs only for a short duration, has always been a concern for independent system operators (ISOs), as it leads to high market prices, operational and reliability concerns.

In recent years, the ISOs have to additionally address the challenge of significantly reducing carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions and the system's dependence on fossil fuels based generation resources. In accordance with the Paris (climate change) Agreement of 2015, countries around the globe, including Canada, are in the transition to a low carbon economy [1]. Accordingly, Canada has set a target to reduce its 2005 GHG emission levels by at least 30%, by 2030 [2]. GHG emission reductions of this scale can be achieved through the decarbonization of the electricity system, for which, a 40% increase in renewable energy sources (RES) is envisioned over the next 10 years in Canada [3]. The high penetration of RES, because of their intermittency and uncertainty, poses operational and reliability issues and thus necessitates an increase in the procurement and deployment of primary and secondary regulation reserves, as well as spinning and non-spinning reserves.

In the context of aforementioned challenges, demand response (DR) and energy storage systems (ESS) have been receiving significant attention in recent years to provide valuable services in power systems because of their various advantages [4, 5]. The characteristic features of DR and ESS such as fast response time, high ramp rate, and the ability to provide flexible upward and downward response as compared to conventional generators, makes them promising and viable options for the ISO to reduce the peak demand, facilitate RES integration and for the provision of ancillary services such as regulation and spinning reserves [5, 6].

As a result, there has been a significant increase in their procurement in electricity markets. For example, the US had the largest contracted DR capacity of 27,541 MW in 2017, which was a 8% increase from the previous year (2016) [7], which increased the peak reduction potential to 5.6% from 5% in 2016 [7]. The Independent Electricity System Operator (IESO) of Ontario, Canada, understanding the importance and benefits of DR, started an auction mechanism in 2016 to procure DR services from industrial loads. In 2019, the DR procurement by IESO was reported to be 850 MW, which is estimated to increase by 20% in 2020 [8].

Similarly, when ESS capacity is analyzed, the trend is also very promising. Globally, the installed capacity of ESS had a growth of 16% from 137 GW in 2010 to 159 GW in 2018 [9]. One of the studies foresee the economic value of ESS at maximum market potential to be \$228 billion in the US and \$600 million in Canada, by 2020 [10]. It is noted that in recent years, among the various storage technologies, battery energy storage system (BESS) deployments have increased significantly. It is estimated that the total BESS capacity installed globally of 11 GWh in 2017 is expected to grow to 100-167 GWh by 2030 [11]. In the PJM market in US, batteries have provided 41% of the frequency regulation capacity in 2018 [12]. The main reasons for the wide acceptance and usage of BESS, as compared to other ESS technologies, are: (i) these can be installed anywhere in the power system without any geographical restriction (ii) have higher ramp rate than some of the storage technologies such as pumped hydro (iii) technologies for deploying and controlling grid-scale BESS are now well matured [13]. Thus, this thesis considers BESS as the representative technology to study the role, impacts and benefits of ESS.

Despite the benefits and the growth opportunities of DR and BESS, there are still many challenges associated with their market participation. For example in the case of DR, the following aspects need attention. Firstly, many electricity markets do not have any provision for DR participation and hence there is a need to develop appropriate mechanisms for DR participation. Furthermore, where such provisions exist, the DR provider has to choose from amongst the currently available participation options in electricity markets such as price responsive demand (PRD) bids or curtailable-based DR offers. Also to determine the bid/offer structure to appropriately offer the available DR capacity simultaneously for services such as energy and spinning reserve. Finally, as the offered and cleared DR quantities are within the biddable and cleared demand quantities, respectively, it is very important to capture the inter-relationships between them. Thus, considering the above aspects, there is a need to appropriately design the bid/offer structure, develop frameworks and mathematical models for DR participation in electricity markets.

While for ESS participation in electricity markets, recently some policy interventions have taken place. The US Federal Energy Regulatory Commission (FERC) Order 841 issued in 2018 [14] requires ISOs to facilitate the participation of ESSs in energy, ancillary services, and capacity markets, at par with other participants, by introducing changes in the market design by December 2019. However, there are still many challenges associated with the implementation of this Order. For example, the BESS owners, in order to effectively participate in the electricity markets, should know the actual/marginal cost of operation of the BESS, which depends on its physical and operational characteristics such as the state of charge (SOC), depth of discharge (DOD), discharge rate, degradation, etc. The BESSs have significant advantages over conventional generators because of their high flexibility in response rates, *i.e.*, the time required to charge or discharge, which is in milliseconds, and their ability to act both as a generation source and a load. Hence there is a need to develop appropriately BESS operations cost function model considering Degradation Cost and Flexibility Cost. Furthermore, based on the proposed cost functions, bid/offer structures for the BESS to provide multiple products in the electricity markets need be developed. Finally, as required by FERC Order 841, there is a need for a unified market settlement framework and comprehensive mathematical models to integrate BESS in electricity markets.

The electricity market operations are subject to various uncertainties arising due to increasing penetration of intermittent and non-dispatchable RES, contingencies such as loss of generators and transmission lines, and sudden load deviations, which can affect the market operation drastically. Accordingly, the generation and loads are dispatched through real-time markets to meet the incremental energy needs vis-a-vis the day-ahead market. Also there is a need to procure and deploy primary and secondary regulation reserves based on probabilistic operating scenarios and contingencies in the same time window of real-time markets. In recent years, BESSs have been considered as promising resources to provide regulation services because of their operational flexibility, as compared to conventional resources. Thus, there is a critical need to develop bid/offer structures, and new frameworks and models for simultaneously procuring energy, and primary and secondary regulation reserves from BESS facilities through real-time markets, along side conventional generators.

From the above discussions it is clear that the need for tools to understand the economic and technical impacts of the increasing penetration of DR and BESS in electricity markets have become the need of the day. This thesis proposes appropriate models and frameworks, which can efficiently integrate these resources into the day-ahead and real-time markets, so as to effectively address the aforementioned challenges.

1.2 Literature Review

1.2.1 DR in Electricity Markets

The DR options available and practiced in electricity markets of today, are: (i) Price-responsive demand (PRD) bids; and (ii) Curtailment-based DR offers. The PRD bids are market price dependent, designed to manage price risks, and the ISO has no control on the demand not cleared. On the other hand, the curtailment based DR provides the customer an opportunity to provide a service, after the price-responsive loads have been dispatched.

There are different ways in which an ISO may procure and deploy DR services [15, 16]. For example, in New York ISO (NYISO) the loads submit DR offers for energy curtailment through their day-ahead DR program (DADRP) [17] and real-time DR programs (RTDRP), and a reserve capacity service through the demand-side ancillary service program [18]. In California ISO (CAISO), there are two types of DR resources: proxy demand resource (PDR) and reliability DR resource (RDRR) [19]. The PDRs bid for energy curtailment and non-spinning reserves in the day-ahead and real-time markets; while RDRRs bid for energy curtailment only, in the day-ahead market. In ISO-New England (ISO-NE), the loads submit DR offers for energy curtailment, as well as offers for providing reserve services, in the day-ahead markets [20].

In PJM, there are two types of DR programs, economic DR program and emergency DR program [21]. In the economic DR program, loads can offer demand reductions in the day-ahead and real-time energy market, and capacity offers for reductions in the synchronized reserve, regulation and day-ahead scheduling reserve markets. In the emergency DR program, customers who voluntarily reduce their usage in the energy market, during the event of an emergency, are compensated. In Mid-Continent ISO (MISO), the DR providers are classified as DR resources (DRR-I and DRR-II) and PRD [22]. Both DRR-I and DRR-II submit offers for curtailment in the day-ahead and real-time energy and spinning reserve market, while only DRR-II can bid for regulating reserve services. It is to be noted from the above discussions that in most of the electricity markets in US the loads can offer for curtailment through the real-time and/or day-ahead energy markets, in addition to participating as usual, to buy energy from the respective energy markets. This implies, the loads providing DR services submit three bid curves - bids to buy energy, DR offers to curtail energy, and a DR offer for reserve capacity.

On the other hand, in Electric Reliability Council of Texas (ERCOT), load resource participation (LRP) is one of the DR programs where customers, referred to as load resources (LR), may participate in the real-time market to buy energy [23]. They submit PRD bids which reflect the LR's willingness to consume up to a specified market price. LRs also provide operating reserves in the ancillary service markets in ERCOT. Therefore, to summarize the ERCOT market, it is the only market in USA to have one energy bid and one DR capacity bid.

In Ontario, Canada, the IESO conducts an annual DR auction with two settlement periods (six months each), namely Winter and Summer, where the participants submit price-quantity offers of the curtailable load [8]; on settlement of the DR auction, the selected loads are contracted on long-term (six months), for being ready to be curtailed at 1-hour notice and are dispatched in the real-time energy market or real-time operating reserve market.

Various researchers have proposed modeling frameworks where DR is considered as an energy market participant [24, 25]. In [24], a day-ahead energy market that integrates DR bids into the market clearing process, is proposed. The DR providers carry out appropriate load shifting and curtailment, and use on-site generation and energy storage systems to respond to ISO's dispatch instructions. In [25], a price-responsive benefit function of customers is considered within an energy market settlement to determine the optimal DR dispatch, although unit commitment (UC) constraints are ignored in the market model.

The flexibility provided by DR makes it an ideal ancillary service provision [26]. The integration of DR in reserve markets have been discussed in [27–29]. In [27], DR provisions for reserves, by voluntary reduction during system contingencies is discussed. The DR reserve offers are modeled considering the additional cost arising from demand recovery effect after deployment of reserve provisions. In [28], a two-stage stochastic model for scheduling of reserves using DR in the wholesale electricity market is presented. The benefits to customers from participating in the DR programs of the ISO are demonstrated. In [29], a market model is proposed where DR provides up-spinning, down-spinning and standing reserve. It is shown that participation of DR in reserve markets increases the social welfare and at the same time provides extra scheduling flexibility.

Although in [24, 25], DR was considered only within the energy market settlement, and in [27–29], these were considered for reserve provisions, ideally DR services can be used in co-optimized energy and spinning reserve markets simultaneously, on a need basis. The co-optimized energy and reserve markets result in better economic utilization of the resources. Some of the markets which use co-optimization for energy and reserve market settlement are PJM, NYISO, MISO, ERCOT, and IESO. In [30–33], DR is considered in co-optimized energy and reserve markets. In [30], a PRD shifting bidding mechanism for demand-side reserve provisions in a co-optimized energy and reserve market is proposed and the effect of the incremental costs of exercising the reserves from the demand-side in the market is investigated. In [31], an energy and spinning reserve market clearing mechanism for a wind-thermal power system including reserve offers from DR providers, with uncertainty in wind power and load forecasts is proposed. The results show that a rise in uncertainty level leads to an increase in total cost and total reserve requirements. However, in [30, 31] the transmission system model has not been considered and hence the impacts on the power system are not studied. Furthermore, demand side participation has been considered only for reserve provisions in the day-ahead market. On the other hand, in [32], [33], DR is considered to provide services in both energy and spinning reserve markets. In [32], DR is modeled as price-responsive, shiftable demand in a co-optimized energy and spinning reserve market, the results show a reduction in total costs and in capacity commitment from generators. However, with the modeling approach in [32], it is difficult to take into account the customer preferences to decide what share of the demand, it would bid for energy and reserve provision. In [33], a stochastic UC model for incorporating DR in co-optimized electricity market coordinating with renewable energy resources is presented and a contractual arrangement through aggregators for coupling of renewable resources with deferrable loads is proposed. However, DR is considered to participate in the market without bidding and receives a particular price from the aggregator for each unit of energy not consumed.

From a review of the literature, it is noted that the previous works have mainly focused on integrating DR into either the energy or the reserve market, and not both. Furthermore, DR is either modeled to capture the price-responsiveness of a load or its curtailment feature, but not both simultaneously. Also, the DR offers are not considered in conjunction with the demand bids, nor DR dispatch in conjunction with the cleared demand. There is also a need to consider what share of a customer's total DR it would like to offer in the energy market and in the spinning reserve market. And finally, none of the reported works on DR participation have considered transmission losses within the market settlement models.

1.2.2 BESS in Electricity Markets

Presently the BESSs participate in electricity markets through different ways and market mechanisms across the ISOs [34–38]. The NYISO was the first to initiate a market design in 2018, whereby the ESSs could offer their services in the wholesale energy, capacity, and ancillary service markets, in line with the FERC Order 841 [35]. In this market design, the physical and operational characteristics of an ESS, such as the upper/lower storage limits, SOC, response rate, etc., are taken into consideration.

In PJM, which has the highest installed BESS capacity of 300 MW in North America, BESS participates in the regulation market by submitting two-part offers (capability and performance); while in the energy market they can only submit positive MW offers (discharging offers) with a $0 offer price [39,40], [41], [42]. However, the PJM market has been redesigned to comply with FERC Order 841 and BESS will be allowed to submit charging, discharging and continuous mode operation bids/offers based on cost curves to participate in the energy market; this change is expected to be operational by the end of 2019 [43].

In CAISO, the BESSs can participate in the day-ahead and real-time regulation markets by submitting simple price-quantity based bids and offers for these services [34], [36]. In ISO New England, under the ongoing market design changes, a BESS sized 5 MW or greater would be able to participate in the regulation market from December 2019 [37].

In Ontario, Canada, the IESO procured 50 MW of ESS capacity in 2014 [38], which includes thermal energy storage, BESS, flywheels, and power-to-gas (hydrogen storage) technologies, which are deployed mainly for ancillary services provisions such as regulation, voltage control and reactive power support. However, the BESSs do not bid to provide these ancillary services but are procured and paid through long-term contracts.

A review of the current practices adopted in various ISOs reveals the need for a unified market settlement framework, as required by FERC Order 841, which will allow BESSs to participate in various markets. To do so, they must submit bids/offers by capturing their physical and operational characteristics.

Day-Ahead Energy and Reserve Markets

There is a growing body of literature on integrating ESSs into power system operations [44–47], some recent research has proposed integrating ESS into electricity markets [48–62]. Few works have focused on determining the optimal strategies for coordinated operation of a wind farm and the ESS facility owned by the same entity and participating in electricity markets [48–51]. The participation of an ESS as a grid-scale, independently owned resource, in day-ahead market is discussed in [52–61], which consider optimal bidding and offering strategies, and dispatch models for ESS considering arbitrage, RES integration, and ancillary service provisions.

In [52], an approach to simultaneously optimize investments in new generation and distributed and bulk storage technologies by minimizing the short-term operation cost is presented. In [53–57], the optimal bidding and scheduling of ESS in electricity markets from an owner's perspective, are presented. In [53], a bidding mechanism based on stochastic programming is developed for a group of ESSs that participate in the day-ahead market to provide energy and reserve capacity, and in the real-time market to provide energy. The uncertainty in market prices due to wind power fluctuations and the impact of ESS size and location are considered, to improve the bidding decisions made by the large ESS units. In [54], an optimal bidding strategy is proposed for a BESS, maximizing its benefits by participating in energy and reserve markets. In [55–57], optimal bidding and scheduling mechanisms for ESS using two stage optimization approaches are proposed. The first stage maximizes ESS profit, while the second stage maximizes the overall market benefit considering generation resources and ESS. However, the research in [52–57] neither considers the loss of life (degradation) aspects of an ESS, nor appropriately model the cost function of the ESSs in terms of their physical and operational characteristics.

Few works have considered battery degradation in BESS models related to their participation in electricity markets [58–62]. In [58], battery degradation is modeled by limiting the discharge cycle of the battery only, but the degradation aspect is not a part of the BESS cost function. While [59–62] have considered including battery degradation in modeling the BESS cost function. In [59], a marginal cost function for BESS based on battery degradation was presented. The degradation cost was formulated using linear or quadratic terms for the different components of battery wear such as, degradation caused by DOD, power, and SOC. In [60], a BESS usage cost model was developed by considering degradation based on cycles and DOD, to determine the optimal schedules in the energy market. In [61], a piece-wise linear cost function based on battery cyclic aging, using the rain flow algorithm, was proposed, with bids designed based on the developed cost function. An optimal bidding strategy was proposed for a BESS in [62] considering the battery cycle life model and participation in day-ahead energy, spinning reserve, and regulation markets. However in these works [58,60–62], other important considerations of the BESS such as the degradation due to discharge rates, the cost of flexibility, etc., have not been considered in the BESS cost function formulations.

In view of the above discussions it is apparent that BESS cost functions need to be modeled in proper detail, considering the important aspects such as Degradation Cost based on DOD and discharge rate, and accounting for their flexibility, in a unified market framework, with the objective of maximizing the benefits of all participants. Furthermore, in the context of FERC Order 841, a generic market operations framework and mathematical model to integrate BESS into the electricity markets are urgently needed.

Real-Time Energy and Regulation Markets

Studies have shown that the system frequency regulation capability (β) of different control areas in the US in last few decades, especially in the Eastern Interconnection, has been declining [63], [64], which has been attributed to high governor dead bands, blocked governors, etc. [65]. To overcome these problems, FERC Order 842 [66] mandates the new generation facilities to install, maintain, and operate equipment capable of providing primary frequency regulation. However, there are no directives in the Order regarding monetary compensation for primary frequency regulation. The decline in β may also be attributed to the design of electricity markets that does not incentivize primary regulation reserves. The need for incentivizing primary regulation is one of the principal recommendations of an IEEE Task Force Report [67].

Some works reported in the literature [68–75] have considered primary frequency regulation market design. For instance, in [68,69], a market design mechanism for incentivizing synchronous generators to provide primary frequency regulation is proposed. This work incorporates metrics for primary regulation such as rate of change of frequency, lowest frequency reached (frequency nadir), time to reach frequency nadir, etc., by accounting for characteristics such as inertia, primary regulation capacity, responsive droop curves, and response triggering time, through various constraints. In [70] a simplified dynamic model is presented considering generator response, demand behavior and load shedding to procure frequency regulation reserves through economic dispatch in pool-based electricity markets. In [71], an algorithm and mathematical model is proposed that simultaneously minimizes the cost of primary regulation reserves, while ensuring secure operation of the power system. A decision tree based approach is used to model each pre-specified contingency and arrive at with a set of constraints which are then used in the economic dispatch problem. In [72], an UC model incorporating system frequency limits, generation ramping and capacity constraints associated with primary frequency regulation and the relation between the reserves and the post-contingency system frequency deviation is presented. The benefits of co-optimized clearing of energy and reserves against sequential clearing, by highlighting the strong coupling between the primary reserve capacity and pre-contingency generation, is demonstrated.

A co-optimized market clearing model for energy and primary regulation was presented in [73] that scheduled and priced the kinetic energy of the generator and primary regulation reserves by combining the market clearing engine with a primary regulation pricing mechanism. In [74], deterministic and probabilistic LMP based market models for energy, and primary, secondary, and tertiary reserves are presented, and a single price for all reserve types is determined. It is noted that all the above works have considered the provision of primary frequency regulation from synchronous generators only, without exploring the participation of other viable resources such as energy storage and demand response. In [75], a market model for procurement of primary regulation from both generators and loads, considering the regulation requirement based on system inertia is presented.

Secondary regulation is used to reduce the area control error (ACE) through a centralized control signal via automatic generation control (AGC), their procurement mechanism varying across ISOs. For example, PJM procures and schedules secondary regulation reserves of 525 MW during non-peak and 800 MW during peak hours through the day-ahead regulation market [76]. While, the IESO in Ontario, Canada procures 228 MW secondary regulation reserves each hour through long-term contracts [77]. It is interesting to note that in PJM only 50-60% [76] and in IESO only 50-70% [77] of the scheduled secondary regulation reserves are actually deployed in real-time. Thus, it would be more economically viable to procure a portion of the secondary regulation requirement through the real-time market, which provides a much closer estimate of the requirement.

It is noted that typically, regulation reserves are procured considering the requirements for the system as a whole [68] or considering nodal reserve requirements [74]. In either cases, the regulation reserve requirements are computed considering deterministic conditions of the system, which, however, may lead to over-estimating the needs, and hence increase the cost. Therefore, it is necessary to consider realistic operating scenarios and contingencies while computing the regulation reserve requirements. With the advancements in computing and software it is possible to adequately consider the contingencies using a probabilistic approach to model the reserve requirements and deployments with a closer time window in real-time markets.

In recent years, ESSs have been considered as promising resources to provide regulation services because of their operational flexibility, characterized by fast response time, high ramp rate, and capability to provide upward and downward response. Among the various storage technologies, BESS deployments are significant. Some recent works have considered BESS participation in regulation markets [78–80]. In [78], an operation and control strategy for a BESS co-located with a wind farm to provide primary and secondary regulation is presented. This work proposes an adaptive SOC feedback control mechanism to maintain the SOC at the optimal value as much as possible and thus reduce the size and extend the lifetime of the BESS. A profit maximization model for BESS considering the battery cycle-life is proposed to optimally bid in performance based regulation markets [79]. It is noted that the works in [78–80] are based on the profit maximization of a BESS owner only and do not consider the overall system benefits and impacts.

From a review of the literature, it is noted that no reported works have considered the simultaneous procurement of primary and secondary regulation reserves provided by BESS in real-time electricity markets. Thus there is a need to develop frameworks and models for simultaneously procuring energy, and primary and secondary regulation reserves from BESS facilities through real-time markets, along side conventional generators.

1.3 Research Objectives

A review of the related works reported in the literature reveals the need for models and frameworks for integrating DR and BESS into day-ahead and real-time electricity markets. Accordingly, the objectives of the present research are the following:

- Develop a new bid/offer structure for DR provisions, simultaneously through PRD based bids and load curtailment based DR offers from customers. Incorporating the DR offer structure, propose a novel day-ahead, co-optimizing market auction framework for DR for simultaneous provisions within energy and spinning reserve markets.

- Develop a comprehensive mathematical model for a DR-energy-spinning reserve market, based on LMPs, which includes transmission loss representation within the dc power flow constraints using a piece-wise linear approximation approach. Investigate the impact of DR on both energy and spinning reserve market prices, market dispatch, line congestions, and other economic indicators, for various scenarios and cases.

- Develop a novel BESS cost function model considering the Degradation Cost, which is based on the DOD and discharge rate, and the Flexibility Cost. Propose a bid/offer structure based on the cost functions, for BESS to participate in day-ahead energy and spinning reserve markets, capturing the inter-relationships between the BESS charging bid and discharging offer quantities.

- Develop a generic market operations framework and comprehensive mathematical model for the integration of BESS in a LMP based, co-optimized, day-ahead energy and spinning reserve market by including the proposed BESS charging bid and discharging offer structure.

- Propose a novel framework for simultaneously procuring primary and secondary regulation reserves alongside energy, in a BESS integrated electricity market, by taking into account probabilistic scenarios of contingencies in the real-time operations.

- Develop an appropriate mathematical model considering BESS alongside conventional generators to determine the optimal real-time primary and secondary regulation reserves and energy market clearing, in a co-optimized, LMP based market, taking into consideration the *a priori* cleared day-ahead market schedules.
- Investigate the impact of participation of BESS in day-ahead and real-time energy and reserve markets on prices, market clearing dispatch, and other economic indicators, for various scenarios and cases.

1.4 Outline of the Thesis

The rest of this thesis is structured as follows: Chapter 2 presents a brief background to the topics related to this research including electricity markets, ancillary services, DR, ESS technologies, and BESS degradation mechanism.

Chapter 3 describes the developed bid/offer structure, framework and mathematical model for simultaneous procurement of DR for energy and spinning reserve provisions in the electricity market.

Chapter 4 presents novel cost function formulations for BESS considering the Degradation Cost, which is based on the DOD and discharge rate, and the Flexibility Cost. Thereafter, the proposed framework and model for BESS participation in day-ahead energy and spinning reserve market is presented.

Chapter 5 presents the framework and mathematical model for simultaneously procuring primary and secondary regulation reserves alongside energy, in a BESS integrated real-time electricity market.

Finally, Chapter 6 presents the main conclusions and contributions of this thesis, and identifies some directions for future research work.

Chapter 2

Background

2.1 Nomenclature

Sets & Indices

e	BESS, $e \in E$.
i, q	Indices for the buses, $i \in I$.
j	Index for the generators, $j \in J$.
k	Indices for time (hour), $k \in K$.
E_i	Set of generators connected to bus i.

Parameters

B	Element of susceptance matrix, p.u.
C^d, C^u	Start-up/shut-down cost of generator, \$.
C^D	Customer's demand bid price, \$/MWh.
C^G	Generator offer price for energy/spinning reserve, \$/MWh.
g	Conductance of transmission line, p.u..
$\overline{P}$, $\underline{P}$	Maximum/minimum limit on power output of generator, MW.
$\overline{P}^{Ch}$, $\overline{P}^{Dch}$	Maximum charging/discharging limit of BESS, MW.

$\overline{P}^D$	Customer's demand bid quantity, MW.
$\overline{P}^G$	Generator offer quantity for energy, MW.
$\overline{PFlow}$	Maximum capacity of transmission line between buses, MW.
RU, RD	Ramp up/down limit of generator, MW/h.
$\overline{SOC}$, $\underline{SOC}$	Maximum/minimum SOC limit of BESS, p.u..
TU, TD	Minimum up/down time of generator, hour.
η	Battery round trip efficiency, %.
η^{Ch}, η^{Dch}	Battery Charging/discharging trip efficiency, %.

Variables

$P^{\boldsymbol{Ch}}$, $P^{\boldsymbol{Dch}}$	Charging/discharging power, MW.
P^D	Demand cleared, MW.
P^G	Generation offer cleared, MW.
P^{loss}	Power loss in the transmission line between buses i and q, MW.
U, V	Binary variable = 1, if generator starts/shut downs, and 0 otherwise.
W	Binary variable = 1, if generator is committed, and 0 otherwise.
X	Binary variable = 1, if demand bid is cleared, and 0 otherwise.
Y	Binary variable = 1, if generator offer is cleared, and 0 otherwise.
$Z1$, $Z2$	Binary variable = 1, if BESS is charging/discharging, and 0 otherwise.
δ	Voltage angle of bus, radian.

2.2 Introduction

This chapter presents a review of the background of the topics related to the research carried out in this thesis. In Section 2.3, a basic overview of electricity markets including LMP-based market settlement model is presented. This is followed by an introduction to ancillary services in Section 2.4. A brief outline of different DR programs is presented in Section 2.5, classification of ESS in Section 2.6, followed by review of important topics related to BESSs such important terminologies, operational models and the battery degradation mechanisms in Section 2.7. Finally, Section 2.8 summarizes the chapter.

2.3 Electricity Markets

Power system restructuring has enabled the emergence of electricity markets around the world. In the electricity market context, a single entity is no longer in charge. Multiple agents competitively participate and interact to deliver energy to customers. The main entities in the electricity markets are: generation company (genco), loads, ISO or market operator, transmission system operator, regulator, distribution company, and retailers.

The main purpose of electricity markets is trading of energy and other services among various participants, with an objective to minimize the cost or maximize the social welfare, subject to generation and transmission constraints [81].

Based on the time scale of operation, there are two types of electricity markets wherein products such as energy, ancillary services are traded.

a) Day-Ahead Market: In these markets, a daily auction is arranged for the next day where buyers and sellers submit their bids and offers for energy and ancillary services. In many jurisdictions, there are separate markets for energy and ancillary services. Usually, the market is cleared hourly, *i.e.* the market participants can submit separate bids for each hour, for the next day [82].

b) Real-Time Market: In these markets, the participants buy and sell electricity close to real-time, usually 5 minutes ahead [82]. The real-time market balances the differences between day-ahead commitments and the actual real-time demand. In some jurisdictions the real-time market is sometimes called balancing market.

In this thesis, 'offer' pertains to any service that results in positive injection into the grid and 'bid' pertains to any service that results in negative injection into the grid

The day-ahead and real-time markets can either be a uniform price market *i.e.*, a single market clearing price is determined for the whole system, or an LMP-based market *i.e.*, the price is determined for each node or a zone in the system. In this thesis LMP based day-ahead and real-time markets have been considered. The basic mathematical model for an LMP-based market is presented in the next subsection.

2.3.1 LMP Based Market Model

The objective is to maximize the social welfare given as follows [81]:

$$J = \sum_{k\in K}\sum_{i\in I} C^{D}_{i,k}P^{D}_{i,k} - \sum_{k\in K}\sum_{j\in J}\left(C^{u}_{j,k}U_{j,k} + C^{d}_{j,k}V_{j,k} + C^{G}_{j,k}P^{G}_{j,k}\right) \tag{2.1}$$

The first term in (2.1) represents the gross surplus of customers, the second term represents the total cost of gencos, which includes the start up cost, shut down cost and the energy cost. The model constraints are discussed next, and are based on [81].

Demand-supply Balance: These constraints ensure a balance between the supply and demand at each bus i at hour k.

$$\sum_{j \in E_j} P^G_{j,k} - P^D_{i,k} = \sum_{q \in I} \Big(B_{i,q}(\delta_{i,k} - \delta_{q,k}) \Big) \qquad \forall k \in K, \forall i, q \in I \tag{2.2}$$

In constraints (2.2) the dc-opf equations are used in place of ac power flow equations so as to reduce the computational burden. It is also to be noted that some LMP-based market models include losses in the demand-supply balance, and this thesis also considers losses in the models presented in the subsequent chapters.

Market Clearing Constraints: These constraints ensure that the cleared demand and generation quantities do not exceed their respective bid/offer quantities,

$$P^D_{i,k} \leq \overline{P}^D_{i,k} \, X_{i,k} \quad \forall k \in K, \forall i \in I \tag{2.3}$$

$$P^G_{j,k} \leq \overline{P}^G_{j,k} \, Y_{j,k} \quad \forall k \in K, \forall j \in J \tag{2.4}$$

Transmission Line Constraints: These constraints ensure that the line power flows on the transmission lines are within their limits.

$$P_{i,q,k} \leq \overline{PFlow}_{i,q} \qquad \forall k \in K, \forall i, q \in I \tag{2.5}$$

where,

$$P_{i,q,k} = B_{i,q}(\delta_{i,k} - \delta_{q,k}) \qquad \forall k \in K, \forall i, q \in I \tag{2.6}$$

Reserve Constraints: These constraint ensure that the spinning reserve requirement for the system is provided by the committed generators, as follows:

$$\sum_j (\bar{P}_j - P^G_{j,k}) W_{j,k} \geq RESV \sum_i P^D_{i,k} \qquad \forall k \in K \tag{2.7}$$

where, $RESV$ is a parameter decided by the ISO.

Generalized UC Constraints: These constraints include generation limits, ramp-up/down constraints, minimum-up/down time constraints and coordination constraints.

The following constraints ensure that the output power of generator j at interval k is within its maximum and minimum limits.

$$\underline{P}_j W_{j,k} \leq P^G_{j,k} \leq \overline{P}_j W_{j,k} \qquad \forall j \in J, \forall k \in K \tag{2.8}$$

The ramp-up/down capability of the generator j at interval k is not violated constraints is ensured by the following constraints,

$$P^G_{j,k} - P^G_{j,k-1} \leq RU_j \qquad \forall j \in J, \forall k \geq 1 \tag{2.9}$$

$$P^G_{j,k-1} - P^G_{j,k} \leq RD_j \qquad \forall j \in J, \forall k \geq 1 \tag{2.10}$$

The following constraints ensure that the generator j at interval k meets the minimum-up and down time, requirements [81].

$$\sum_{t=k-TU_j+1}^{k} U_{j,t} \ \leq \ W_{j,k} \qquad \forall t \in [TU_j, K], \forall j \in J, \forall k \geq 1 \tag{2.11}$$

$$\sum_{t=k-TD_j+1}^{k} V_{j,t} \ \leq \ 1 - W_{j,k} \qquad \forall t \in [TD_j, K], \forall j \in J, \forall k \geq 1 \tag{2.12}$$

The following constraints ensure proper transition of UC states from 0 to 1 and vice-versa with unit start-up, shut-down decisions,

$$U_{j,k} - V_{j,k} = W_{j,k} - W_{j,k-1} \qquad \forall j \in J, \forall k \geq 1 \tag{2.13}$$

$$U_{j,k} + V_{j,k} \leq 1 \qquad \forall j \in J, k \tag{2.14}$$

The above presented market model pertains to a day-head market, the model for a real-time market is almost similar with same objective function and set of constraints excluding the UC (start-up and shut-down) constraints. In some real-time market models the objective function may also include the deviation penalties from day-ahead market [83].

The goal of the market operator is to determine the dispatch that maximizes the social welfare, subject to various constraints. This process determines the marginal cost of meeting an increment of load at each bus which are referred to as LMPs, which are the Lagrangian multipliers associated with the supply balance equation in (2.2).

