THE COMPARATIVE ECONOMIC ASSESSMENT OF THE IMPACTS OF ENERGY STORAGE AND DEMAND RESPONSE RESOURCE PARTICIPATION IN THE DAY-AHEAD ELECTRICITY MARKETS

BY

KAI EMERSON VAN HORN

THESIS

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Adviser:

Professor George Gross

ABSTRACT

Electricity is the prototypical just-in-time product due to the limited means to economically store it on a large-scale basis. As such, electricity must be consumed as soon as it is produced. In areas of the U.S. grid with competitive electricity markets, independent system operators (*ISO*s) run day-ahead electricity markets (*DAM*s) to determine which resources will meet the demand and ensure adequate capacity is committed so that the supply-demand balance can be met around the clock. System operators have met the demand by controlling the output of the supply-side resources, namely generators, since there is a limited amount of grid-scale energy storage (*ES*) in operation today and little participation from the demand-side in meeting the supply-demand balance. The reliance on supply-side resources to maintain the supply-demand balance results, at times, in high prices, marked price volatility, and even price spikes. These price issues, along with advances in storage and communication technology, have reinvigorated the drive of policymakers, system planners and operators, private investors and other electricity grid stakeholders to expand the utilization of *ES* and demand response (*DR*) resources to reliably and effectively meet the supply-demand balance.

ES and *DR* resources provide the *ISO* with additional degrees of freedom in meeting the supply-demand balance by enabling electricity to be stored and shifted from peak load hours to lower load hours, which may decrease the operational costs and improve system reliability.

We know of no work which has studied the economic impacts of integrated *DR* and *ES* resources in depth. Consequently, there is a limited understanding among electricity grid stakeholders of the economic impacts of deepening *ES* and *DR* resource penetrations on the *DAM*s. To develop operational and planning strategies which are effective and policies which incentivize appropriate penetrations of *ES* and *DR* resources, grid stakeholders need to understand these impacts.

In this work, we provide a comparative economic assessment of the impacts of *DR* and *ES* resources participating in the *DAM*s. In order to perform the assessment, we construct a flexible simulation approach which represents the salient aspects of the *DAM*s and the current regulatory environment. The engine of our approach is the extended transmission-constrained market clearing problem (*EMCP*). In the *EMCP* framework, we explicitly account for *ES* and *DR* resources and the transmission-constrained network. Furthermore, we represent *DR* resources (*DRR*s) as a special case of *ES* resources (*ESR*s), which allows for the comparison of *ES* and *DR* resources on equal footing. Our approach also allows the assessment of the impacts of *DRR* recovery energy—an important, and often ignored, component of economic impacts of *DRR*s on the *DAM*s. This flexible approach provides stakeholders the means to develop a deeper understanding of the economic impacts of integrated *ES* and *DR* resources participating in the *DAM*s.

We apply the simulation approach to perform the comparative economic assessment of the impacts of deepening capacity penetrations of *ES* and *DR* resources with their explicit participation in *DAM*s using data from the *ISO*-New England (*ISO-NE*) and Midwest *ISO* (*MISO*). Through our extensive studies, we have determined the average buyer locational marginal price (*ABLMP*) to be an effective metric for measuring the economic impacts of *DR* and *ES* resources on the *DAM*s. In our studies, we investigate the reductions in average buyer locational marginal price (*ABLMP*) which result from the participation of *ES* and *DR* resources with capacities penetrations in the 0% to 30% of system peak load range.

We find the deployment of *ESR*s has a greater impact on reducing the *ABLMP* than *DRR*s at each penetration investigated, reducing the *ABLMP*s by as much as 9.2% compared to the base case system with no deployed *DR* or *ES* resources. *DRR*s, on the other hand, resulted in *ABLMP* reductions of at most 2.7% compared to the base case due to the additional regulatory constraints in place for *DRRs*. Furthermore, we find that *DRR*s cause increases in the *ABLMP* at relatively low penetrations when *DRR* energy recovery is taken into account—contrary to the results of other studies which have investigated the economic impacts of *DRR*s in the market environment. Additionally, we find that systems which experience a greater difference between the average peak and off-peak locational marginal prices (*LMP*s) and/or a higher ratio of average peak to off-peak loads accommodate deeper penetrations of *ES* and *DR* resources before the *ABLMP* reductions are saturated with respect to *ES* and/or *DR* resources—the sensitivity of the *ABLMP* reductions compared to the base case to an additional MW of *ES* and *DR* resource capacity becomes zero or negative. We find that the economic impacts of *DRR*s on the *ABLMP*s saturate at 2%–6% penetration while those of *ESR*s saturate at 9%–20% penetration of the system peak load.

The results of such studies provide useful information for planning, the development of operational procedures, the formulation of effective policy and other electricity grid stakeholder decision making processes. Moreover, the flexible market simulation approach developed in this work provides electricity grid stakeholders a means to perform a number of "what if" studies to analyze the economic impacts of the various aspects of *ES* and *DR* resources on the *DAM*s.

To my parents, for teaching me to believe in myself and to never cease to question.

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CHAPTER 1

INTRODUCTION

In this chapter, we set the stage for the work presented in this thesis. In this work, we provide a comparative economic assessment of the impacts of demand response (DR) and energy storage (ES) resources participating in the day-ahead electricity markets (DAMs). In order to perform the assessment, we construct a flexible market simulation approach which explicitly represents both ES and DR resources and the transmission-constrained network and takes into account the current regulatory environment.

Our flexible simulation approach represents the salient aspects of the DAMs and the current regulatory environment. The engine of our approach is the extended transmission-constrained market clearing problem ($EMCP$). In the $EMCP$ framework, we explicitly account for ES and DR resources and the transmission-constrained network. Furthermore, we represent DR resources (DRRs) as a special case of ES resources (ESRs), which allows for the comparison of ES and DR resources on equal footing. Our approach also allows the assessment of the impacts of DRR recovery energy—an important, and often ignored, component of economic impacts of DRRs on the DAMs. This flexible approach provides stakeholders a means to develop a deeper understanding of the economic impacts of integrated ES and DR resources participating in the DAMs.

We apply the simulation approach to perform the comparative economic assessment of the impacts of deepening capacity penetrations of ES and DR resources with their explicit participation in DAMs using data from the ISO-New England (ISO-NE) and the $MISO$. Through our extensive studies, we have determined the average buyer locational marginal price ($ABLMP$) to be an effective metric for measuring the economic impacts of DR and ES resources on the DAMs. In our studies, we investigate the reductions in average buyer locational marginal price ($ABLMP$) which result from the participation of ES and DR

resources with capacities penetrations in the 0% to 30% of system peak load range.

We find the deployment of *ESR*s has a greater impact on reducing the *ABLMP* than *DRR*s at each penetration investigated, reducing the *ABLMP*s by as much as 9.2% compared to the base case system with no deployed *DR* or *ES* resources. *DRR*s, on the other hand, resulted in *ABLMP* reductions of at most 2.7% compared to the base case due to the additional regulatory constraints in place for *DRRs*. Furthermore, we find that *DRR*s cause increases in the *ABLMP* at relatively low penetrations when *DRR* energy recovery is taken into account—contrary to the results of other studies which have investigated the economic impacts of *DRR*s in the market environment. Additionally, we find that systems which experience a greater difference between the average peak and off-peak locational marginal prices (*LMP*s) and/or a higher ratio of average peak to off-peak loads accommodate deeper penetrations of *ES* and *DR* resources before the *ABLMP* reductions are saturated with respect to *ES* and/or *DR* resources—the sensitivity of the *ABLMP* reductions compared to the base case to an additional MW of *ES* and *DR* resource capacity becomes zero or negative. We find that the economic impacts of *DRR*s on the *ABLMP*s saturate at 2%–6% penetration while those of *ESR*s saturate at 9%–20% penetration.

The results of such studies provide useful information for planning, the development of operational procedures, the formulation of effective policy and other electricity grid stakeholder decision making processes. Furthermore, the flexible market simulation approach developed in this work provides electricity grid stakeholders a means to perform a number of "what if" studies to analyze the economic impacts of the various aspects of *ES* and *DR* resources on the *DAM*s.

We begin this chapter by providing some necessary background on *DR* and *ES* resources and motivating our interest in the subject. We continue with a description of the state-of-the-art of research in *DR* and *ES* resource economic impacts. We then describe the nature and scope of our contributions. We end this chapter with an outline of the remaining chapters in the thesis.

1.1 Background and Motivation

Electricity is the prototypical just-in-time product due to the limited means to economically store it on a large-scale basis. As such, electricity must be consumed as soon as it is produced. In areas of the U.S. grid with competitive electricity markets, independent system operators (*ISO*s) run *DAM*s to determine which resources will meet the cleared demand and ensure adequate capacity is committed so that the supply-demand balance can be met around the clock. There is a limited amount of grid-scale *ES* in operation today. Furthermore, there is little participation from the demand-side in meeting the supply-demand balance. As a result, system operators have met the demand by controlling the output of the supply-side resources, namely generators. The reliance on supply-side resources to maintain the supply-demand balance results, at times, in high prices, marked price volatility, and even price spikes. These price issues, along with advances in storage and communication technology, have reinvigorated the drive of policymakers, system planners and operators, private investors and other electricity grid stakeholders to expand the utilization of *ES* and demand response (*DR*) resources to reliably and effectively meet the supply-demand balance.

*DRR*s and *ESR*s provide the system operator with additional degrees of freedom to meet the supply-demand balance, which may decrease the operational cost, relieve peak-hour congestion and increase system reliability. *DRR*s are consumers of electricity who provide reductions in the consumption of electric energy from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy at specified times. *ESR*s are devices that have the capability to store electric energy, acting as a load, and discharge the energy in the future, acting as a generator. *ESR*s may have the capability to store energy for discharge over periods of hour or days, as in the case of compressed air or pumped hydro storage, or for a matter of seconds or minutes, as in the case of flywheels or super capacitors. Our focus is on former and not the latter.

In the restructured electricity system, *DR* and *ES* resources participate in the *ISO*-run *DAM*s. With participation in the electricity market from *DR* and *ES* resources, the *ISO* has the ability to shape the load through demand reductions or the transfer of demand from peak to off-peak hours or days. The system benefits of the appropriate use of *ES* and *DR* resources for load shaping may lead to:

- attenuated *DAM* price volatility;
- increased reliability via increased reserve margins and resource flexibility;
- delayed need for investment in new transmission and generation due to a reduced system peak load met by the supply-side; and
- mitigated impacts of the intermittency and variability from renewable resource generation [1], [2].

In this work we focus on the economic impacts of *ES* and *DR* resources on the *DAM*s.

In the *ISO*-run *DAM*s, supply-side resources (sellers) offer the quantities of energy they are willing to provide and the prices at which they are willing to provide them and demand-side resources (buyers) bid to buy electricity in amounts to meet their loads and at prices commensurate with their willingness to pay.[1] The *ISO* constructs an offer curve by sorting the supply-side resource offers in a non-descending order of price. Similarly, the *ISO* constructs a demand curve by sorting the demand bids in a non-ascending order of price. In a transmission-unconstrained system, the point of intersection of the offer and demand curves is the market clearing point with a single system-wide marginal price. When the system is transmission-constrained, the markets are cleared on a nodal basis resulting in node-dependent locational marginal prices (*LMP*s).

Figure 1.1 depicts the average hourly July *DAM* offer curve from the *ISO* of New England (*ISO-NE*) system with three load levels. When the offer curve has small slope, such as point A in the Fig. 1.1, small changes in the supply result in small changes in the price. Consequently, the price increases very little with increases in the load. When the slope of the offer curve is bigger, such as point B in Fig. 1.1, small increases in the supply have a greater impact on the price. Consequently, increases in the load cause greater increases

[1] Most of the demand bid into the *DAM*s is bid by energy service providers (*ESP*s) which have an obligation to serve the loads of their customers. As such, the *ESP*'s willingness to pay in the *DAM*s is very high and we consider their demand fixed.