2.4 Ancillary Services

The North American Electric Reliability Council (NERC) defines the ancillary service as: *" An interconnected operation service that is necessary to effect a transfer of electricity between purchasing and selling entities, and which a transmission provider must include in an open access transmission tariff."* [84]. The ancillary services that are relevant in this research are briefly discussed:

a) Frequency response service: It refers to the continual balancing of generation and load to maintain the system's frequency within an acceptable range. Frequency response service is the immediate governor response resulting from a change in interconnection frequency. This service is explicitly meant for a condition which arises due to a disturbance in the system.

b) Regulation: It refers to the minute-to-minute adjustment of a generator output to meet the imbalance between total supply and demand in the system. This instantaneous response of a generating unit is usually achievable through the use of the governor-droop characteristic or AGC from the control area determining the required change (up and down) to the real power output to correct the area control error to be within bounds.

c) Spinning reserves: The provision of unloaded generating capacity that is synchronized to the grid and can immediately respond to correct for generation/load imbalances, caused by generation and/or transmission outages, and that is fully available within several minutes, typically within 10 minutes as specified by several ISO's in US and Canada.

2.5 Demand Response

Demand Side Management (DSM) is the planning and implementation of those utility activities designed to influence the customer's use of electricity in ways that will produce the desired changes in the utility's load shape, *i.e.*, changes in the pattern and magnitude of a utility's load [4]. It comprises the whole range of management schemes linked with demand-side activities, and it can be classified into DR programs and Energy Efficiency programs.

Demand Response or DR is defined as *"changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity,* *or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized"* [4]. DR can be classified as:

Incentive based program (IBP): In this type of program, customer participation is recognized by providing incentives, since the utility can operate more economically and reliably. Some of the existing IBPs, such as direct load control (DLC), emergency DR, demand side bidding and buyback (DR auction markets) are briefly explained next [4].

a) DLC: The utility or system operator remotely turns off or changes the temperature set points of a customer's electrical equipment, such as air conditioner and water heater, on short notice, during critical periods. The customers are generally paid through an incentive mechanism in the form of electricity bill credits. Program participants are generally residential and small commercial customers. An example of DLC programs is the PeaksaverPLUS program, which is implemented in Ontario. In this program, residential customer's loads such as air conditioner and water heater are remotely controlled by the IESO [85].

b) Emergency DR Programs: Customers reduce their loads voluntarily when instructed by the ISO, and receive incentives based on a pre-specified rate offered by the utility. There is no penalty applied to the customers if they do not reduce the load when called for.

c) Demand Side Bidding (DR Auction Markets): These programs allow large customers to offer a certain amount of load reduction with an associated price in the wholesale electricity market auction. Once cleared in the auction, these are scheduled and dispatched in the same way as generators.

Price-Based Programs (PBP): Customers receive price signals for efficient and economic management of their loads. These DR programs encourage customers to alter their load pattern such that the system load profile is modified, and at the same time the customer's overall electricity cost is reduced. These include three main categories based on Time of use (TOU) rates, Critical peak pricing (CPP), and Real-time pricing (RTP) [4].

a) TOU Rates: These are pre-set tariff rates, depending on the time of the day and season of the year, in order to reduce the electricity use at certain time-periods.

b) CPP: It is a modified form of the TOU tariff where during critical peaks, prices are considerably higher than the average TOU rates. CPP reflects the system stress, and hence, even though these prices are pre-set, they are applied to customers on short notice, when required. An example of CPP program is the Industrial Conservation Initiative program, which is implemented in Ontario. In this program, industrial customer's loads are charged the Global Adjustment which is based on their load demand during the five coinciding peaks in the system [86].

c) RTP: Unlike TOU and CPP, RTP continuously varies and is not pre-set. This is related to the wholesale and retail electricity market, and encourages price responsiveness of customer in real-time markets.

2.6 Energy Storage Systems

Energy storage refers to the process of storing energy that can then be released to perform useful operations at a later stage; and an ESS is one which can absorb energy from the grid (during the period of surplus), store the energy, and inject it back to the grid at a later time (during period of high demand).

Effective utilization of ESS can contribute significantly to achieve the following goals in the system: energy security and reliability, electricity price stability, decarbonisation. The benefits offered by ESS have consequently resulted in their inclusion in electricity markets. The FERC of US allows the participation of ESS in energy and operating reserve markets, which has led to over 200 ESS projects in several electricity jurisdictions in the US [7]. Currently, electricity markets in Canada are also witnessing increased interest from the industry. In Ontario for instance, the IESO was mandated by the Ministry of Energy to procure 50 MW of ESS by the end of 2014 [38]; the procurement was planned in two phases, in Phase - I, 34 MW of ESS was contracted from five companies to provide ancillary services to the grid. While in Phase - II, 16.75 MW was contracted for 10-years to five companies, for nine separate ESS projects using thermal energy storage, BESS, flywheels, power-to-gas (hydrogen storage) technologies.

2.6.1 Classification of ESS Technologies

ESS technologies can be classified according to the form of stored energy, as discussed below [13]:

a) Electrochemical: These type of storage utilize chemical reactions to convert electrical energy to chemical energy and vice-versa. The process of energy conversion takes place in an electrochemical cell, where the electrons are transferred between electrodes, through electrolytic solution. The examples of electrochemical storage are batteries, which are further divided into two types - conventional batteries and flow batteries. The examples of conventional batteries are lead-acid, nickel-based, lithium-ion *etc.*, while flow batteries include redox flow batteries, hybrid flow batteries *etc.* Amongst the various battery technologies lithium-ion batteries being widely deployed for grid scale applications. The battery storage systems have

b) Electrical: These type of storage include double layer capacitors and super capacitors, where energy is stored in electric fields between charged plates having dielectric material between them. The capacitors are used for high power applications because they can discharge very high power in very short duration of time.

c) Electromagnetic: These storage includes superconducting magnetic energy storage systems which utilize dc currents in superconducting coils to store energy in a magnetic field. These storage technology, similar to capacitors are suitable for high power and low energy applications.

d) Mechanical: These type of storage convert electric energy into mechanical energy and vice-versa via rotating electric machine, such motor or generator. The energy is stored in the form of kinetic energy or potential energy. The examples of most widely used mechanical storage are as follows:

    i) Compressed air energy storage (CAES): These type of storage operate in two m odes - charging and discharging. In charging mode, motors are used to power turbo compressors to compress large volumes of air into reservoirs usually called caverns. While in the discharging mode, the compressed air is expanded by heating and used to drive turbines to generate electricity.

    ii) Flywheel Energy Storage: These type of storage use motor and power electronic devices to accelerate at very high speeds a shaft with a high moment of inertia. Energy is stored in the rotating shaft as kinetic energy.The fly wheels are are useful in power applications which requires high response time such as regulation services.

    iii) Pumped hydro storage (PHS): This is one of the most matured and widely deployed ESS. In PHS, motor pumps are used to pump water from a lower level reservoir to a higher level reservoir during periods when electricity prices are low. While during peak hours, stored water is released to rotate turbines and generate electricity.

The research presented in this thesis considers BESS for the studies and hence the following section presents a brief background to BESS.

2.7 Battery Energy Storage Systems

In recent years, there has been an increase in BESS deployment compared with other ESS as a result of advantages they offer such as high ramp rates, significantly reducing costs, can be installed without any geographic restrictions etc., in comparison to some other ESS technologies. In this section a brief review of the BESS components, related important terminologies, the operational model and the degradation mechanism is presented.

2.7.1 BESS Components

The main components are battery, power converter, transformer, controller, and battery management system, as shown in Figure 2.7.1 [13]. The basic component BESS is a battery pack, which is made up of many cells connected in various combination depending upon the application. For example, for achieving particular voltage level cells are connected in series, and for achieving particular power rating cells are connected in parallel. The second important component of the BESS is a power conversion system, which acts as an inverter when battery is in discharging mode and as a rectifier in charging mode. The converter is connected to a step-up transformer, which connects the BESS to the main grid. The controller is the brain of the BESS, which has the logic of the BESS operation and controls the converter based on pre-defined algorithm. The battery management system monitors the SOC, charging and discharging levels, temperature *etc.*, to ensure safe and optimal operation of BESS.

2.7.2 Important BESS Terminologies

The following terminologies are very important for a BESS and have been extensively used in this thesis. Thus a brief description is given as follows [87, 88]:

- Capacity: The capacity of a battery is a measure of the amount of energy that it can deliver in a single discharge [87]. Battery capacity is normally expressed in amp-hours (Ah) or in watt-hours (Wh).

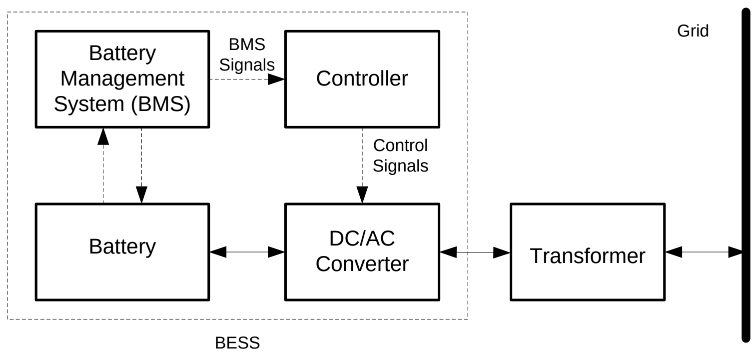


Figure 2.1: BESS Layout

- SOC: It represents the available battery capacity (energy) as a percentage of the maximum battery capacity [87]. It is usually represented in p.u. or percentage (%).

- DOD: It represents the battery capacity that has been discharged expressed as a percentage of the maximum battery capacity [87]. It is usually represented in p.u. or percentage (%). For example, 50% DOD means that half of the energy in the battery is discharged. A 70% DOD means that seventy percent of the battery is discharged and now battery holds on 30% of the energy.

  Thus, DOD = 1- SOC

- Discharge rate: The rate at which the battery is discharged with respect to its maximum capacity.

  In this thesis, the discharge rate of a battery, denoted by DCR, is expressed as the change of SOC per unit time, given as follows:

$$DCR_k = \frac{SOC_{k-1} - SOC_k}{T} = \Delta SOC_k \quad \forall k \in K \tag{2.15}$$

  The discharge rate is represented in terms of 'C', where 1C denotes the full discharge of the battery in 1-hour, 2C the full discharge in 30 minutes, 3C the full discharge in 20 minutes and so on. In the same context, 0.5C denotes 50% of the full discharge in 1-hour.

- Cycle Life: The number of discharge-charge cycles the battery can experience before it fails to meet specific performance criteria [88]. Cycle life is estimated for specific charge and discharge conditions. It is to be noted that the actual operating life of the battery is affected by the discharge rate and DOD and by other conditions such as temperature and humidity. The higher the DOD, the lower the cycle life.

- P/E ratio: It is the ratio of the rated power capacity of the battery, P (kW or MW) to rated energy capacity of the battery, E (kWh or MWh) [88].

- Droop characteristics: Governor droop refers to the speed (frequency) versus output characteristic of the generator. Traditionally, droop control is deployed to enable parallel operation among spinning generators, for sharing the load change in the system, which results in a deviation in the system frequency. Each generator with a different operating condition has a different droop characteristic and it shares the change in the system load as per its preset droop rate. Of late, the droop control technique has been applied to applications such as DC grid, HVDC and ESS [89].

  The droop characteristics of a BESS is different from those of generators because of its distinct charging and discharging modes of operation. The BESS droop characteristic is dependent on the SOC of the battery; a typical BESS droop characteristic is shown in Fig. 2.2 and discussed in [89]. In recent years, BESSs have been considered as promising resources to provide regulation services because of their operational flexibility, characterized by fast response time, high ramp rate, and capability to provide upward and downward response. This thesis considers BESS for primary regulation reserve provisions based on its droop characteristics, as in Fig. 2.2.

2.7.3 BESS Operational Model

The general model of a BESS is described here [54]. The BESS constraints include the energy balance and constraints to prevent simultaneous charging/discharging, and limits on SOC and charging/discharging power, as follows:

$$SOC_{e,k+1} - SOC_{e,k} = \left(P_{e,k}^{Ch} \eta_e^{Ch} - \frac{P_{e,k}^{Dch}}{\eta_e^{Dch}} \right) \Delta k \quad \forall e, \forall k \geq 1 \tag{2.16}$$

Constraints (2.16) ensure the energy balance of the ESS.

$$Z1_{e,k} + Z2_{e,k} \leq 1 \quad \forall e, k \tag{2.17}$$

Constraints (2.17) ensure that that the charging and discharging operation in an ESS does not take place simultaneously.

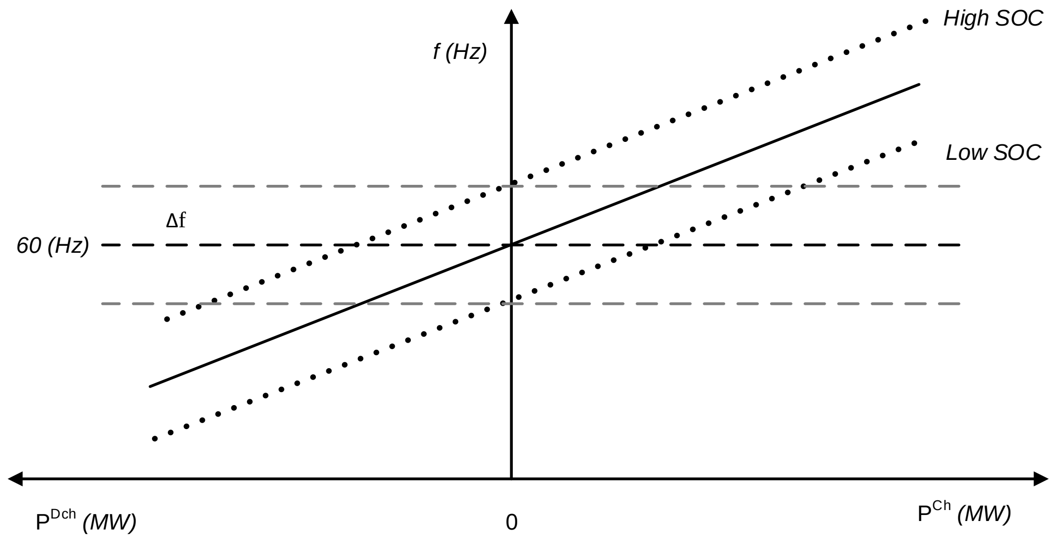


Figure 2.2: BESS Droop Characteristics [87]

$$\underline{SOC}_e \leq SOC_{e,k} \leq \overline{SOC}_e \quad \forall e, k \tag{2.18}$$

Constraints (2.18) ensure the SOC of the ESS is within its limits.

$$P^{Ch}_{e,k} \leq \overline{P}^{Ch}_e \quad Z1_{e,k} \quad \forall e, k \tag{2.19}$$

$$P^{Dch}_{e,k} \leq \overline{P}^{Dch}_e \quad Z2_{e,k} \quad \forall e, k \tag{2.20}$$

Constraints (2.19) and (2.20) ensure that the ESS charging and discharging power are within their limits.

2.7.4 BESS Degradation Mechanism

In most of the electrochemical batteries, the battery degradation results in two types of aging: (i) calender aging, and (ii) cyclic aging. The capacity fading and increase in battery resistance over a period of time, without the influence of external factors, is referred to as degradation due to calender aging; the degradation that occurs due to the actual operation of the battery *i.e.*, its cycling during charging and discharging modes, is referred to as degradation due to cyclic aging [90]. Degradation due to calender aging is minimal when short-term operation is considered, and hence can be neglected. As the scope of this thesis pertains to short-term operation of BESS, the battery's degradation due to cyclic aging has been considered in the cost function modelling presented in Chapter 4.

The cyclic aging is influenced by non-operational factors such as ambient temperature, ambient humidity, battery state of health *etc.*, and operational factors such as DOD, appropriate SOC limits, charge/discharge rate, *etc.*

Among the aforementioned, the operational factors significantly affect the degradation mechanism when considered for short-term operations, of which, the DOD is the most important factor as it affects the cycle life the most. For example, a lithium ion battery used for grid scale applications would be able to operate for only 800 cycles when cycled at 80% DOD whereas can operate for 6000 cycles when at 10% DOD. Such non-linear relationships between cycle-life and the DOD is observed in most of the static electrochemical batteries. Similarly, the high charge/discharge rate of BESS accelerates the degradation process. So is the effect of extreme value of SOC. Hence it is very important to consider these operational factors while modelling the battery degradation.

2.8 Summary

In this chapter, an overview of electricity markets was presented, elaborating upon the structure and types of markets and the mathematical formulation of the LMP-based market. Thereafter discussion on various ancillary services and a brief review of the DR programs were presented. The BESS operational characteristics and degradation process was discussed since it is an essential feature considered in this research.

Chapter 3

Simultaneous Procurement of DR in Energy and Spinning Reserve Markets[1]

3.1 Nomenclature

Sets & Indices

i, q	Indices for the buses, $i \in I$.
j	Index for the generators, $j \in J$.
k, t	Indices for time (hour), $k \in K$.
h	Index for blocks of customer bids, $h \in N_{CB}$.
n	Index for blocks of generator offers, $n \in N_{GB}$.
l	Index for segments in piece-wise linear approximation, $l \in L$.
E_i	Set of generators connected to bus i.

[1]Parts of this chapter have been published in: N. Padmanabhan, M. Ahmed, and K. Bhattacharya, "Simultaneous procurement of demand response provisions in energy and spinning reserve markets",*IEEE Trans. Power Systems,* vol. 33, no. 5, pp. 4667-4682, Sep. 2018.

Parameters

B	Element of susceptance matrix, p.u.
C^d, C^u	Start-up/shut-down cost of generator, \$.
C^D	Customer's demand bid price, \$/MWh.
C^{DRE}, C^{DRSR}	DR offer price in energy/spinning reserve auctions, \$/MWh.
C^G, C^{GSR}	Generator offer price for energy/spinning reserve, \$/MWh, \$/MW.
$\overline{DRT}$	Maximum duration of DR service offered by a customer at a bus in a day, hour.
g	Conductance of transmission line, p.u..
$\overline{P}$, $\underline{P}$	Maximum/minimum limit on power output of generator, MW.
$\overline{P}^D$	Customer's demand bid quantity, MW.
$\overline{P}^{DRE}$, $\overline{P}^{DRSR}$	DR offer quantity in energy/spinning reserve auctions, MW.
$\overline{P}^G$, $\overline{P}^{GSR}$	Generator offer quantity for energy/spinning reserve, MW.
$\overline{PFlow}$	Maximum capacity of transmission line between buses, MW.
RU, RD	Ramp up/down limit of generator, MW/h.
TU, TD	Minimum up/down time of generator, hour.
α	Slope of segment of the linearized voltage angle difference between buses.
β	Share of the total DR offer quantity, as a fraction of the maximum demand bid of the customer at the bus.
β_1, β_2	Share of the DR offer quantity for energy/spinning reserve provision, as a fraction of the maximum demand bid of the customer at the bus.
γ	Share of the total cleared DR quantity, as a fraction of the total cleared demand of the customer at the bus.
γ_1, γ_2	Share of the cleared DR quantity for energy/spinning reserve provision, as a fraction of the total cleared demand of the customer at the bus.
γ_3	Share of the cleared DR quantity for energy provision, as a fraction of the difference of demand cleared and DR contracted for spinning reserve services.

γ_4	Share of the cleared DR quantity for spinning reserve provision, as a fraction of the difference of demand cleared and DR dispatched for energy services.
ω	Share of the generator's total offer quantities, as a fraction of the maximum capacity of the generator.
ω_1, ω_2	Share of the generator's offer quantities for energy/spinning reserve, as a fraction of the maximum capacity of the generator.
$\Delta\delta$	Upper bound on piece-wise angle blocks, radian.

Variables

P^D	Demand cleared, MW.
P^{DRE}, P^{DRSR}	DR cleared in energy/spinning reserve auctions, MW.
P^G, P^{GSR}	Generation/spinning reserve offer cleared, MW.
P^{loss}	Power loss in the transmission line between buses i and q, MW.
U, V	Binary variable = 1, if generator starts/shut downs, and 0 otherwise.
W	Binary variable = 1, if generator is committed, and 0 otherwise.
W^s	Binary variable = 1, if energy offer of generator is cleared and 0 otherwise.
X	Binary variable = 1, if demand bid is cleared, and 0 otherwise.
Y, Z	Binary variable = 1, if DR is cleared in energy/spinning reserve auction, and 0 otherwise.
δ	Voltage angle of bus, radian.
λ^E	Market clearing price for energy at a bus, \$/MWh.
λ^{SR}	Market clearing price for spinning reserve, \$/MW.

3.2 Introduction

DR is an important tool for the ISO for reliable operation of electricity markets, and there has been considerable interest from load-side market participants as well, to offer their services for DR provisions. In this environment, the ISO needs to develop effective mathematical models for procurement of DR so as to maximize its benefits, such as reducing the peak demand, regulating electricity price shocks, and exploiting its flexibility attributes.

This chapter first presents a novel and comprehensive formulation of the DR offers, taking into account customer preferences for simultaneous participation in energy and spinning reserve markets. Various parameters of the DR offers and their inter-relationships with the demand offers, and the clearance of the demand and DR bids are brought out. Thereafter, a new mathematical model for an LMP-based, loss included, day-ahead, co-optimized, energy and spinning reserve market including DR provisions, is proposed. A new proposition for DR participants to submit their offers in both energy and spinning reserve markets is presented. Case studies of DR providers participating only in the energy market, both energy and spinning reserve markets, and only in the spinning reserve market, are considered, to examine the impact on system operation, market prices and DR provider's benefits. The proposed model is tested on the IEEE Reliability Test System (RTS) to demonstrate its functionalities and the results clearly justify the merits of DR being included in a co-optimized energy and spinning reserve market.

3.3 Modeling of DR Offers

3.3.1 Customer's DR Offers:

It is proposed that large industrial or commercial customers can provide DR services in the day-ahead energy market and the spinning reserve market. The customer will have provision to participate in the markets in three ways (i) buy energy as a PRD, (ii) provide DR services in the energy market, and (iii) provide DR services in the spinning reserve market. Accordingly, the customer will submit in the day-ahead energy market, PRD bids to buy energy and DR offers to curtail its demand, and submit DR offers in the spinning reserve market to provide reserve capacity. The difference between the two DR products in the energy and spinning reserve markets is that, if DR offers are cleared in the day-ahead energy market, it would be available for dispatch in the real-time operations, and if it is cleared in the spinning reserve market it would provide a reserve capacity. The demand bids and DR offers are submitted in price-quantity pairs, as step functions. A general representation of the customer's demand bid, DR offer quantities and cleared quantities, along with the time-line of the operational events are shown in Fig. 3.1. During the offer submission period, the customer submits its demand bids and DR offers in blocks, where DR offers are parts of the demand bids, as shown in Fig. 3.1. After market clearing, the dispatch schedules are obtained, and it is noted that the cleared DR quantities need be within the window of respective DR offers.

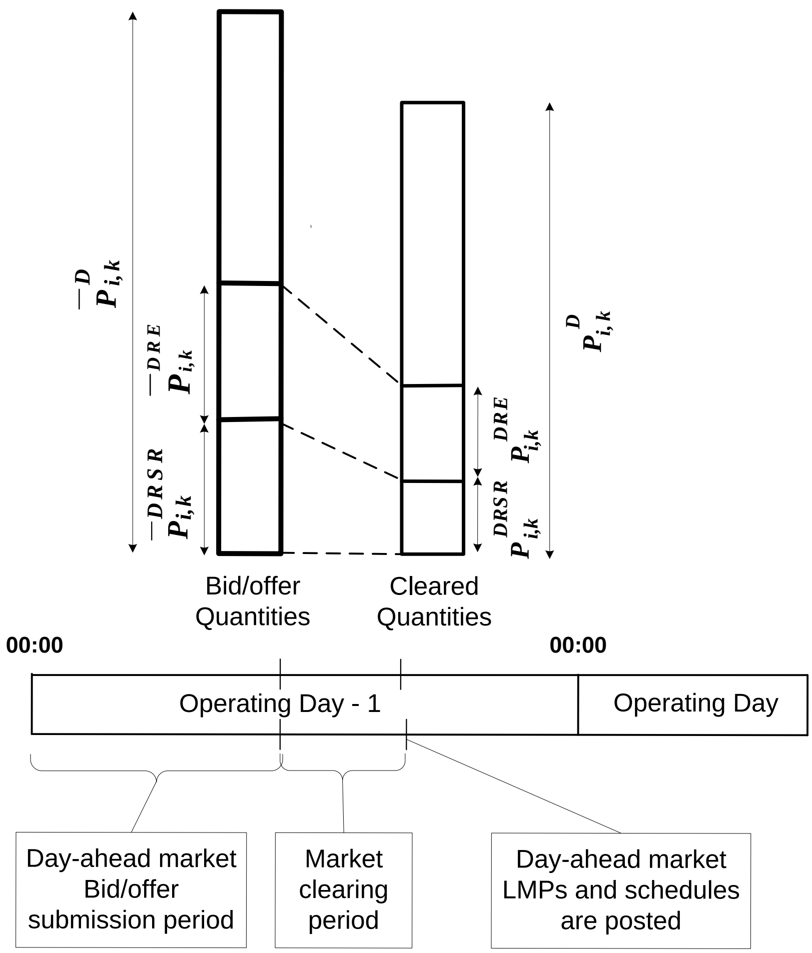


Figure 3.1: Customer's bid/offer and cleared quantities in day-ahead energy and spinning reserve markets

The total DR offer in the day-ahead energy market and the spinning reserve market by a customer at bus i and hour k is limited by a parameter β denoting the share, the total DR provisions account for, as a fraction of the maximum demand bid of the customer at the bus, as follows:

$$\overline{P}^{DRE}_{h,i,k} + \overline{P}^{DRSR}_{h,i,k} \leq \beta\, \overline{P}^{D}_{h,i,k} \quad \forall h \in N_{CB}, \forall i \in I, \forall k \in K \tag{3.1}$$

Also, the DR quantities offered in the day-ahead energy market and the spinning reserve market by the customer at bus i and hour k are limited by the parameters β_1 and β_2 denoting the share of these services as a fraction of the maximum demand bid of the customer, as follows:

$$\overline{P}^{DRE}_{h,i,k} \leq \beta_1 \, \overline{P}^{D}_{h,i,k} \quad \forall h \in N_{CB}, \forall i \in I, \forall k \in K \tag{3.2}$$

$$\overline{P}^{DRSR}_{h,i,k} \leq \beta_2 \, \overline{P}^{D}_{h,i,k} \quad \forall h \in N_{CB}, \forall i \in I, \forall k \in K \tag{3.3}$$

$$\beta_1 + \beta_2 \leq \beta \tag{3.4}$$

It is to be noted that the parameters β, β_1 and β_2 will be decided by the customer. However, β need be capped by the market regulator so as to reduce the market power of any given customer.

3.3.2 Genco Offers:

The ISO also receives offers from generating companies (gencos) for both the energy and spinning reserve markets, and the total offer by a generator j at hour k is limited by a parameter ω of the maximum capacity of the generator, as follows:

$$\sum_{n \in N_{GB}} \overline{P}^{G}_{n,j,k} + \sum_{n \in N_{GB}} \overline{P}^{GSR}_{n,j,k} \leq \omega \, \overline{P}_j \quad \forall j \in J, \forall k \in K \tag{3.5}$$

It is to be noted that, the parameter ω is supposed to be in the range of [0,1]. In this work we assume ω=1, which means the full capacity of the generator is utilized to provide energy and spinning reserve service only. If ω is less than 1, it implies the generator is providing some other ancillary service for which capacity is reserved, such as regulation reserve.

The generator offer quantities in day-ahead energy market and spinning reserve markets respectively by generator j at hour k, are limited by the parameters ω_1 and ω_2 denoting the maximum share of these components as a fraction of the maximum capacity of the generator, as follows:

$$\sum_{n \in N_{GB}} \overline{P}^{G}_{n,j,k} \leq \omega_1 \, \overline{P}_j \qquad \forall j \in J, \forall k \in K \tag{3.6}$$

$$\sum_{n \in N_{GB}} \overline{P}^{GSR}_{n,j,k} \leq \omega_2 \, \overline{P}_j \qquad \forall j \in J, \forall k \in K \tag{3.7}$$

It is to be noted that the parameters ω, ω_1 and ω_2 will be decided by the genco, while satisfying the relation:

$$\omega_1 + \omega_2 \leq \omega \tag{3.8}$$

The structure of the day-ahead market settlement model with DR is shown in Fig. 3.2. The ISO receives detailed information on the bids and offers, for energy, DR and spinning reserve services, from both customers and gencos, as per the bid-offer structure of these entities, discussed earlier. Other supplementary information on system operation from various market participants are also received by the ISO. Based on these inputs, the proposed markets are simultaneously cleared through the joint optimization model, as discussed in Section 3.4. The outcomes include the dispatch schedules for all entities, and market prices.

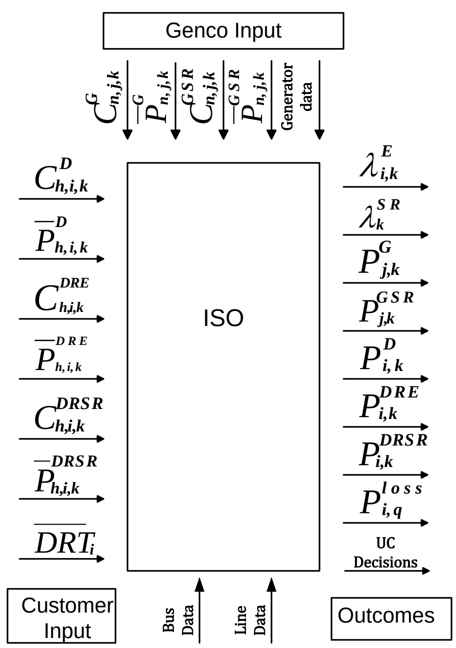


Figure 3.2: Proposed framework for DR participation in day-ahead energy market and spinning reserve markets

3.4 Proposed Market Model Including DR

3.4.1 Detailed Formulation

Objective Function

The objective is to maximize the social welfare, given as follows:

$$
\begin{aligned}
J = \sum_{k\in K}\sum_{i\in I}\sum_{h\in N_{CB}} C^{D}_{h,i,k}P^{D}_{h,i,k} \\
-\sum_{k\in K}\sum_{j\in J}\left(C^{u}_{j,k}U_{j,k} + C^{d}_{j,k}V_{j,k} + \sum_{n\in N_{GB}} C^{G}_{n,j,k}P^{G}_{n,j,k}\right) \\
-\sum_{k\in K}\sum_{i\in I}\sum_{h\in N_{CB}}\left(C^{DRE}_{h,i,k}P^{DRE}_{h,i,k} + C^{DRSR}_{h,i,k}P^{DRSR}_{h,i,k}\right) \\
-\sum_{k\in K}\sum_{j\in J}\sum_{n\in N_{GB}} C^{GSR}_{n,j,k}P^{GSR}_{n,j,k}
\end{aligned}
\quad (3.9)
$$

The first term in (3.9) represents the gross surplus of customers, the second term represents the total cost of gencos, which includes the start up cost, shut down cost and the energy cost. It should be noted that the no-load cost of the generators are represented by the first block of the 3-block offer price submitted by them. Furthermore, the quantity corresponding to the first offer block is chosen as the minimum loading of the generator ($\underline{P}_j$). The third term represents the total cost for the DR provider for DR provisions in the energy market and the spinning reserve market, and the fourth term represents the cost of spinning reserve provisions from generators. The objective function in (3.9) is subjected to the following constraints,

Demand Supply Balance

This constraint ensures a balance between the supply and demand at each bus i and hour k.

$$
\sum_{j\in E_j} P^{G}_{j,k} + P^{DRE}_{i,k} - P^{D}_{i,k} = \sum_{q\in I}\left(0.5P^{loss}_{i,q} + B_{i,q}(\delta_{i,k} - \delta_{q,k})\right) \quad (3.10)
$$

where, the cleared generation for a generator j at hour k is the sum of generation cleared in n blocks of that generator as follows,

$$P^{G}_{j,k} = \sum_{n \in N_{GB}} P^{G}_{n,j,k} \qquad \forall j \in J, \forall k \in K \tag{3.11}$$

The cleared DR for energy provisions for a customer at bus i and hour k is the sum of DR cleared in h blocks of that customer as follows,

$$P^{DRE}_{i,k} = \sum_{h \in N_{CB}} P^{DRE}_{h,i,k} \quad \forall i \in I, \forall k \in K \tag{3.12}$$

The cleared demand for a customer at bus i and hour k is the sum of demand cleared in h blocks of that customer as follows,

$$P^{D}_{i,k} = \sum_{h \in N_{CB}} P^{D}_{h,i,k} \qquad \forall i \in I, \forall k \in K \tag{3.13}$$

In real power systems, transmission losses are typically in the range of 4-6% [91], and ignoring this in market clearance and dispatch models gives rise to significant levels of approximation and differences from actual. Even in the well designed IEEE RTS considered for studies, it is noted that system transmission losses account for about 1.5% of the dispatched energy or 1000 MWh of energy loss over a day. Therefore, it was felt necessary to explore the comprehensive behavior of the power system through modeling, for the proposed market auction model. The transmission line losses are included in the model by means of a piece-wise linear approximation [81], as follows,

$$P^{loss}_{i,q} = g_{i,q} \sum_{l=1}^{L} \alpha_{i,q}(l)(\delta_i(l) - \delta_q(l)) \qquad \forall i, q \in I \tag{3.14}$$

where,

$$\alpha_{i,q}(l) = (2l - 1)\Delta\delta \qquad \forall i, q \in I, \forall l \in L \tag{3.15}$$

Market Clearing Constraints

These constraints ensure that cleared demand bids, generator offers and DR offers do not exceed their respective maximum bid and offer quantities.

$$P^{G}_{n,j,k} \leq \overline{P}^{G}_{n,j,k} W^{s}_{n,j,k} \quad \forall j \in J, \forall k \in K, \forall n \in N_{GB} \tag{3.16}$$

$$P^{GSR}_{n,j,k} \leq \overline{P}^{GSR}_{n,j,k}\, W^{s}_{n,j,k} \quad \forall j \in J, \forall k \in K, \forall n \in N_{GB} \tag{3.17}$$

The cleared generation quantity and spinning reserve capacity of a generator j at hour k, should not exceed the maximum offer quantity of that generator, as per (3.16)-(3.17).

$$P^{D}_{h,i,k} \leq \overline{P}^{D}_{h,i,k}\, X_{h,i,k} \quad \forall i \in I, \forall k \in K, \forall h \in N_{CB} \tag{3.18}$$

$$P^{DRE}_{h,i,k} \leq \overline{P}^{DRE}_{h,i,k}\, Y_{h,i,k} \quad \forall i \in I, \forall k \in K, \forall h \in N_{CB} \tag{3.19}$$

$$P^{DRSR}_{h,i,k} \leq \overline{P}^{DRSR}_{h,i,k}\, Z_{h,i,k} \quad \forall i \in I, \forall k \in K, \forall h \in N_{CB} \tag{3.20}$$

The cleared demand and cleared DR service in energy and spinning reserve market for a customer at bus i and hour k should not exceed the maximum energy buy bid quantity and DR offer quantity of that customer as per (3.18)-(3.20).

DR Constraints

It is very important to ensure that the DR cleared in the energy market and in the spinning reserve market should come only from the cleared demand. These are ensured by the following constraints:

$$P^{DRE}_{i,k} + P^{DRSR}_{i,k} \leq \gamma P^{D}_{i,k} \quad \forall i \in I, \forall k \in K \tag{3.21}$$

Note that the baseline demand from which the load is curtailed, is the market clearing demand, $P^{D}_{i,k}$, given by (3.13), and depends on the PRD bids and prevailing system and market conditions. This is in line with the practice adopted in some electricity markets, where a customer baseline load, for an hour, is determined from the actual demand of the customer, typically considering a period of previous 5 to 10 days [18], [92], [93].

The constraint (3.21) limits the DR dispatched for energy services and the DR committed for spinning reserve by the customer at bus i and hour k by a parameter γ denoting the share, the total cleared DR provision account for, as a fraction of the cleared demand for the customer.

The DR quantities cleared in the energy market and the spinning reserves market for the customer at bus i and hour k is limited by a parameters γ_1 and γ_2 denoting the share, of these DR services account for, as a fraction of the cleared demand for the customer. These are ensured by the following constraints:

$$P^{DRE}_{i,k} \leq \gamma_1 P^{D}_{i,k} \quad \forall i \in I, \forall k \in K \tag{3.22}$$

$$P_{i,k}^{DRSR} \leq \gamma_2 P_{i,k}^{D} \quad \forall i \in I, \forall k \in K \tag{3.23}$$

$$\gamma_1 + \gamma_2 \leq \gamma \tag{3.24}$$

It is to be noted that, γ, γ_1, γ_2 are imposed by the ISO depending on the various conditions in the market. For example, on a peak summer day or a peak winter day, the ISO forsees a sudden increase in the peak demand. In this situation, the ISO would appropriately increase the value of γ_1, so as to procure more DR in the energy market to reduce the peak demand. Similarly, when sufficient spinning reserve cannot be procured from generators because of maintenance, repair *etc.*, more spinning reserve would need be procured through DR, and this will result in increased value of γ_2.

Additionally, the DR provision for the customer at bus i and hour k in energy market is limited by a parameter γ_3 which denotes the share of the cleared demand net of the DR contracted for spinning reserve services. Also, the DR provision for the customer at bus i and hour k in spinning reserve market is limited by a parameter γ_4 which denotes the share of the cleared demand net of the DR dispatched for energy services. These are ensured by the following constraints,

$$P_{i,k}^{DRE} \leq \gamma_3 (P_{i,k}^{D} - P_{i,k}^{DRSR}) \quad \forall i \in I, \forall k \in K \tag{3.25}$$

$$P_{i,k}^{DRSR} \leq \gamma_4 (P_{i,k}^{D} - P_{h,i,k}^{DRE}) \quad \forall i \in I, \forall k \in K \tag{3.26}$$

$$\gamma_3 + \gamma_4 \leq \gamma \tag{3.27}$$

It should be noted that the parameters γ_3 and γ_4 overlap with γ_1 and γ_2 to some extent; γ_3 and γ_4 are included to account for the inter-relationships between $P_{i,k}^{DRE}$ and $P_{i,k}^{DRSR}$, which being provided by the same DR provider at the same time. The parameters γ_3 and γ_4 are new propositions by the authors with an understanding that the allocation of DR from a customer for energy and spinning reserve provisions should be comparable in quantities, as far as possible. The values of γ_3 and γ_4 would be selected by the ISO from *a priori* knowledge of system conditions and reserve availability from conventional generators, and can vary with time.

The normal operation of the customer should not be affected when it provides DR services. The DR provider will specify in its offers, the maximum duration for which it is willing to provide services in the energy and the spinning reserve markets. This is included as a constraint as follows,

$$\sum_{k} Y_{h,i,k} + \sum_{k} Z_{h,i,k} \ \leq \ \overline{DRT}_i \qquad \forall i \in I, h = 1 \tag{3.28}$$

Spinning Reserve Constraints

These constraints ensure that the spinning reserve requirement for the system is met for each hour k. It is assumed that the total spinning reserve requirement at an hour k is at least 10% of the net demand at that hour,

$$\sum_{j} P_{j,k}^{GSR} + \sum_{i} P_{i,k}^{DRSR} \geq 0.1 \sum_{i} (P_{i,k}^{D} - P_{i,k}^{DRE}) \qquad \forall k \in K \tag{3.29}$$

where, the spinning reserve cleared from a generator j at hour k is the sum of the spinning reserve cleared in n blocks of that generator as follows,

$$P_{j,k}^{GSR} = \sum_{n \in N_{GB}} P_{n,j,k}^{GSR} \qquad \forall j \in J, \forall k \in K \tag{3.30}$$

The cleared DR service for spinning reserve provisions from a customer at bus i and hour k is the sum of DR cleared in h blocks of that customer, as follows,

$$P_{i,k}^{DRSR} = \sum_{h \in N_{CB}} P_{h,i,k}^{DRSR} \qquad \forall i \in I, \forall k \in K \tag{3.31}$$

The spinning reserve provided by a generator is constrained by its capacity net of the cleared dispatch, given as follows:

$$P_{j,k}^{GSR} \leq \overline{P}_j - P_{j,k}^{G} \qquad \forall j \in J, \forall k \in K \tag{3.32}$$

Transmission Line Constraints

These constraints ensure that the line power flows are within their limits.

$$B_{i,q}(\delta_{i,k} - \delta_{q,k}) \leq \overline{PFlow}_{i,q} \qquad \forall i, q \in I \tag{3.33}$$

Generation Limits

These constraints ensure that the output power of generator j at interval k is within its maximum and minimum limits.

$$\underline{P}_j \, W_{j,k} \;\leq\; P_{j,k}^{G} \;\leq\; \overline{P}_j \, W_{j,k} \qquad \forall j \in J, \forall k \in K \tag{3.34}$$

Ramping Constraints

The ramp-up/down capability of the generator j at interval k is not violated constraints is ensured by the following constraints,

$$P^G_{j,k} \leq P^G_{j,k-1} + RU_j \qquad \forall j \in J, \forall k \in K \tag{3.35}$$

$$P^G_{j,k-1} - P^G_{j,k} \leq RD_j \qquad \forall j \in J, \forall k \in K \tag{3.36}$$

Minimum-Up and Down Constraints

These constraints ensure that the generator j at interval k meets the minimum-up and down time requirements [24].

$$\sum_{t=k-TU_j+1}^{k} U_{j,t} \leq W_{j,k} \qquad \forall t \in [TU_j, K], \forall j \in J \tag{3.37}$$

$$\sum_{t=k-TD_j+1}^{k} V_{j,t} \leq 1 - W_{j,k} \qquad \forall t \in [TD_j, K], \forall j \in J \tag{3.38}$$

Coordination Constraints

These constraints ensure proper transition of UC states from 0 to 1 and vice versa with unit start-up, shut-down decisions.

$$W^s_{1,j,k} = W_{j,k} \qquad \forall j \in J, \forall k \in K \tag{3.39}$$

$$W_{j,k} - W_{j,k-1} \leq U_{j,k} - V_{j,k} \qquad \forall j \in J, \forall k \in K \tag{3.40}$$

$$U_{j,k} + V_{j,k} \leq 1 \qquad \forall j \in J, \forall k \in K \tag{3.41}$$

3.4.2 Market Design Aspects

In the proposed market model, the selection of the parameters associated with DR services are vital for the proper functioning of the model and also impact the market price. The parameters β, β_1, β_2 relate to the customer side of the DR offers while γ, γ_1, γ_2, γ_3, γ_4 govern the clearing of DR offers by the ISO. These parameters are inter-related as discussed in the mathematical formulation of the market model. Fig. 3.3 shows how these parameters are input to the model. The customer side parameter β decides the total DR offer quantity of the customer, while β_1 and β_2 specify the share of DR quantity offered to the different markets, respectively. On the other hand, γ specifies the total amount of DR to be cleared in the market and γ_1 and γ_2 represent the DR share the ISO would like to procure from each market, and would ideally be based on a load forecast and prevailing system conditions. The parameters γ_3, and γ_4, which are mutually coupled, relate the cleared DR quantities for different services. The ISO will typically announce the parameters γ, γ_1, γ_2, γ_3 and γ_4 in advance, and based on this information, the DR providers would decide the appropriate values of β_1 and β_2. However, there is a need for more detailed studies and analyses to bring out the best possible values of these parameters such that the overall market efficiency is improved.

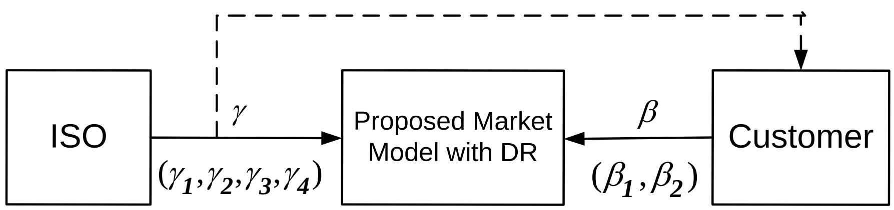


Figure 3.3: Interrelationship of DR parameters in the market operation

3.5 Results & Discussions

To validate the proposed day-ahead market model for energy and spinning reserve with DR provisions, a slightly modified version of the IEEE RTS (Fig. 3.4) [94] is considered, which includes 32 generators, loads at 17 buses, and 37 transmission lines. The hydro generators are neglected and the loads are scaled up by 25%. The generator supply offers and customer DR offers are in three price-quantity blocks with increasing steps of prices for each block. It is assumed that the generators offer their energy at the incremental cost of generation, and spinning reserve at 40% of their incremental cost. It is also assumed that the full capacity of a generator is utilized to provide energy and spinning reserve service only ($i.e., \omega = 1$) and the generator bids 80% of its capacity for energy ($i.e., \omega_1 = 0.8$) and 20% for spinning reserves ($i.e., \omega_2 = 0.2$). The generator offers for energy and spinning reserves are given in Appendix (Table B.1).

The demand buy bids are of the same structure as generator supply offers but in decreasing steps of prices for each block. It is assumed that 70% of the total demand is price inelastic and their bid prices are considered to be very high. Each DR provider submits separate offers for energy and spinning reserve services. It is assumed that the offer price for DR provision in spinning reserve market is 40% of the offer price for energy services. The maximum DR offer from a customer is assumed to be 10% of its demand bid quantity. The demand bids to buy energy, and DR offers for energy and spinning reserves are given in Appendix (Table B.2). For the sake of simplicity, we have considered only one customer at each bus.

The proposed model is formulated as a mixed integer programming (MIP) problem and solved using the CPLEX solver in General Algebraic Modelling System (GAMS) [95]. To investigate the impact of DR on market clearing and on the system operation, four scenarios are considered as follows:

- Scenario 1: Normal operation.
- Scenario 2: 155 MW generator at bus-16 is on outage during hours 17-20.
- Scenario 3: Line 14-16 is on outage during hours 16-21.
- Scenario 4: 20% increase in demand at hour 18, 19.

Each scenario examines four market design cases as follows:

- Case 1: Base case with PRD only.
- Case 2: DR services in energy market only (β_1=0.1, β_2=0, γ_1=0.1, γ_2=0, γ_3=0.05, γ_4=0.05).
- Case 3: DR services equally offered in both energy and spinning reserve market (β_1=0.05, β_2=0.05, γ_1=0.05, γ_2=0.05, γ_3=0.05, γ_4=0.05).
- Case 4: DR services in spinning reserve market only (β_1=0, β_2=0.1, γ_1=0, γ_2=0.1, γ_3=0.05, γ_4=0.05).

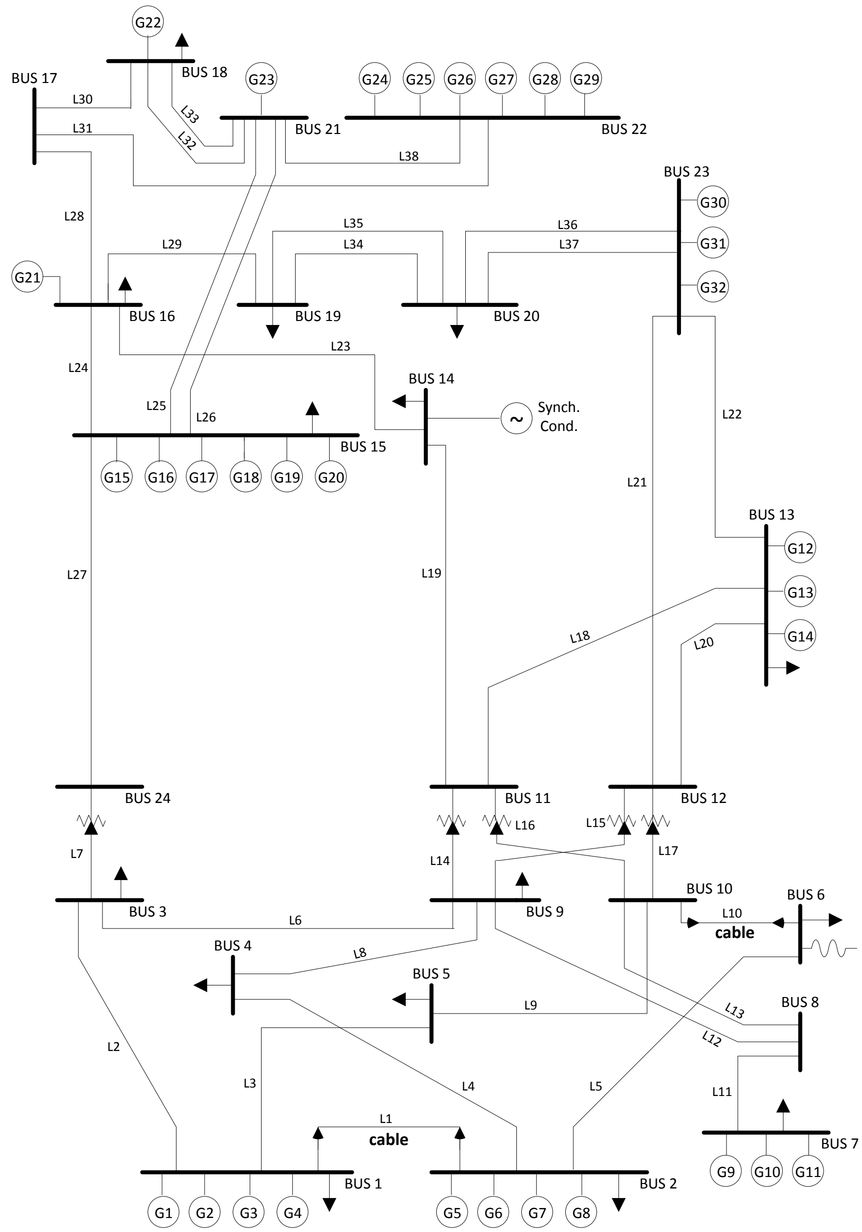


Figure 3.4: Schematic Diagram of IEEE RTS [92]

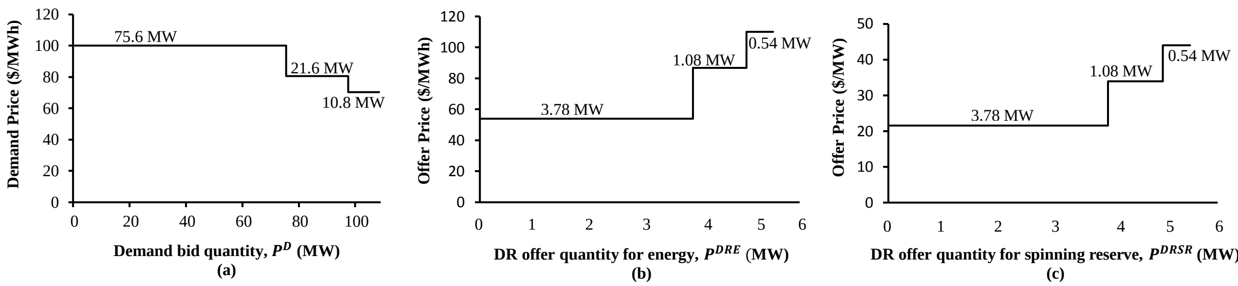


Figure 3.5: Bid/offer curves for a customer at bus-1, hour-18

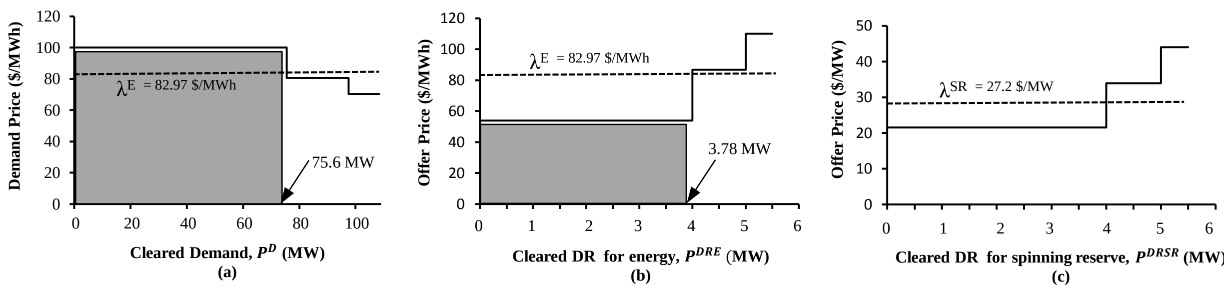


Figure 3.6: Cleared quantities for a customer at bus-1, hour-18

3.5.1 Scenario-1: Normal Operation

The bid/offer curves of the customer at bus-1, hour-18 *(PRD bid curve to buy energy, the curtailment based DR offer curves for energy and capacity respectively)* are shown as price-quantity blocks in Fig. 3.5. The bid/offer data are extracted from the Appendix (Table B.2). A brief insight is provided next to demonstrate how the customer decides its DR offer quantities for energy and spinning reserve provisions, as per equations (3.1)-(3.4) of the proposed model:

- Let the customer choose $\beta = 0.1$, and $\beta_1 = \beta_2 = 0.05$.
- $\beta = 0.1$ implies that a maximum share of 10% of the customers demand bid is available for total DR provisions in the energy and spinning reserve markets, as per (3.1).
- $\beta_1 = \beta_2 = 0.05$ implies that a maximum share of 5% of the customers demand bid is offered as DR in the energy and spinning reserve market, respectively, as per (3.2) and (3.3).

- Accordingly,
  - When $\overline{P}^{D}_{1,1,18}$=75.6 MW (From Table B.2), then 7.56 MW is available from the customer for $\overline{P}^{DRE}_{1,1,18}$ and $\overline{P}^{DRSR}_{1,1,18}$ provisions, *i.e.*, $\overline{P}^{DRE}_{1,1,18} + \overline{P}^{DRSR}_{1,1,18} \leq 7.56$ MW.
  - Also, $\overline{P}^{DRE}_{1,1,18} \leq 3.78$ MW and $\overline{P}^{DRSR}_{1,1,18} \leq 3.78$ MW.
  - While satisfying the above relations, the customer's DR offers are arbitrarily selected as follows: $\overline{P}^{DRE}_{1,1,18} = \overline{P}^{DRSR}_{1,1,18} = 3.78$ MW.

The determination of $P^{D}_{h,i,k}$,$P^{DRE}_{h,i,k}$, $P^{DRSR}_{h,i,k}$ are based on the market clearing prices for energy and spinning reserves, discussed as follows:

- *Demand Clearing*: The LMP obtained from the proposed model is $\lambda^{E}_{1,18} = 82.97$ \$/MWh. Those demand bids with prices higher than 82.97 \$/MWh are cleared. It is seen from Fig. 3.5(a) that only the first block is cleared and the total demand cleared is $P^{D}_{1,18} = 75.6$ MW $= P^{D}_{1,1,18}$.
- *Clearing of DR in Energy Market*: The blocks which have an offer price less than $\lambda^{E}_{1,18}$ are cleared. It is seen from Fig. 3.5(b) that only one block of DR is cleared, for an amount $P^{DRE}_{1,18} = 3.78$ MW $= P^{DRE}_{1,1,18}$.
- *Clearing of DR in Spinning Reserve Market*: Offers with prices below $\lambda^{SR}_{1,18} = 27.2$ \$/MW are cleared. It can be noted from Fig. 3.5(c) that although the offer price of the first block is less than $\lambda^{SR}_{1,18}$, this block is not cleared. This is because of (3.28), which limits the maximum duration for which the customer can provide DR service (*i.e.*, $\overline{DRT}_1 = 4$ hours). The customer is cleared to provide DR in energy market for 4 hours, during hours 18-21, and no DR is cleared for the spinning reserve market, *i.e.*, $P^{DRSR}_{1,18} = 0$ MW. Accordingly,

$$Y_{1,1,k} = \begin{cases} 1, & \forall k = 18, 19, 20, 21 \\ 0, & \text{Otherwise} \end{cases} \tag{3.42}$$

$$Z_{1,1,k} = 0 \qquad \forall k \tag{3.43}$$

The market clearing for the customer for hour-18 is shown in Fig. 3.6. The relationship between the cleared demand ($P^{D}_{1,18}$) and DR quantities ($P^{DRE}_{1,18}$, $P^{DRSR}_{1,18}$) to meet the customer's physical constraints and preferences are related by (3.21)-(3.28) of the proposed model and are discussed next.

- It is assumed that the ISO chooses $\gamma = 0.1$, $\gamma_1 = \gamma_2 = 0.05$, $\gamma_3 = \gamma_4 = 0.05$.
- $\gamma = 0.1$ implies that the total DR quantity that can be cleared in the energy and spinning reserve market is limited to 10% of total cleared demand, as per (3.21).
  - Thus, when $P^{D}_{1,18} = 75.6$ MW, the maximum total DR that can be cleared for energy and spinning reserve provisions is 7.56 MW. As per Fig. 3.6(b) and 3.6(c), it is noted that the total DR cleared is 3.78 MW, which satisfies (3.21).
- $\gamma_1 = \gamma_2 = 0.05$ implies that the DR quantity cleared in the energy market and spinning reserve market, separately, has to be less than 5% of the cleared demand of the customer.
  - Hence $P^{DRE}_{1,18} \leq 3.78$ MW and $P^{DRSR}_{1,18} \leq 3.78$ MW, as per (3.22) and (3.23), respectively.
  - As noted earlier, based on market price, the system need, and physical constraints of the customer, the DR cleared is $P^{DRE}_{1,18} = 3.78$ MW and $P^{DRSR}_{1,18} = 0$ MW.
- $\gamma_3 = 0.05$ implies that the DR quantity cleared in the energy market has to be less than 5% of the cleared demand net of DR cleared for spinning reserve, as per (3.25). Similarly, $\gamma_4 = 0.05$ implies that the DR quantity cleared in the spinning reserve market has to be less than 5% of the cleared demand net of the DR cleared for energy provision, as per (3.26).
  - Hence $P^{DRE}_{1,18} \leq 3.78$ MW, and $P^{DRSR}_{1,18} \leq 3.59$ MW.
  - Note from Fig. 3.6(b) and 3.6(c) that $P^{DRE}_{1,18} = 3.78$ MW and $P^{DRSR}_{1,18} = 0$ MW, which satisfies (3.25) and (3.26).

Finally, the actual consumption of the customer at bus-1, hour-18, is given by:

- Demand cleared in the market - DR cleared for energy provision
  = $P^{D}_{1,18}$ - $P^{DRE}_{1,18}$
  = 75.6 MW - 3.78 MW = 71.82 MW

- Spinning reserve provision, $P_{1,18}^{DRSR} = 0$ MW.

The relationship between the bid/offer quantities and the cleared quantities of the customer at bus-1 is depicted in Fig. 3.7.

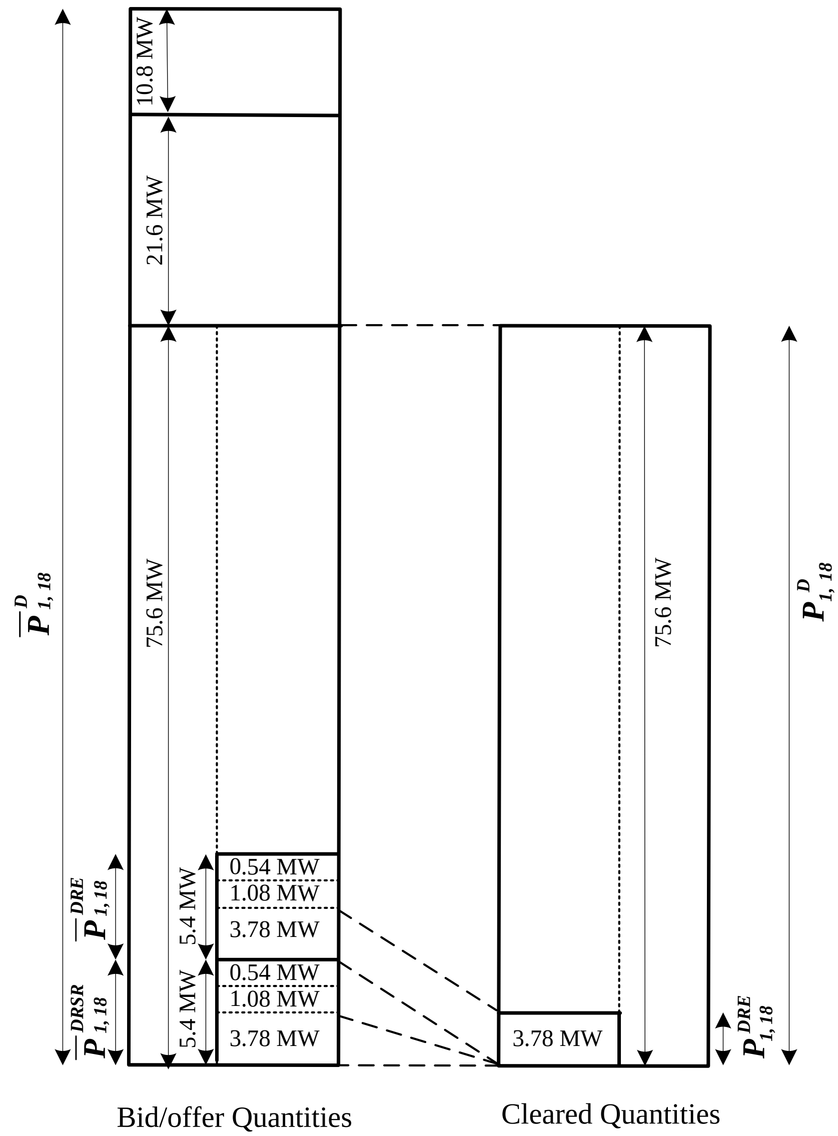


Figure 3.7: Bid/offer and cleared quantities of a customer at bus-1, hour-18

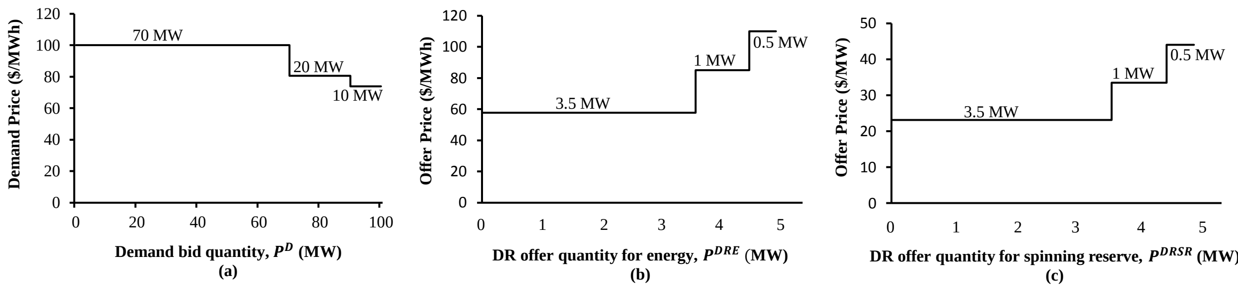


Figure 3.8: Bid/offer curves for a customer at bus-16, hour-18

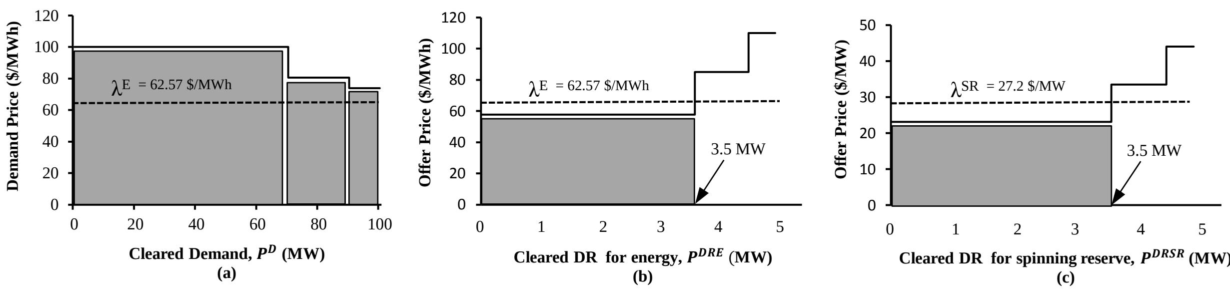


Figure 3.9: Cleared quantities for a customer at bus-16, hour-18

Next, an example is considered to demonstrate a case where the market model selects DR for both energy and spinning reserves, at a given hour. The bid/offer data of a customer at bus-16 for hour-18 is used, extracted from the Appendix (Table B.2). It is assumed that all the market parameters (βs and γs) have same values as in the previous example, and the selections of bid/offer quantities and market clearings are carried out in the same step-by-step manner. Accordingly, the bid/offer curves and the cleared quantities of the customer are shown in Fig. 3.8 and Fig. 3.9, respectively.

- The LMP was obtained as $\lambda^E_{16,18} = 62.57$ \$/MWh; since all three demand bids have prices higher than 62.57 \$/MWh, (Fig. 3.8(a)), they are cleared and the total cleared demand $P^D_{16,18} = 100$ MW.

- Only the first DR block for DR offers in energy market (Fig. 3.8(b)) is cleared since it had an offer price less than $\lambda^E_{16,18}$. Thus, $P^{DRE}_{16,18} = 3.5$ MW.