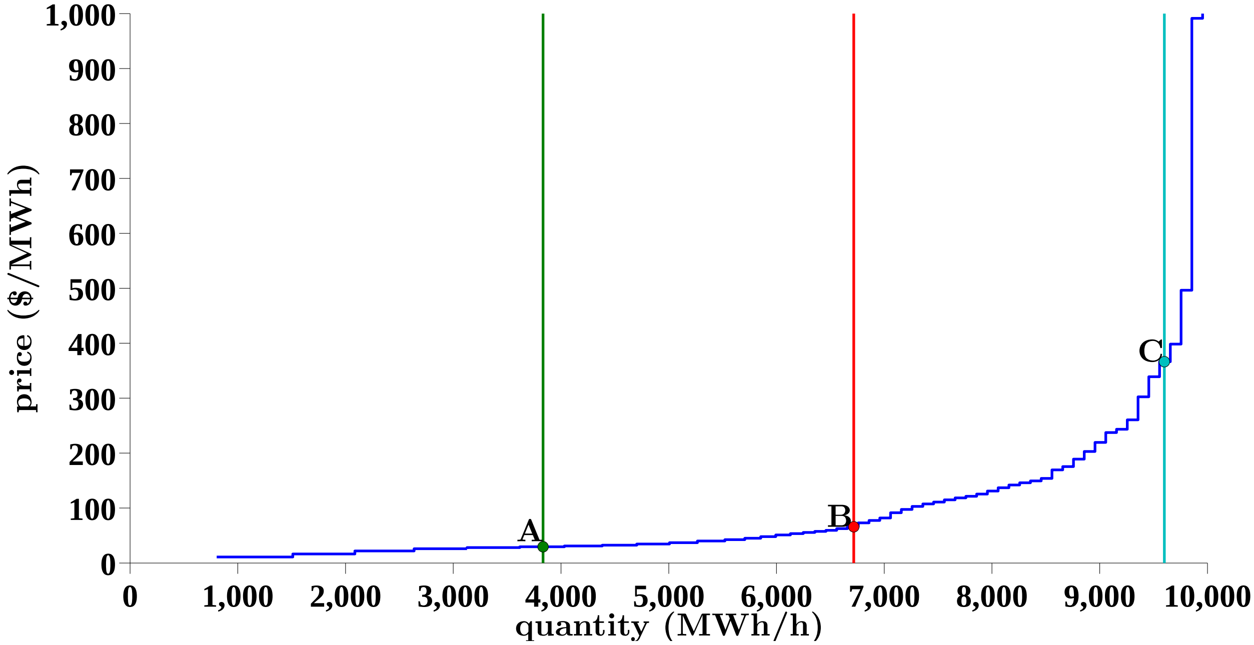

Figure 1.1: An *ISO-NE* offer curve for July 2010 with three load levels

in the price. When the slope of the offer curve is even greater, such as point C in Fig. 1.1, small changes in the supply can have a significant impact on the price and therefore, small increases (decreases) in the load cause significant increases (decreases) in the prices. The evident "hockey stick" shape of the curve is characteristic of the offer curves in many electricity markets. Figure 1.2 depicts the hourly loads and hourly *LMP*s for an of *ISO-NE* load zone for the week of July 12–18, 2010. It is clear from Fig. 1.2 that the load in the *ISO-NE* system is periodic; it is high in the peak, afternoon, hours and low in the off-peak, night, hours. It is also evident that the prices are positively correlated with the loads; as the loads in Fig. 1.2 increase we see subsequent increases in the *LMP*s in Fig. 1.2. The load increases shift the market clearing point in the direction from point B to point C on the offer curve in Fig. 1.1. In the absence of demand-side approaches to meeting the supply-demand balance, the system operator must rely solely on supply-side resources. We also see that the percent increase in price is greater than that of the increase in loads due to the lower elasticity of supply resulting in much higher prices in high load hours of Fig. 1.2. In this *ISO-NE* load zone, the peak load hour prices are as much as four times the off-peak load hour prices.

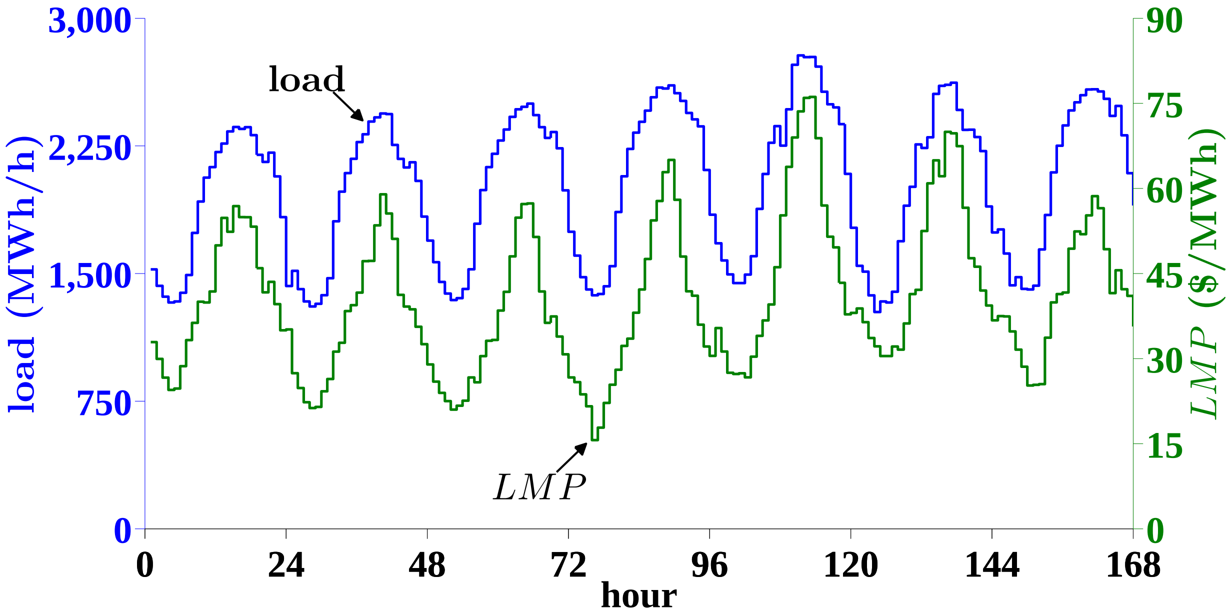

Figure 1.2: The hourly loads and the hourly *LMP*s for a load zone in *ISO-NE* for the week of July 12–18, 2010

*ESR*s (*DRR*s) provide discharges (curtailments) which impact the market outcomes by displacing (reducing the need for) higher-priced generators in peak load hours, shifting the market clearing point down the offer curve and resulting in reduced peak prices. The energy discharged (curtailed) is then charged (recovered) in off-peak load hours, shifting the market clearing point up the offer curve in those hours and resulting in increased off-peak prices. However, since the slope of the offer curve in the off-peak hours is, in general, less than that of the offer curve in the peak hours, the off-peak price increases are less than the peak price decreases.

The *DOE*, seeking to accelerate the pace of utility-scale *ESR* adoption, has funded over a dozen *ESR* pilot projects with $158 million in funding from the American Recovery and Reinvestment Act (*ARRA*) which has been matched by $585 million from industry [3]. One example is Southern California Edison who, in a partnership with A123 Systems and with *DOE* funding, will test an 8 MW 32 MWh phosphorus lithium-ion battery storage facility located near a number of wind farms in the Tehachapi Mountains beginning in late 2012. The tests will include the use of *ESR*s to shift demand from peak to off-peak as well as explore other services *ESR*s may provide to the grid [4]. In another example, the Northern

California utility Pacific Gas and Electric was awarded $50 million in *ARRA* funding to explore the installation of a 300 MW, 10 hr, compressed air energy storage facility which is intended to support the integration of wind resources in the Tehachapi Mountains. The technologies tested in these pilot projects represent the next generation of utility-scale *ESR*s and will demonstrate the utilization of *ESR*s to shift demand across the hours of the day. Pike research estimated new *ESR* deployment to be 121 MW in 2011 and forecasts new deployment to grow to 2353 MW by 2021 [3]. The pace of *ESR* installation is increasing and it will have a greater role in maintaining a secure and cost-effective grid into the future. The recent push for pilot projects has been accompanied by a number of policy initiatives designed to promote greater use of *ES* and *DR* resources, such as the Energy Policy Act of 2005 (*EPAct*) and *FERC* Order Nos. 719 and 745.

The major regulatory push for the greater integration of *DR* and *ES* resources into electricity markets came with the *EPAct*. *EPAct* required the *DOE* to identify and quantify the benefits of *ES* and *DR* resources and make recommendations for achieving them and authorized $2 billion in loan guarantees for innovative energy technologies [1]. A resulting *DRR*-related report describes several studies which quantify the benefits of *DRR*s and makes a number of general recommendations for achieving deeper penetrations of demand-side participation including integrating demand response into resource planning, and improving incentive-based demand response programs [5]. *EPAct* and this initial report provided the basis and impetus for further regulatory action on *DRR*s.

The *ISO*-run markets are overseen by the Federal Energy Regulatory Commission (*FERC*). *FERC* regulates the electricity and ancillary service markets to ensure they remain competitive and that all players are treated in a just and not unduly discriminatory manner. *DRR*s have been the subject of two *FERC* orders since EPAct [6], [7]. *FERC* Order No. 745 on the wholesale energy market compensation of *DRR*s encourages direct competition between *DRR*s and supply-side resources in wholesale energy markets. The order lays out the following two requirements:

1. *ISO*s must develop a "Net Benefits Test" to determine on a monthly basis, using historical supplier offer data, the generation mix and fuel prices, a "threshold price";

and

2. If the LMP exceeds the threshold price at a given node in a market interval, i.e., an hour, all cleared DRRs at the node in that interval must be compensated at the LMP. The costs of these DRR curtailments are to be allocated to those loads which experience a reduced LMP as a result of the DRR curtailments.

The Net Benefits Test is designed to determine the minimum price where the benefits of a DRR curtailment, in the form of reduced prices faced by the remaining loads, exceed the costs, in the form of distributing the incentive payments made by the remaining loads to compensate DRRs for their curtailments. To determine the price at which DRRs become a cost-effective alternative to supply-side resources, the Net Benefits Test uses a system-wide threshold price calculated from the ISO supply curve. The implementation of the specific Net Benefits Test is left of up the individual ISO, though all have developed some variation of regression of historical supply offers to determine the point on a monthly aggregate supply curve at which the elasticity of supply is equal to one—the point at which a 1% change in price causes a corresponding 1% change in quantity and thus the incremental benefits of DRR curtailment are exactly equal to costs.

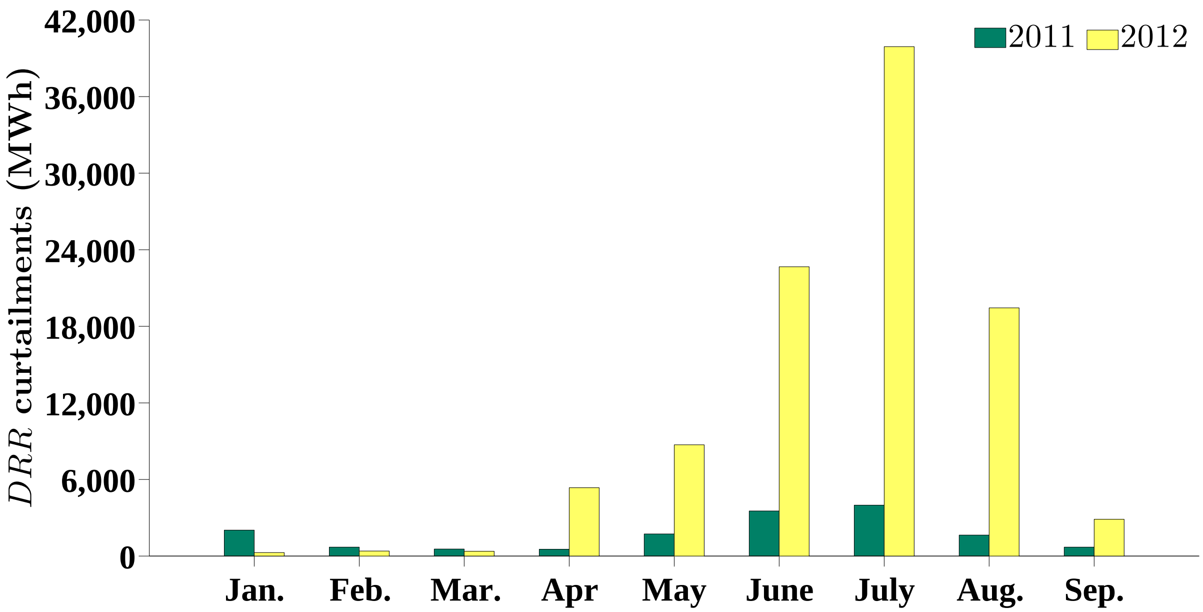

Figure 1.3: DRR curtailments in the PJM for January–September of 2011 and 2012

The *FERC* estimates a potential peak load reduction from *DRR*s operating in organized markets increased 16% from 2009 to 2010 to 31,700 MW. Furthermore, *FERC* Order No. 745 will likely have a profound effect on participation of *DRR*s in wholesale energy markets, accelerating the current pace of *DRR* entrance. In many cases, the level of compensation *DRR*s receive under the new rule, the *LMP*, will increase over current compensation levels, providing additional incentives for *DRR* participation. Figure 1.3 shows the total monthly *DRR* curtailments in the Pennsylvania, New Jersey, Maryland Interconnection (*PJM*)—the first system operator to implement the threshold price requirement of *FERC* Order No. 745—for the first nine months of 2011 and 2012. Clearly, the implementation of the threshold price requirement of the Order in the first months of 2012 had a significant impact on the participation of *DRR*s compared to the same period in 2011 [8]. The impacts of the *FERC* Order No. 745 on *DRR* participation are significant and so it is imperative that methods for simulating the impacts of *DRR*s take the current regulatory environment into account.

In the past five years, curtailment service providers (*CSP*s) have emerged as third party aggregators of smaller loads into quantities large enough to be offered as *DRR*s in wholesale markets. Similar entities will likely emerge for *ESR*s, as the U.S. vehicle fleet moves towards partially and fully electric vehicles, in order to harness the value of tens of thousands of electric vehicle batteries for providing grid services. *CSP*s have significantly widened the field of potential *DRR*s and have emerged as a major provider of *DRR*s in wholesale energy markets [9] and *ESR* aggregators have the potential to do the same for *ESR*s. As the pool of potential *DR* and *ES* resources grows, the need for tools to understand the economic impacts of the deepening *DR* and *ES* resources penetrations also becomes greater.

1.2 Conceptual Aspects of *DR* and *ES* Resources

Physically, *ES* and *DR* resources may be viewed in many ways as substitutable resources—both enable the *ISO* to shift load from peak to off-peak hours by providing a means of storing energy. *ESR*s store energy directly, whether it be in a water reservoir for pumped hydro or a chemical battery, and must charge at least every MWh they discharge and even more when the efficiency of the unit is less than one. *DRR*s, on the other hand, provide energy storage by deferring or eliminating the use of energy and need not recover every MWh curtailed. The amount of energy recovered depends on the process being curtailed or the preferences of the customer providing the curtailment. In fact, *DRR*s may sometimes provide reductions by utilizing on-site generators. If on-site generators provide for the *DRR* curtailment the energy recovery may even reach zero, since no actual demand curtailment has occurred.