- Only the first DR block for DR offers in spinning reserve market (Fig. 3.8(c)) is cleared since it had an offer price less than $\lambda^{SR}_{16,18} = 27.2$ \$/MW. Thus, $P^{DRSR}_{16,18} = 3.5$ MW.

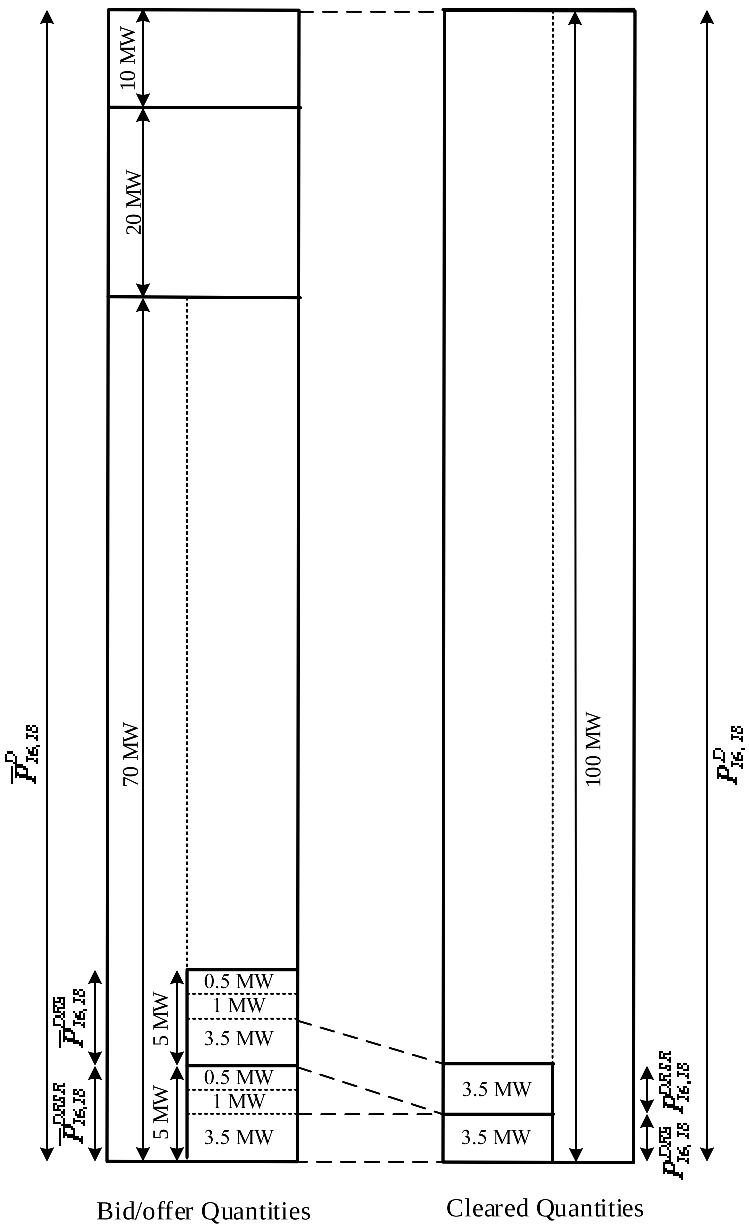


Figure 3.10: Bid/offer and cleared quantities of a customer at bus-16, hour-18

- Since the customer can provide DR services for a maximum of 4 hours ($i.e.$,$\overline{DRT}_{16}$ = 4 hours), this customer is cleared for 2 hours each in energy and spinning reserve markets during hours 18-19. Accordingly,

$$Y_{1,16,k} = \begin{cases} 1, & \forall k = 18, 19 \\ 0, & \text{Otherwise} \end{cases} \tag{3.44}$$

$$Z_{1,16,k} = \begin{cases} 1, & \forall k = 18, 19 \\ 0, & \text{Otherwise} \end{cases} \tag{3.45}$$

- Based on the market price, the system need, and physical constraints of the customer, the DR cleared for this customer is $P^{DRE}_{16,18} = 3.5$ MW and $P^{DRSR}_{16,18} = 3.5$ MW.

The relationship between the bid/offer quantities and the cleared quantities of the customer at bus-16 is depicted in Fig. 3.10.

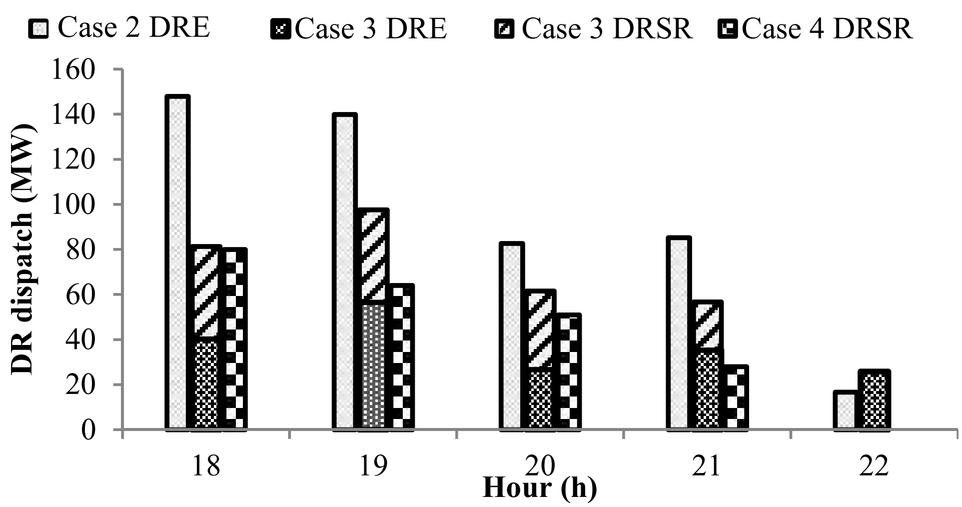


Figure 3.11: DR dispatch in the energy and spinning reserve market

Fig. 3.11 shows the DR dispatch in the energy market and in the spinning reserve market (*denoted by DRE and DRSR respectively, in Fig. 3.11*); it is noted that DR is dispatched only during the peak load hours 18-22. Since the DR providers also provide spinning reserve services in Case 3, the DR amount dispatched in the energy market in this case is lower than in Case 2.

Fig. 3.12 shows the bus-wise dispatch of DR in energy and spinning reserve markets, and it is noted that DRs are selected at those buses where the offer prices are low. Furthermore,

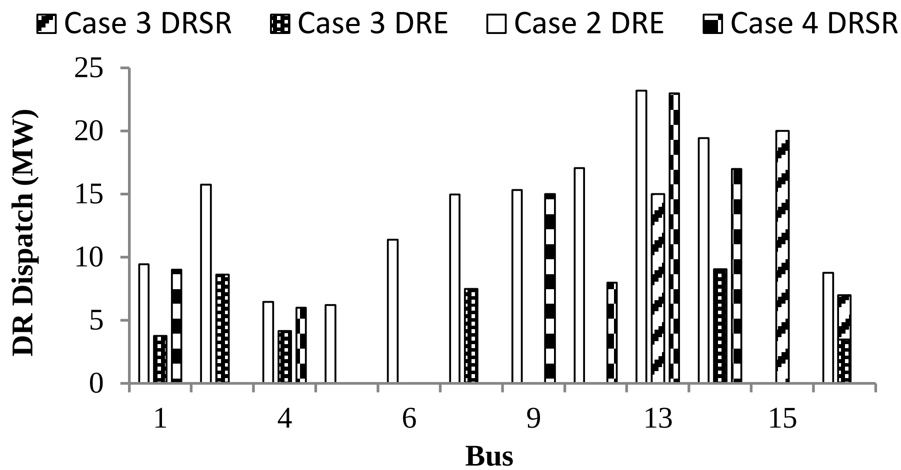


Figure 3.12: Locational dispatch of DR in the energy and spinning reserve market

studies also show that DR can reduce congestion on some lines in certain hours. For example, line 10-6 is congested during hours 1-4, 7, 8, 10-23 in Case 1, and with DR dispatch in Case 2 the congestion is relieved at hours 18-22, and at hours 19-22 in Case 3. Also, congestion on line 24-3 in Case 1 is relieved for four hours during the peak load in Case 2 and Case 3.

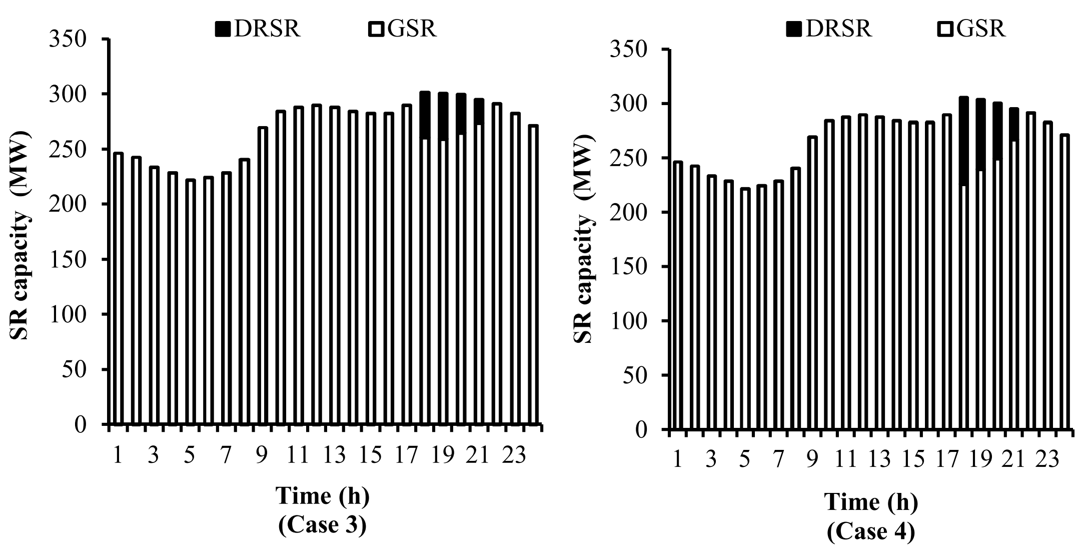


Figure 3.13: Spinning reserve contracted over 24 hours in Case 3

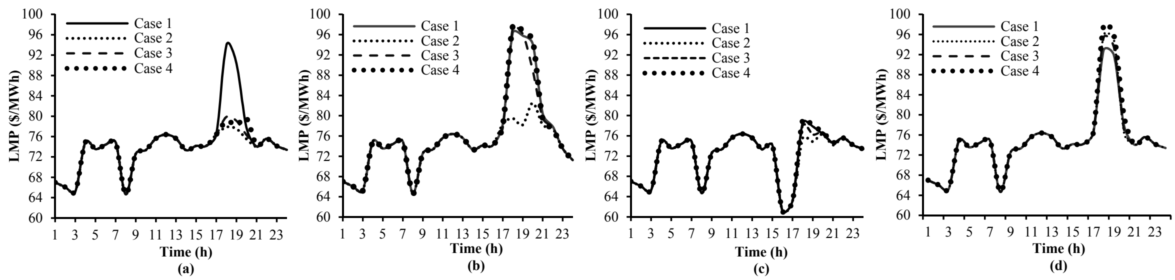


Figure 3.14: LMP at bus-14 in (a) Scenario-1 (b) Scenario-2 (c) Scenario-3 (d) Scenario-4

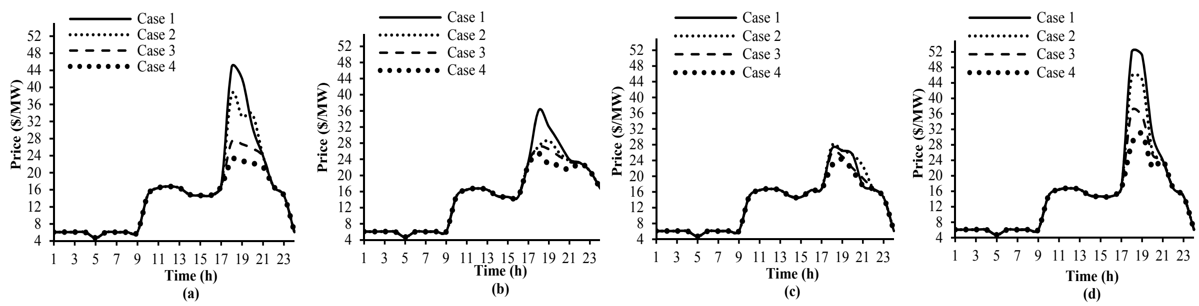


Figure 3.15: Spinning reserve prices (a) Scenario-1 (b) Scenario-2 (c) Scenario-3 (d) Scenario-4

Fig. 3.13 shows the spinning reserves provided by generators and DR providers in Case 3 and Case 4 (*denoted by GSR and DRSR respectively, in Fig. 3.13*). It is noted that while generators provide the lion's share of spinning reserve requirements, DR providers supplement this service during the peak load hours 18-21 to help in system reliability. During hour-18, the share of spinning reserve from DR providers is 11% in Case 3 and 27% in Case 4, which is fairly significant.

Fig. 3.14(a) shows the LMPs (considering losses) at bus-14 for Scenario-1; since no DR is dispatched in Case 2, Case 3 and Case 4 between hours 1-17 and 23-24, LMPs are same at these hours for these cases. However, the LMP reduces significantly during peak hours 18-22, in Case 2, Case 3 and Case 4, more so in Case 2, because of the participation of DR in energy market only. Thus, it is noted that DR can play a vital role in stabilizing the market prices, reducing market imperfections and gaming possibilities of generators.

It is noted from the plot of spinning reserve prices for Scenario-1 (Fig. 3.15(a)) that when DR providers supply this service, in Case 3 and Case 4, the peak hour prices are reduced significantly, because of their cheaper offers which replaces the expensive offers from generators. The price reduction in Case 4 is more prominent because of the larger quantity of DR quantity dispatched for spinning reserve. In Case 2, there is a reduction in net demand because DR participates in energy market only, which reduces the spinning reserve requirement, and hence brings about the dip in spinning reserve price.

Table 3.1: All day market clearing results (considering losses) in Scenario-1

	Case 1	Case 2	Case 3	Case 4
Generation Dispatch (MWh)	65,585	65,531	65,642	65,738
GSR (MWh)	6,458	6,453	6,353	6,250
DRE (MWh)	0	472	206	0
DRSR (MWh)	0	0	110	223
Demand cleared (MWh)	64,584	65,009	64,850	64,736
Losses (MWh)	1,001	994	998	1,002
Social Welfare ($)	4,462,866	4,471,784	4,468,279	4,464,547
Energy Cost ($)	1,052,727	1,049,178	1,054,010	1,058,159
GSR Cost ($)	32,827	32,801	31,113	29,400
DRE Cost ($)	0	28,350	12,348	0
DRSR Cost ($)	0	0	2,626	4,912
DRE payment ($)	0	34,998	15,658	0
DRSR payment ($)	0	0	2,912	5,018

Table 3.1 presents a summary of market clearing results considering transmission losses. Case 1 is the base case, with PRD only; the cleared generators meet the cleared demand taking into account system losses. Case 2 to Case 4 considers both PRD and DR offers in the energy and spinning reserve markets. In Case 2, the participation of DR in energy market results in an increase in the cleared demand, but the net demand (*i.e.* the difference between cleared demand and DR dispatched for energy services) is reduced, leading to a reduction in generation, and hence a reduction in energy cost. The social welfare increases, as expected, and is the highest amongst all cases. The DR payments are high in Case 2, which makes it more attractive to the load participants to participate in DR provisions.

In Case 3, the DR participates in both energy and spinning reserve markets and accordingly the DR quantity dispatched in the energy market is reduced, compared to Case 2, resulting in an increase in net demand and generation, and hence an increase in energy cost. There is a reduction in the spinning reserve cost of generators, because the more expensive generators which were scheduled for spinning reserves are now replaced by cheaper DR spinning reserve services. The total DR payment to customers is almost half of that in Case 2, because the spinning reserve market price is considerably lower than the energy market price. The social welfare decreases slightly from Case 2. It can be noted that the inclusion of DR for energy services helps to reduce the system losses in both Case 2 and Case 3, albeit marginally.

In Case 4, when DR participates only in spinning reserve services, there is an increase in the generation and net demand, thus resulting in increased energy cost. The share of DR in the spinning reserve market is highest among all cases, which helps to bring down the spinning reserve cost of generators. Since DR provides only spinning reserve services, the DR payment is the least, which is favorable from the perspective of the ISO. The social welfare reduces further in this case, from Case 3.

The results indicate that the social welfare increases in Cases 2, 3, and 4 as compared to Case 1, which justifies that PRD bids and curtailment based DR offers considered together are more beneficial. It is also noted that although Case 2 results in the highest social welfare, it is not necessarily the most preferred option for the ISO because DR is cleared only in the energy market. Furthermore, fast response time, high ramp rate, and controllability of response, which makes DR services desirable options in the spinning reserve market, are not utilized in Case 2. On the other hand, Case 4 focuses only on the ISO's perspective and allocates all the DR service to the spinning reserve market. Consequently, the spinning reserve market price drops during peak hours and the ISO's payment burden is the least, but at a disadvantage to the DR providers. Therefore, considering all the above aspects, Case 3 presents a more balanced combination of DR participation in the two markets.

Impact of Market Parameters β_1

Analysis is carried out to understand the impact of β_1 on social welfare and DR payments.

Fig. 3.16 shows the variation of social welfare with variations in the parameter β_1 over the range from 0 to 0.1 (for fixed values of γ_1). It is noted that as β_1 increases there is an increase in the social welfare, the social welfare attains a maximum value corresponding to each chosen value of γ_1 and decreases thereafter with further increase in β_1. Similarly, as the parameter β_1 increases there is an increase in the DR payments (Fig. 3.17), which attains a maximum, corresponding to each chosen value of γ_1 and decreases thereafter with further increase in β_1.

It can be noted that the social welfare and DR payments are higher when ISO chooses to clear more quantity of DR for energy provisions *i.e.*, a higher value of γ_1 is chosen.

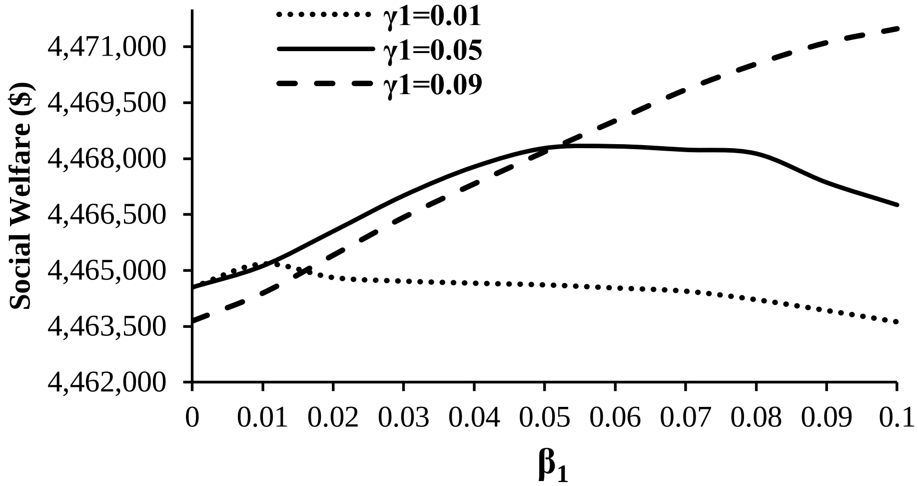


Figure 3.16: Variation in social welfare with variation in β_1

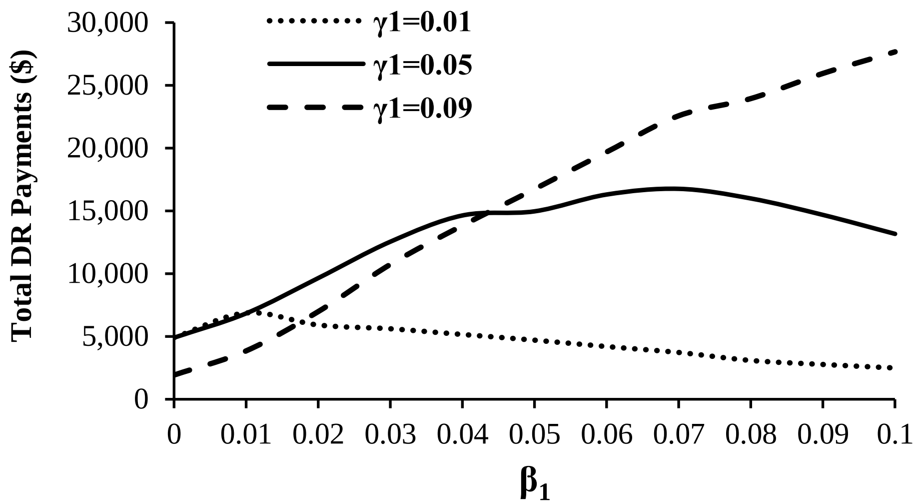


Figure 3.17: DR payments with variation in β_1

Impact of Ignoring Transmission Losses

It is important to examine the impact of neglecting transmission losses in an LMP based market, as losses can account for significant amount of energy.

Fig. 3.18 shows the LMPs considering losses and without losses (*denoted by L and*

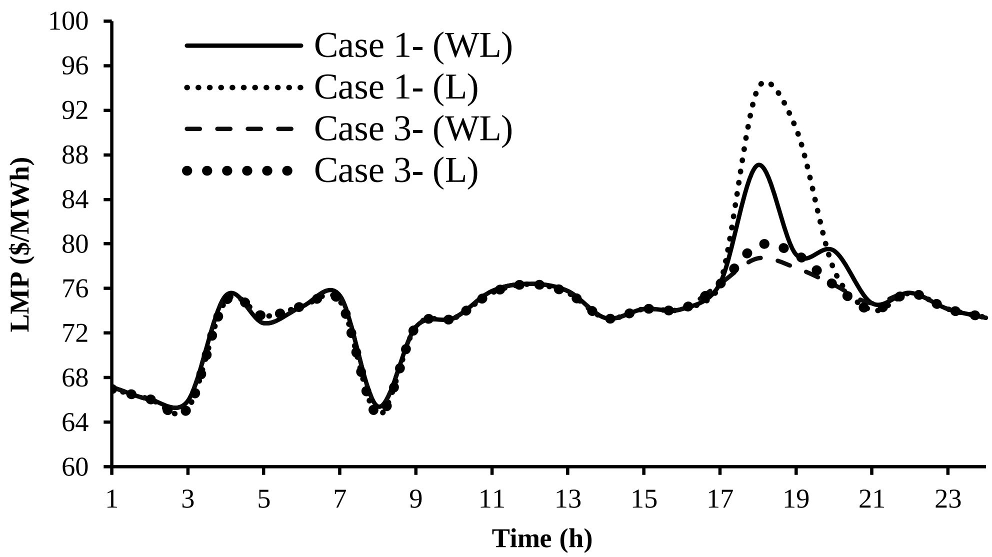


Figure 3.18: LMP at bus-14 with and without losses

WL respectively, in Fig. 3.18) at bus-14, for Case 1 and Case 3, for Scenario-1 (normal operation). It is noted that when losses are neglected the LMPs reduce significantly during peak hours 18-22 in Case 1-(WL), compared to the case considering losses. This is because losses being neglected, the generation dispatch is reduced and thus avoiding scheduling of more expensive generators. While in Case 3-(WL), DR provisions for energy service results in replacing the expensive generator offers and thus the LMPs are reduced even more. There is a minimal change in the LMPs between hours 1-17 and 23-24, as losses are less prominent during off-peak hours.

Fig. 3.19 shows spinning reserve prices considering losses and without losses (*denoted by L and WL respectively, in Fig. 3.19*) for Case 1 and Case 3. It is noted that in both Case 1 and Case 3, when losses are neglected, the spinning reserve prices reduce significantly during peak hours 18-22 in Case 1-(WL), compared to the case considering losses. This is because with losses being neglected, the generation dispatch is reduced and thus avoiding avoiding scheduling of expensive generators for spinning reserve services. While in Case 3-(WL), with DR providing spinning reserves, the peak hour spinning reserve prices are reduced even more because of expensive generator offers for spinning reserves being now replaced with cheaper DR offers.

Table 3.2 presents a summary of market clearing results without considering losses. It is noted that the total generation dispatch reduces, resulting in reduction in the energy

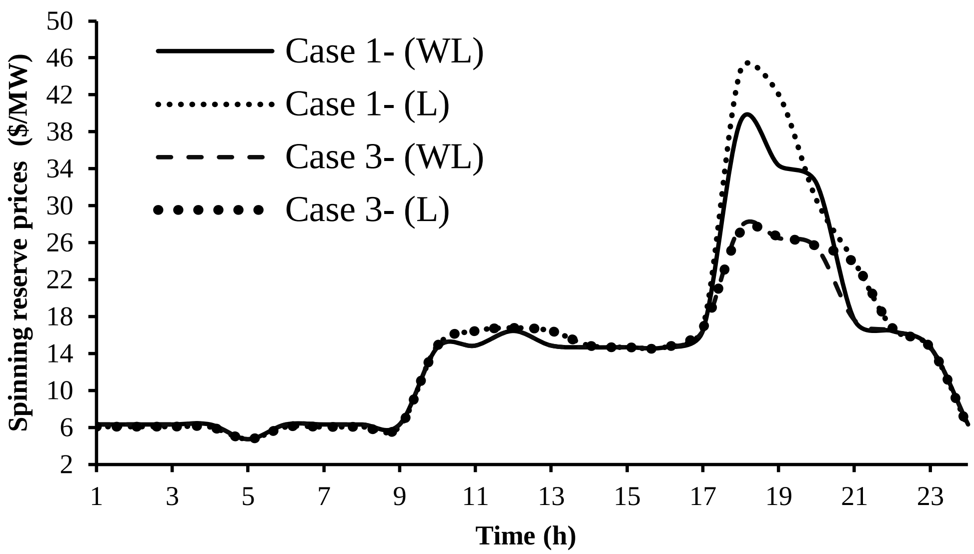


Figure 3.19: Spinning reserve prices with and without losses

Table 3.2: All day market clearing results (without losses) in Scenario-1

	Case 1	Case 2	Case 3	Case 4
Generation Dispatch (MWh)	64,840	64,765	64,858	64,949
GSR (MWh)	6,484	6,476	6,485	6,494
DRE (MWh)	0	473	207	0
DRSR (MWh)	0	0	84	157
Demand cleared (MWh)	64,840	65,238	65,065	64,949
Social Welfare ($)	4,498,858	4,506,558	4,503,336	4,499,836
Energy Cost ($)	1,037,808	1,033,597	1,037,691	1,041,940
GSR Cost ($)	29,199	29,175	27,938	26,831
DRE Cost ($)	0	28,399	12,463	0
DRSR Cost ($)	0	0	1,993	3,479
DRE payment ($)	0	35,058	15,783	0
DRSR payment ($)	0	0	2,312	3,789

cost and thereby an increase in the social welfare, in all four cases, as compared to the cases when losses are considered. Furthermore, there is not much variation in the DR quantity cleared for energy provision but the DR quantity cleared for spinning reserve provision is reduced, thereby leading to reduction in total DR payments.

3.5.2 Other Scenarios

In Scenario-2, which considers the generator at bus-16 on outage during hours 17-20, the generation and the cleared demand during these hours are reduced as compared to Scenario-1. There is a slight increase in the DR dispatch and a change in the location of DR selections. The demand at bus-14 is mainly supplied by the generator at bus 16. As a result of outage of this generator, there is a significant increase in the LMP at bus-14 in Case 3 and Case 4 during these hours compared to the same cases in Scenario-1, whereas LMP in Case 2 is not much affected since DR is scheduled at bus-14 (Fig. 3.14(b)). The spinning reserve prices are reduced in Scenario-2 as seen in Fig. 3.15(b), because there is a reduction in the net demand. The social welfare in all the four cases have decreased compared to Scenario-1.

In Scenario-3, which considers line 14-11 on outage during hours 16-21, the generation and cleared demand during these hours are almost same as in Scenario-1. There is a slight decrease in the amount of DR dispatched in the energy market in Case 2 and Case 3 but the DR dispatched in the spinning reserve market in Case 3 and Case 4 are considerably reduced, compared to the same cases in Scenario-1. As a result of the outage, the congestion on line 16-14 is reduced, thereby reducing the LMP at bus-14 in all cases (Fig. 3.14(c)). It is also noted that cheaper generators are scheduled for spinning reserve, compared to those in Scenario-1, thus leading to a reduction in the spinning reserve prices (Fig. 3.15(c)).

In Scenario-4, which considers a 20% demand spike at hours 18 and 19, the total generation and cleared demand increases during these hours as compared to Scenario-1. There is an increase in the DR quantity cleared in the energy market by about 25% and that in the spinning reserve market by about 15%. It is noted that there is a sharp increase in the LMPs in Case 2, Case 3, and Case 4, compared to Scenario-1 during hours 18 and 19 (Fig. 3.14(d)), because the cleared demand, generation and DR dispatch increases and which is being supplied by more expensive generators and DR providers. As there is an increase in the net cleared demand during hours 18 and 19, the total spinning reserve requirement increases, hence resulting in a sharp increase in the spinning reserve prices also (Fig. 3.15(d)). The social welfare increased in all the four cases as compared to Scenario-1.

3.6 Conclusions

In this chapter, a novel and comprehensive formulation of DR provisions through PRD and load curtailment based DR bids simultaneously, taking into account customer preferences for simultaneous participation in energy and spinning reserve markets was proposed. Various parameters of DR offers and their inter-relationships with the demand offers, and the clearance of the demand and DR bids were brought out. Based on the proposed novel bidding structure, a new mathematical model for an LMP-based, loss included, day-ahead, co-optimized energy and spinning reserve market including DR provisions was proposed. The effectiveness of the model was validated on the IEEE RTS by considering four case studies under four scenarios. It was seen that the inclusion of DR reduced the energy prices and also helped in reducing congestion in the system when it provided energy services. When the DR provided spinning reserve services, it helped reduce the cost of spinning reserve service of generators. The DR provisions, simultaneously considering PRD bids and DR offers, in energy and spinning reserve markets, resulted in increased social welfare. Thus, the customers were benefited from lowering of energy prices. The integration of DR in the energy and spinning reserve market enhanced the economic and technical benefits for the ISO by providing more options for system operation. The impact of selection of the parameters related to DR offer quantities and cleared DR quantities on social welfare and DR payments were also examined.

Chapter 4

BESS in Day-Ahead Energy and Reserve Markets[1]

4.1 Nomenclature

Sets & Indices

e	BESS, $e \in E$.
h	Blocks of customer bids, $h \in N_{CB}$.
i, q	Bus, $i \in I$.
j	Generators, $j \in J$.
k, t	Time (hour), $k \in K$.
n	Blocks of generator offers, $n \in N_{GB}$.
ES_i	Set of BESS connected to bus i.
G_i	Set of generators connected to bus i.

Note: The parameters and variables are listed without their indices, for brevity.

[1] Parts of this chapter have been submitted for review in: N. Padmanabhan, M. Ahmed, and K. Bhattacharya, "Battery energy storage systems in energy and reserve markets, *IEEE Trans. Power Systems,* 2018.

Parameters

B	Element of susceptance matrix, p.u.
B^E_{Cap}	Battery energy capacity, MWh.
$C1$	Degradation cost based on DOD and discharge rate, \$/MWh.
a, b, c, d	Coefficients of $C1$.
$C2$	Battery flexibility cost, \$.
C^B	Battery cost, \$.
C^{Ch}	BESS charging bid price, \$/MWh.
C^D	Customer's demand bid price, \$/MWh.
$C^{\boldsymbol{ESR}}$	Spinning reserve offer price of BESS, \$/MWh.
C^G	Generator offer price for energy, \$/MWh.
$C^{\boldsymbol{GSR}}$	Generator spinning reserve offer price, \$/MW.
C^{sd}, C^{su}	Shut-down/ start-up cost of generator, \$.
$DCR^{\boldsymbol{max}}$	Maximum discharge rate limit of BESS, p.u.
$DCR^{\boldsymbol{min}}$	Minimum discharge rate limit of BESS, p.u.
$\overline{P}$, $\underline{P}$	Maximum/minimum limit on power output of generator, MW.
$\overline{P}^{Ch}$, $\overline{P}^{Dch}$	Maximum charging/discharging limit of BESS, MW.
$\overline{P}^{D}$, $\overline{P}^{G}$	Demand bid/ Generator offer quantity, MW.
$\overline{P}^{\boldsymbol{GSR}}$	Generator spinning reserve offer quantity, MW.
$\overline{SOC}$, $\underline{SOC}$	Maximum/minimum SOC limit of BESS, p.u..
α	Fraction of battery cost accounting its flexibility characteristic.
$\beta^{\boldsymbol{Ch}}$, $\beta^{\boldsymbol{Dch}}$	BESS charging/discharging capacity share, as a fraction of the available BESS energy capacity.
$\beta^{\boldsymbol{SR}}$	BESS offer quantity share, for spinning reserve, as a fraction of available BESS energy capacity.
η	Battery round trip efficiency, %.
η^{Ch}, η^{Dch}	Battery Charging/discharging trip efficiency, %.

Variables

DCR	Discharge rate of the BESS, p.u.
$E^{\boldsymbol{Ch}}$	Charging energy, MWh.
$P^{\boldsymbol{ChE}}$, $P^{\boldsymbol{DchE}}$	Charging/discharging power, MW.
$P^{\boldsymbol{ESR}}$	Spinning reserve from BESS, MW.
P^{D}, P^{G}	Cleared demand/generation, MW.
$P^{\boldsymbol{GSR}}$	Spinning reserve cleared from generator, MW.
P^{loss}	Power loss in the transmission line, MW.
SOC	State of charge, p.u.
$SOC^{\boldsymbol{Dch}}$	SOC after the discharging operation, MWh.
$SOC^{\boldsymbol{SR}}$	Energy capacity of the BESS cleared for spinning reserve provision, p.u.
$SOC^{\boldsymbol{SRcap}}$	BESS cleared capacity for spinning reserve, MWh.
$U_{j,k}$, $V_{j,k}$	Binary variable = 1, if generator starts/shut downs, and 0 otherwise.
W^{G}, $W^{\boldsymbol{SR}}$	Binary variable = 1, if energy/spinning reserve offer of generator is cleared, and 0 otherwise.
X	Binary variable = 1, if demand bid is cleared, and 0 otherwise.
$Z1$, $Z2$	Binary variable = 1, if BESS is charging/discharging, and 0 otherwise.
$Z3$	Binary variable = 1, if BESS is providing spinning reserve provision, and 0 otherwise.
δ	Voltage angle of the bus, radian.

4.2 Introduction

Recently some policy interventions have taken place for increasing the ESS participation in electricity markets. For example, the FERC Order 841 [14] requires that ISOs facilitate the participation of ESSs in energy, ancillary services, and capacity markets, by including the ESS bidding parameters that represent their physical and operational characteristics. However, there are still many challenges associated with the implementation of this Order. For example, in the existing market frameworks that allow BESSs to participate by bidding in electricity markets, the bids and offers do not explicitly represent the physical and operational characteristics such as the SOC, discharge rate, degradation, *etc.*

In the view of aforementioned challenges, this chapter first presents a novel BESS cost function model, considering Degradation Cost, based on DOD and discharge rate, and Flexibility Cost, in terms of the battery P/E ratio. The model is developed considering Lithium-ion batteries, and the approach can be applied to other conventional electrochemical batteries, but not flow batteries. A detailed bid/offer structure based on the proposed cost functions is formulated. Thereafter, a new framework and mathematical model for BESS participation in an LMP-based, co-optimized, day-ahead energy and spinning reserve market, are developed. Three case studies are presented to investigate the impact of BESS participation on system operation and market settlement. The proposed model is validated on the IEEE RTS to demonstrate its functionalities.

4.3 BESS Cost Function Model

The special characteristics of a BESS enables it to participate in the electricity markets both as a load and a generator, and hence the BESS can submit bids to charge and offers to discharge. The bids and offers should reflect the marginal operating cost of the BESS. Furthermore, the BESS can also participate in reserve markets by providing its capacity, in the form of a discharge offer; the discharging quantity can be available during both charging and discharging operations. The following aspects need be taken into consideration in developing the operating cost function of a BESS:

- When a BESS participates in the electricity market, its charging / discharging profiles are expected to be significantly different from those considered in its testing phase. Therefore, it is important to take into account the variable, and usage dependent, BESS degradation characteristics in the cost model.
- BESSs are capable of providing a high degree of operational flexibility, which makes them competent ancillary service resources. It is necessary to consider the value of flexibility in their operating cost model.
- BESSs being limited energy sources, it is more realistic to formulate their cost functions and bids/offers in terms of their energy capacity or SOC, instead of power quantities.

It is to be noted that among the aforementioned aspects, the battery degradation mechanism has the most significant impact on the operational cost of a BESS and thus it is very important to capture it in the cost. The battery degradation is dependent on factors such as the DOD, discharge rate, limits on SOC, ambient temperature, etc., and these dependencies are nonlinear in nature. In order to reduce battery degradation modeling complexity, the following assumptions are made: (i) the impact of high temperature is disregarded as all BESSs have an appropriate climate control system; (ii) the impact of SOC limits is minimal, by appropriate choice of the minimum/maximum limits on SOC; (iii) assuming that the BESS charging and discharging energies are identical over a day's cycle, battery degradation only occurs during the discharge stage of the cycle, and the charging half cycle causes no cycle aging [61].

Thus, the operations cost of a BESS is comprised of the following components: (i) Degradation Cost Based on DOD and discharge Rate, (ii) Flexibility Cost (iii) Spinning Reserve Cost.

4.3.1 Degradation Cost Based on DOD and Discharge Rate

In this work, we model battery degradation based on two important factors: DOD and discharge rate. When considering the BESS degradation due to DOD, an important factor to be considered is from what level of SOC the battery starts discharging and to what level it reaches at the end of the discharging interval. For example, let us consider two cases of battery discharge: (i) SOC of 100% to 40% (ii) SOC of 80% to 20%. Although the DOD in both cases is 60%, the degradation is more severe in case (ii), as per [96]. Hence it is very important to capture the impact of starting and ending levels of the SOC on the degradation cost. Furthermore, it is to be noted that it is a common practice to use the SOC as the state variable in BESS operation models rather than the DOD [53, 60].

In the context of ESS participating in the electricity markets, the ISOs typically adopt two modes: (i) ISO-monitored energy level mode, (ii) self-monitored energy level mode [35, 97]. In the former mode of participation, the SOC, and lower/ upper storage limits of the ESS are available to ISO, to ensure that the storages' schedules in the day-ahead and real-time markets are feasible within their operating limits. In the latter mode of participation, the ESSs themselves manage their energy level constraints, thus do not participate by providing their SOC level or other operating limits to the ISO. For example, in NYISO [35] both modes are available for the ESS to participate in the market, while in MISO [97], the ESSs participate only through ISO monitored energy level mode. In the proposed work, we consider that the SOC of the battery is known and monitored by the market operator, as practiced in NYISO.

The second important factor contributing the battery degradation are the high charging and discharging currents. In this work, the discharge rate of a battery, denoted by DCR, is expressed as the change of SOC per unit time, given as follows:

$$DCR_k = \frac{SOC_{k-1} - SOC_k}{T} = \Delta SOC_k \qquad \forall k \in K \tag{4.1}$$

Since a 1-hour time interval is considered, *i.e.*, $T = 1$.

In this work, discharge rate is represented in terms of 'C', where 1C denotes the full discharge of the battery in 1-hour, 2C the full discharge in 30 minutes, 3C the full discharge in 20 minutes and so on. In the same context, 0.5C denotes 50% of the full discharge in 1-hour.

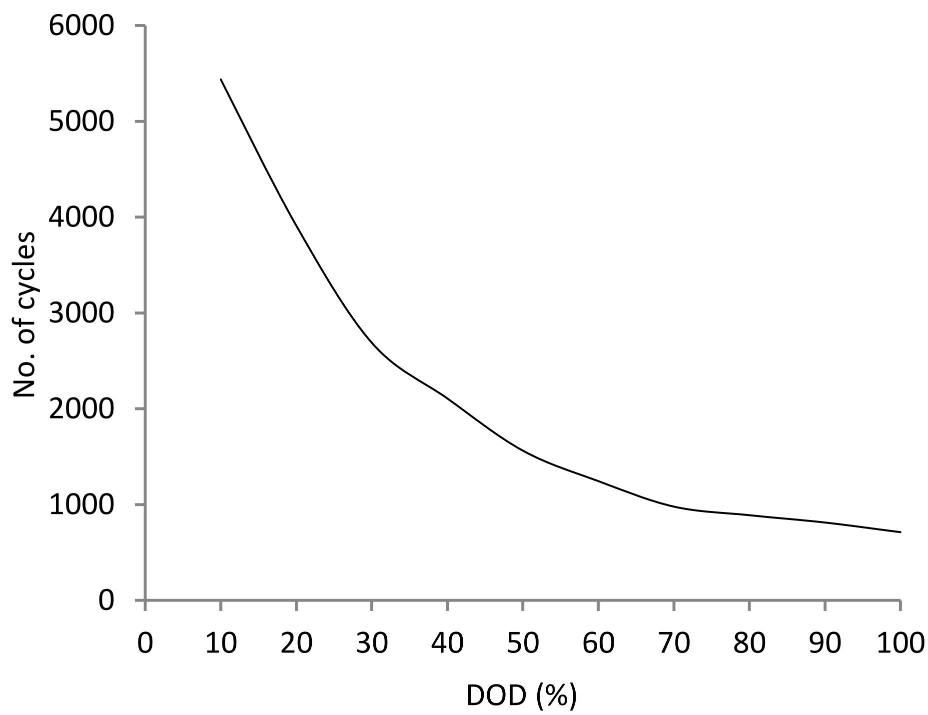


Figure 4.1: Relationship between number of cycles and DOD, for discharge rate of 1C [97,98]

In order to model the battery degradation correctly, it is important to understand the impact of DOD and discharge rate on the number of cycles. The relationship of DOD with battery cycle life for a Lithium ion battery (at a given temperature and discharge rate) shown in Fig. 4.1, is obtained through tests and are provided by the battery manufacturer [98], [99].

The relationship between cycle life and DOD for the Lithium ion battery as per the curve in Fig.1 can be expressed as follows:

$$L(D) = \gamma D^{-\omega} \tag{4.2}$$

where, γ and ω, are coefficients capturing the relationship between the number of cycles and the DOD, for an assumed discharge rate of 1C, and their typical values are given in [98], [99].

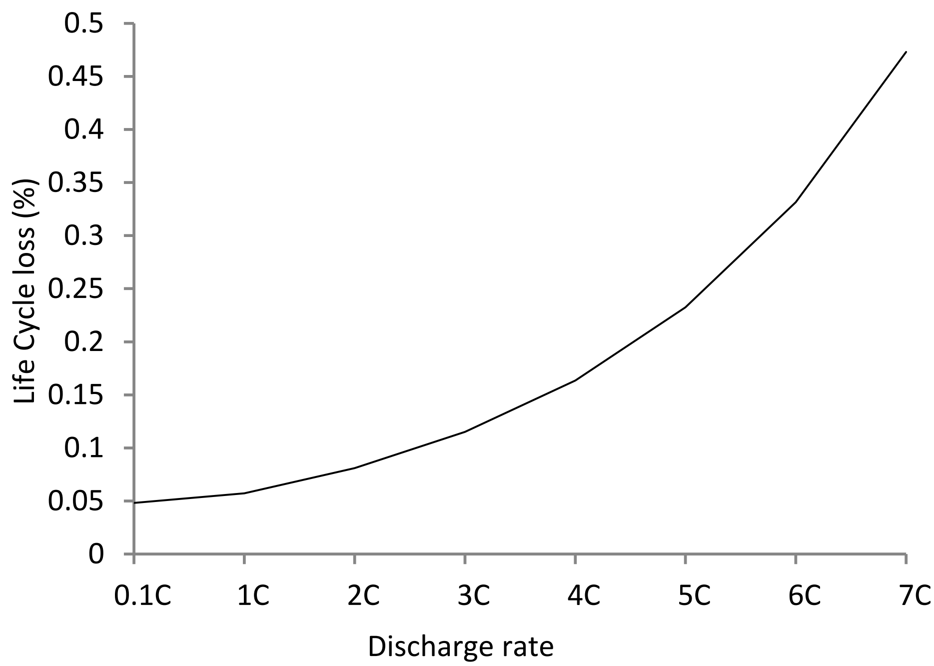


Figure 4.2: Cycle life loss versus discharge rate [99]

Similarly, the relationship between cycle life loss and discharge rate for the Lithium ion battery is shown in Fig. 4.2 [100]. It can be noted from Fig. 4.2, the impact of discharge rate on the cycle life is almost linear for discharge rates up to 3C and thereafter it is exponential. With this inference, and the knowledge of parameters γ and ω for other

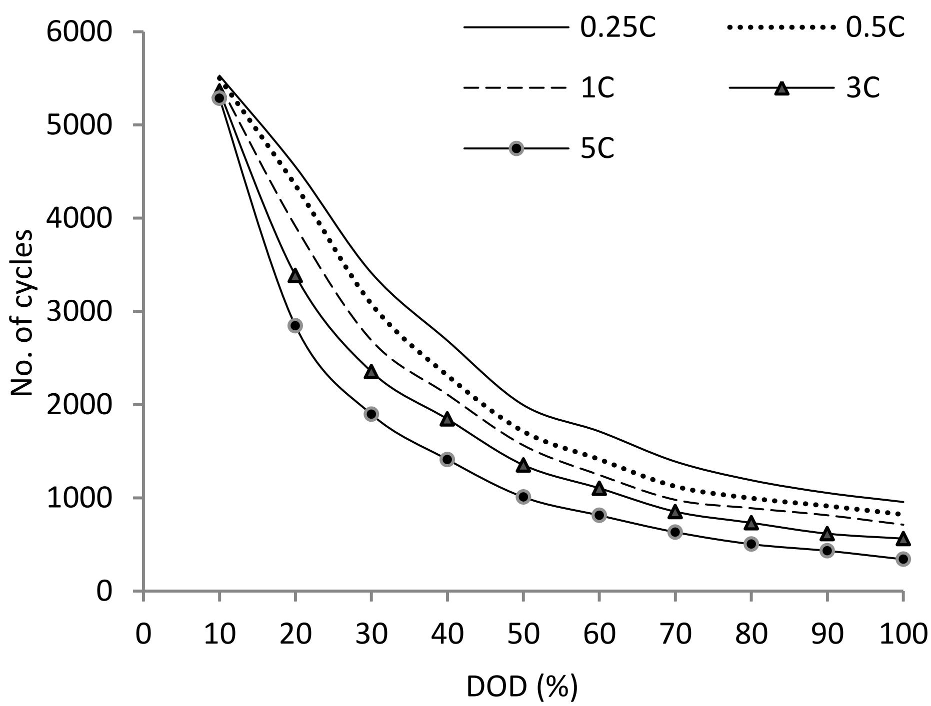


Figure 4.3: Relationship between number of cycles and DOD, for different discharge rates

values of discharge rates, the relationship between the number of cycles and DOD for various discharge rates can be developed, and represented as shown in Fig. 4.3.

Now, taking into account the impact of starting and ending levels of the SOC, before and after the discharge operation, the Degradation Cost ($C1_k$) for a particular discharge rate, can be expressed in terms of the SOC as follows [96],

$$C1_k = \frac{C^B}{B^E_{cap}\eta^2\,\gamma}((1 - SOC_k)^\omega - (1 - SOC_{k-1})^\omega) \quad \forall k \in K \tag{4.3}$$

Using (4.3), for different possible values of SOC_k and SOC_{k-1} and discharge rate, the battery degradation cost for various scenarios can be generated and represented as shown in Fig. 4.4; where each layer represents the Degradation Cost corresponding to various DOD, expressed in terms of SOC_k and SOC_{k-1}, and a particular discharge rate.

It is to be noted that $C1_k$ in (4.3) is a nonlinear function of DOD and discharge rate, expressed in terms of SOC_k and SOC_{k-1} and for different discharge rates. In order to

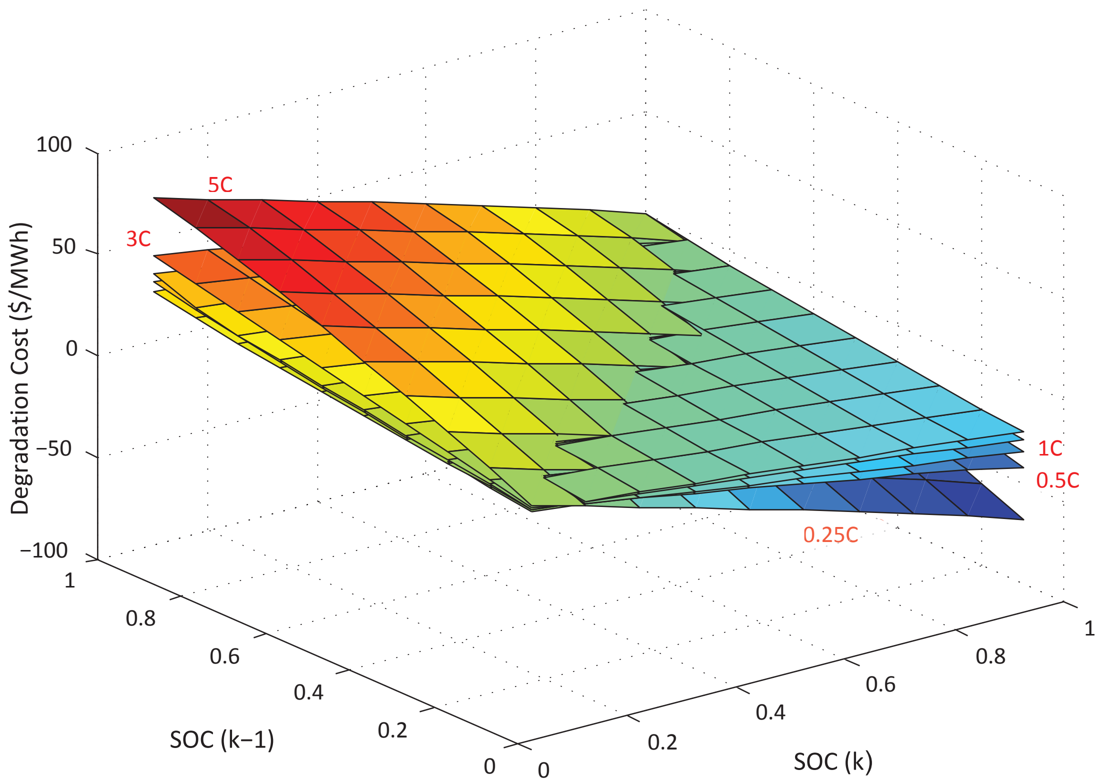


Figure 4.4: Degradation Cost for various DOD and discharge rates

obtain a cost function which can be easily integrated to a market model, the Degradation Cost function (4.3) can be linearized using the well known multi-linear regression method, and expressed as follows:

$$C1_k = aSOC_k + bSOC_{k-1} + cDCR_k + d \qquad \forall k \in K \tag{4.4}$$

where, a, b, c and d are the coefficients of the Degradation Cost based on DOD and discharge rate.

It can be noted that the proposed Degradation Cost model of BESS is time dependent unlike the generator cost models, to account for the fact that the costs are based on DOD, SOC, and discharge rate, which are also time dependent.

In order to compare the accuracy of the linear regression model in (4.4) with a non-linear regression model, a non-linear regression analysis with the same data was carried out. It was noted that the 'Adjusted R-square' parameter, which measures the *goodness* *of fit* of a multi-variable regression, was 0.8657 in linear regression and 0.9319 in nonlinear regression, which are very close. Furthermore, the corresponding 'Standard Error' values, which provide a measure of the variation of the estimated points from the actuals, were 5.17% and 3.79%, respectively, which are also close. Thus the linearized model used in (4.4) adequately represents the functional relationships between the Degradation Cost, DOD and the discharge rate.

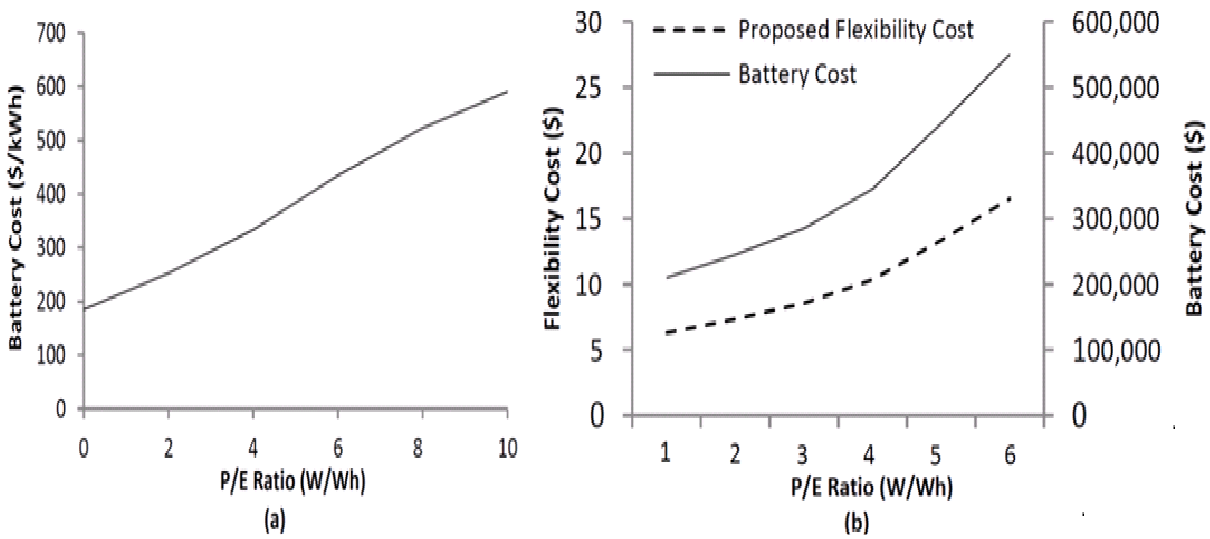


Figure 4.5: (a) Battery Pack Cost versus P/E ratio [99] (b) Battery Cost and Flexibility Cost versus P/E ratio

4.3.2 Flexibility Cost

The flexibility feature of a battery is characterized by its ability to act both as a generation source and a load, and by its high response rate, *i.e.*, to provide energy in a very short time interval. The BESS have significant advantages over conventional generators because of their high flexibility in response rates *i.e.*, the time required to charge or discharge, which is in milliseconds. It is to be noted that the flexibility attribute of a BESS is largely dependent on the P/E ratio of the BESS. This is evident from considering batteries (with same energy capacity but different power ratings) with different P/E ratios; the one with high P/E ratio will deliver proportionately more energy than the battery with a lower P/E ratio, for very short durations, because of its higher power rating. It may thus be inferred that the battery with high P/E ratio has greater flexibility. Furthermore, as noted in [101] and Fig. 4.5(a), the P/E ratio has a direct impact on the cost of the BESS. Hence, the Flexibility Cost of the BESS can be given as follows:

$$C2 = \alpha C^B \tag{4.5}$$

where, α is a fraction of the battery cost accounting for its flexibility characteristic and C^B is the battery cost in \$, as a function of its P/E ratio. A plot of the battery cost versus P/E ratio, for a 10 MWh battery, using the relation of [101] is given in Fig. 4.5(b). As per our proposition, the Flexibility Cost (C2) is considered to be a proportional fraction of the battery cost, as given in equation (4.5), and hence it will also be a function of the P/E ratio of the battery, as shown in Fig. 4.5(b).

4.3.3 Spinning Reserve Cost

The BESS can also participate in the spinning reserve market by providing its capacity, in the form of an offer. However, when the BESS provides spinning reserve, it forgoes the opportunity to participate in the energy-only market. Therefore, the opportunity cost of not participating in energy-only markets can be attributed to the spinning reserve cost of the BESS. The spinning reserve cost of the BESS is its opportunity cost, which is the difference in its revenue earnings from its participation in energy-only market with that in a co-optimized energy and spinning reserve market.

Assuming the BESS revenue in the co-optimized market is 75% of its earnings in energy-only market, its opportunity cost, and hence the spinning reserve cost, would be 25% of the revenue. Since the market price is unknown at the bidding stage, we assume that the spinning reserve cost is 25% of the BESS operations cost ($C1_k$). In the context of conventional generators providing spinning reserves, similar assumptions on the cost of spinning reserve have been made in [55], [102].

The BESS can offer spinning reserve when it is operating in discharging mode, charging mode or idle mode. While offering spinning reserve in the day-ahead market, the BESS would commit a reserve capacity. If this capacity is called or activated in real time, then in charging mode it would have to reduce that much capacity from its charging level and act as a demand response, while in, discharging mode it would have to additionally supply that reserve quantity, like a generation resource. And during its idle mode, the BESS can commit the capacity and provide reserve by either charging or discharging, if required. Furthermore, when required to deploy its reserve in real-time operation, the BESS will additionally receive the energy market price for the quantity of energy it supplied.

It is to be noted that flow batteries have a completely different degradation characteristic as compared to conventional electrochemical batteries (such as Lithium-ion, Lead-acid, Nickel-based, etc.,). In fact, it can be said that flow batteries have very low degradation [103]. Therefore, the proposed operational cost function model of the BESS is not applicable to flow batteries. In [99] battery characteristic curves and models for battery loss of life as a function of DOD, are presented for Lithium-ion and a few other conventional electrochemical batteries such as Lead-acid and Nickel metal halide. Since the Lead-acid and Nickel-based models in [99] are similar to Lithium-ion model, although varying in the mathematical function type, the proposed approach to model the operational cost of the Lithium-ion battery can be extended to these conventional electrochemical batteries. In this work, Lithium-ion batteries are considered because these are most widely used for grid-scale applications.

4.4 Proposed Structure of BESS Charging Bids and Discharging Offers

It is proposed that a grid-scale, independently owned BESS, will participate in the energy and spinning reserve markets in three ways (i) buy energy during charging operation, (ii) sell energy during discharging operation, and (iii) provide capacity in spinning reserve market during both charging or discharging operations. Accordingly, the BESS owner will submit bids to charge and offers to discharge, in the energy market, and offers to discharge and hence provide reserve capacity in the spinning reserve market. The structure of BESS bids/offers are discussed next.

4.4.1 Charging Bids

Charging Price

It is assumed that the BESS will seek to maximize the possibilities of energy arbitrage for making profit, hence it will submit a high charging bid price, such that it is cleared in the market during charging operation, to procure sufficient energy which it can discharge when the market price is high.

Charging Quantity

This is limited by a parameter $\beta_{e,k}^{Ch}$ denoting the fraction of BESS capacity available for charging. The BESS submits the $\beta_{e,k}^{Ch}$ parameter as its charging quantity bid in the energy market.

4.4.2 Discharging Offers

Discharging Price

The BESS owner submits offers to the energy market using $C1_k$ in terms of the coefficients a, b, c and d, as per (4.4).

Discharging Quantity

This is limited by a parameter $\beta_{e,k}^{Dch}$ denoting the fraction of BESS capacity available for discharging. The BESS submits the $\beta_{e,k}^{Dch}$ parameter as its discharging quantity offer in the energy market.

4.4.3 Flexibility Offers

The BESS owner submits the Flexibility offers to the market operator in terms of the Flexibility Cost parameter α, and the battery cost C^B, as per (4.5). Note that the Flexibility offers are submitted for both charging and discharging operation of the BESS.

4.4.4 Spinning Reserve Offers

The BESS submits price-quantity offers to provide capacity in the spinning reserve market, during both charging and discharging operation, a price C^{ESR} and a parameter $\beta_{e,k}^{SR}$ denoting the fraction of the BESS capacity available for spinning reserve provision.

Table 4.1 presents a summary of all the BESS bid/offer parameters submitted by the BESS owners to the market operator, and their respective interpretations.

The ISO receives bids and offers from the various market participants. The loads submit the energy buy bids and the generators submit energy and spinning reserve offers.

Table 4.1: Interpretation of BESS bid/offer parameters

BESS Bid/Offer Parameters	Interpretation
a, b	Accounts for the impact of the DOD on the battery cycle life, which in turn affects the Degradation Cost.
c	Accounts for the impact of the discharge rate on the battery cycle, which in turn affects the Degradation Cost.
d	Linearization offset term in Degradation cost, depending on battery capacity.
$C2$	Flexiblity Cost of the battery represented as a fraction (α) of the battery cost (C_B) accounting for its flexibility characteristic.
$\beta^{Ch}, \beta^{Dch}, \beta^{SR}$	Denotes the fraction of the available battery capacity that is bid/offered for charging, discharging and spinning reserve, respectively.

The structure of the demand bids and conventional generator offers are assumed to be as considered in [21]. The BESS submit the charging bids the discharging offers for providing energy and spinning reserve service, as per the structure discussed earlier. With these inputs, the energy and spinning reserve markets are simultaneously cleared using the novel and comprehensive joint optimization model, discussed in Section 4.5. The outcomes of the market settlement include the dispatch schedules, UC decisions, and market prices.

4.5 Proposed Day-Ahead Market Model Including BESS

Objective Function

Maximize the social welfare, given as follows:

$$
\begin{aligned}
J = & \underbrace{\sum_{k\in K}\left(\sum_{i\in I}\sum_{h\in N_{CB}}(C^{D}_{h,i,k}P^{D}_{h,i,k}) + \sum_{e\in E} C^{Ch}_{e,k}E^{Ch}_{e,k}\right)}_{\text{(a)}} \\
& - \underbrace{\sum_{k\in K}\sum_{j\in J}\left(C^{su}_{j,k}U_{j,k} + C^{sd}_{j,k}V_{j,k} + \sum_{n\in N_{GB}} C^{G}_{n,j,k}P^{G}_{n,j,k}\right)}_{\text{(b)}} \\
& - \underbrace{\sum_{k\in K}\sum_{j\in J}\sum_{n\in N_{GB}} C^{GSR}_{n,j,k}P^{GSR}_{n,j,k}}_{\text{(c)}} \\
& - \underbrace{\sum_{k\in K}\sum_{e\in E}\left((a_e SOC^{Dch}_{e,k} + b_e SOC^{Dch}_{e,k-1} + c_e DCR_{e,k} + d_e)\right)}_{\text{(d)}} \\
& - \underbrace{\sum_{k\in K}\sum_{e\in E}\left(C2_e Z1_{e,k} + C2_e Z2_{e,k}\right)}_{\text{(e)}} \\
& - \underbrace{\sum_{k\in K}\sum_{e\in E}\left(C^{ESR}_{e,k} SOC^{SRcap}_{e,k}\right)}_{\text{(f)}}
\end{aligned} \tag{4.6}
$$

The gross surplus of customers and the BESS during charging, is represented in (a), the total cost of generators, which includes the generator start-up cost and shut-down cost, and the energy cost is represented in (b). The cost of spinning reserve provisions from generators is represented in (c), the cost of BESS for energy provisions during discharging, accounting for degradation based on DOD and discharge rate is given in (d), the Flexibility

Cost considered during the charging and discharging operation is given in (e). The cost of spinning reserve provision from the BESS during discharging, is represented in (f). The objective function in (4.6) is subjected to the following constraints,

Demand Supply Balance

These constraints are formulated using the dc load flow equations to ensure a balance between the supply and demand at each bus.

$$\sum_{j\in G_j} P^{G}_{j,k} + \sum_{e\in ES_i} P^{DchE}_{e,k} - P^{D}_{i,k} - \sum_{e\in ES_i} P^{ChE}_{e,k} = \sum_{q\in I}\left(0.5P^{loss}_{i,q} + B_{i,q}(\delta_{i,k}-\delta_{q,k})\right) \forall i \in I, \forall k \in K \quad (4.7)$$

The transmission line losses are included in the dc load flow equations using the approach discussed in [21].

Market Clearing Constraints

These constraints ensure that the cleared demand bids and generator energy and spinning reserve offers do not exceed their respective maximum bid and offer quantities.

$$P^{D}_{h,i,k} \le \overline{P}^{D}_{h,i,k} X_{h,i,k} \quad \forall i \in I, \forall k \in K, \forall h \in N_{CB} \quad (4.8)$$

$$P^{G}_{n,j,k} \le \overline{P}^{G}_{n,j,k} W^{G}_{n,j,k} \quad \forall j \in J, \forall k \in K, \forall n \in N_{GB} \quad (4.9)$$

$$P^{GSR}_{n,j,k} \le \overline{P}^{GSR}_{n,j,k} W^{SR}_{n,j,k} \quad \forall j \in J, \forall k \in K, \forall n \in N_{GB} \quad (4.10)$$

BESS Energy Arbitrage Constraints

The following constraints ensure that the charging and discharging quantities cleared from a BESS are within its maximum bid and offer capacity.

$$SOC_{e,k} - SOC_{e,k-1} \le \beta^{Ch}_{e,k}(\overline{SOC}_e - SOC_{e,k-1}) + (1 - Z1_{e,k})\overline{SOC}_e \quad \forall e \in E, \forall k \in K \quad (4.11)$$

$$SOC_{e,k-1} - SOC_{e,k} \leq \beta^{Dch}_{e,k}(SOC_{e,k-1} - SOC^{SR}_{e,k-1} - \underline{SOC}_e) + (1 - Z2_{e,k})\overline{SOC}_e \quad \forall e \in E, \forall k \in K \quad (4.12)$$

During the charging operation ($Z1_{e,k}$=1 and $Z2_{e,k}$=0), (4.11) becomes a binding constraint and (4.12) is a redundant constraint; thus (4.11) would be activated to ensure that the charging quantity cleared from a BESS is within its maximum bid capacity; and similarly, during discharging operation ($Z1_{e,k}$=0 and $Z2_{e,k}$=1), and vice-versa applies.