The main difference between *ES* and *DR* resources is the flexibility they offer to the *ISO*. *ESR*s are simply treated as a generator when discharging (as a load when charging) and are paid (pay) the *LMP*. If utilized as a system resource, *ESR*s are dispatched by the *ISO* to have the greatest impact on the *ISO*'s objective—typically the maximization of the social surplus. However, while load recovery for *DRR* curtailments is still simply treated as additional demand paid for at the *LMP*, compensation paid to *DRR*s for curtailments since the issuance of *FERC* Order No. 745 is dictated by the threshold price condition. Therefore, when utilized as a system resource, *DRR*s are also dispatched by the *ISO* to have the greatest impact on the system objective, but their utilization is further constrained by the threshold price condition. As mentioned above, *DRR*s need not recover every MWh of energy curtailed—or may even recover *more* than the total MWh curtailment—which gives *DRR*s an additional level of flexibility which *ESR*s do not have.

While, currently, participation in electricity markets by *DR* and *ES* resources remains low compared to the quantity of supply-side resources, such as generators, the continued growth of *DR* and *ES* resources and strong policy support for the integration of these resources into wholesale electricity markets will likely result in deeper *DR* and *ES* penetrations in the near future. These developments necessitate the creation of tools to assess the economic impacts of *DR* and *ES* resources and studies which provide insights into the economic impacts of deepening penetrations of *DR* and *ES* resources. Furthermore, the substitutability of *DR* and *ES* resources in providing energy storage service to the system motivates a need develop tools to quantify the market impacts of *DR* and *ES* resources and to study which resources are most cost effective at providing energy storage service. Such tools provide electricity grid stakeholders the necessary information to create policy for, and plan and operate, the power system reliably and effectively.

1.3 A Survey of the State of the Art

The utilization of *ES* and *DR* resources in the power system has been the topic of power systems research for the past three decades. A number of papers and reports have outlined conceptually, and to some degree quantified, the economic impacts of *DR* and *ES* resources. In this section, we give an overview of the literature related to the assessment of the economic impacts of *DR* and *ES* resources operating in wholesale electricity markets.

Utilities have a long history of utilizing *ESR*s, in the form of pumped hydro energy storage, and demand-side management (*DSM*)—the predecessor to *DRR*s. In the vertically integrated utility context, *DSM* and *ESR*s were used to improve the efficiency of generation asset operation and reduce operational costs [10]. A number of operational strategies have been proposed over the past two decades for the efficient utilization of *DSM*s and *ESR*s from a cost reduction perspective [11].

In addition, utility planning and operations models have been proposed which take DSM and *ESR*s into account [12]. There is a large body of work on optimization models for utility planning, some of which have considered *DSM* and various forms of uncertainty [13]. Huang et al. develop a model for *DSM* which considers seven load sectors and applies reductions sector by sector to assess the impacts of demand reductions on the basis of each sector on generator adequacy over longer-term periods in [14]. These works consider the utilization of *DSM* and *ES* from the utility perspective and do not consider operations in the increasingly prevalent market environment.

With the onset of electricity industry restructuring, which unbundled generation, transmission, and retail electricity sales, and the introduction of organized wholesale electricity markets, the roles of *ESR*s and the demand-side as resources for meeting the supply-demand balance have changed. Until recently, DSM and *ESR*s were treated much as they were under vertically integrated utilities. However, high prices, price volatility, supply-side market power concerns and a glut of investment in new generation and transmission assets have driven electricity grid stakeholders to again look towards the demand-side and *ESR*s to economically meet the supply-demand balance and maintain system reliability. A high-level framework for assessing the economic value of utilizing *ERS*s integration into electricity markets and estimates of the market potential of various applications of utility-scale *ESR*s is given in [2].

A number of works have explored the economic impacts *ESR*s in electricity markets [15], [16], [17], [18]. Sioshansi et al. quantify the economic impacts of *ESR* capacity, capability, and efficiency in backcast studies for the *PJM* for the years 2002–2007 [16]. They explore the impacts of price-taker *ESR*s—those which do not impact the market clearing price—and, to a more limited extent, the impacts of larger-scale *ESR*s. Lamont proposes a framework to determine the optimal *ESR* capacity in [15]. Figueiredo et al. evaluate the economics of *ESR*s in fourteen electricity markets for use in load shifting and exploitation of inter-temporal arbitrage opportunities in [18]. These works, however, do not account for the transmission-constrained network and do not evaluate the impacts of *ESR* penetrations deeper than around one percent of the system peak load.

DSM has been replaced by incentive-based *DRR*s and dynamic pricing in the market environment. The benefits of utilizing *DRR*s to meet the supply-demand balance and enhance the economic efficiency and reliability by increasing the effective elasticity of demand have long been recognized [19]. Cappers et al. summarize the existing contribution of *DRR*s in the U.S. electricity markets with a primary focus on enrollment and performance of incentive-based *DR* programs in organized markets in [20]. Many economists favor exposing retail consumers of electricity to wholesale prices under dynamic pricing schemes rather than incentive-based *DR* programs to improve the efficiency of electricity markets. A case study using a California utility found a potential peak reduction of 1% to 9% may be achieved under such pricing schemes [21]. Another study calculates a 5% reduction in national peak demand can yield operational cost savings of $3 billion/year, but does not take into account the impacts of curtailed energy recovery [22].

The benefits of dynamic pricing and demand-side participation were clearly laid out in the 1980s [23]. More recently, Spees et al. discussed empirical results which show the responsiveness of electricity consumers to price and demonstrate the significant potential of demand-side reductions to assist in meeting the supply-demand balance in [24]. In recent years there has been a focus among energy service providers and regulators on incentive based *DR* programs. Bushnell et al. discuss the potential pitfalls of incentive based *DR* programs and highlight the benefits of dynamic pricing in [25]. Despite widespread agreement about the greater economic efficiency of dynamic pricing over incentive-based *DRR*s, political hurdles and lack of experience with dynamic pricing have led to a continued focus on incentive-based *DRR*s.

DR and *ES* resources now fill the role of either a system resource or a merchant resource. In either role, these resources offer reliability and economic benefits. However, the objective of their operations has shifted from cost minimization to the maximization of social surplus, when operated as a system resource, or the maximization of profit, when operated as a merchant resource.

There is also a long history of work on integrating demand-side resources into the market clearing in economic dispatch and unit commitment frameworks [26], [27]. More recently, models which consider both energy and ancillary services and explicitly consider *DRR* curtailment recovery energy have been proposed [28]. These works outline market clearing mechanisms which explicitly account for *DRR*s.

Many existing as well as a number of newly built *ESR* facilities are operated by private entities offering in *ISO*-run energy and ancillary service markets. Several works have focused on strategies for merchant resources seeking to maximize profits in the wholesale market [29]. Researchers from the Pacific Northwest National Laboratory developed a method to generate optimal bid schedules for a hybrid *ESR* systems (those systems which include a fast-response component, such as a flywheel or battery, and a slow response component, such as a pumped-hydro) participating in both energy and regulation service markets in [30]. Much of the work in this area does not consider the transmission network or interactions with *DRR*s.

Until now there has been little work which discusses the conceptual and physical similarities of *DR* and *ES* resources. We have not seen any work which represents *DRR*s as a special case of *ESR*s in a comprehensive deterministic approach capable of quantifying the economic impacts of *ES* and *DR* resources. Moreover, few studies have assessed in depth the economic impacts of *DR* and *ES* resources on a transmission-constrained system. To our knowledge, no studies have been published which compare the economic impacts of *DR* and *ES* resources on the *DAM*s in a transmission-constrained system.

1.4 The Scope and Nature of the Contributions of the Thesis

In this work, we provide a comparative economic assessment of the impacts of *DR* and *ES* resources participating in the *DAM*s. In order to perform the assessment, we construct a flexible market simulation approach which explicitly represents both *ES* and *DR* resources and the transmission-constrained network and takes into account the current regulatory environment.

In our studies, we consider multiple *ISO*-controlled *DR* and *ES* resources scheduled as a system resources for inter-temporal energy arbitrage in the *DAM*s. Our studies are backcasts and assume perfect knowledge of the loads. The *ESR* scheduling period is multi-day to capture the periodic nature of the load shape. We also consider the requirements of the recent *FERC* Order No. 745 on *DRR* scheduling. We consider all generators to be self-committed and the demand in each hour to be inelastic.

This work makes several contributions to the state-of-the-art. Our flexible simulation approach represents the salient aspects of the *DAM*s and the current regulatory environment. The engine of our approach is the *EMCP*. In the *EMCP* framework, we explicitly account for *ES* and *DR* resources and the transmission-constrained network. Furthermore, we represent *DRR*s as a special case of *ESR*s, which allows for the comparison of *ES* and *DR* resources on equal footing. Our approach also allows the assessment of the impacts of *DRR* recovery energy—an important, and often ignored, component of economic impacts of *DRR*s on the *DAM*s. This flexible approach provides stakeholders a means to develop a deeper understanding of the economic impacts of integrated *ES* and *DR* resources participating in the *DAM*s.

We apply the simulation approach to perform the comparative economic assessment of the impacts of deepening capacity penetrations of *ES* and *DR* resources with their explicit participation in *DAM*s using data from the *ISO-NE* and *MISO*. In our studies, we investigate the reductions in *ABLMP* which result from the participation of *ES* and *DR* resources with capacities penetrations in the 0% to 30% of system peak load range. We quantify the range of benefits and limitations of integrated *DR* and *ES* resources with case studies on modified *IEEE* 57- and 118-bus test systems (MTS_{57} and MTS_{118}, respectively). We summarize our key insights as follows:

- *ABLMP*s reductions are the highest on the MTS_{57} for *DR* and *ES* resource penetrations of 2% and 9%, respectively;
- *ABLMP*s reductions are the highest on the MTS_{118} for *DR* and *ES* resource penetrations of 6% and 20%, respectively;
- the shape of the offer curve is an important factor determining the price impacts of *DR* and *ES* resources: systems with a lower ratio of the elasticity of supply in the curtailment/discharge periods to the elasticity of supply in the recover/charge periods can accommodate deeper penetrations of *DR* and *ES* resources;
- the load shape is an important factor determining the price impacts of *DR* and *ES* resources: systems with a higher ratio of load in peak periods to load in off-peak periods can accommodate deeper penetrations of *DR* and *ES* resources; and
- the requirements of *FERC* Order No. 745, which limit the number of degrees of freedom *ISO*s have in controlling *DRR*s by prescribing a system-wide curtailment threshold price, are a principal factor in the reduced price effectiveness of *DR* as compared to *ES* resources.

The flexible market simulation approach developed in this work provides electricity grid stakeholders a means to perform a number of "what if" studies to analyze the economic impacts of the various aspects of *ES* and *DR* resources on the *DAM*s. The results of such studies provide useful information for planning, the development of operational procedures, the formulation of effective policy to incentivize appropriate penetrations of *ES* and *DR* resources and other electricity grid stakeholder decision making processes.

1.5 Outline of the Thesis

This thesis consists of four additional chapters and three appendices. In Chapter 2 we develop models for *ESR*s and *DRR*s as a special case of *ESR*s. We then develop the *EMCP* which includes *ES* and *DR* resources and takes explicit account of the transmission-constrained network.

In Chapter 3 we give an in-depth description of the flexible simulation approach which is the basis of our *DR* and *ES* resource *DAM* economic impact comparative analysis. We then describe implementation of the *EMCP* in the market simulation and the multi-day *ESR* scheduling and *DRR* curtailment scheduling processes and discuss worthwhile applications for the simulation approach.

In Chapter 4 we present representative results from the extensive studies we have carried out on numerous systems using real *MISO* and *ISO-NE* data to perform the comparative assessment of *DR* and *ES* resources. We find the deployment of *ESR*s has a greater impact on reducing the *ABLMP* than *DRR*s at each penetration investigated, reducing the *ABLMP*s by as much as 10% compared to the base case system with no deployed *DR* or *ES* resources. *DRR*s, on the other hand, resulted in *ABLMP* reductions of at most 3% compared to the base case due to the additional regulatory constraints in place for *DRRs*.

In Chapter 5 we summarize the main results of the thesis and point out directions for future research. Appendix A provides a summary of notation used in the formulation of the *TCMCP*. Appendix B contains the test-system data used in the case studies in Chapter 4. In Appendix C we report the *ABLMP* reductions for all the sensitivity cases on the test systems discussed in Chapter 4.

CHAPTER 2

THE INCORPORATION OF *ES* AND *DR* RESOURCES IN THE TRANSMISSION-CONSTRAINED MARKET ENVIRONMENT

In this chapter we give an overview of our model for *ESR*s and apply the rationale from our discussion of the conceptually and physical similarities between *ES* and *DR* resources to represent *DRR*s as a special case of *ESR*s in the *ESR* model. We continue with a description of the extensions to the *MCP* we make in order to incorporate *ES* and *DR* resources into what we term the extended *MCP* (*EMCP*). We close by stating the *EMCP* and providing some insights gained from the structure of the framework.

2.1 *ES* and *DR* Resource Models

In this section we develop the *ESR*s model to represent the salient aspects of *ESR*s in the transmission-constrained market environment. We then describe how the *ESR* model can be applied to represent *DRR*s as a special case of *ESR*s.