The SOC of a BESS at the end of the discharging operation need be within the limits and are ensured by the following constraints,

$$\underline{SOC}_e\, B^E_{Cap,e}\, Z2_{e,k} \leq SOC^{Dch}_{e,k} \leq \overline{SOC}_e\, B^E_{Cap,e}\, Z2_{e,k} \qquad \forall e \in E, \forall k \in K \qquad (4.13)$$

where, the SOC after the discharging operation are obtained from the following,

$$SOC_{e,k}\, B^E_{Cap,e} - (1 - Z2_{e,k})\, \overline{SOC}_e\, B^E_{Cap,e} \leq SOC^{Dch}_{e,k} \leq SOC_{e,k}\, B^E_{Cap,e} - (1 - Z2_{e,k})\, \underline{SOC}_e\, B^E_{Cap,e} \quad \forall e \in E, \forall k \in K \quad (4.14)$$

During the discharging operation ($Z2_{e,k}$=1), (4.14) determines the value of the SOC of the BESS at the end of the discharge interval and (4.13) ensures that the SOC is within its limits.

The cleared energy during charging operation is obtained as follows,

$$(SOC_{e,k} - SOC_{e,k-1})\, B^E_{Cap,e} - (1 - Z1_{e,k})\, \overline{SOC}_e\, B^E_{Cap,e} \leq E^{Ch}_{e,k} \leq (SOC_{e,k} - SOC_{e,k-1})\, B^E_{Cap,e} + (1 - Z1_{e,k})\, \underline{SOC}_e\, B^E_{Cap,e} \quad \forall e \in E, \forall k \in K \quad (4.15)$$

$$\underline{SOC}_e\, B^E_{Cap,e}\, Z1_{e,k} \leq E^{Ch}_{e,k} \leq \overline{SOC}_e\, B^E_{Cap,e}\, Z1_{e,k} \qquad \forall e \in E, \forall k \in K \qquad (4.16)$$

During the charging operation ($Z1_{e,k}$=1), (4.15) determines the value of the cleared energy of the BESS and (4.16) ensures that the cleared energy is within its limits.

The discharge rate of the battery is limited by its maximum/minimum discharge rate limits, given by,

$$DCR^{min}_{e,k} Z2_{e,k} \leq DCR_{e,k} \leq DCR^{max}_{e,k} Z2_{e,k} \quad \forall e \in E, \forall k \in K \quad (4.17)$$

where the DCR is obtained from the following:

$$\begin{aligned}(SOC_{e,k-1} - SOC_{e,k}) - (1 - Z2_{e,k})\ DCR^{max}_{e,k}& \\ \leq DCR_{e,k}& \\ \leq (SOC_{e,k-1} - SOC_{e,k}) + (1 - Z2_{e,k}) DCR^{min}_{e,k}& \\ \forall e \in E, \forall k \in K& \quad (4.18)\end{aligned}$$

During the discharging operation ($Z2_{e,k}$=1), (4.18) determines the value of the discharge rate of the BESS and (4.17) ensures that the discharge rate is within its limits.

BESS Spinning Reserve Market Clearing Constraints

The cleared spinning reserve capacity from a BESS should not exceed its maximum offer quantity.

$$SOC^{SR}_{e,k} \ \leq\ \beta^{SR}_{e,k}\, \overline{SOC}_e\, Z3_{e,k} \qquad \forall e \in E, \forall k \in K \tag{4.19}$$

The cleared spinning reserve capacity from a BESS is obtained from the following,

$$\begin{aligned}SOC^{SR}_{e,k}\, B^{E}_{Cap,e} - (1 - Z3_{e,k})\, \overline{SOC}_e\, B^{E}_{Cap,e} \ \leq SOC^{SRcap}_{e,k}& \\ \leq\ SOC^{SR}_{e,k}\, B^{E}_{Cap,e} - (1 - Z3_{e,k})\, \underline{SOC}_e\, B^{E}_{Cap,e}& \\ \forall e \in E, \forall k \in K& \quad (4.20)\end{aligned}$$

If the BESS is cleared to provide spinning reserve ($Z3_{e,k}$=1), (4.20) determines the value of the cleared spinning reserve capacity from the BESS and (4.19) ensures that the cleared spinning reserve is within its limits.

BESS Operational Constraints

These include the energy balance, the limits on the SOC, charging/discharging power and the constraints to prevent simultaneous charging and discharging, as follows:

$$SOC_{e,k} = P^{ChE}_{e,k}\eta^{Ch} - P^{DchE}_{e,k}/\eta^{Dch} + SOC_{e,k-1} \qquad \forall e \in E, \forall k \in K \tag{4.21}$$

$$\underline{SOC}_e + SOC^{SR}_{e,k} \ \leq\ SOC_{e,k} \ \leq\ \overline{SOC}_e \qquad \forall e \in E, \forall k \in K \tag{4.22}$$

$$0 \leq P_{e,k}^{ChE} \leq \overline{P}_e^{Ch} Z1_{e,k} \quad \forall e \in E, \forall k \in K, \tag{4.23}$$

$$0 \leq P_{e,k}^{DchE} \leq \overline{P}_e^{Dch} Z2_{e,k} \quad \forall e \in E, \forall k \in K \tag{4.24}$$

$$Z1_{e,k} + Z2_{e,k} \leq 1 \qquad \forall e \in E, \forall k \in K \tag{4.25}$$

System Spinning Reserve Constraints

These constraints ensure that the system spinning reserve requirement is met for each hour. It is assumed that the total system spinning reserve requirement is 10% of the gross demand at that hour,

$$\sum_j P_{j,k}^{GSR} + \sum_e P_{e,k}^{ESR} \geq 0.1(\sum_i P_{i,k}^{D} + \sum_e P_{e,k}^{ChE}) \qquad \forall k \in K \tag{4.26}$$

$$\text{Where,} \qquad P_{j,k}^{GSR} \leq \overline{P}_j - P_{j,k}^{G} \qquad \forall j \in J, \forall k \in K \tag{4.27}$$

The cleared spinning reserve from a BESS is given as follows,

$$P_{e,k}^{ESR} = SOC_{e,k}^{SR} \, B_{Cap,e}^{E} \qquad \forall e \in E, \forall k \in K \tag{4.28}$$

Transmission Line Constraints

These constraints ensure that the line power flows are within their limits.

$$B_{i,q}(\delta_{i,k} - \delta_{q,k}) \leq \overline{PFlow}_{i,q} \qquad \forall i, q \in I \tag{4.29}$$

Other Constraints

These constraints include generation limits, ramp-up/down constraints, minimum-up / down time constraints, coordination constraints, and line flow constraints, as discussed in Chapter 3 and not presented here for brevity.

4.6 Results & Discussions

To validate the proposed BESS integrated energy and spinning reserve market model, a slightly modified version of the IEEE RTS [94] is considered, which includes 32 generators, loads at 17 buses, and 37 transmission lines. There are 10 BESS units with total capacity of 250 MW/240 MWh spread over 5 buses as follows:

- ES1, ES2 at Bus-4, each with capacity of [30 MW, 15 MWh]
- ES3, ES4 at Bus-5, each with capacity of [30 MW, 30 MWh]
- ES5, ES6 at Bus-9, each with capacity of [25 MW, 50 MWh]
- ES7, ES8 at Bus-19, each with capacity of [20 MW, 12.5 MWh]
- ES9, ES10 at Bus-20, each with capacity of [20 MW, 12.5 MWh]

The loads at each bus are scaled up by 25% from the given data. The demand bids and generator offers for energy and spinning reserves are chosen as given in [104]. The BESS owners submit bids and offers for participating in the energy and spinning reserve markets, as discussed in Section 4.4.

The proposed model is formulated as a MIP problem and solved using the CPLEX solver [105] in GAMS [95]. To order to study the impact of BESS participation on market settlement and system operation, three case studies are considered as follows:

- Case 1: Base case without BESS participation.
- Case 2: BESS participation, simple bid/offer model.
- Case 3: BESS participation, proposed bid/offer model.

In Case 2 the BESS bids/offers do not take into account the degradation and flexibility costs, and are solely based on market price forecasts. For the purpose of present studies, high charging bid prices and low discharging offer prices are considered. In Case 3, the values of the BESS bidding parameters are as follows: $a = -36.23$, $b = 34.80$, $c = 2.77$, $d = -2.45$, $\eta = 0.9$, $\alpha = 0.000003$ to 0.000005, $\beta^{Ch} = \beta^{Dch} = 0.5$ to 1, $\beta^{SR} = 0.1$ to 0.2, $\overline{DCR} = 1$, which are chosen based on the discussions in Section 4.3, and [98–100].

Table 4.2 presents an aggregated summary of market clearing results. In Case 1, the cleared generators meet the cleared demand plus the system losses. In Case 2 & 3, there is

Table 4.2: All day aggregate market clearing results

	Case 1	Case 2	Case 3
Energy cleared (MWh)	67,923	67,984	68,064
Generation dispatch (MWh)	68,928	69,059	69,103
BESS charging energy (MWh)	-	331	249
BESS discharging energy (MWh)	-	299	221
Losses (MWh)	1,005	1,043	1,011
BESS charging cost ($)	-	17,907	12,721
BESS degradation cost, C1 ($)	-	-	7,352
BESS flexibility cost, C2 ($)	-	-	1,547
BESS spinning reserve cost ($)	-	7,582	6,952
BESS energy market revenue ($)	-	23,115	16,447
BESS spinning reserve market revenue ($)	-	15,458	15,037
BESS profit ($)	-	13,084	10,264
Social Welfare ($)	4,716,866	4,769,135	4,771,524

a slight increase in the generation, which is to meet the additional BESS charging demand and the increased losses. However, as a result of BESS participation in the energy market, the cheaper BESS discharging offers could replace some of the expensive generators. Note that the charging/ discharging energy is more in Case 2 compared to Case 3. This is because, in Case 3 the Degradation Cost and Flexibility Cost are accounted for, which limits the clearing of charging and discharging quantities from the BESS. It should also be noted that, when battery Degradation Cost is accounted for, it helps in the economic operation of the BESS and increases years of useful operation.

It is noted that the participation of BESS (Case 2 and Case 3) has resulted in an increase in the social welfare of the system, more so in Case 3, compared to Case 1 and Case 2. Although the profit in Case 2 is higher, compared to Case 3, it should be noted that Case 3 correctly captures the actual cost of BESS operation, accounting for its degradation and flexibility attributes, thus providing realistic market clearing decisions, from the view point of both the ISO and BESS owners.

Fig. 4.6 shows the LMPs at bus-18 for the three cases; the LMP reduces during the two peak periods (hours 10-16 and 18-20) in Case 2 & 3 because of the cheaper BESS charging offers in the energy market. The reduction is more significant (upto 33% at hour-14 and 24% at hour-18) in Case 3. Thus, it is noted that BESS can play a vital role in stabilizing

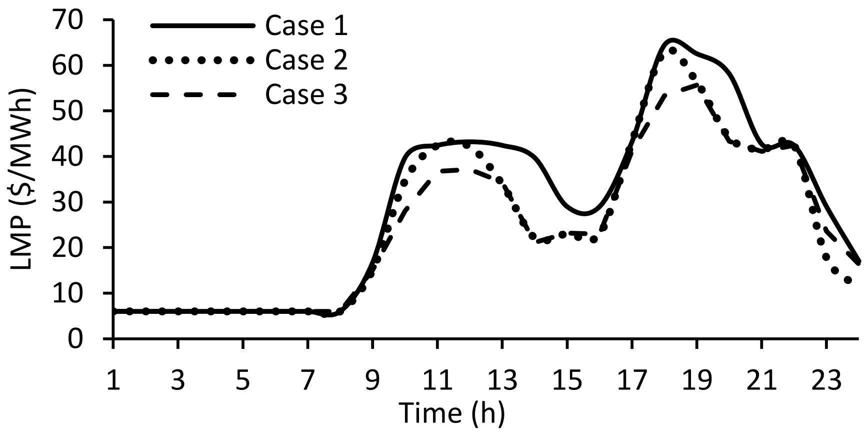


Figure 4.6: Energy market clearing price, LMP at bus-18

the market prices.

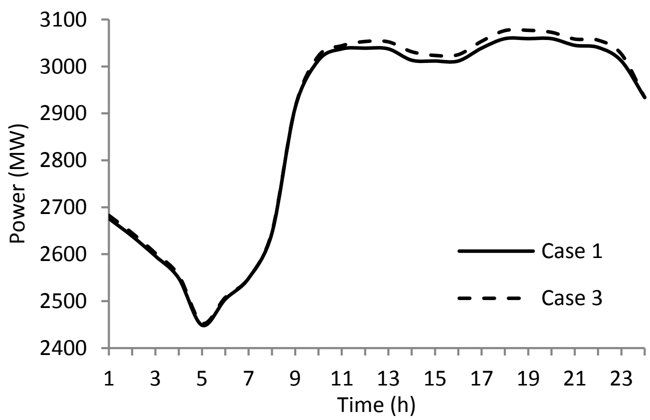


Figure 4.7: Generation dispatch over 24 hours in Case 1 and Case 3

It is noted from Fig. 4.7 that in Case 3 the dispatched generation is slightly higher than in Case 1 during the hours 11-20. This is because there is a slight increase in the cleared demand during these hours as a result of BESS participation with lower priced discharge offers.

Fig. 4.8 shows the aggregated charging and discharging power from all BESS units, in Case 3 on an hourly basis. It is noted that BESS charging takes place mainly during the off peak hours 3-8, while the discharging occurs mainly during the peak hours 11-12 and 17-21, thus resulting in an increased benefit for the BESS owners from energy arbitrage.

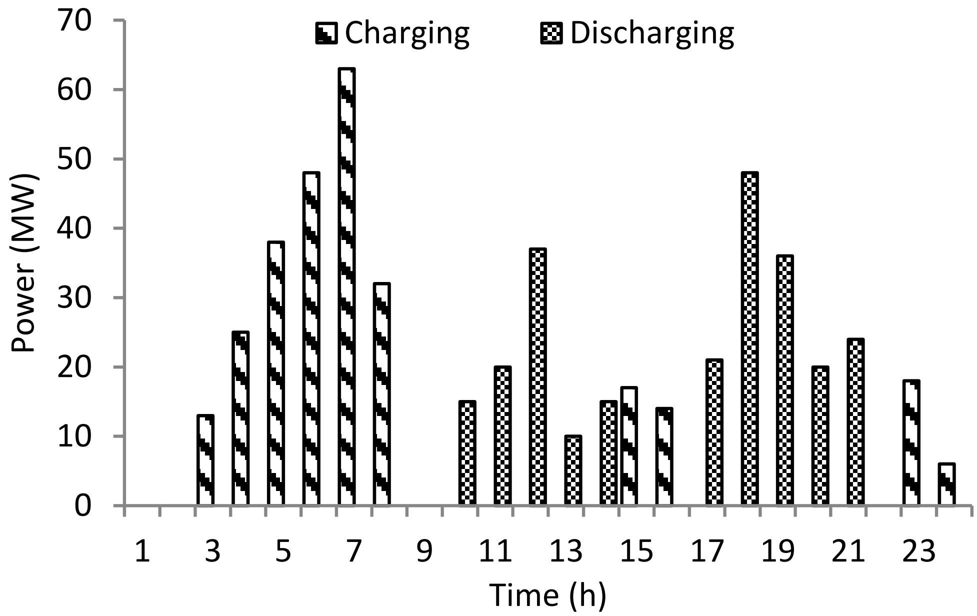


Figure 4.8: Aggregate charging/discharging after market dispatch in Case 3

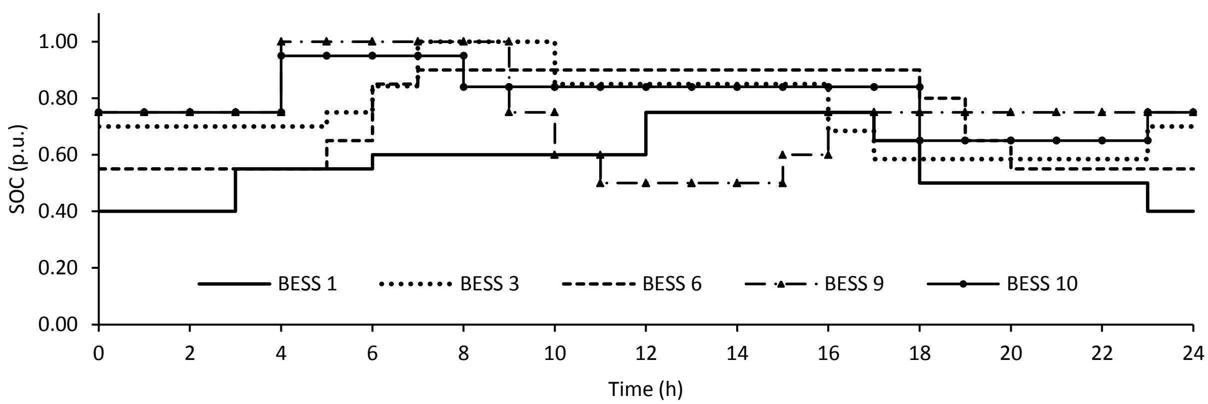


Figure 4.9: SOC profiles of BESS after market dispatch in Case 3

The SOC profiles of randomly chosen five BESS units in Case 3 are shown in Fig. 4.9. It is noted that the BESS units have varying charging and discharging profiles because of their locational placement and the variations in theirs cost components which determine their market clearance and dispatch.

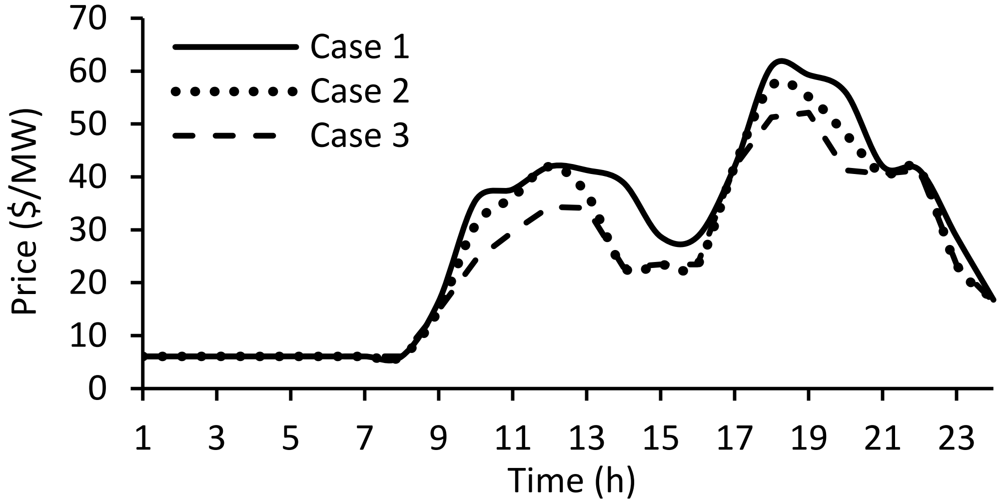


Figure 4.10: Spinning reserve market clearing price

It is noted that the spinning reserve prices (Fig. 4.10) in Case 3, the spinning reserve prices are significantly reduced in hours 10-16 and 18-20, because the cheaper offers from BESS have replaced some of the expensive generator offers in Case 1.

Fig. 4.11 shows the contracted spinning reserve capacity in Case 1 (from generators only) and Case 3 (from generators and BESS). It is noted that in Case 3, while the generators provide the significant share of the spinning reserve requirements, BESS is able to provide about 8% of system spinning reserve requirement and thus providing more options to the ISO. Furthermore, it is interesting to note that the BESS provides spinning reserve during charging operations also (hours 1, 2, 6, and 7) apart from the discharging operation hours, which may be perceived as a demand response provision.

4.7 Conclusions

In this Chapter, a novel BESS cost function model was proposed that considers Degradation Cost, based on the DOD and discharge rate, and Flexibility Cost, in terms of battery cost, as a function of its P/E ratio. The model was developed considering Lithium-ion batteries, and the approach can be applied to other conventional electrochemical batteries, but not flow batteries. A detailed charging bid and discharging offer structure based on the proposed cost functions was formulated. Subsequently, a new framework and mathematical model for BESS participation in an LMP-based co-optimized energy and spinning

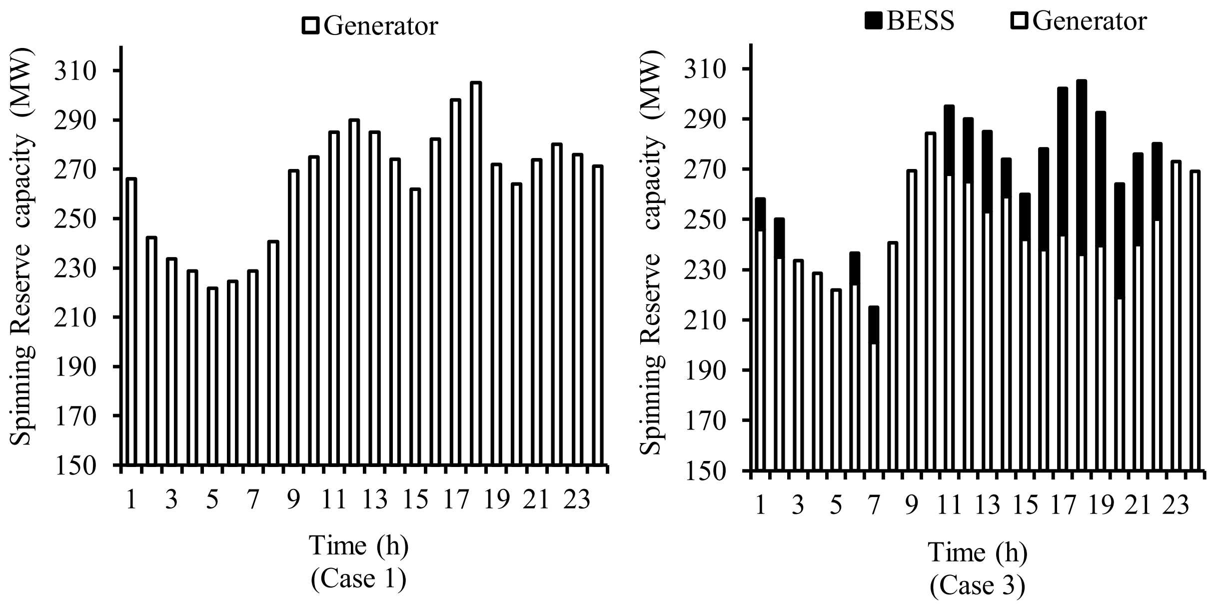


Figure 4.11: Spinning reserve contracted over 24 hours in Case 1 and Case 3

reserve market was developed. The effectiveness of the BESS inclusive market model was validated on the IEEE RTS and compared with two other realistic market structures: (a) traditional structure with only generator and load participation (b) BESS bidding as the generator/load with price quantity pair. BESS participation using the proposed cost function and bid/offer structure resulted in a higher social welfare than when no BESS was present or with a simple bid/offer structure for BESS, based on market price expectations. The participation of BESS also reduced energy and spinning reserve prices when it provided services in the energy and spinning reserve markets. Overall, the inclusion of BESS in the electricity markets has resulted in improving the economic and technical benefits for the ISO by providing more options for system operation.

The advantages of the proposed work are that: (i) it correctly captured the actual cost of BESS operation, accounting for its degradation and flexibility attributes, thus providing realistic market clearing decisions, (ii) it appropriately met the important requirement of FERC Order 841 to develop a participation model for ESS, accounting for their physical and operational characteristics such as the SOC, discharge rate, etc., in the ESS bidding parameters, to facilitate their participation in ISO markets.

Chapter 5

BESS in Real-Time Energy and Regulation Markets[1]

5.1 Nomenclature

Sets & Indices

e	BESS, $e \in E$.
i, q	Bus, $i \in I$.
j	Generators, $j \in J$.
s	Scenario, $s \in S$; $S = [S_0,\, S_1,\, S_2]$.
S_0	Set of normal operation scenarios, $S_0 \in S$.
S_1	Set of contingency scenarios, $S_1 \in S$.
S_2	Set of load deviation scenarios, $S_2 \in S$.
ES_i	Set of BESS connected to bus i.
G_i	Set of generators connected to bus i.

Note: All parameters and variables pertain to the real-time market unless they are explicitly stated to be day-ahead with superscript 'DA'.

[1]Parts of this chapter have been submitted for review in: N. Padmanabhan, K. Bhattacharya, and M. Ahmed, "Battery energy storage systems for primary and secondary regulation in real-time electricity markets, *IEEE Trans. Smart Grid,* 2019.

Parameters

B	Element of susceptance matrix, p.u.
$C^{\boldsymbol{Ch}}$,$C^{\boldsymbol{Dch}}$	BESS charging/discharging bid/offer price, \$/MWh.
C^{D}	Customer's demand bid price, \$/MWh.
$C^{\boldsymbol{EPRU}}$,$C^{\boldsymbol{EPRD}}$	Primary regulation up/down offer price of BESS, \$/MWh.
$C^{\boldsymbol{ESRU}}$,$C^{\boldsymbol{ESRD}}$	Secondary regulation up/down offer price of BESS, \$/MWh.
C^{G}	Generator offer price for energy, \$/MWh.
$C^{\boldsymbol{GPRU}}$, $C^{\boldsymbol{GPRD}}$	Generator primary regulation up/down offer price, \$/MWh.
$C^{\boldsymbol{GSRU}}$, $C^{\boldsymbol{GSRD}}$	Generator secondary regulation up/down offer price, \$/MWh.
$\overline{E}^{Ch}$, $\overline{E}^{Dch}$	Maximum charging/discharging energy capacity of BESS, MWh.
$E^{\boldsymbol{Ch,DA}}$, $E^{\boldsymbol{Dch,DA}}$	Charging/discharging energy cleared in day-ahead (DA) market, MWh.
$\overline{E}^{Dn}$	Maximum offer by a BESS for 'down' services (*i.e.*, charging, primary-down and secondary-down regulation), MWh.
$\overline{E}^{\boldsymbol{PRU}}$, $\overline{E}^{\boldsymbol{PRD}}$	Maximum primary regulation up/down energy capacity of BESS, MWh.
$\overline{E}^{\boldsymbol{SRU}}$, $\overline{E}^{\boldsymbol{SRD}}$	Maximum secondary regulation up/down energy capacity of BESS, MWh.
$E^{\boldsymbol{SR,DA}}$	Spinning reserve capacity cleared from BESS in DA market, MWh.
$\overline{E}^{Up}$	Maximum offer by a BESS for 'up' services (*i.e.*, discharging, primary-up and secondary-up regulation), MWh.
$\overline{P}$, $\underline{P}$	Maximum/minimum limit on power output of generator, MW.
$P^{\boldsymbol{ChE,DA}}$, $P^{\boldsymbol{DchE,DA}}$	Charging/discharging power in DA market, MW.
$P^{\boldsymbol{D,DA}}$	Demand cleared from generator in day-ahead market, MW.
$P^{\boldsymbol{Dev\text{-}Dn/Up}}$	Load deviations, MW.
$\overline{P}^{Dn}$	Maximum offer by a generator for 'down' services (*i.e.*, primary-down and secondary-down regulation), MW.
$P^{\boldsymbol{G,DA}}$	Generation cleared from generator in day-ahead market , MW.
$P^{\boldsymbol{GSR,DA}}$	Spinning reserve cleared from generator in DA market, MW.

$\overline{P}^{\boldsymbol{ChE}}$, $\overline{P}^{\boldsymbol{DchE}}$	Maximum charging/discharging power of BESS, MW.
$\overline{P}^{D}$, $\overline{P}^{G}$	Demand bid/ Generator offer quantity, MW.
$\overline{P}^{\boldsymbol{EPRU}}$, $\overline{P}^{\boldsymbol{EPRD}}$	Maximum primary regulation up/down power of BESS, MW.
$\overline{P}^{\boldsymbol{ESRU}}$, $\overline{P}^{\boldsymbol{ESRD}}$	Maximum secondary regulation up/down power of BESS, MW.
$\overline{PFlow}$	Maximum capacity of transmission line, MW.
$\overline{P}^{\boldsymbol{GPRU}}$, $\overline{P}^{\boldsymbol{GPRD}}$	Maximum primary regulation up/down power from generator, MW.
$\overline{P}^{\boldsymbol{GSRU}}$, $\overline{P}^{\boldsymbol{GSRD}}$	Maximum secondary regulation up/down power from generator, MW.
$P^{\boldsymbol{Out}^{+/-}}$	Outage power, MW.
$\overline{P}^{Up}$	Maximum offer by a generator for 'up' services (*i.e.*, energy, primary-up and secondary-up regulation), MW.
R_e	BESS droop, Hz/MW.
R_{eq}	Total droop in the system, Hz/MW.
R_j	Generator droop, Hz/MW.
RU, RD	Ramp up/down limit of generator, MW/min.
$\overline{SOC}$, $\underline{SOC}$	Maximum/minimum SOC limit of BESS, MWh.
SOC^0	SOC of battery at the start of each interval of real-time market settlement, MWh.
W^{DA}	Commitment status of generator in DA market, equals 1, if energy offer of is cleared, and 0 otherwise.
X^{DA}	Clearing status of demand in DA market, equals 1, if demand bid is cleared in DA market, and 0 otherwise.
$Z1^{DA}$, $Z2^{DA}$	Operational status of BESS in DA market, equals 1, if BESS is charging/discharging, and 0 otherwise.
α	Share of the different offered generator quantities, as a fraction of the maximum generator offer for 'down'/'up' services.
γ	Share of the different offered BESS quantities, as a fraction of the maximum BESS offer for 'down'/'up' services.
Δf^{min}, Δf^{max}	Minimum/maximum frequency deviation, Hz.
Δk	Market settlement interval, hour.

η	Battery round trip efficiency, %.
η^{Ch}, η^{Dch}	Battery Charging/discharging efficiency, %.
ρ_s	Probability of occurrence of scenario s.
ρ_0	Probability that none of the contingencies occur.

Variables

$E^{\boldsymbol{Ch}}$, $E^{\boldsymbol{Dch}}$	Charging/discharging energy, MWh.
$E^{\boldsymbol{PRU}}$, $E^{\boldsymbol{PRD}}$	Primary regulation up/down energy from BESS, MWh.
$E^{\boldsymbol{SRU}}$, $E^{\boldsymbol{SRD}}$	Secondary regulation up/down energy from BESS, MWh.
$P^{\boldsymbol{ChE}}$, $P^{\boldsymbol{DchE}}$	Charging/discharging power, MW.
$P^{\boldsymbol{EPRU}}$, $P^{\boldsymbol{EPRD}}$	Primary regulation up/down power from BESS, MW.
$P^{\boldsymbol{ESRU}}$, $P^{\boldsymbol{ESRD}}$	Secondary regulation up/down power from BESS, MW.
P^{D}, P^{G}	Cleared demand/generation, MW.
$P^{\boldsymbol{GPRU}}$, $P^{\boldsymbol{GPRD}}$	Primary regulation up/down from generator, MW.
$P^{\boldsymbol{GSRU}}$, $P^{\boldsymbol{GSRD}}$	Secondary regulation up/down from generator, MW.
P^{loss}	Power loss in the transmission line, MW.
SOC	State of charge, MWh.
$W^{\boldsymbol{GRU}}$, $W^{\boldsymbol{GRD}}$	Binary variable = 1, if regulation up/down offer/bid of generator is cleared, and 0 otherwise.
$Z^{\boldsymbol{ERU}}$, $Z^{\boldsymbol{ERD}}$	Binary variable = 1, if regulation up/down offer/bid of BESS is cleared, and 0 otherwise.
δ	Voltage angle of the bus, radian.
Δf	frequency deviation, Hz.

5.2 Introduction

Electricity market operations are subject to various uncertainties arising due to increasing penetration of intermittent and non-dispatchable RES, contingencies such as loss of generators and transmission lines, and sudden load deviations. Accordingly, the generation and loads are dispatched through real-time markets to meet the system demand more accurately vis-a-vis the day-ahead market, and also to procure and deploy primary and secondary regulation reserves. In the previous chapter, BESS were considered as day-ahead market participants, providing energy and spinning reserves service. However, in recent years, BESSs have been considered as promising resources to provide regulation services because of their operational flexibility, as compared to conventional resources.