We consider a set of U storage units $\mathscr{U} = \{u_1, u_2, \ldots, u_U\}$. Each unit u is fully specified by the upper and lower bounds on its charge and discharge capacity, in MW, the upper and lower bounds on its charge capability, in MWh, and its charge and discharge efficiencies. We use the notation $[\cdot]$ after a variable to represent the discrete nature of the hourly *DAM* quantities and define a set of H hours $\mathscr{H} = \{h_1, h_2, \ldots, h_H\}$. For a storage unit u, let $p^u[h]$ be the storage capacity (charge or discharge) at an hour h and let $p^u[h] > 0$ when discharging and $p^u[h] < 0$ when charging. For clarity in formulating the problem we define

$$c^u[h] = \begin{cases} -p^u[h] & \text{if } p^u[h] < 0 \\ 0 & \text{otherwise} \end{cases}$$

$$d^u[h] = \begin{cases} p^u[h] & \text{if } p^u[h] > 0 \\ 0 & \text{otherwise} \end{cases}$$

We denote for an hour h the charge capacity upper and lower bounds by $c^u_M[h]$ and $c^u_m[h]$, respectively, the discharge capacity upper and lower bounds by $d^u_M[h]$ and $d^u_m[h]$, respectively, the upper and lower bounds on charge capability by $y^u_M[h]$ and $y^u_m[h]$ and the charge and discharge efficiency to be η^u_c and η^u_d, respectively. We define $\eta^u_r = \eta^u_c \eta^u_d$ to be the *ESR* round trip efficiency. The *ESR* capacity constraints are

$$c^u_m[h] \leq c^u[h] \leq c^u_M[h] \tag{2.1}$$

$$d^u_m[h] \leq d^u[h] \leq d^u_M[h] \tag{2.2}$$

The stored energy in an *ESR* unit u at the beginning of an hour h is given by

$$y^u[h] = y^u[h_0] + \sum_{i=h_1}^{h-1} \left(\eta^u_d c^u[i] - \frac{d^u[i]}{\eta^u_d} \right)$$

where $y^u[h_0]$ is the initial stored energy. The stored energy constraints are

$$y^u_m[h] \leq y^u[h] \leq y^u_M[h] \tag{2.3}$$

The stored energy constraints are key. These so called "coupling constraints" couple the hours of the *DAM*s. To integrate an additional degree of freedom for *ESR* control, we introduce a constraint which governs the energy required to be in the storage reservoir in hour h_H

$$\sum_{h \in \mathscr{H}} \left(\eta^u_d c^u[i] - \frac{\alpha^u_k d^u[i]}{\eta^u_d} \right) = 0 \tag{2.4}$$

where α^u_k is the proportion of discharged energy which must be charged in unit u by hour h_H of a day k.

We represent *DRR*s with the *ESR* model by replacing u with $\tilde{b}$ and considering *DRR* curtailment the analogue of *ESR* discharge and *DRR* recovery the analogue of *ESR* charge. In line with Kowli in [31], we segment the set of buyers $\mathscr{B}$ into two non-overlapping subsets to delineate the set of *DRR*s.

We denote the subset of buyers operating as pure buyers as $\bar{\mathscr{B}}$ and the subset of buyers capable of providing *DR* by $\tilde{\mathscr{B}}$ such that $\mathscr{B} = \tilde{\mathscr{B}} \cup \bar{\mathscr{B}}$ and $\tilde{\mathscr{B}} \cap \bar{\mathscr{B}} = \emptyset$. Furthermore, we denote, in an hour h, $p^{\bar{b}}[h]$ to be the load of a pure buyer $\bar{b}$, $p^{\tilde{b}}[h]$ to be the load of a *DRR* capable buyer $\tilde{b}$ and $\tilde{p}^{\tilde{b}}[h]$ the curtailment or recovered energy of *DRR* capable buyer $\tilde{b}$, analogous to $p^u[h]$ for an *ESR*, such that $p^{\tilde{b}}[h] \geq \tilde{p}^{\tilde{b}}[h]$. We define the set $\mathscr{E} = \mathscr{U} \cup \tilde{\mathscr{B}}$ indexed by e, to make the statement of the *EMCP* more compact.

In this section we have developed a model to represent *ESR*s and we showed how we may represent *DRR*s with the *ESR* model as a special case of *ESR*s. In Section 2.2 we incorporate the *ES* and *DR* resource models in into the *MCP* to develop the *EMCP*.

2.2 The Incorporation of *ES* and *DR* Resources in the *MCP*

In this section we describe the incorporation in of the *ES* and *DR* resource models into the transmission constrained market framework. Our development of the market simulation framework is based on two main assumptions:

A1. The network is lossless.

A2. The DC power flow assumptions hold.

Assumption A1 is reasonable in dense networks without long transmission lines. Assumption A2 is standard for electricity market clearing and market simulation [32].

We consider a power system which consists of a set $(N+1)$ nodes $\mathscr{N} = \{0, 1, \ldots, N\}$, with the slack bus at node 0, and the set of L lines $\mathscr{L} = \{\ell_1, \ell_2, \ldots, \ell_L\}$. We denote each line by the ordered pair $\ell = (n, m)$ where n is the *from* node and m is the *to* node with $n, m \in \mathscr{N}$. Real power flow $f_\ell \geq 0$ whenever the flow is from n to m and $f_\ell < 0$ otherwise. We consider the system to be lossless and each node to be connected to at least one other node. We denote the diagonal branch susceptance matrix by $\underline{\boldsymbol{B}}_d \in \mathbb{R}^{L \times L}$. Let $\underline{\boldsymbol{A}} \in \mathbb{R}^{L \times N}$ be the reduced node incidence matrix for the subset of nodes $\mathscr{N} \setminus \{0\}$ and $\underline{\boldsymbol{B}} \in \mathbb{R}^{N \times N}$ be the nodal susceptance matrix. We assume the network contains no phase shifting devices and so $\underline{\boldsymbol{B}} = \underline{\boldsymbol{B}}^T$. We denote the slack bus nodal susceptance vector by $\underline{\boldsymbol{b}}_0 = [b_{01}, \ldots, b_{0N}]^T \in \mathbb{R}^N$.

We use this network description to formulate the *MCP* for a set of S sellers $\mathscr{S} = \{s_1, s_2, \ldots, s_S\}$ and a set of B buyers $\mathscr{B} = \{b_1, b_2, \ldots, b_B\}$ over a set of hours $\mathscr{H}$, which we denote by $\bar{\mathcal{M}}(\mathscr{H}, \mathscr{S}, \mathscr{B})$, as described by Liu and Gross in [33].

$$
\begin{array}{lll}
max & \displaystyle\sum_{h\in\mathscr{H}} \left\{ \sum_{b\in\mathscr{B}} \mathcal{B}^b\left(p^b[h]\right) - \sum_{s\in\mathscr{S}} \mathcal{C}^s\left(p^s[h]\right) \right\} & \\
s.t. & \underline{\boldsymbol{p}}^g[h] - \underline{\boldsymbol{p}}^d[h] = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}[h] & \leftrightarrow \underline{\boldsymbol{\lambda}}[h] \\
& p_0^g[h] - p_0^d[h] = \underline{\boldsymbol{b}}_0^T \underline{\boldsymbol{\theta}}[h] & \leftrightarrow \lambda_0[h] \\
& p_m^s[h] \le p^s[h] \le p_M^s[h] & \leftrightarrow \mu_M^s[h],\ \mu_m^s[h] \\
& p_m^b[h] \le p^b[h] \le p_M^b[h] & \leftrightarrow \mu_M^b[h],\ \mu_m^b[h] \\
& \underline{\boldsymbol{f}}^m[h] \le \underline{\boldsymbol{f}}[h] \le \underline{\boldsymbol{f}}^M[h] & \leftrightarrow \underline{\boldsymbol{\xi}}^M[h],\ \underline{\boldsymbol{\xi}}^m[h] \\
& \forall b \in \mathscr{B},\ \forall s \in \mathscr{S},\ \forall h \in \mathscr{H} &
\end{array}
\tag{2.5}
$$

where, for an hour h, $p^s[h]$ is the scheduled output of seller s, in MWh/h, bounded above and below by $p_M^s[h]$ and $p_m^s[h]$, respectively, $p^b[h]$ is the scheduled consumption of buyer b in MWh/h, which is bounded below by $p_m^b[h]$ and above by $p_M^b[h]$, $\mathcal{C}^s(p^s[h])$ is the integral of seller s's marginal offer price as a function of the scheduled output $p^s[h]$, $\mathcal{B}^b(p^b[h])$ is the integral of buyer b's marginal bid price as a function of scheduled consumption $p^b[h]$ and $\underline{\boldsymbol{\theta}}[h]$ is the vector nodal voltage angles. The vector of line flows $\underline{\boldsymbol{f}}[h] = [f_{\ell_1}[h], \ldots, f_{\ell_L}[h]]^T \in \mathbb{R}^L$ is given by

$$\underline{\boldsymbol{f}}[h] = \underline{\boldsymbol{B}}_d \underline{\boldsymbol{A}}\,\underline{\boldsymbol{\theta}}[h]$$

and is bounded above and below by the vectors of line flow limits $\underline{\boldsymbol{f}}^M[h]$ and $\underline{\boldsymbol{f}}^m[h]$, respectively, $p_n^d[h] = \sum_{\substack{b\in\mathscr{B}\, is \\ at\, node\, n}} p^b[h]$ is the sum of the withdrawals at a node n, $p_n^g[h] = \sum_{\substack{s\in\mathscr{S}\, is \\ at\, node\, n}} p^s[h]$ is the sum of the injections at a node n and

$$
\begin{aligned}
\boldsymbol{p}^d[h] &= \left[p_1^d[h], p_2^d[h], \ldots, p_N^d[h]\right]^T \in \mathbb{R}^N \\
\boldsymbol{p}^g[h] &= [p_1^g[h], p_2^g[h], \ldots, p_N^g[h]]^T \in \mathbb{R}^N
\end{aligned}
$$

are the vectors of withdrawals and injections at all nodes $n \in \mathscr{N} \setminus \{0\}$. The variables to the right of the two-headed arrows in Eq. (2.5) are the dual variables of their respective constraints.

To incorporate *ES* and *DR* resources in this framework we define

$$c_n^{\mathscr{E}}[h] = \sum_{\substack{e \in \mathscr{E}\, is \\ at\, node\, n}} c^e[h]$$

$$d_n^{\mathscr{E}}[h] = \sum_{\substack{e \in \mathscr{E}\, is \\ at\, node\, n}} d^e[h]$$

to be the total charge (recovery) and discharge (curtailment) quantities at a node n and

$$\underline{\boldsymbol{c}}^{\mathscr{E}}[h] = \left[c_1^{\mathscr{E}}[h], c_2^{\mathscr{E}}[h], \ldots, c_N^{\mathscr{E}}[h]\right]^T \in \mathbb{R}^N$$

$$\underline{\boldsymbol{d}}^{\mathscr{E}}[h] = \left[d_1^{\mathscr{E}}[h], d_2^{\mathscr{E}}[h], \ldots, d_N^{\mathscr{E}}[h]\right]^T \in \mathbb{R}^N$$

to be the vectors of nodal charge (recovery) and discharge (curtailment). With *ES* and *DR* resources included, the power flow constraints may be restated as

$$\left(\underline{\boldsymbol{p}}^g[h] + \underline{\boldsymbol{d}}^{\mathscr{E}}[h]\right) - \left(\underline{\boldsymbol{p}}^d[h] + \underline{\boldsymbol{c}}^{\mathscr{E}}[h]\right) = \underline{\boldsymbol{B}}\, \underline{\boldsymbol{\theta}}[h]$$

For simplicity and without loss of generality we assume there are no *DR* or *ES* resources at the slack node. We also define

$$\mathscr{D} = \mathscr{S} \cup \bar{\mathscr{B}} \cup \tilde{\mathscr{B}} \cup \mathscr{E}$$

to make the statement of the *EMCP* more compact and make one additional assumption.

A3. The *DR* and *ES* resources are utilized as *system resources*;

Due to this assumption, *DR* and *ES* resources are not represented in the objective function of the *EMCP*. We extend the *MCP* in Eq. (2.5) with the constraints to represent *ES*, and therefore *DR*, resources in Eqs. (2.1–2.4) and the modified power flow constraint in Eq.

(2.2). We denote the *EMCP* by $\mathcal{M}(\mathscr{H}, \mathscr{D})$ and state it as follows:

$$\begin{aligned}
max \quad & \sum_{h\in\mathscr{H}} \left\{ \sum_{\bar{b}\in\bar{\mathscr{B}}} \mathcal{B}^{\bar{b}}\left(p^{\bar{b}}[h]\right) + \sum_{\tilde{b}\in\tilde{\mathscr{B}}} \mathcal{B}^{\tilde{b}}\left(p^{\tilde{b}}[h] - d^{\tilde{b}}[h]\right) - \sum_{s\in\mathscr{S}} \mathcal{C}^{s}\left(p^{s}[h]\right) \right\} && (2.6)\\
s.t. \quad & \left(\underline{\boldsymbol{p}}^{g}[h] + \underline{\boldsymbol{d}}^{\mathscr{E}}[h]\right) - \left(\underline{\boldsymbol{p}}^{d}[h] + \underline{\boldsymbol{c}}^{\mathscr{E}}[h]\right) = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}[h] && \leftrightarrow \underline{\bar{\boldsymbol{\lambda}}}[h]\\
& p_0^{g}[h] - p_0^{d}[h] = \underline{\boldsymbol{b}}_0^{T}\underline{\boldsymbol{\theta}}[h] && \leftrightarrow \bar{\lambda}_0[h]\\
& p_m^{s}[h] \leq p^{s}[h] \leq p_M^{s}[h] && \leftrightarrow \mu_M^{s}[h],\ \mu_m^{s}[h]\\
& p_m^{b}[h] \leq p^{b}[h] \leq p_M^{b}[h] && \leftrightarrow \mu_M^{b}[h],\ \mu_m^{b}[h]\\
& \underline{\boldsymbol{f}}^{m}[h] \leq \underline{\boldsymbol{f}}[h] \leq \underline{\boldsymbol{f}}^{M}[h] && \leftrightarrow \underline{\boldsymbol{\xi}}^{M}[h],\ \underline{\boldsymbol{\xi}}^{m}[h]\\
& c_m^{e}[h] \leq c^{e}[h] \leq c_M^{e}[h] && \leftrightarrow \nu_{m,c}^{e}[h], \nu_{M,c}^{e}[h]\\
& d_m^{e}[h] \leq d^{e}[h] \leq d_M^{e}[h] && \leftrightarrow \nu_{m,d}^{e}[h],\ \nu_{M,d}^{e}[h]\\
& y_m^{e}[h] \leq y^{e}[h_0] + \sum_{i=h_0}^{h-1}\left(\eta_c^{e}c^{e}[i] - \frac{d^{e}[i]}{\eta_d^{e}}\right) \leq y_M^{e}[h] && \leftrightarrow \chi_M^{e}[h],\ \chi_m^{e}[h]\\
& \sum_{h\in\mathscr{H}}\left(\eta_c^{e}c^{e}[h] - \frac{\alpha_k^{e}d^{e}[h]}{\eta_d^{e}}\right) = 0 && \leftrightarrow \phi^{e}\\
& \forall e\in\mathscr{E},\ \forall s\in\mathscr{S},\ \forall h\in\mathscr{H},\ \forall b\in\mathscr{B}
\end{aligned}$$

The optimal solution to $\mathcal{M}(\mathscr{H}, \mathscr{D})$ is, $\forall h \in \mathscr{H}$, the optimal seller outputs $[p^{s}[h]]^{\star}$, $\forall s \in \mathscr{S}$, the optimal pure buyer consumption $\left[p^{\bar{b}}[h]\right]^{\star}$, $\forall \bar{b} \in \bar{\mathscr{B}}$, the optimal *DR*-capable buyer consumption $\left[p^{\tilde{b}}[h]\right]^{\star}$, $\forall \tilde{b} \in \tilde{\mathscr{B}}$, the optimal *DRR* curtailment and recovery schedule $\left[\tilde{p}^{\tilde{b}}[h]\right]^{\star}$, $\forall \tilde{b} \in \tilde{\mathscr{B}}$ and the optimal *ES* resource schedule $[p^{u}[h]]^{\star}$, $\forall u \in \mathscr{U}$. In addition, the optimal dual variables associated with the power flow constraints $[\lambda_n[h]]^{\star}$, $\forall n \in \mathscr{N}$ provide the *LMPs*.

FERC Order No. 745 specifies the incentive payments to *DRR*s for reductions in demand should be allocated proportionally to all entities that purchase from the relevant energy market in area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched [7]. Considering this requirement, we define $\lambda^{r}[h]$ to be the system-wide threshold price for an hour h, $\hat{\lambda}_n[h]$ to be the pre-curtailment *LMP* at a node n and $\hat{\mathscr{N}}[h]$ to be the subset of nodes of $\mathscr{N}$ where $\lambda_n[h] \leq \hat{\lambda}_n[h]$. We may then define the additional charge to buyers at node n for *DRR* curtailments in an hour h

$$\upsilon_n[h] = \begin{cases} \dfrac{\displaystyle\sum_{n\in\mathscr{N}} \left[d_n^{\tilde{\mathscr{B}}}\right]^\star [\lambda_n[h]]^\star}{\displaystyle\sum_{n\in\hat{\mathscr{N}}[h]} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}\right]^\star\right)} & \text{if } n \in \hat{\mathscr{N}}[h] \\ \\ \dfrac{\displaystyle\sum_{n\in\mathscr{N}} \left[d_n^{\tilde{\mathscr{B}}}\right]^\star [\lambda_n[h]]^\star}{\displaystyle\sum_{n\in\mathscr{N}} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}\right]^\star\right)} & \text{if } \hat{\mathscr{N}}[h] = \emptyset \\ \\ 0 & \text{otherwise} \end{cases}$$

If $\hat{\mathcal{N}}[h] = \emptyset$ for an hour h, the costs of *DRR* curtailments are socialized to all loads on a pro-rata basis.

The solution of the *EMCP* may be used to calculate the system metrics such as the seller payments, pure and *DR*-capable buyer payments, the *DRR* payments and the *ESR* payments. For an hour h, the total seller payments are

$$\rho^{\mathscr{S}}[h] = \sum_{n\in\mathscr{N}} [p_n^g[h]]^\star \cdot [\lambda_n[h]]^\star \tag{2.7}$$

The total buyer payments are

$$\rho^{\mathscr{B}}[h] = \sum_{n\in\mathscr{N}} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}[h]\right]^\star\right) \cdot \left([\lambda_n[h]]^\star + \upsilon_n[h]\right) \tag{2.8}$$

The incentive payments to *DRR*s for curtailed energy are

$$\rho_d^{\tilde{\mathscr{B}}}[h] = \sum_{n\in\mathscr{N}} \left[d_n^{\tilde{\mathscr{B}}}[h]\right]^\star \cdot [\lambda_n[h]]^\star \tag{2.9}$$

and the payments by *DRR*s for recovered energy are

$$\rho_c^{\tilde{\mathscr{B}}}[h] = \sum_{n \in \mathscr{N}} \left[c_n^{\tilde{\mathscr{B}}}[h]\right]^\star \cdot [\lambda_n[h]]^\star \tag{2.10}$$

We also define the payments to *ESR*s for discharged energy

$$\rho_d^{\mathscr{U}}[h] = \sum_{n \in \mathscr{N}} \left[d_n^{\mathscr{U}}[h]\right]^\star \cdot [\lambda_n[h]]^\star \tag{2.11}$$

and the payments by *ESR*s for charged energy

$$\rho_c^{\mathscr{U}}[h] = \sum_{n \in \mathscr{N}} \left[c_n^{\mathscr{U}}[h]\right]^\star \cdot \left([\lambda_n[h]]^\star + \upsilon_n[h]\right) \tag{2.12}$$

In this section we described the incorporation of the *ES* and *DR* resource models into the comprehensive *EMCP* framework. In Section 2.3 we highlight the notable aspects of the *EMCP* framework.

2.3 Salient Aspects of the *EMCP* Framework

In this section we discuss the salient aspects of the *EMCP* framework. The *EMCP* we have formulated in this chapter is a flexible and comprehensive platform on which to develop our deterministic simulation approach. The framework can represent the markets over various time periods, allowing us to formulate not only the *DAM*s but also to apply the *EMCP* framework to develop longer-term *ESR* schedules. The linear formulation of the power flow equations is consistent with industry market simulation practice and allows us to represent larger systems over longer-term time periods and still obtain a solution in a reasonable amount of time. Furthermore, the generality of our formulation can be easily extended to incorporate renewable resources and their various sources of uncertainty—an area for future work.

There are also some challenges which arise from our formulation. Assumption A2 dictates our linear formulation with the associated computational speed benefits. However, this assumption may not hold for some systems, which restricts the applicability of the framework to some degree. Assumption A3 does not allow for offers and bids from *DR* and *ES* resources with this framework. However, the explicit representation of private *DR* and *ES* player offers and bids is another easily obtainable extension of this work and so another opportunity for future research.

2.4 Summary

In this chapter we developed a model for *ESR*s and showed how *DRR*s may be represented in the *ESR* model as a special case of *ESR*s. We then formulated the *EMCP* to explicitly represent *ES* and *DR* resources in the transmission-constrained market environment and described the salient aspects of the *EMCP* framework. In the Chapter 3 we describe the implementation of the *EMCP* into a simulation approach capable of quantifying the economic impacts of *ES* and *DR* resources.

CHAPTER 3

SIMULATION METHODOLOGY

In this chapter we describe the implementation of the *EMCP* framework formulated in Chapter 2 into a flexible deterministic simulation approach which is the basis of our comparative economic assessment of the impacts of *DR* and *ES* resources on the *DAM*s. In the approach, we apply the *EMCP* to simulate the *DAM*s for a given physical system, market structure, and regulatory environment to determine the market outcomes and assess the impacts of a number of salient *DR* and *ES* resource characteristics. Furthermore, our approach integrates multi-day *ESR* scheduling and the requirements of the recent *FERC* Order No. 745.

We begin this chapter with an overview of the key aspects of our simulation. Next we describe the *DRR* curtailment and multi-day *ESR* scheduling processes. We continue with a description of the complete simulation approach. We close with a discussion of several applications of interest for the approach including *DRR* energy recovery, *ESR* efficiency, carbon emissions impacts and the impacts of deepening capacity penetrations of *DR* and *ES* resources.

3.1 Overview of the Simulation Approach

In this section, we provide an overview of the deterministic simulation approach which is the basis of our comparative economic assessment of the impacts of *DR* and *ES* resources on the *DAMs*. The *EMCP* framework formulated in Chapter 2 is the engine of our simulation approach. The approach explicitly represents *DR* and *ES* resources in the transmission-constrained market environment and captures the economic impacts of *ES* and *DR* resources participation in the *DAM*s over multiple timescales. Moreover, we utilize the *EMCP* to integrate multi-day *ESR* scheduling the requirements of the recent *FERC* Order No. 745

into our simulation approach. Our simulation approach is applicable to systems with a wide range of physical, market and regulatory characteristics. We refer to these characteristics collectively as the *system description*.

The time-period over which we apply the approach to perform a study we call the *study period*. To capture the economic impacts of interest on time scales smaller than the study period, we segment the study period into T non-overlapping *simulation periods* and denote by

$$\mathscr{T} = \{t : t = 1, \ldots, T\}$$

the index set of the simulation periods. We assume the system description remains unchanged over each simulation period but may change between simulation periods. We segment each simulation period t into K non-overlapping *daily subperiods* and denote by

$$\mathscr{K}_t = \{k : k = k_1, \ldots, k_K\}$$

The index set of the daily subperiods. We show the segmentation of the study period into simulation periods and daily subperiods in Fig. 3.1. We are interested in the assessment of

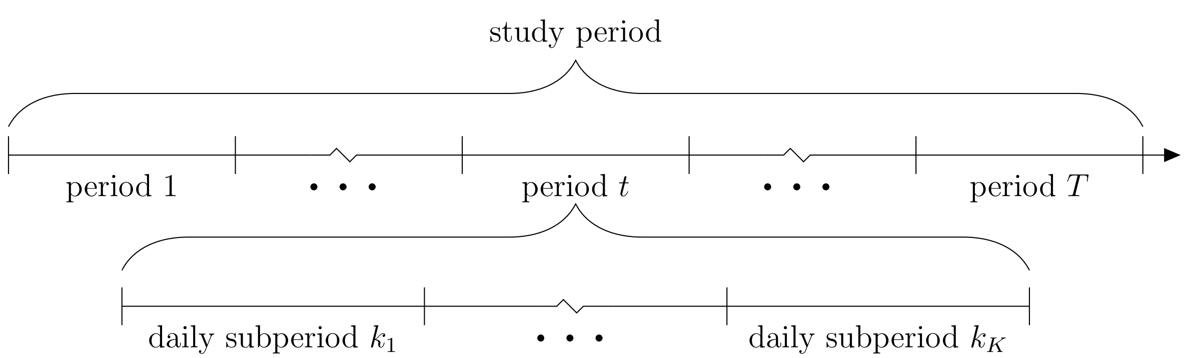

Figure 3.1: segmenting the study period into simulations periods and daily subperiods

the impacts of *DR* and *ES* resources on the *DAM*s and so the daily subperiod is the basic time unit of the simulations. However, each set of *DAM*s consists of 24 hourly markets and so we segment daily subperiod k into 24 non-overlapping *hourly subperiods* and denote by

$$\mathscr{H}_k = \{h : h = h_1, \ldots, h_{24}\}$$

the indexed set of hourly subperiods. The hourly subperiod is the smallest indecomposable time unit in our simulation approach. As such, all intra-hourly phenomenon, such as short-term system dynamics, are ignored.

For each daily subperiod k we execute two-pre market processes

1. The *curtailment scheduling process* in which the pre-curtailment *LMP*s are compared to the system-wide threshold price to determine the *DRR* curtailments in the current day's markets; and

2. The *ESR scheduling process* to determine the multi-day *ESR* schedules which in turn determine the hours of charge and discharge for, and the stored energy at the end of, the current day's markets.

We employ the outcomes of these processes to determine additional schedule information $\forall h \in \mathscr{H}_k$ which is used to constrain the operation of *DR* and *ES* resources in the day k *DAM*s. With this scheduling information we utilize the *EMCP* formulated in Chapter 2 with a given system description to simulate the day k *DAM*s.

The *DAM*s outcomes are the resource quantities and prices $\forall h \in \mathscr{H}_k$. We use the *DAM* outcomes for each daily subperiod $k \in \mathscr{K}_t$ to assess the *DAM* economic impacts of *ES* and *DR* resources for simulation period t. We then aggregate the economic impacts for each $t \in \mathscr{T}$ to evaluate the study period impacts.

In this section we have developed the core aspects of a comprehensive deterministic approach to simulating the impacts of *DR* and *ES* resources on the *DAM*s. In Sections 3.1.1 and 3.1.2 we describe the *DRR* curtailment and *ESR* scheduling processes in greater detail. Then in Section 3.1.3 we give a detailed summary of the market simulation at each subperiod k.

3.1.1 The Pre-Market Curtailment Scheduling Process

The key requirement of *FERC* Order No. 745 related to *DRR* market scheduling is the application the threshold price criterion for determining the *DRR* compensation. As described in Section 1.1, the threshold price criterion determines if *DRR*s are compensated at the *LMP*. In this section we describe the implementation of the threshold price criteria into a curtailment scheduling process in our simulation approach using the *EMCP*.