To this effect, in this chapter, a novel framework and mathematical model are proposed for simultaneously procuring primary and secondary regulation reserves alongside energy, in a BESS integrated electricity market, by taking into account probabilistic scenarios of contingencies in the real-time operations. Two case studies, each considering four contingency and two load deviation scenarios, are presented to investigate the impact of BESS participation on system operation and market settlement. The proposed model is validated on the IEEE RTS to demonstrate its functionalities.

5.3 Proposed Real-time Market Framework Including BESS

The proposed real-time market will dispatch the BESS alongside generators and loads to meet the incremental energy needs vis-a-vis the day-ahead market, and the primary and secondary regulation reserve requirements. The real-time market is coupled with the day-ahead market and thus to correctly capture the interactions, the following assumptions are made:

- Only participants cleared in the day-ahead market can participate in the real-time market.
- The day-ahead market is settled *a priori* and the UC and dispatch schedules are already available before the real-time market clearing.

The loads will submit bids to buy energy, generators will submit offers/bids for energy and regulation reserves, over and above their day-ahead settlements, and BESS will submit charging bids, discharging offers and offers for reserve provisions. The ISO will receive detailed information on the bids and offers, in price-quantity pairs, from all market participants, as per the bid-offer structure of these entities, discussed in the next subsection.

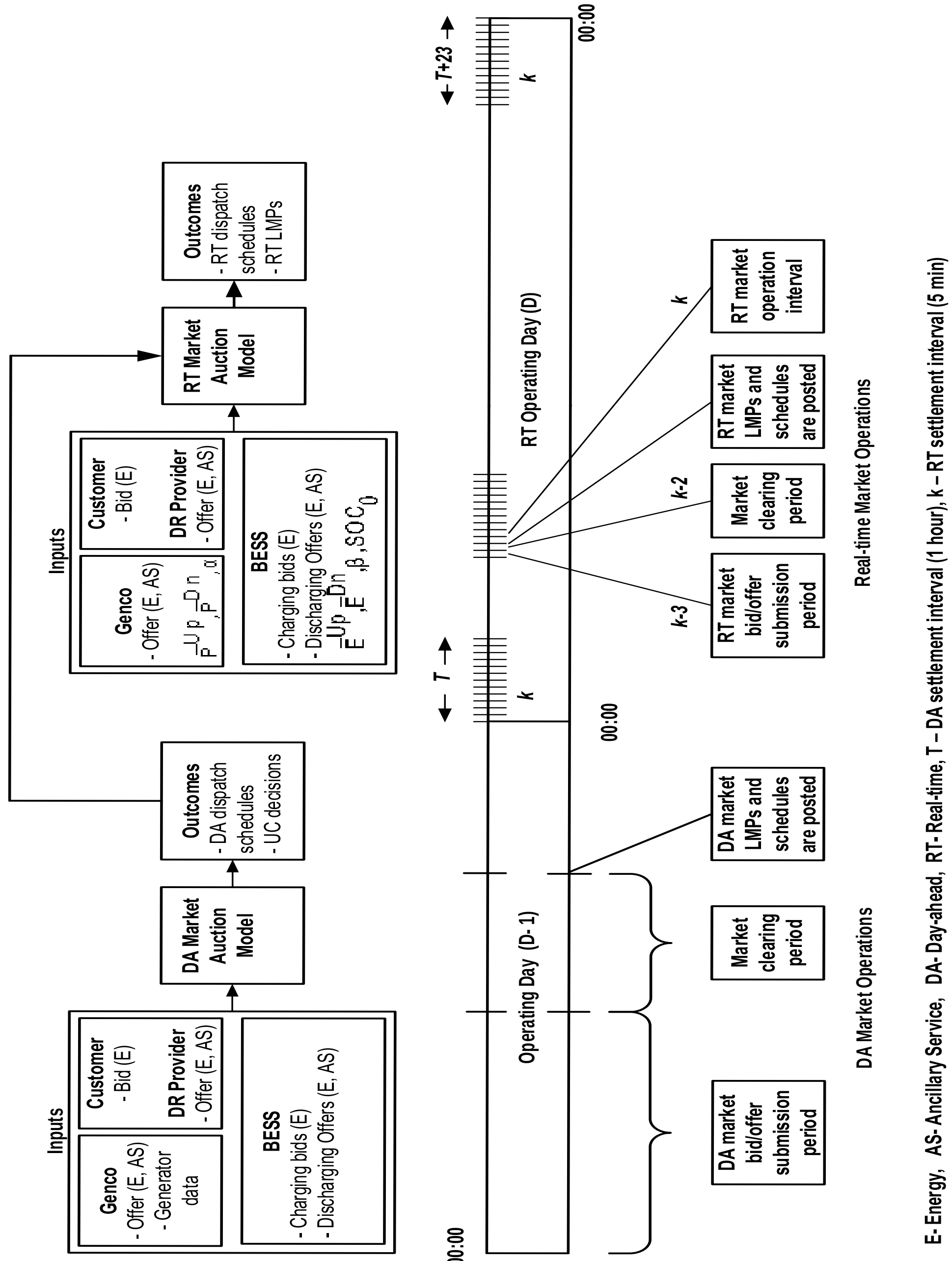


Figure 5.1: BESS integrated real-time market framework

Based on these inputs, the proposed market is simultaneously cleared and the outcomes, which include the dispatch schedules for all entities, and market prices, are obtained. The framework of the proposed real-time market settlement with BESS is shown in Fig. 5.1.

5.3.1 Generator Offers

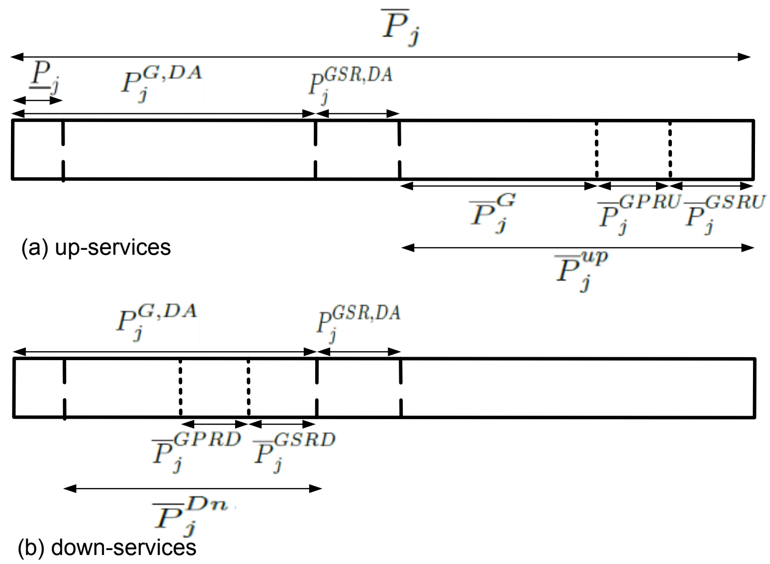


Figure 5.2: Generator offer quantities in real-time energy and regulation reserve markets, (a) up-services, (b) down-services

The maximum offer by a generator j for 'up' services (*i.e.*, energy, primary-up and secondary-up regulation) for a particular real-time market interval, is based on its scheduled day-ahead energy and spinning reserve capacity, and is limited by its ramping capability, as follows:

$$\overline{P}_j^{up} = \overline{P}_j - P_j^{G,DA} - P_j^{GSR,DA} \qquad \forall j \in J \tag{5.1}$$

$$\overline{P}_j^{up} \leq RU_j \qquad \forall j \in J \tag{5.2}$$

The individual components of the generator offer quantities for energy, primary-up and secondary-up regulation are limited by the parameters α_1, α_2, and α_3, which denote the maximum share of these components as a fraction of $\overline{P}_j^{up}$, given as follows:

$$\overline{P}_{j,s}^{G} = \alpha_{1,j}\overline{P}_j^{up};\ \ \overline{P}_j^{GPRU} = \alpha_{2,j}\overline{P}_j^{up};\ \ \overline{P}_j^{GSRU} = \alpha_{3,j}\overline{P}_j^{up} \qquad \forall j \in J \tag{5.3}$$

Fig. 5.2(a) shows the total available capacity for 'up' services ($\overline{P}_j^{up}$) from a generator in the real-time market, the components for various services, and also the day-ahead market commitments.

The maximum bid by a generator j for 'down' services (*i.e.*, primary-down and secondary-down regulation) for a particular real-time market interval, is based on its scheduled day-ahead energy dispatch and minimum generator capacity, and is limited by its ramping capability, given as follows:

$$\overline{P}_j^{Dn} = P_j^{G,DA} - \underline{P}_j \qquad \forall j \in J \tag{5.4}$$

$$\overline{P}_j^{Dn} \leq \; RD_j \qquad \forall j \in J \tag{5.5}$$

The individual components of the generator bid quantities for primary-down and secondary-down regulation are limited by the parameters α_4, and α_5, which denote the maximum share of these components as a fraction of $\overline{P}_j^{Dn}$, given as follows:

$$\overline{P}_j^{GPRD} = \alpha_{4,j}\overline{P}_j^{Dn}; \qquad \overline{P}_j^{GSRD} = \alpha_{5,j}\overline{P}_j^{Dn} \qquad \forall j \in J \tag{5.6}$$

Fig. 5.2(b) shows the total available capacity for 'down' services ($\overline{P}_j^{Dn}$) from a generator in the real-time market, the components for various services, and also the day-ahead market commitments.

It is to be noted that the parameters α_1 - α_5 will be decided by the genco, while satisfying the relations:

$$\alpha_{1,j} + \alpha_{2,j} + \alpha_{3,j} \leq \; 1 \qquad \forall j \in J \tag{5.7}$$

$$\alpha_{4,j} + \alpha_{5,j} \leq \; 1 \qquad \forall j \in J \tag{5.8}$$

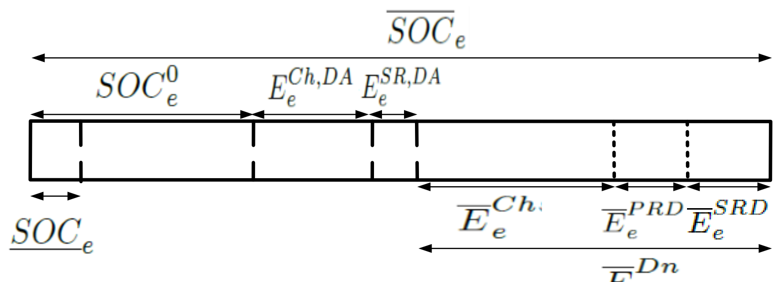
5.3.2 BESS Offers

The maximum bid by a BESS e for 'down' services (*i.e.*, charging, primary-down and secondary-down regulation) for a particular real-time market interval, is based on its scheduled day-ahead charging energy, reserved spinning reserve capacity, and SOC at start of the real-time interval, given as follows:

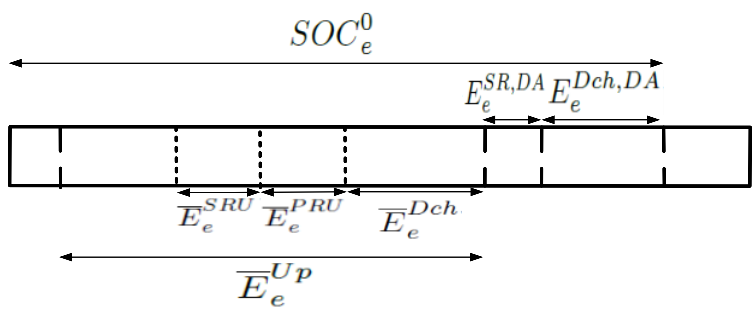
$$\overline{E}_e^{Dn} = \overline{SOC}_e - E_e^{Ch,DA} - E_e^{SR,DA} - SOC_e^0 \qquad \forall e \in E \tag{5.9}$$

The individual components of the BESS bid quantities in real-time for charging, primary-down, and secondary-down regulation, are limited by the parameters γ_1, γ_2, and γ_3, which denote the maximum share of these components as a fraction of $\overline{E}_e^{Dn}$, given as follows:

$$\overline{E}_e^{Ch} = \gamma_{1,e}\overline{E}_e^{Dn};\;\; \overline{E}_e^{PRD} = \gamma_{2,e}\overline{E}_e^{Dn};\;\; \overline{E}_e^{SRD} = \gamma_{3,e}\overline{E}_e^{Dn} \qquad \forall e \in E \tag{5.10}$$



(a) Charging bids



(b) Discharging offers

Figure 5.3: BESS offer quantities in real-time energy and regulation reserve markets (a) charging bids, (b) discharging offers

Fig. 5.3(a) shows the total available capacity for 'down' services ($\overline{E}_e^{Dn}$) from a BESS in the real-time market, the components for various services, and also the day-ahead market commitments.

The maximum offer by a BESS e for 'up' services (*i.e.*, discharging, primary-up, and secondary-up regulation) for a particular real-time market interval, is based on its scheduled day-ahead discharging energy, spinning reserve capacity, and SOC at start of the real-time interval, given as follows:

$$\overline{E}_e^{Up} = SOC_e^0 - E_e^{Dch,DA} - E_e^{SR,DA} - \underline{SOC}_e \qquad \forall e \in E \tag{5.11}$$

The individual components of the BESS offer quantities for discharging, primary-up, and secondary-up regulation, are limited by the parameters γ_4, γ_5, and γ_6, which denote the maximum share of these components as a fraction $\overline{E}_e^{Up}$, given as follows:

$$\overline{E}_{e,s}^{Dch} \leq \gamma_{4,e}\overline{E}_e^{Up};\ \ \overline{E}_e^{PRU} \leq \gamma_{5,e}\overline{E}_e^{Up};\ \ \overline{E}_e^{SRU} \leq \gamma_{6,e}\overline{E}_e^{Up} \qquad \forall e \in E \tag{5.12}$$

Fig. 5.3(b) shows the total available capacity for 'up' services ($\overline{E}_e^{Up}$) from a BESS in the real-time market, the components for various services, and also the day-ahead market commitments.

It is to be noted that the parameters γ_1 - γ_6 will be decided by the BESS owner, while satisfying the relations:

$$\gamma_{1,e} + \gamma_{2,e} + \gamma_{3,e} \leq\ 1 \qquad \forall e \in E \tag{5.13}$$

$$\gamma_{4,e} + \gamma_{5,e} + \gamma_{6,e} \leq\ 1 \qquad \forall e \in E \tag{5.14}$$

5.4 Proposed Real-Time Market Model Including BESS

5.4.1 Objective Function

Maximize the expected social welfare, given as follows:

$$
\begin{aligned}
J = & \underbrace{\sum_{i \in I} \sum_{s \in S_0} (\rho_s C^D_{i,s} P^D_{i,s} \Delta k) + \sum_{e \in E} \sum_{s \in S_0} (\rho_s C^{Ch}_{e,s} E^{Ch}_{e,s})}_{\text{(a)}} - \underbrace{\sum_{j \in J} \sum_{s \in S_0} (\rho_s C^G_{j,s} P^G_{j,s} \Delta k)}_{\text{(b)}} \\
& - \underbrace{\sum_{j \in J} \sum_{s \in S_1} \rho_s \left(C^{GPRU}_{j,s} P^{GPRU}_{j,s} \Delta k + C^{GPRD}_{j,s} P^{GPRD}_{j,s} \Delta k \right)}_{\text{(c)}} \\
& - \underbrace{\sum_{j \in J} \sum_{s \in S_2} \rho_s \left(C^{GSRU}_{j,s} P^{GSRU}_{j,s} \Delta k + C^{GSRD}_{j,s} P^{GSRD}_{j,s} \Delta k \right)}_{\text{(d)}} \\
& - \underbrace{\sum_{e \in E} \sum_{s \in S_0} (\rho_s C^{Dch}_{e,s} E^{Dch}_{e,s})}_{\text{(e)}} \\
& - \underbrace{\sum_{e \in E} \sum_{s \in S_1} \rho_s \left(C^{EPRU}_{e,s} E^{PRU}_{e,s} + C^{EPRD}_{e,s} E^{PRD}_{e,s} \right)}_{\text{(f)}} \\
& - \underbrace{\sum_{e \in E} \sum_{s \in S_2} \rho_s \left(C^{ESRU}_{e,s} E^{SRU}_{e,s} + C^{ESRD}_{e,s} E^{SRD}_{e,s} \right)}_{\text{(g)}}
\end{aligned} \tag{5.15}
$$

In 5.15, the term (a) represents the expected gross surplus of customers and the BESS during charging while the expected energy cost of generators is represented by (b). The expected costs of up/down primary regulation and up/down secondary regulation provisions from generators are represented by (c) and (d), respectively. The expected cost of BESS for energy provisions during discharging is given in (e). The expected costs of up/down primary regulation and up/down secondary regulation provisions from the BESS, are represented by (f) and (g), respectively.

5.4.2 Constraints

The objective function in (5.15) is subjected to the following constraints,

Pre-disturbance Demand-Supply Balance

These constraints are formulated using the dc load flow equations to ensure a balance between the supply and demand at each bus for the normal operating condition of the system.

$$\begin{aligned}\sum_{j\in G_i}(P^{G}_{j,s_0}+P^{G,DA}_{j})+\sum_{e\in ES_i}(P^{DchE}_{e,s_0}+P^{DchE,DA}_{e})\\ -(P^{D}_{i,s_0}+P^{D,DA}_{i})-\sum_{e\in ES_i}(P^{ChE}_{e,s_0}+P^{ChE,DA}_{e})\\ =\sum_{q\in I}\left(0.5P^{loss}_{i,q,s_0}+B_{i,q,s_0}(\delta_{i,s_0}-\delta_{q,s_0})\right) \qquad \forall i\in I \quad (5.16)\end{aligned}$$

Demand-Supply Balance Considering Primary Regulation Service

The following constraints are formulated using the dc load flow equations to ensure a balance between the supply and demand at each bus considering a set of contingency scenarios and the primary regulation services being in effect.

$$\begin{aligned}\sum_{j\in G_j}(P^{G}_{j,s_0}+P^{G,DA}_{j}+P^{GPRU}_{j,s})\\ +\sum_{e\in ES_i}(P^{DchE}_{e,s_0}+P^{DchE,DA}_{e}+P^{EPRU}_{e,s})\\ -(P^{D}_{i,s_0}+P^{Out^+}_{i,s}+P^{D,DA}_{i})-\sum_{e\in ES_i}(P^{ChE}_{e,s_0}+P^{ChE,DA}_{e})\\ =\sum_{q\in I}\left(0.5P^{loss}_{i,q,s}+B_{i,q,s}(\delta_{i,s}-\delta_{q,s})\right) \qquad \forall i\in I,\forall s\in S_1 \quad (5.17)\end{aligned}$$

$$\begin{aligned}\sum_{j\in G_j}(P^{G}_{j,s_0}+P^{G,DA}_{j}-P^{GPRD}_{j,s})+\sum_{e\in ES_i}(P^{DchE}_{e,s_0}+P^{DchE,DA}_{e})\\ -(P^{D}_{i,s_0}-P^{Out^-}_{i,s}+P^{D,DA}_{i})-\sum_{e\in ES_i}(P^{ChE}_{e,s_0}+P^{ChE,DA}_{e}+P^{EPRD}_{e,s})\\ =\sum_{q\in I}\left(0.5P^{loss}_{i,q,s}+B_{i,q,s}(\delta_{i,s}-\delta_{q,s})\right) \qquad \forall i\in I,\forall s\in S_1 \quad (5.18)\end{aligned}$$

Demand-Supply Balance Considering Secondary Regulation Services

The following constraints are formulated using the dc load flow equations to ensure a balance between the supply and demand at each bus considering a set of load deviation scenarios and the secondary regulation services being in effect.

$$\begin{aligned}\sum_{j\in G_i}&(P_{j,s_0}^{G} + P_j^{G,DA} + P_{j,s}^{GSRU})\\ &+ \sum_{e\in ES_i}(P_{e,s_0}^{DchE} + P_e^{DchE,DA} + P_{e,s}^{ESRU})\\ &- (P_{i,s_0}^{D} + P_{i,s}^{Dev-up} + P_i^{D,DA}) - \sum_{e\in ES_i}(P_{e,s_0}^{ChE} + P_e^{ChE,DA})\\ &= \sum_{q\in I}\left(0.5P_{i,q,s}^{loss} + B_{i,q,s}(\delta_{i,s} - \delta_{q,s})\right) \qquad \forall i \in I, \forall s \in S_2 \quad (5.19)\end{aligned}$$

$$\begin{aligned}\sum_{j\in G_i}&(P_{j,s_0}^{G} + P_j^{G,DA} - P_{j,s}^{GSRD})\\ &+ \sum_{e\in ES_i}(P_{e,s_0}^{DchE} + P_e^{DchE,DA})\\ &- (P_{i,s_0}^{D} - P_{i,s}^{Dev-Dn} + P_i^{D,DA}) - \sum_{e\in ES_i}(P_{e,s_0}^{ChE} + P_e^{ChE,DA} + P_{e,s}^{ESRD})\\ &= \sum_{q\in I}\left(0.5P_{i,q,s}^{loss} + B_{i,q,s}(\delta_{i,s} - \delta_{q,s})\right) \qquad \forall i \in I, \forall s \in S_2 \quad (5.20)\end{aligned}$$

Market Clearing Constraints for Generators and Loads

These constraints ensure that during normal operating conditions the cleared demand and generation quantities do not exceed their respective bid/offer quantities,

$$P_{i,s_0}^{D} \leq \overline{P}_{i,s_0}^{D} X_i^{DA} \qquad \forall i \in I \quad (5.21)$$

$$P_{j,s_0}^{G} \leq \overline{P}_{j,s_0}^{G} W_j^{DA} \qquad \forall j \in J \quad (5.22)$$

The following constraints ensure that during contingency conditions arising in the system, the primary-up and -down regulation quantities do not exceed their respective offer/bid quantities,

$$P_{j,s}^{GPRU} \leq \overline{P}_{j,s}^{GPRU}\, W_j^{DA}\, W_{j,s}^{GRU} \qquad \forall j \in J, \forall s \in S_1 \tag{5.23}$$

$$P_{j,s}^{GPRD} \leq \overline{P}_{j,s}^{GPRD}\, W_j^{DA}\, W_{j,s}^{GRD} \qquad \forall j \in J, \forall s \in S_1 \tag{5.24}$$

The following constraints ensure that during load deviation conditions arising in the system, the cleared secondary-up and -down regulation quantities do not exceed their respective offer/bid quantities,

$$P_{j,s}^{GSRU} \leq \overline{P}_{j,s}^{GSRU}\, W_j^{DA}\, W_{j,s}^{GRU} \qquad \forall j \in J, \forall s \in S_2 \tag{5.25}$$

$$P_{j,s}^{GSRD} \leq \overline{P}_{j,s}^{GSRD}\, W_j^{DA}\, W_{j,s}^{GRD} \qquad \forall j \in J, \forall s \in S_2 \tag{5.26}$$

Generators cannot simultaneously offer regulation-up and regulation-down services, and that is ensured by the following constraints,

$$W_{j,s}^{GRU} + W_{j,s}^{GRD} \leq\ 1 \qquad \forall j \in J, \forall s \in S_1, S_2 \tag{5.27}$$

The total cleared energy and reserve provisions by the generator should be within its operating limits and is ensured by the following constraints,

$$\begin{aligned} \underline{P}_j\, W_j^{DA} \ \leq\ (P_j^{G,DA} + P_j^{GSR,DA} + P_{j,s_0}^{G} + P_{j,s}^{GPRU} - P_{j,s}^{GPRD} \\ + P_{j,s}^{GSRU} - P_{j,s}^{GSRD}) \ \leq\ \overline{P}_j\, W_j^{DA} \qquad \forall j \in J, \forall s \in S_1, S_2 \end{aligned} \tag{5.28}$$

Market Clearing Constraints for BESS

The following constraints ensure that the charging and discharging quantities cleared from a BESS are within its bid/offer capacity,

$$E_{e,s_0}^{Ch} \leq \overline{E}_{e,s_0}^{Ch} Z1_e^{DA} \qquad \forall e \in E \tag{5.29}$$

$$E_{e,s_0}^{Dch} \leq \overline{E}_{e,s_0}^{Dch} Z2_e^{DA} \qquad \forall e \in E \tag{5.30}$$

The cleared primary-down/ -up regulation quantity from a BESS should not exceed its bid/offer quantity.

$$E_{e,s}^{PRD} \leq \overline{E}_{e}^{PRD} Z1_e^{DA} Z_{e,s}^{ERD} \qquad \forall e \in E, \forall s \in S_1 \tag{5.31}$$

$$E_{e,s}^{PRU} \leq \overline{E}_e^{PRU} Z2_e^{DA} Z_{e,s}^{ERU} \qquad \forall e \in E, \forall s \in S_1 \tag{5.32}$$

The cleared secondary-down/ -up regulation capacity from a BESS should not exceed its bid/offer quantity.

$$E_{e,s}^{SRD} \leq \overline{E}_e^{SRD} Z1_e^{DA} Z_{e,s}^{ERD} \qquad \forall e \in E, \forall s \in S_2 \tag{5.33}$$

$$E_{e,s}^{SRU} \leq \overline{E}_e^{SRU} Z2_e^{DA} Z_{e,s}^{ERU} \qquad \forall e \in E, \forall s \in S_2 \tag{5.34}$$

BESS cannot simultaneously offer regulation-up and regulation-down services and that is ensured by the following constraints,

$$Z_{e,s}^{ERU} + Z_{e,s}^{ERD} \leq 1 \qquad \forall e \in E, \forall s \in S_1, S_2 \tag{5.35}$$

Primary Regulation Related Constraints

The system frequency deviation following an outage is governed by the following relations,

$$\sum_j P_{j,s}^{GPRU} + \sum_e P_{e,s}^{EPRU} = \frac{\Delta f_s}{R_{eq}} \qquad \forall s \in S_1 \tag{5.36}$$

$$\sum_j P_{j,s}^{GPRD} + \sum_e P_{e,s}^{EPRD} = \frac{\Delta f_s}{R_{eq}} \qquad \forall s \in S_1 \tag{5.37}$$

The share of the primary-up regulation from a generator and BESS are governed by their respective droop characteristics, as per the following relations,

$$P_{j,s}^{GPRU} = \frac{-\Delta f_s}{R_j} \qquad \forall j \in J, \forall s \in S_1 \tag{5.38}$$

$$P_{e,s}^{EPRU} = \frac{-\Delta f_s}{R_e} \qquad \forall e \in E, \forall s \in S_1 \tag{5.39}$$

Similarly, the share of the primary-down regulation from a generator and BESS are governed by their respective droop characteristics, as per the following relations,

$$P_{j,s}^{GPRD} = \frac{\Delta f_s}{R_j} \qquad \forall j \in J, \forall s \in S_1 \tag{5.40}$$

$$P_{e,s}^{EPRD} = \frac{\Delta f_s}{R_e} \qquad \forall e \in E, \forall s \in S_1 \tag{5.41}$$

In this work, the values for generator and BESS droops, R_j and R_e are considered to be in the range of 0.0075 to 0.1 Hz/MW, depending on the maximum power rating of the respective generator and BESS unit. Similarly, the value of R_{eq} is chosen as 0.00086 Hz/MW.

Furthermore, the system frequency deviation must be maintained within the limits, which is ensured by the following constraints,

$$\Delta f^{min} \leq \Delta f_s \leq \Delta f^{max} \qquad \forall s \in S_1 \tag{5.42}$$

In this work, the maximum frequency deviation is considered to be $\Delta f^{max} = \Delta f^{min} = 0.2$ Hz.

Secondary Regulation Related Constraints

The secondary-up and down regulation service provided from generator and BESS should meet the load changes and is ensured by the following constraints,

$$\sum_j P_{j,s}^{GSRU} + \sum_e P_{e,s}^{ESRU} = P_s^{Change\text{-}Up} \qquad \forall s \in S_2 \tag{5.43}$$

$$\sum_j P_{j,s}^{GSRD} + \sum_{e,s} P_{e,s}^{ESRD} = P_s^{Change\text{-}Dn} \qquad \forall s \in S_2 \tag{5.44}$$

BESS Operational Constraints

The BESS energy balance relates the SOC at a given time interval with its charging/ discharging operation and regulation provisions, given as follows,

$$\begin{aligned} SOC_e - SOC_e^0 = \Bigg(& (P_{e,s_0}^{ChE} + P_{e,s}^{EPRD} + P_{e,s}^{ESRD})\eta^{Ch} \\ & - (P_{e,s_0}^{DchE} + P_{e,s}^{EPRU} + P_{e,s}^{ESRU})/\eta^{Dch} \Bigg) \Delta k \qquad \forall e \in E, \forall s \in S_1, S_2 \end{aligned} \tag{5.45}$$

The total cleared energy and reserve capacity provisions by the BESS should be within its limits and is ensured by the following constraints,

$$\underline{SOC}_e \leq \Bigg((E_e^{Dch,DA} + E_e^{SR,DA} + E_{e,s_0}^{Dch} + E_{e,s}^{PRU} + E_{e,s}^{SRU}) + (E_e^{Ch,DA} + E_{e,s_0}^{Ch} + E_{e,s}^{PRD} + E_{e,s}^{SRD}) \Bigg) \leq \overline{SOC}_e \qquad \forall e \in E, \forall s \in S_1, S_2 \quad (5.46)$$

The following constraints ensure that the power drawn/supplied during the charging/discharging and regulation provisions are within the respective limits, as follows,

$$P_{e,s_0}^{ChE} \leq \overline{P}_e^{Ch} Z1_e^{DA} \qquad \forall e \in E \quad (5.47)$$

$$P_{e,s_0}^{DchE} \leq \overline{P}_e^{Dch} Z2_e^{DA} \qquad \forall e \in E \quad (5.48)$$

$$P_{e,s}^{EPRU} \leq \overline{P}_{e,s}^{EPRU} Z2_e^{DA} \qquad \forall e \in E, \forall s \in S_1, S_2 \quad (5.49)$$

$$P_{e,s}^{ESRU} \leq \overline{P}_{e,s}^{ESRU} Z2_e^{DA} \qquad \forall e \in E, \forall s \in S_1, S_2 \quad (5.50)$$

$$P_{e,s}^{EPRD} \leq \overline{P}_{e,s}^{EPRD} Z1_e^{DA} \qquad \forall e \in E, \forall s \in S_1, S_2 \quad (5.51)$$

$$P_{e,s}^{ESRD} \leq \overline{P}_{e,s}^{ESRD} Z1_e^{DA} \qquad \forall e \in E, \forall s \in S_1, S_2 \quad (5.52)$$

The following relations relates the power and energy quantities cleared from a BESS during charging, discharging and regulation services, for a given real-time market interval.

$$P_{e,s} \Delta k = E_{e,s} \qquad \forall e \in E, \forall s \quad (5.53)$$

Transmission Line Constraints

These constraints ensure that the line power flows are within their limits.

$$B_{i,q,s}(\delta_{i,s} - \delta_{q,s}) \leq \overline{PFlow}_{i,q} \qquad \forall i, q \in I, \forall s \quad (5.54)$$

5.5 Energy and Reserve Market Price Determination

The proposed mathematical model for the BESS integrated, real-time, energy and regulation reserve market, presented in Section 5.4 can be summarized as follows:

$$Max \;\; J(x,y) \tag{5.55}$$

Subject to:

$$h_0(x,y) = 0 \qquad (\psi_0) \tag{5.56}$$

$$h_s^{PRU}(x,y) = 0 \qquad (\psi_s^{PRU}) \tag{5.57}$$

$$h_s^{PRD}(x,y) = 0 \qquad (\psi_s^{PRD}) \tag{5.58}$$

$$h_s^{SRU}(x,y) = 0 \qquad (\psi_s^{SRU}) \tag{5.59}$$

$$h_s^{SRD}(x,y) = 0 \qquad (\psi_s^{SRD}) \tag{5.60}$$

$$g(x,y) \leq 0 \qquad (\mu) \tag{5.61}$$

In the above model, x represents the vector of all continuous decision variables *i.e.*, the power and energy quantities cleared during the normal, contingency and load deviation scenarios and y represents the vector of binary decision variables *i.e.*, the status parameters.

The equality constraints (5.56)-(5.60) represent the nodal supply-demand balance for normal, primary regulation and secondary regulation scenarios (5.16)-(5.20). The Lagrangian multipliers for the equality constraints (ψ_0, ψ_s^{PRU}, ψ_s^{PRD}, ψ_s^{SRU}, and ψ_s^{SRD}) are shown in the brackets corresponding to each set of equation.

The marginal cost of energy is the change in the value of J in (5.15) for an infinitesimal change in P_{i,s_0}^{D} (5.16)-(5.20). Similarly, the marginal cost of PR reserves is the change in the value of J for an infinitesimal change $P_{i,s}^{Out}$ (5.17)-(5.18) and the marginal cost of SR reserves is the change in the value of J for an infinitesimal change $P_{i,s}^{Dev-Up/Dn}$ (5.19)-(5.20).