The threshold prices are determined monthly on the basis of the seller offers, the fuel prices and the *ISO* generation mix. A detailed description of the process by which the threshold prices are determined is given in [34].

Given the threshold price, we may determine the *DRR* curtailments. An overview of the curtailment scheduling process is shown in Fig. 3.2. We first run the *DAM*s without *DR*

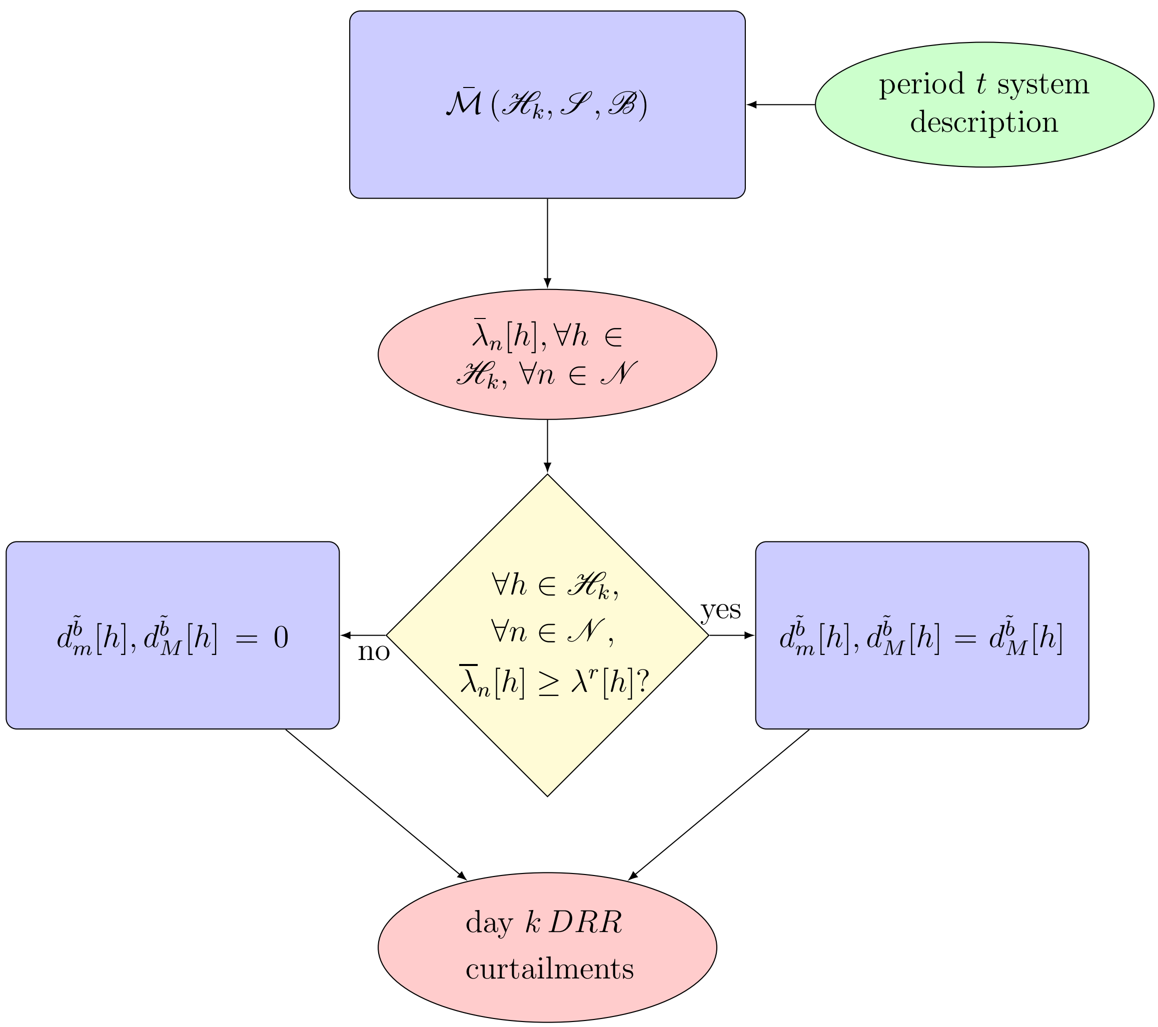

Figure 3.2: An overview of the curtailment scheduling process for a daily subperiod k

or *ES* resources to determine the *DRR* curtailments in a daily subperiod k. We indicate the outcomes of $\bar{\mathcal{M}}\,(\mathscr{H}_k, \mathscr{S}, \mathscr{B})$ by an over bar. The solution to $\bar{\mathcal{M}}\,(\mathscr{H}_k, \mathscr{S}, \mathscr{B})$ provides us the *LMP*s, $\underline{\bar{\boldsymbol{\lambda}}}[h] \in \mathbb{R}^N$, which we compare on a nodal basis to the threshold price $\lambda^r[h]$.

Assuming *DRR*s offer their maximum curtailment quantity, if for a node n, $\bar{\lambda}_n \geq \lambda^r[h]$, then all cleared *DRR* curtailments offered at node n are accepted and we fix the curtailment quantities by fixing the curtailment bounds

$$d_m^{\tilde{b}}[h], d_M^{\tilde{b}}[h] \;=\; \begin{cases} d_M^{\tilde{b}}[h] & \text{if } \bar{\lambda}_n \geq \lambda^r[h], \text{for } n : \tilde{b} \text{ is at } n \\ 0 & \text{otherwise} \end{cases}$$

The hourly curtailments are used with the recovered energy proportion $\alpha_k^{\tilde{b}}$ to determine the total curtailed energy recovered over the day according to the right-hand side of the constraint in Eq. (2.4), $\forall \tilde{b} \in \tilde{\mathscr{B}}$:

$$\sum_{h \in \mathscr{H}} c^{\tilde{b}}[h] = \alpha_k^{\tilde{b}} \sum_{h \in \mathscr{H}} d^{\tilde{b}}[h]$$

The curtailment quantities are inputs to, and the recovered energy quantities become constraints in, the day k *DAM*s. In this section we have described the curtailment scheduling process which integrates the requirements of *FERC* Order No. 745 into the scheduling approach. We now turn to the development of the multi-day *ESR* schedules.

3.1.2 The Pre-Market *ESR* Scheduling Process

In this work we consider utility-scale *ESR*s with capabilities on the order of MW-weeks. Such *ESR*s have the capability to shift energy across time periods of hours or days. To realize the economic potential of MW-week scale *ESR*s to the fullest extent possible, the *ESR* scheduling period must be commensurate with the *ESR* capability.

If MW-week capability *ESR*s are scheduled in the *DAM*s without consideration of the future days, information about the opportunities for discharge and charge in those future days are not taken into consideration in the *ESR* schedule. As such, the *ESR* is used only to have the greatest impact on the *ISO* objective in the current day's *DAM*s and not the greatest impact overall. For example, if the *ESR* scheduling period is seven days, an *ESR* may store energy during the highest priced hours of the weekend days because the prices in these hours are much lower than the weekday peak period prices. However, if the *ESR* scheduling period is only a one day, the current *DAM*s , the same *ESR* will discharge in the highest price hours of the current day, be it a weekend or weekday, since those hours present the greatest opportunity with the available information. In this section we describe the implementation of the *EMCP* into the multi-day *ESR* scheduling process.

To account for the longer-term *ESR* discharge opportunities, we consider an $m+1$ day *ESR* schedule. To formulate the $m+1$ day *ESR* schedule on day k, we use Eq. (2.6) with the ordered set of hours $\mathscr{H}_{k,m} = \bigcup_{i=k}^{k+m} \mathscr{H}_i$. The multi-day *ES* resource scheduling process is summarized in Fig. 3.3. We indicate outcomes from $\mathcal{M}\left(\mathscr{H}_{k,m}, \mathscr{D}\right)$ with an over bar. The

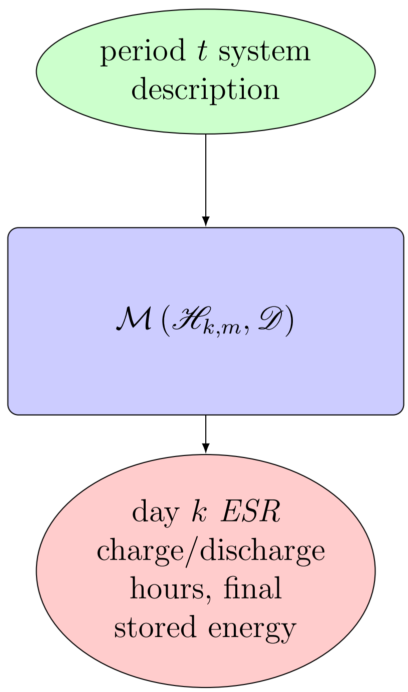

Figure 3.3: The multi-day *ESR* schedule

solution to $\mathcal{M}\left(\mathscr{H}_{k,m}, \mathscr{D}\right)$ provides us the *ESR* charge and discharge quantities $\forall h \in \mathscr{H}_k$ for each storage unit u:

$$
\begin{aligned}
\left[\underline{\bar{\boldsymbol{c}}}^u\right]^\star &= \left[\left[\bar{c}^u[h_1]\right]^\star, \left[\bar{c}^u[h_2]\right]^\star, \ldots, \left[\bar{c}^u[h_H]\right]^\star\right]^T \in \mathbb{R}^H \\
\left[\underline{\bar{\boldsymbol{d}}}^u\right]^\star &= \left[\left[\bar{d}^u[h_1]\right]^\star, \left[\bar{d}^u[h_2]\right]^\star, \ldots, \left[\bar{d}^u[h_H]\right]^\star\right]^T \in \mathbb{R}^H
\end{aligned}
$$

We use the charge and discharge quantities to constrain the operation of the *ESR*s in the

*DAM*s. Each *ESR* is constrained to charge, discharge, and idle as determined in the multi-day schedule, and thus we fix the charge and discharge variables in the *DAM*s such that

$$d_m^u[h], d_M^u[h] \;=\; \begin{cases} 0 & \text{if } \left[\bar{c}^u[h]\right]^\star > 0 \\ d_m^u[h], d_M^u[h] & \text{otherwise} \end{cases}$$

$$c_m^u[h], c_M^u[h] \;=\; \begin{cases} 0 & \text{if } \left[\bar{d}^u[h]\right]^\star > 0 \\ c_m^u[h], c_M^u[h] & \text{otherwise} \end{cases}$$

In addition, we fix the stored energy in the *DAMs* for each *ESR* at the value determined by the multi-day schedule allowing only the intra-day rescheduling of the charge and discharge quantities. We do so by setting the value of α^u

$$\alpha_k^u = \frac{\displaystyle\sum_{i=h_1}^{h_{24}} \eta_c^u \left[\bar{c}^u[i]\right]^\star}{\displaystyle\sum_{i=h_1}^{h_{24}} \frac{\left[\bar{d}^u[i]\right]^\star}{\eta_d^u}} \tag{3.1}$$

Application of the constraint given in Eq. (3.1) ensures the *ESR*s keep to the multi-day schedule in the *DAM*s even though the *DAM*s time horizon is only 24 hourly markets. In this section we described the multi-day *ESR* schedule and the integration of information from the multi-day *ESR* scheduling process into the *DAM* simulations. In Section 3.1.3 we give a detailed summary of the *DAM* simulations for a daily subperiod.

3.1.3 The *DR* and *ES* Resource Market Economic Impact Simulation Approach

In this section we describe the combination of the pre-market processes described in Sections 3.1.1 and 3.1.2 to describe the complete *DAM* market simulation. The market simulation approach utilizes the *EMCP* in Eq. (2.6) as its engine to simulate the *DAM*s taking explicit account of *DR* and *ES* resources and the transmission constrained network.

An overview of the market simulation approach for a day k is shown in Fig. 3.4. For each

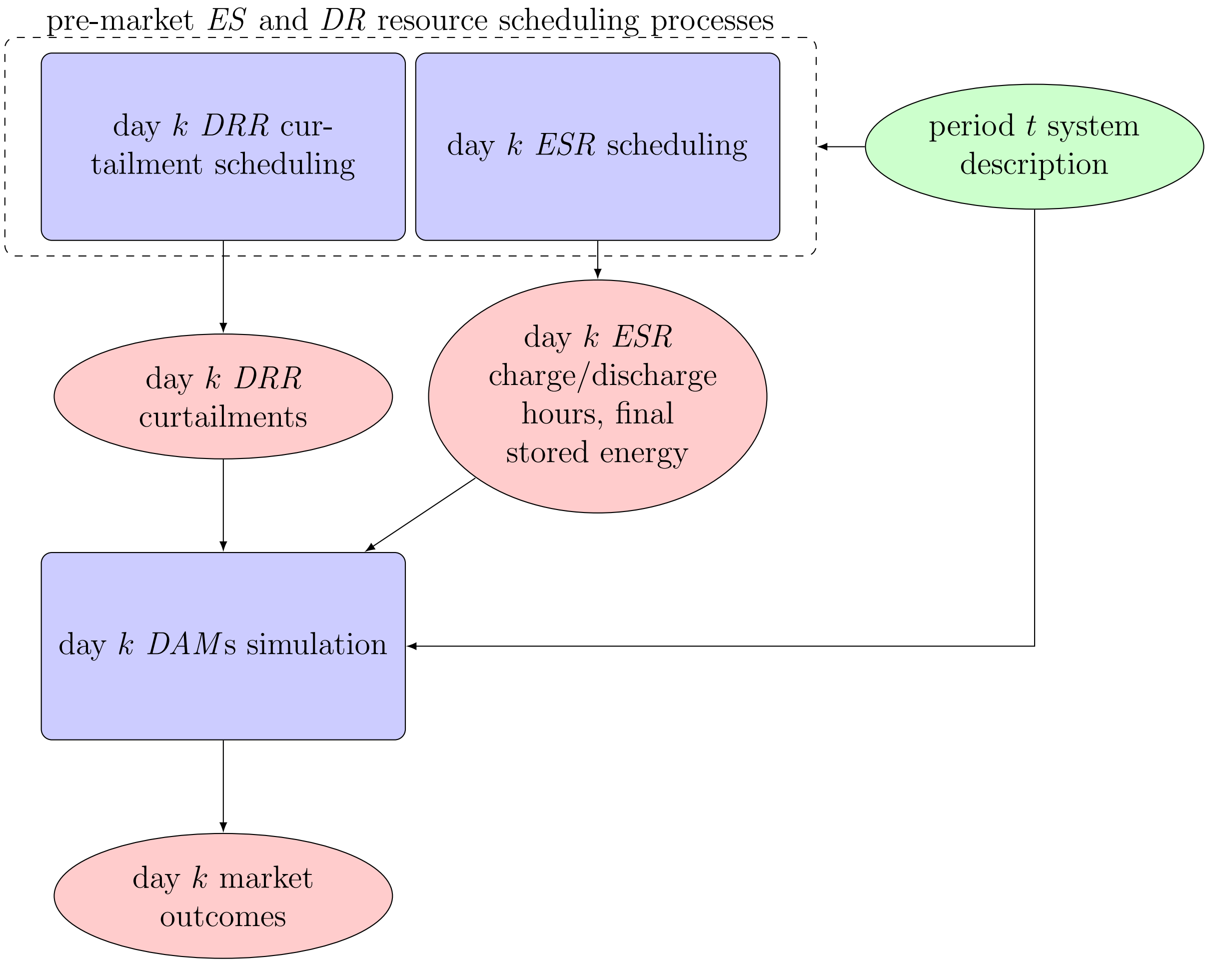

Figure 3.4: Overview the *DAM*s simulation approach for a day k

day k in the simulation period, we first determine the *DRR* curtailment and the *ESR* charge and discharge hours and final stored energy from the respective pre-market processes. This *DR* and *ES* resource schedule information, along with the period t system description, are the inputs to the day k market simulation. The market outcomes are the *ESR* charge and discharge quantities, the *DRR* recovery quantities, and the seller quantities for each hour of day k. This process is repeated for each simulation period $t \in \mathscr{T}$.

From day k market outcomes we calculate the *ES* and *DR* resource payments, the seller payments, and the buyer payments using Eqs. (2.7)–(2.12). The resource payments are then used to calculate other economic figures of merit which form the basis of an economic assessment.

3.2 Applications of the Simulation Approach

The simulation approach based on our *EMCP* formulation and developed in this chapter is highly flexible and may be used to study the economic impacts of a number of salient *DR* and *ES* resources characteristics and represent a variety of *ESR* technologies. In this section, we give an overview of several applications of interest including *DRR* energy recovery, *ESR* efficiency, carbon emissions impacts and the impacts of deepening capacity penetrations of *DR* and *ES* resources.

The price reductions from *DRR* curtailments are only one component of the economic impacts of *DRR* utilization. Since in many cases, the energy curtailed in peak hours will be recovered in off-peak hours, the economic impacts of *DRR* curtailed energy recovery are an important second component of the overall *DRR* economic impacts. In some cases of *DRR* curtailment, such as the curtailment of energy for lighting or the use of back-up generation, the energy curtailed may be greater than the energy recovered. Conversely, the energy curtailed may be less than the recovered energy. The economic impacts of *DRR* energy recovery have been the subject of few studies. The approach presented here has the capability to quantify the range of economic impacts which would occur for various levels of *DRR* curtailed energy recovery by adjusting the values of the *DRR* parameters $\alpha_k^{\tilde{b}}$. Such studies shed light on the full economic impacts of *DRR* utilization.

The round trip efficiency of *ESR*s is an important factor determining the magnitude of the economic impacts of *ESR*s. The *ESR* efficiency governs the ratio of the maximum charge price to the minimum discharge price an *ESR* may pay over a specified period to operate economically. The greater the efficiency, the greater the ratio of the maximum charge price to the minimum discharge price and the greater the number of hours the *ESR* may operate economically. We may use the approach to study the economic impacts of varying the efficiency of *ESR*s by varying the values of parameters η_c^u and η_d^u to adjust the round trip efficiency η_r^u and quantify the range of *ESR* efficiency economic impacts.

Concerns about climate change have driven state and federal policy that aims to reduce carbon emissions in the electricity sector. The electricity sector accounts for around 40% of U.S. carbon emissions [35] and so will be an important part of any meaningful strategy to reduce national carbon emissions. *ES* and *DR* resources have an important role to play in the reduction in system-wide carbon emissions in the electricity sector. Given the generation mix of a particular system, the approach presented here allows the study of the carbon emissions impacts of *ES* and *DR* resources along the same dimensions as the economic assessment and provide system operators and policymakers insights to develop operational strategies and policy to effectively reduce system wide carbon emissions.

The economic impacts of deepening *DR* and *ES* resource penetration are of increasing interest to electricity grid stakeholders. Our market simulation approach has the capability to perform *DR* and *ES* resource capacity penetration studies by varying the *DR* and *ES* resource capacity bound constraints to observe the economic impacts of deepening resource capacity penetrations. These studies allow policy makers and resource planners to answer questions such as "How much *ESR* (*DRR*) is too much?" and identify incentive structures to encourage new resource development appropriate *ESR* (*DRR*) penetrations. We present the results of our comparative economic assessment of *DR* and *ES* resource capacity penetration impacts on the *DAM*s in Chapter 4.

In this Section we gave an overview of some worthwhile applications of the flexible market simulation approach. In Section 3.3 we summarize the approach discussed here.

3.3 Summary

In this chapter we described the implementation of the *EMCP* into a flexible market simulation approach which explicitly represents both *ES* and *DR* resources and the transmission-constrained network over multiple timescales and takes into account the current regulatory environment. We then described the development of the curtailment and multi-day *ESR* scheduling processes. We ended this chapter with description of the complete simulation approach and an overview of some worthwhile applications. In Chapter 4 we describe the application of the simulation approach to perform the comparative economic assessment of the impacts of deepening DR and ES resource penetration on the DAMs.

CHAPTER 4

CASE STUDIES

In this chapter we present illustrative results from the extensive studies of the economic impacts of *DR* and *ES* resources on the *DAM*s we have performed on numerous test systems using *MISO* and *ISO-NE* data. We compare *DR* and *ES* resources side-by-side and demonstrate the sensitivity of *ABLMP* to deepening *DR* and *ES* resource penetrations. Through comparison of illustrative results from two of the test systems, we develop some intuition about the system characteristics which affect the impacts of deepening *DR* and *ES* resource penetrations. We identify the key factors, such as the load shape and the seller offers, which contribute to the magnitude of the price impacts of *DR* and *ES* resources. Moreover, we focus on the limitations of *DRR*s which lessen their price impacts compared to *ESR*s and interpret the economic impacts of the constraints imposed on *DR* and *ES* resources in our model.

We begin this chapter by describing the objective and nature of our case studies and the test systems used. We then proceed to describe our findings and the insights gained from our case studies. We conclude the chapter with a summary of the key findings.

4.1 The Test Systems and the Nature of the Case Studies

The illustrative results we present in this thesis are drawn from case studies on modified *IEEE* 57- and 118-bus test systems (MTS_{57} and MTS_{118}, respectively) [36]. To gain a better understanding of the economic impacts of *ES* and *DR* resources in the *DAM*s, we use market and load data from the *MISO* and the *ISO-NE* for the year 2010 [37], [38].

We observe little variation in the seller offer data on time-scales less than a month, so we average the *ISO* offer data over each month on an hourly basis to construct 12 average hourly *ISO* supplier offer curves. This process reduces the computational burden of hourly offer changes while preserving the seasonality effects on the seller offers. The test system seller offer prices and quantities are replaced with the twelve 2010 *ISO* average hourly offer data for each respective month of the one year simulation. We assume the supplier offers change on a monthly basis but are the same in every hour of a month. Furthermore, we assume the buyers have an arbitrarily high willingness to pay in each hour.

In both systems, we modify the line flow limits to induce transmission congestion in peak-load periods. The load data and the total installed generation capacity from each *ISO* are scaled to 9600 MW peak and 9960 MW, respectively. We place the *DRR*s in both systems at all the load buses in proportion to the bus peak load. We place four equally sized *ESR*s located at each of the four buses with the largest load concentration in each system. We summarize test system specific modifications in Table 4.1. The full set of market and network

Table 4.1: Test system modifications for the case studies

test system	offer & load data source	# of generators	*ESR* buses
MTS_{57}	*MISO*	25	6, 8, 9, 12
MTS_{118}	*ISO-NE*	54	15, 59, 80, 116

data and the one-line diagram for each of the modified systems are presented in Appendix B, and the load data may be obtained from [37] and [38].

The total *DR* and *ES* resource capacity penetrations in each case are calculated as a percentage of the annual peak load. From here on, reference to resource penetration is synonymous with resource capacity penetration unless otherwise noted.

We perform *DRR* capacity sensitivity studies for penetrations from 0 to 15% on each of the MTS_{57} and MTS_{118}. The capacity of each *DRR* is the product of the percent *DRR* penetration and the load at the respective bus in the system peak load hour. *DRR*s are assumed to recover energy at a capacity no greater than their curtailment capacity and we assume 100 percent of curtailed energy is recovered in all cases. We assume *DRR*s offer curtailments at the threshold price in the curtailment scheduling process so that the threshold price extends from compensation to dispatch. We restrict *DRR* curtailments to between the hours of 10:00 a.m. and 10:00 p.m., both because *DRR*s are unlikely to curtail in off-peak hours so as to allow for energy recovery and because off-peak curtailment is rare due to low load and prices in off-peak hours. Moreover, we assume *DRR*s recover curtailed energy in the same 24 hour period (midnight to midnight) in which it was curtailed. We assume the *DRR*s are operated as a system resource and so submit curtailment quantities to the *ISO* for those hours in which curtailments are permitted and allow the *ISO* to schedule the recovered energy. We assume there are no *ESR*s in the *DRR* sensitivity cases.

We perform *ESR* capacity sensitivity studies for penetrations from 0 to 15% on the MTS_{57} and 0 to 35% on the MTS_{118}. The combined capacity of the four *ESR*s divided by the peak load is equal to the percent penetration for the case under consideration and the storage capability of the *ESR*s is considered to be 24 times the capacity. We assume the *ESR*s have a round trip efficiency of 0.8. Such capabilities and efficiencies are consistent with commercial pumped hydro and compressed-air *ESR*s [39]. We select a three-day time period for the pre-market *ESR* schedule. Additionally, we do not consider additional cases of *ESR* capability or efficiency in this work leaving the sensitivity of *ABLMP* to changes in the *ESR* capability and efficiency as a topic for future research. We assume there are no *DRR*s in the *ESR* sensitivity cases.

The objectives of the sensitivity studies presented here are to

- explore the limitations of the reductions in *ABLMP* which are achieved by deepening penetrations of *DR* and *ES* resource capacity; and
- compare the price impacts of *DR* vs. *ES* resources at each penetration.

We compare the economic impacts of *DR* and *ES* resources on the *DAM*s on the basis of capacity. The studies are backcast scenarios for the year 2010 with deepening penetrations of *DR* and *ES* resources assuming perfect knowledge of the load. Each simulation does not account for any sources of uncertainty and so all the case studies are deterministic.

Through our extensive studies, we have determined the *ABLMP* to be an effective metric for measuring the economic impacts of *DR* and *ES* resources on the *DAM*s. The *ABLMP* is defined to be the ratio of the total buyer payments over a specified period to the total purchased quantity over the same period. The *ABLMP* is our primary metric of comparison in our comparative assessment. A complete set of *ABLMP* reduction results from our studies is given in Appendix C.

We denote each case by $\mathbb{P}^k_{i,j}$ where k is the case test system, i is the penetration of *DRR*s and j is the penetration of *ESR*s. The case with no *DR* or *ES* resources, $\mathbb{P}^k_{0,0}$, is taken as the base case scenario for each system. When evaluating the seasonal impacts of *DR* and *ES* resources, we consider the spring period to encompass the months of March, April and May; the summer period to encompass the months of June, July and August; the fall period to encompass the months of September, October, and November; and winter period to encompass the months of December, January and February.

In this section we gave an overview of the test systems used for our case studies and discussed the nature of the studies. In Section 4.2 we describe the impacts *ESR* on *ABLMP*s and the system characteristics which make *ESR* more or less effective.

4.2 The Economic Impacts of *ESR*s

In this section we discuss the economic impacts of deepening *ESR* penetration on the annual *ABLMP*s in the two test systems. In addition, we break down the impacts seasonally to analyze the differences across the seasons and gain insight into the characteristics of the load and generator offers which contribute to the price impacts of *ESR*s. Moreover, we discuss the price impacts of multi-day *ESR* scheduling.

Table 4.2 summarizes the *ABLMP* reductions from deepening *ESR* penetrations seasonally and annually for the MTS_{57}. Figure 4.1 depicts the annual *ABLMP*s for deepening *ESR* penetrations. From Fig. 4.1 we note a maximum annual *ABLMP* reduction of around 2.4% which occurs at an *ESR* penetrations of 13% or deeper. There is, however, tremendous variability in the *ABLMP* reductions between the summer and other seasons driven by differences in the loads and the generator offers. *ESR*s have the highest price impact in the summer where the greatest *ABLMP* reduction is 7.6% at 13% *ESR* penetration. *ESR*s have the least price impact in the winter where the greatest *ABLMP* reduction is around 0.2% at *ESR* penetrations of 5% or deeper. *ESR*s also show limited price impacts in the spring and fall which is comparable to that of the winter.