The infinitesimal change in J is given as follows,

$$\begin{aligned}\Delta J = (\psi_0)^T \Delta P_{i,s_0}^{D} + \sum_{s\in S_1} \Big(((\psi_s^{PRU})^T + (\psi_s^{PRD})^T)(\Delta P_{i,s_0}^{D} + \Delta P_{i,s}^{Out^{+/-}}) \Big) \\ + \sum_{s\in S_2} \Big(((\psi_s^{SRU})^T + (\psi_s^{SRD})^T)(\Delta P_{i,s_0}^{D} + \Delta P_{i,s}^{Dev-Up/Dn}) \Big)\end{aligned} \tag{5.62}$$

And, the nodal marginal cost of energy is given as follows,

$$\lambda^E = \frac{\partial J}{\partial P^D_{i,s_0}} = \psi_0\rho_0 + \sum_{s\in S_1,S_2}\left(\psi_s^{PRU}\rho_s + \psi_s^{PRD}\rho_s + \psi_s^{SRU}\rho_s + \psi_s^{SRD}\rho_s\right) \tag{5.63}$$

the nodal marginal cost of reserve is given as follows,

$$\lambda^R = \frac{\partial J}{\partial P^{Out+/-}_{i,s}} + \frac{\partial J}{\partial P^{Dev-Up/Dn}_{i,s}} = \sum_{s\in S_1}\Bigg(\psi_s^{PRU}\rho_s + \psi_s^{PRD}\rho_s\Bigg) + \sum_{s\in S_2}\left(\psi_s^{SRU}\rho_s + \psi_s^{SRD}\rho_s\right) \tag{5.64}$$

5.6 Results & Discussions

To validate the proposed BESS integrated energy and regulation reserve market model, the IEEE RTS [94], considered in the previous Chapters, is used. Also, BESS units of different sizes are located at buses - 4, 5, 9, 19 and 20, as given in Chapter-4, Section 4.6. To demonstrate the functionalities of the proposed market model, the results of a single settlement period (first 5-minute interval of hour-18) is presented. The loads, gencos and BESS owners submit bids and offers for participating in the energy and regulation reserve markets, as discussed in Section 5.3. The demand bids, generator bid/offers, BESS bid/offers for the first 5-minute interval in the real-time market is considered with a 10-25% scaling of the bid/offer data given in Appendix (Table B.1, B.2, B.4).

The proposed model is formulated as a MIP problem and solved using the CPLEX solver in GAMS [95, 105]. In order to study the impact of BESS participation on market settlement and system operation, two case studies are considered:

- Case 1: Base case (no BESS participation) - only generators and loads participate in the real-time energy and regulation markets.
- Case 2: With BESS participation - in addition to generators and loads, there are 10 BESS units located across five buses participating in energy and regulation markets.

To investigate the impact of uncertainties on market clearing and on system operation, seven scenarios are constructed by considering specific probabilities associated with each (ρ_s), the details of which are given in Table 5.1.

Table 5.1: Operational Scenarios

Set	Scenario (s)	Description	ρ_s
S_0	Sc_1	Normal operation.	0.79
S_1	Sc_2	Generator G-1 at bus-1 scheduled for 20 MW under normal operation, is on outage.	0.1
	Sc_3	Generator G-9 at bus-7 scheduled for 50 MW under normal operation, is on outage.	0.04
	Sc_4	Generator G-13 at bus-13 scheduled for 85 MW under normal operation, is on outage.	0.05
	Sc_5	Line 13-23 is on outage.	0.004
S_2	Sc_6	A sudden load increase of 30 MW at bus-7	0.01
	Sc_7	A sudden load reduction of 20 MW at bus-13	0.01

5.6.1 Case 1: Base Case (no BESS participation)

Table 5.2 shows the expected generation and the expected primary-up/down and secondary-up/down regulation reserve quantities cleared in the real-time market. The real-time expected generation cleared for each generator, $E[P^G]$, is over and above that cleared in the day-ahead market. The expected values of primary-up and down, and secondary-up and down regulation reserves, $E[P^{GPRU}]$, $E[P^{GPRD}]$, $E[P^{GSRU}]$, and $E[P^{GSRD}]$, respectively, are obtained considering the various contingency and load deviation scenarios, with their respective probabilities, and using the demand-supply balance constraints (5.17)-(5.18) for primary regulation, and (5.19)-(5.20) for secondary regulation, in place of (5.16).

Table 5.2: Expected generation and regulation reserve schedules for Case-1 (MW)

	$E[P^G]$	$E[P^{GPRU}]$	$E[P^{GPRD}]$	$E[P^{GSRU}]$	$E[P^{GSRD}]$	$E[Dispatch]$
G1	11.06	0	0	0	0	11.06
G2	0	0.72	0	0.06	0	0.78
G5	0	0.82	0	0.04	0	0.86
G6	0	0.66	0	0.04	0	0.7
G9	24.49	4.1	0	0	0	28.59
G10	25.28	1.35	0	0	0	26.63
G11	25.28	0.6	0	0	0	25.88
G13	88.48	0	0.1	0	0.1	88.28
G14	46.61	0	0	0	0.1	46.51
G15	0	0	0	0.16	0	0.16
Total	221.2	8.25	0.1	0.3	0.2	229.45

As noted from Table 5.2, generators G-13 and G-14 provide significant portion of the

Table 5.3: Expected cleared demand, $E[P^D]$ (MW)

	Case-1	Case-2
Bus-1	60.04	64.97
Bus-8	64.78	65.8
Bus-13	95.08	97.13
Total	219.9	227.9

additional demand appearing in the real-time market, this is because of their lowest offer prices. In Sc_2, Sc_3, and Sc_4, the loss of generation as a result of the outage of the respective generators G-1, G-9 and G-13 respectively, is made up through the primary-up regulation reserve provided by other generators. While in the case of a line outage (between bus 13-23) considered in Sc_5 the generator, G-13 provides the primary-down regulation reserve.

The total expected demand cleared in the real-time market, over and above the day-ahead cleared demand, is 219.9 MW (Table 5.3), plus the system losses (1.3 MW), is same as the total of $E[P^G]$ in Table 5.2.

The expected social welfare in Case-1 is $10,498.

Table 5.4: Expected Lagrangian multipliers for different Scenarios, Case-1 ($/MWh)

	$E[\psi_0]$	$E[\psi_s^{PRU}]$			$E[\psi_s^{PRD}]$	$E[\psi_s^{SRU}]$	$E[\psi_s^{SRD}]$
	Sc_1	Sc_2	Sc_3	Sc_4	Sc_5	Sc_6	Sc_7
Bus-1	69.78	3.34	1.38	1.73	0	0.33	0
Bus-2	71.45	0	2.10	2.67	0	0.26	0
Bus-7	39.39	2.98	1.56	0	0	0	0
Bus-13	68.13	0	0	3.29	0.08	0	0.29
Bus-15	49.51	0	0	0	0	0.21	0

The expected values of the Lagrangian multipliers associated with the power balance equations corresponding to the normal operation (5.16), under contingency [5.17-5.18], and load deviation [5.19-5.20]scenarios are shown in Table 5.4. It is to be noted that $E[\psi_0]$ related to the pre-disturbance condition are higher at Bus-1 and 2 because of a congestion arising on line 1-2 and the expensive generator located at these Bus-2. Similarly, the values $E[\psi_s^{PRU}]$ related to primary regulation reserves is higher at Bus-1 and 13 because of the contingency occuring at these buses.

The expected nodal energy prices, $E[\lambda_E]$ and nodal reserve prices, $E[\lambda_R]$, are reported

Table 5.5: Expected nodal energy and reserve prices for Case-1 ($/MWh)

	$E[\psi_0]$	$E[\sum \psi_s^{PRU/PRD}]$	$E[\sum \psi_s^{SRU/SRD}]$	$E[\lambda_E]$	$E[\lambda_R]$
Bus-1	69.78	6.45	0.33	76.56	6.78
Bus-2	71.45	4.77	0.26	76.48	5.03
Bus-7	39.39	4.54	0	43.93	4.54
Bus-13	68.13	3.37	0.29	71.79	3.66
Bus-15	49.51	0	0.21	49.72	0.21

in Table 5.5, given by (5.63) and (5.64) respectively, and are obtained from the values of $E[\psi_0]$, $E[\psi_s^{PRU}]$ and $E[\psi_s^{PRD}]$, $E[\psi_s^{SRU}]$ and $E[\psi_s^{SRD}]$ given in Table 5.4. It is to be noted that the expected nodal energy prices, $E[\lambda_E]$ includes the reserve price component $E[\lambda_R]$; while $E[\lambda_R]$ is also explicitly given for the sake of clarity, in Table 5.5. For example, at Bus-1, the energy component is 69.78$/MWh, the reserve component is 6.78 $/MWh, and these together constitutes the nodal energy price of 76.56$/MWh.

5.6.2 Case 2: With BESS participation

Table 5.6 shows the expected cleared generation, BESS discharge and primary-up/down and secondary-up/down reserve quantities cleared in the real-time market, for the respective generators and BESSs. It is noted that there is a slight increase in the total expected generation (including BESS discharge) cleared, *i.e.*, $E[P^G] + E[P^{DchE}]$, as a result of increase in the total expected demand cleared in the real-time market, in Case-2 as compared to Case-1 (Table 5.3).

It is also noted that with the participation of BESS, there is a change in $E[P^G]$ in Case-2 as compared to Case-1, except for G-13 and G-14, which are at their maximum capacity since these are the cheapest unit. Furthermore, the participation of BESS has resulted in reduction of $E[P^{GPRU}]$ and $E[P^{GPRD}]$ from expensive generators G-2, G-5, G-6, and G-9 in Case-2 as compared to Case-1, because of the cheaper reserve offers from BESS. However, the contribution of BESS for secondary regulation services is minimal as compared to generators; this is be attributed to their limited stored energy capacity, as these BESS are providing energy and primary regulation service also.

It is noted that the participation of BESS has resulted in an increase in the social welfare of the system in Case-2 ($10,617) as compared to Case 1 ($10,498), which is a 1.1% increase with respect to the Base Case. The increase in the social welfare ($119 or 1.1%)

Table 5.6: Expected generation, regulation reserve and BESS schedules for Case-2 (MW)

	$E[P^G]$	$E[P^{GPRU}]$	$E[P^{GPRD}]$	$E[P^{GSRU}]$	$E[P^{GSRD}]$	$E[Dispatch]$
G1	0	0	0	0	0	0
G2	0	0.25	0	0.06	0	0.31
G5	0	0.25	0	0.04	0	0.29
G6	0	0.62	0	0.04	0	0.66
G9	22.12	2.75	0	0	0	24.87
G10	23.7	1.35	0	0	0	25.05
G11	23.7	0.6	0	0	0	24.3
G13	88.48	0	0.08	0	0.1	88.3
G14	46.61	0	0	0	0.1	46.51
G15	0	0	0	0.16	0	0.16
	$E[P^{DchE}]$	$E[P^{EPRU}]$	$E[P^{EPRD}]$	$E[P^{ESRU}]$	$E[P^{ESRD}]$	
ES1	7.11	1.21	0	0.06	0	8.38
ES3	12.64	1.22	0	0.02	0	13.88
ES8	4.74	0	0	0	0.1	4.64
Total	229.1	8.25	0.08	0.38	0.3	237.35

between Case-1 and Case-2 may seem low, but when considered for a day or a year, it would be a significantly large value.

Table 5.7: Expected Lagrangian multipliers for different Scenarios, Case-2 ($/MWh)

	$E[\psi_0]$	$E[\psi_s^{PRU}]$			$E[\psi_s^{PRD}]$	$E[\psi_s^{SRU}]$	$E[\psi_s^{SRD}]$
	Sc_1	Sc_2	Sc_3	Sc_4	Sc_5	Sc_6	Sc_7
Bus-1	65.08	3.15	0.00	0.00	0.00	0.33	0
Bus-2	66.15	0.00	1.38	2.42	0.00	0.20	0
Bus-7	38.98	2.99	2.50	0	0.00	0	0
Bus-13	69.47	0.00	0.00	0.00	0.07	0	0.26
Bus-15	51.37	0.00	0.00	0.00	0.00	0.20	0
Bus-4	55.43	2.76	1.11	1.57	0.05	0	0
Bus-5	49.56	2.48	0.99	1.54	0	0.16	0
Bus-19	44.89	0.00	0.90	1.13	0.05	0	0

The expected values of the Lagrangian multipliers associated with the power balance equations corresponding to the normal operation (5.16), under contingency [5.17-5.18], and load deviation [5.19-5.20] scenarios in Case-2, are shown in Table 5.7. It is noted that the participation of BESS has resulted in significant reduction in the Lagrangian multiplier $E[\psi_0]$ at Bus-1 and 2 because of the reduction of generation from G-1, which removes the congestion on line 1-2.

Table 5.8: Expected nodal energy and reserve prices for Case-2 ($/MWh)

	$E[\psi_0]$	$E[\sum\psi_s^{PRU/PRD}]$	$E[\sum\psi_s^{SRU/SRD}]$	$E[\lambda_E]$	$E[\lambda_R]$
Bus-1	65.08	3.15	0.33	68.56	3.48
Bus-2	66.15	3.80	0.20	70.15	4.00
Bus-7	38.98	5.49	0.00	44.47	5.49
Bus-13	69.47	0.02	0.26	69.75	0.28
Bus-15	51.37	0.00	0.20	51.57	0.20
Bus-4	55.43	5.48	0.01	60.88	5.49
Bus-5	49.56	5.01	0.16	54.73	5.17
Bus-19	44.89	2.07	0.01	46.93	2.08

The expected nodal energy prices, $E[\lambda_E]$ and nodal reserve prices, $E[\lambda_R]$ for Case-2 are shown in Table 5.8. It is noted that with the BESS participation, the nodal energy and reserve prices at all buses except Bus-13 and 15 in Case-2 as compared to Case-1 have reduced, this is because the cheaper BESS offers replaces some of the expensive generators. The slight increase in the nodal price at Bus-13 and Bus-15 is because there is an increase in demand cleared at Bus-13, which has to be supplied from other buses as the cheapest generator, G-13 located at this bus is operating at its maximum limit.

5.7 Conclusions

In this chapter, a novel framework and mathematical model for simultaneously procuring primary and secondary regulation reserves, alongside energy, in a BESS integrated electricity market, by taking into account probabilistic scenarios of contingencies in the real-time operations was proposed. The proposed market model is a co-optimized, LMP-based, which takes into consideration the *a priori* cleared day-ahead market schedules. The effectiveness of the model was validated on the IEEE RTS by considering two realistic case studies, each with a normal operation scenario, four contingency scenarios, and two load deviation scenarios. It was noted that BESS participation using the proposed framework resulted in a higher social welfare, than, when no BESS was present. The advantage of the proposed method is that, it helps in avoiding over-estimating the regulation reserve requirements, thus reducing the system operation cost. It was also seen that the participation of BESS reduced the energy and reserve prices when it provided services simultaneously in the energy and regulation reserve markets and helped in relieving line congestions when placed at appropriate locations.

Chapter 6

Conclusions

6.1 Summary and Conclusions

The research presented in this thesis focuses on the development of frameworks and models for integrating DR and BESSs into electricity markets by considering the various important features and characteristics of these resources in their bid/offers structure, cost function models, and operational constraints. The motivations to pursue this research were presented in Chapter 1, and the research objectives were identified based on a critical review of the literature.

In Chapter 2, a brief background to the topics related to the research carried out in this thesis were reviewed. A basic overview of electricity markets including LMP-based market settlement model and the definitions of the important ancillary services were presented. Different DR programs in electricity markets were then outlined. Finally, the classifications of different ESSs, and the important topics related to BESSs such important terminologies, operational models and the battery degradation mechanisms were presented.

In Chapter 3, a novel and comprehensive formulation of DR bid/offer structure through PRD and load curtailment based DR bids simultaneously, taking into account customer preferences for simultaneous participation in energy and spinning reserve markets was proposed. A new framework and mathematical model for an LMP-based, loss included, day-ahead, co-optimized energy and spinning reserve market including DR provisions was proposed. The effectiveness of the proposed model was validated on the IEEE RTS by considering four case studies under four scenarios.

In Chapter 4, novel BESS cost function models for Degradation Cost, based on its DOD and discharge rate, and Flexibility Cost are developed. The model is developed considering

Lithium-ion batteries, and the approach can be applied to other conventional electrochemical batteries, but not flow batteries. These cost functions are used to formulate detailed BESS bid/offer structures. A new framework and mathematical model were proposed for BESS participation in an LMP-based, co-optimized, energy and spinning reserve market. Three case studies are presented to investigate the impact of BESS participation on system operation and market settlement using the IEEE RTS.

In Chapter 5, a novel framework and mathematical model were proposed for simultaneously procuring primary and secondary regulation reserves alongside energy, in a BESS integrated electricity market, by taking into account probabilistic scenarios of contingencies in the real-time operations. Detailed studies considering the IEEE RTS, demonstrating the applicability of the proposed technique, were presented.

The main conclusions of the presented research are:

- The DR provisions, simultaneously considering PRD bids and DR offers, in energy and spinning reserve markets, resulted in increased social welfare.
- The integration of DR in the energy and spinning reserve market enhanced the economic and technical benefits for the ISO by providing more options for system operation.
- The BESS participation in the day-ahead market, using the proposed cost function and bid/offer structure, resulted in a higher social welfare than when no BESS was present or with a simple bid/offer structure for BESS. The participation of BESS also reduced energy and spinning reserve prices when it provided services in the energy and spinning reserve markets.
- The studies reveal that BESS participation in day-ahead market: (i) correctly captured the actual cost of BESS operation, accounting for its degradation and flexibility attributes, thus providing realistic market clearing decisions, (ii) it appropriately met the important requirement of FERC Order 841 to develop a participation model for ESS, accounting for their physical and operational characteristics such as the SOC, discharge rate, etc., in the ESS bidding parameters, to facilitate their participation in ISO markets.
- The BESS participation in the real-time market using the proposed framework resulted in a higher social welfare, than, when no BESS was present. It was also seen that the participation of BESS reduced the energy and reserve prices when it provided services simultaneously in the energy and regulation reserve markets and helped in relieving line congestions when placed at appropriate locations.

- The advantage of including BESS in real-time markets is that, it helps in avoiding over-estimating the regulation reserve requirements, thus reducing the system operation cost.

6.2 Contributions

The main contributions of the research presented in this thesis can be summarized as follows:

- A new bid/offer structure for DR provisions, simultaneously through PRD based bids and load curtailment based DR offers from customers has been developed.
- A novel framework and comprehensive mathematical model have been proposed for a DR-energy-spinning reserve market, based on LMPs, which includes transmission loss representation within the dc power flow constraints using a piece-wise linear approximation approach.
- For the first time, a BESS cost function model considering the Degradation Cost, which is based on the DOD and discharge rate, and the Flexibility Cost, has been developed. The model is developed considering Lithium-ion batteries, and the approach can be applied to other conventional electrochemical batteries, but not flow batteries. A bid/offer structure for BESS to participate in day-ahead energy and spinning reserve markets, capturing the inter-relationships between the BESS charging bid and discharging offer quantities has been proposed.
- A generic day-ahead market operations framework and comprehensive mathematical model have been proposed for the integration of BESS in an LMP-based, co-optimized, day-ahead energy and spinning reserve market by including the proposed BESS charging bid and discharging offer structure.
- A novel framework for simultaneously procuring primary and secondary regulation reserves alongside energy has been proposed, in a BESS-integrated, electricity market, by taking into account probabilistic scenarios of contingencies in the real-time operations.
- A novel mathematical model has been developed considering BESS alongside conventional generators to determine the optimal real-time primary and secondary regulation reserves and energy market clearing, in a co-optimized, LMP based market, taking into consideration the *a priori* cleared day-ahead market schedules.

- All the above formulations and propositions pertaining to BESS, were one of the first to appropriately meet the important requirement of FERC Order 841 to develop a participation model for ESSs, accounting for their physical and operational characteristics, such as the SOC, discharge rate, etc., in the ESS bidding parameters, so as to facilitate their participation in ISO markets.

- The DR and BESS integrated market model presented in this thesis were proposed for LMP based markets, which are widely adopted in US. However, all the proposed bid/offer structures, cost functions, and market models are easily adaptable to uniform price markets.

- Finally, the impacts of participation of DR in day-ahead, and BESS in day-ahead and real-time energy and reserve markets, on market prices, market clearing dispatch, and other economic indicators, for various scenarios and cases have been carried out.

The main contents and contributions of Chapter 3 have been published in IEEE Transactions on Power Systems [104] and 2019 CIGRE Canada Conference [16]. The main contents of Chapter 4 has been reported in a paper currently under review for publication in IEEE Transactions on Power Systems [106], and the main contents of Chapter 5 has been reported in a paper currently under review for publication in IEEE Transactions on Smart Grid [107].

6.3 Future Work

- In order to capture the full impact of DR participation in electricity markets, the proposed DR models, bid/offer structures in this thesis should be extended to real-time markets too. This will enhance the system performance and introduce a new revenue stream for DR providers.

- The inclusion of RES, by appropriately capturing their uncertain behaviour in the proposed day-ahead and real-time electricity market models need be investigated; this will highlight the benefits of the proposed frameworks and show how the developed models in this thesis could hedge the risks from increasing RES penetration.

- The BESS cost function models and bid offer structures proposed in Chapter 4 of the thesis were based on the characteristics of lithium ion batteries. Similar cost functions and bid/offer structures need be developed for other battery technologies such as lead acid, nickel cadmium etc., using the approach proposed in this thesis.

- In this thesis the focus was at the wholesale market and system level. But when the distribution system level is considered, the local distribution companies (LDCs) also encounter challenges such as increasing peaks, increased losses, deterioration in voltage profiles, etc. At the same time, there has been a significant increase in the residential ESS deployment in recent years in Ontario [38]. In this context, it is important to examine if medium/small-scale ESS and DR can provide cost effective solutions for some of the aforementioned problems for the LDCs, which can be carried out in line with the frameworks and model presented in this thesis.

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APPENDICES

Appendix A

IEEE Reliability Test System Data

Table A.1: Generating unit location & capability [92]

Generator Number	Bus	Pgmax (MW)
1	1	20
2	1	20
3	1	76
4	1	76
5	2	20
6	2	20
7	2	76
8	2	76
9	7	100
10	7	100
11	7	100
12	13	197
13	13	197
14	13	197
15	15	12
16	15	12
17	15	12
18	15	12
19	15	12
20	15	155
21	16	155
22	18	400
23	21	400
24	22	50
25	22	50
26	22	50
27	22	50
28	22	50
29	22	50
30	23	155
31	23	155
32	23	350

Table A.2: Generator Min./Max. Up/Down time and reliability data [92]

Unit Group	Unit Size	Unit Type	Forced Outage Rate	Min. Down Time (Hr)	Min.Up Time (Hr)	Ramp Rate (MW/minute)
U12	12	Oil/Steam	0.02	2	4	2
U20	20	Oil/CT	0.1	1	1	3
U50	50	Hydro	0.01	N/A		
U76	76	Coal/Steam	0.02	4	8	2
U100	100	Oil/Steam	0.04	8	8	7
U155	155	Coal/Steam	0.04	8	8	3
U197	197	Nuclear	0.05	10	12	20
U350	350	Coal/Steam	0.08	48	24	4
U400	400	Nuclear	0.12	1	1	20

Table A.3: Bus load data

Bus	Load (MW)
1	108
2	97
3	180
4	74
5	71
6	136
7	125
8	171
9	175
10	195
13	265
14	194
15	317
16	100
18	333
19	181
20	128
Total	2850

Table A.4: Hourly peak load in percent of daily peak [92]

Hour	Hourly Load (%)
12:00 -1:00 AM	78
1:00 - 2:00 AM	72
2:00 - 3:00 AM	68
3:00 - 4:00 AM	66
4:00 - 5:00 AM	64
5:00 - 6:00 AM	65
6:00 - 7:00 AM	66
7:00 - 8:00 AM	70
8:00 - 9:00 AM	80
9:00 - 10:00 AM	88
10:00 - 11:00 AM	90
11:00 - Noon	91
Noon - 1:00 PM	90
1:00 - 2:00 PM	88
2:00 - 3:00 PM	87
3:00 - 4:00 PM	91
4:00 - 5:00 PM	100
5:00 - 6:00 PM	99
6:00 - 7:00 PM	97
7:00 - 8:00 PM	95
8:00 - 9:00 PM	94
9:00 - 10:00 PM	92
10:00 - 11:00 PM	87
11:00 - 12:00 AM	81

Table A.5: Transmission line length, impedance and rating data [92]

Line Number	From Bus	To Bus	Length (mile)	Impedance P.U./ 100MVA Base			Rating (MVA)
				R	X	B	
1	1	2	3	0.003	0.014	0.461	175
2	1	3	55	0.055	0.211	0.057	175
3	1	5	22	0.022	0.085	0.023	175
4	2	4	33	0.033	0.127	0.034	175
5	2	6	50	0.05	0.192	0.052	175
6	3	9	31	0.031	0.119	0.032	175
7	3	24	0	0.002	0.084	0	400
8	4	9	27	0.027	0.104	0.028	175
9	5	10	23	0.023	0.088	0.024	175
10	6	10	16	0.014	0.061	2.459	175
11	7	8	16	0.016	0.061	0.017	175
12	8	9	43	0.042	0.161	0.044	175
13	8	10	43	0.043	0.165	0.045	175
14	9	11	0	0.043	0.165	0.045	175
15	9	12	0	0.002	0.084	0	400
16	10	11	0	0.002	0.084	0	400
17	10	12	0	0.002	0.084	0	400
18	11	13	33	0.006	0.048	0.1	500
19	11	14	29	0.005	0.042	0.088	500
20	12	13	33	0.006	0.048	0.1	500
21	12	23	67	0.012	0.097	0.203	500
22	13	23	60	0.011	0.087	0.182	500
23	14	16	27	0.005	0.059	0.082	500
24	15	16	12	0.002	0.017	0.036	500
25	15	21	34	0.006	0.049	0.103	500
26	15	21	34	0.006	0.049	0.103	500
27	15	24	36	0.007	0.052	0.109	500
28	16	17	18	0.003	0.026	0.055	500
29	16	19	16	0.003	0.023	0.049	500
30	17	18	10	0.002	0.014	0.03	500
31	17	22	73	0.014	0.105	0.221	500
32	18	21	18	0.003	0.026	0.055	500
33	18	21	18	0.003	0.026	0.055	500
34	19	20	27.5	0.005	0.04	0.083	500
35	19	20	27.5	0.005	0.04	0.083	500
36	20	23	15	0.003	0.022	0.046	500
37	20	23	15	0.003	0.022	0.046	500
38	21	22	47	0.009	0.068	0.142	500

Appendix B

Generator, DR and BESS data

Table B.1: Generator offers in energy and spinning reserve markets

		Generator - Energy Offers						Generator - Spinning reserve offers					
Gen. Size	Gen. Type	Block 1		Block 2		Block 3		Block 1		Block 2		Block 3	
		Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price
12 MW	Oil/Steam	5	45.68	6	52.73	1	55.54	1	18.27	1	21.09	0	22.22
20 MW	Oil/CT	5	56.41	10	105.12	5	129.47	1	22.56	2	42.05	1	51.79
76 MW	Coal/Steam	25	12	40	15.15	11	16.02	5	4.80	7	6.06	2	6.41
100 MW	Oil/Steam	35	37.14	35	41.92	10	44.05	7	14.86	9	16.77	4	17.62
155 MW	Coal/Steam	50	10.33	80	11.47	25	11.82	10	4.13	15	4.59	6	4.73
197 MW	Oil/Steam	60	36.68	100	41.1	37	42.74	12	14.67	20	16.44	8	17.10
350 MW	Coal/Steam	120	10.49	175	12	55	12.42	24	4.20	36	4.80	10	4.97
400 MW	Nuclear	150	5.76	200	6	50	6.06	30	2.30	40	2.40	10	2.42

Note: All bid/offer quantities are in MW, energy prices are in \$/MWh, and spinning reserve prices in \$/MW

Table B.2: Demand energy bids and DR energy, spinning reserve offers (for hour-18)

	Demand Bids						DRE - Offers						DRSR - Offers					
Bus	Block 1		Block 2		Block 3		Block 1		Block 2		Block 3		Block 1		Block 2		Block 3	
	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price
1	75.6	100	21.6	80.6	10.8	70.4	0.54	110	1.08	84.7	3.78	53.9	0.54	44	1.08	33.9	3.78	21.6
2	67.9	100	19.4	90.4	9.7	85.9	0.5	110	1	94.9	3.4	90.2	0.5	44	1	38	3.4	36.1
3	126	100	36	72.2	18	67.1	0.9	110	1.8	75.8	6.3	70.4	0.9	44	1.8	30.3	6.3	28.2
4	51.8	100	14.8	86.7	7.4	73.5	0.4	110	0.7	91.1	2.6	57.1	0.4	44	0.7	36.4	2.6	22.9
5	49.7	100	14.2	70.7	7.1	68.5	0.4	110	0.7	74.2	2.5	72	0.4	44	0.7	29.7	2.5	28.8
6	95.2	100	27.2	80.3	13.6	74.6	0.7	110	1.4	84.3	4.8	58.4	0.7	44	1.4	33.7	4.8	23.3
7	87.5	100	25	95.7	12.5	90.4	0.6	110	1.3	100.5	4.4	95	0.6	44	1.3	40.2	4.4	38
8	119.7	100	34.2	73.3	17.1	67.8	0.9	110	1.7	76.9	6	71.2	0.9	44	1.7	30.8	6	28.5
9	122.5	100	35	72.2	17.5	62.2	0.9	110	1.8	72.6	6.1	55.3	0.9	44	1.8	29	6.1	22.1
10	136.5	100	39	83.5	19.5	58.5	1	110	2	86.7	6.8	57.4	1	44	2	34.7	6.8	23
13	185.5	100	53.0	75.5	26.5	56	1.3	110	2.7	78	9.3	56.8	1.3	44	2.7	31.2	9.3	22.7
14	135.8	100	38.8	81.3	19.4	67.5	1	110	1.9	78.3	6.8	57.4	1	44	1.9	31.3	6.8	23
15	221.9	100	63.4	74.6	31.7	60.1	1.6	110	3.2	75.9	11.1	63.1	1.6	44	3.2	30.3	11.1	25.3
16	70	100	20	79.8	10	74.1	0.5	110	1	83.8	3.5	57.8	1	44	1	33.5	3.5	23.1
18	233.1	100	66.6	95.7	33.3	86.3	1.7	110	3.3	100.5	11.7	90.6	1.7	44	3.3	40.2	11.7	36.2
19	126.7	100	36.2	91.0	18.1	88.1	0.9	110	1.8	95.6	6.3	92.5	0.9	44	1.8	38.2	6.3	37
20	89.6	100	25.6	89.6	12.8	84.2	0.6	110	1.3	94.0	4.5	88.4	0.6	44	1.3	37.6	4.5	35.4

Note: All bid/offer quantities are in MW, energy prices are in \$/MWh, and spinning reserve prices in \$/MW

Table B.3: Maximum duration of DR provision at a bus

Bus	1	2	3	4	5	6	7	8	9	10	13	14	15	16	17	18	19	20
DRT (Hours)	4	2	4	4	4	4	3	4	4	4	4	2	4	4	4	2	2	2

Table B.4: BESS data

BESS	$\underline{E}$ (MWh)	$\overline{E}$ (MWh)	SOC_0 (p.u)	$\overline{P}^{ch}/\overline{P}^{dch}$ (MW)	η_{ch}/η_{dch} (p.u.)	DCR^{max} (p.u.)	a (\$/MWh)	b (\$/MWh)	c (\$)	d (\$)	$C2$ (\$)
1	3	15	0.4	25	0.95	1	-36.23	34.80	2.77	-3.45	18
2	3	15	0.5	25	0.95	1	-36.23	34.80	2.77	-3.45	18
3	6	30	0.7	15	0.95	1	-36.23	34.80	2.77	-2.90	12
4	6	30	0.7	15	0.95	1	-36.23	34.80	2.77	-2.90	12
5	10	50	0.3	20	0.95	1	-36.23	34.80	2.77	-2.45	8
6	10	50	0.3	20	0.95	1	-36.23	34.80	2.77	-2.45	8
7	2	12.5	0.75	20	0.95	1	-36.23	34.80	2.77	-3.75	15
8	2	12.5	0.75	20	0.95	1	-36.23	34.80	2.77	-3.75	15
9	2	12.5	0.5	20	0.95	1	-36.23	34.80	2.77	-3.75	15
10	2	12.5	0.5	20	0.95	1	-36.23	34.80	2.77	-3.75	15