Table 4.2: The seasonal and annual $ABLMP$ reductions for deepening penetrations of ESRs on the MTS_{57}

ESR penetration (%)	average buyer LMP reduction (%)				
	spring	summer	fall	winter	annual
1	0.06	1.97	0.07	0.08	0.61
3	0.16	4.14	0.14	0.12	1.27
5	0.22	5.54	0.22	0.23	1.74
7	0.30	6.39	0.29	0.22	2.02
9	0.32	6.90	0.30	0.20	2.17
11	0.31	7.40	0.34	0.16	2.31
13	0.30	7.60	0.33	0.23	2.39
15	0.29	7.54	0.39	0.23	2.39

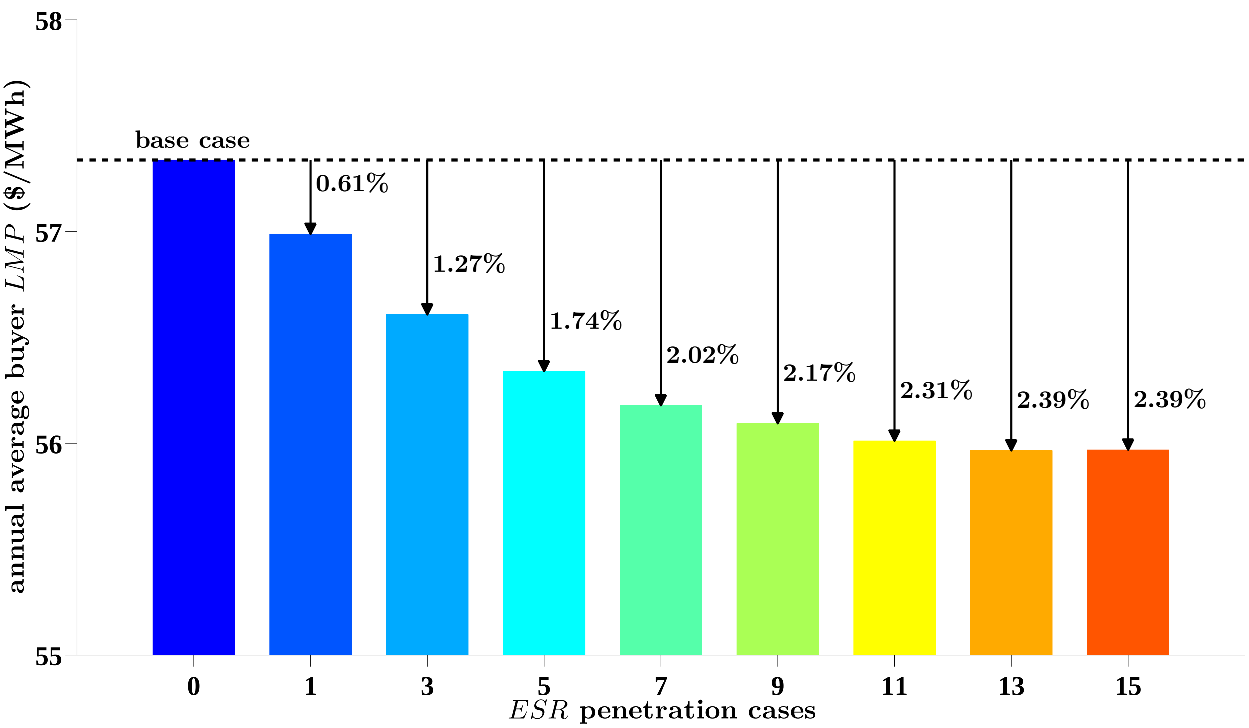

Figure 4.1: The annual $ABLMP$ for deepening penetrations of ESRs on the MTS_{57}

To illustrate and explain the seasonality impacts on ES resource utilization, we use the hourly LMPs and the hourly loads for representative summer and winter weeks at a representative system bus. We focus on the summer and winter ESR impacts to illustrate the range of impacts observed in our studies. We show in Figs. 4.2 and 4.3 the hourly LMPs and the hourly loads for the representative summer week of August 9–15 for sensitivity cases

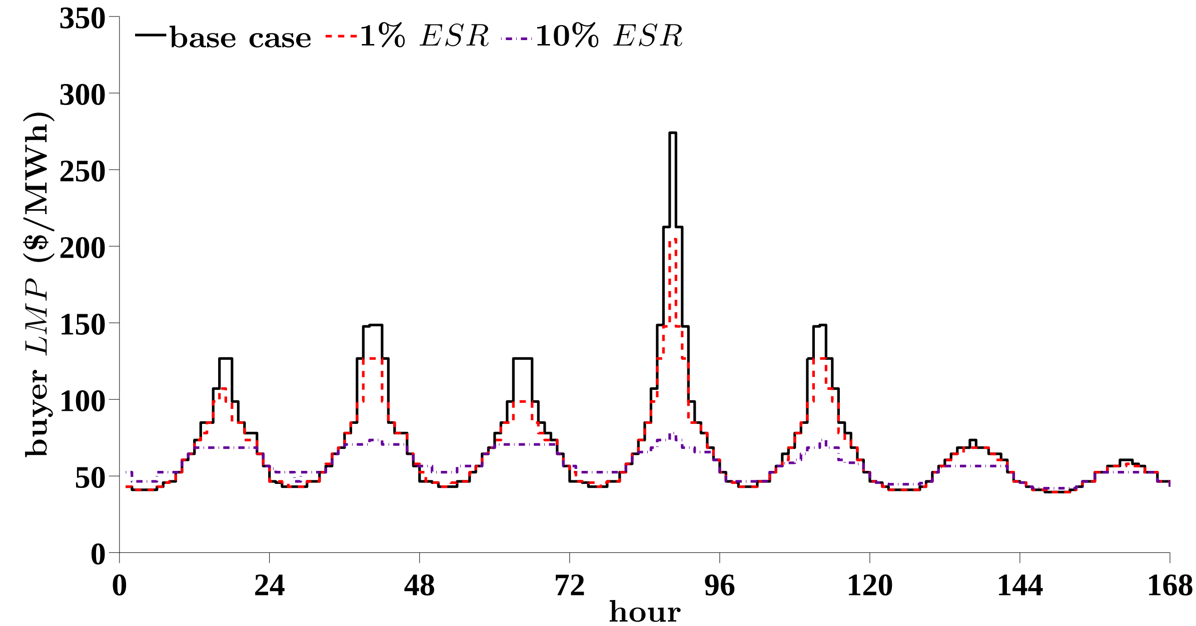

Figure 4.2: The hourly LMPs at bus 12 for the week of Aug. 9–15, 2010, on the MTS_{57}

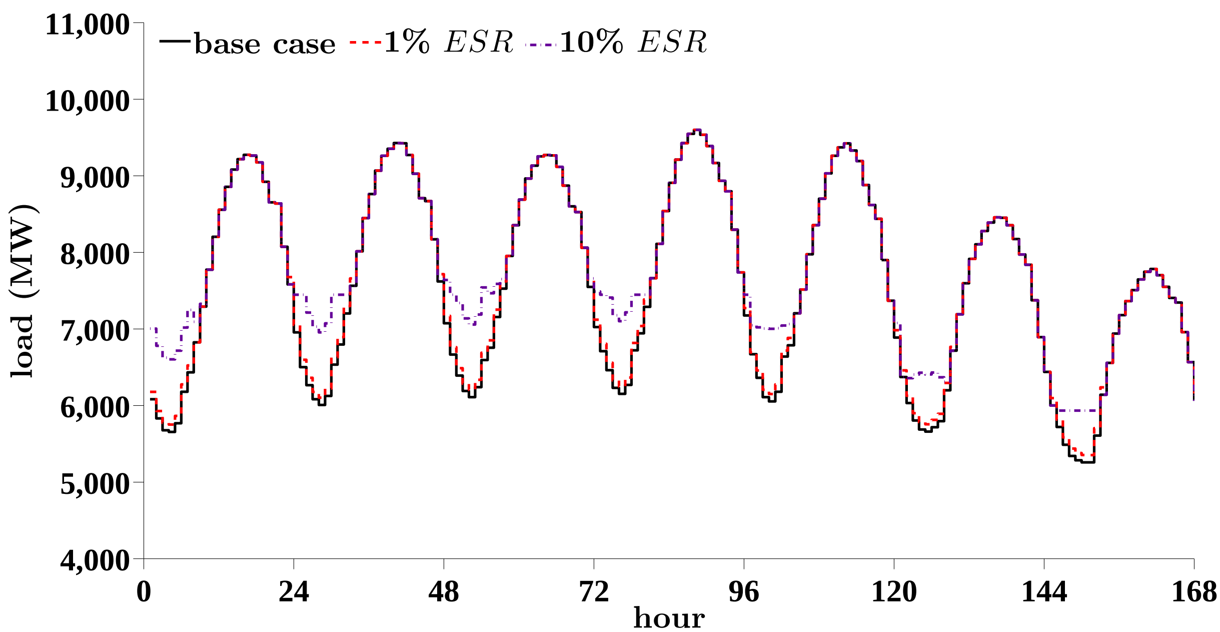

Figure 4.3: The hourly loads for the week of Aug. 9–15, 2010, on the MTS_{57}

$\mathbb{P}^{57}_{0,0}$, $\mathbb{P}^{57}_{0,1}$ and $\mathbb{P}^{57}_{0,10}$ at bus 12.

One of the primary drivers of the $ABLMP$ reductions resulting from ESR utilization is the relationship between the load in the peak periods, when ESRs typically discharge resulting price reductions, and the load in the off-peak periods, when ESRs typically charge resulting in price increases. As depicted in Fig. 4.3, the summer peak-period loads are as much as twice the off-peak period loads. The significant variations in the loads drive significant variations in the prices. As shown in Fig. 4.2, in case $\mathbb{P}^{57}_{0,0}$ there are peak- to off-peak period price differences of as high as \$250. As the penetration of *ESR*s is increased from case $\mathbb{P}^{57}_{0,0}$ to $\mathbb{P}^{57}_{0,1}$ and then to case $\mathbb{P}^{57}_{0,10}$, the peak prices fall a disproportionately greater amount than the off-peak prices rise as a result of *ESR* discharge and charge, respectively. It is precisely these disproportionate peak price decreases compared to off-peak price increases combined with the high peak to off-peak load ratio that results in reductions in the *ABLMP*s. Indeed, in case $\mathbb{P}^{57}_{0,1}$ there is almost no impact on the off-peak prices while the peak prices fall by as much as \$70. Even in case $\mathbb{P}^{57}_{0,10}$, the increase in off-peak prices is about a tenth of the decrease in peak prices. Such differences result in the approximately 7% reduction in the summer period *ABLMP*s for case $\mathbb{P}^{57}_{0,10}$, despite increases in the off-peak *LMP*s. The pronounced *ESR LMP* impacts in the summer week are contrasted by the lesser *ESR LMP* impacts in the representative winter week. Figures 4.4 and 4.5 depict the *LMP* and the loads for the

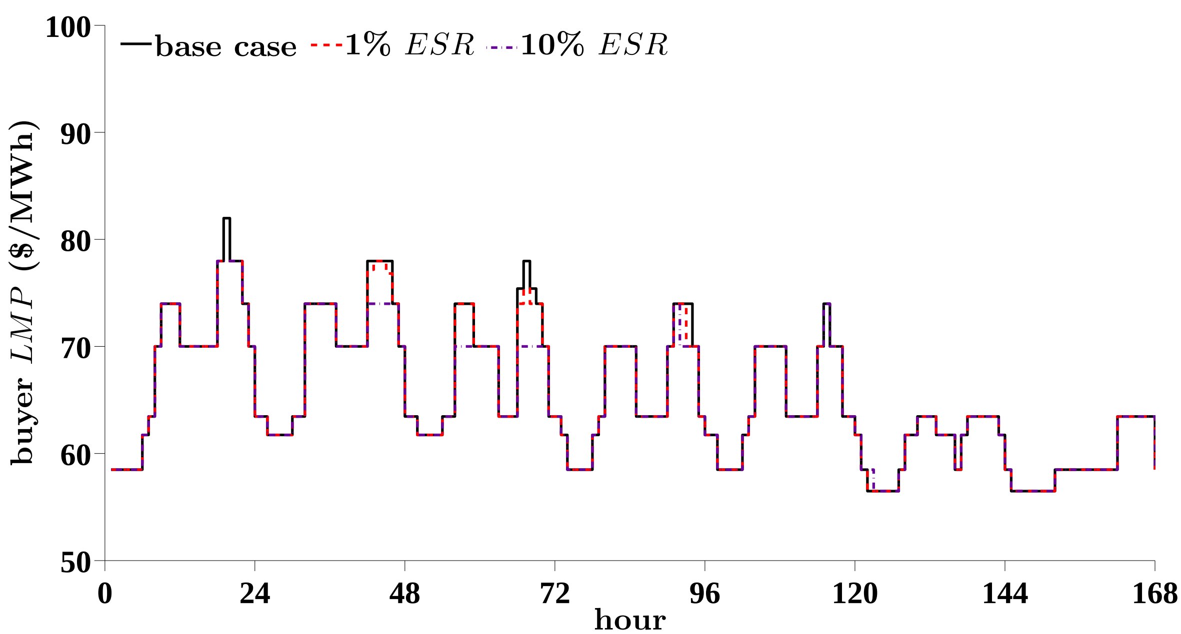

Figure 4.4: The hourly *LMP*s at bus 12 for the week of Dec. 13–19, 2010, on the MTS_{57}

representative winter week of December 13–19, 2010, for cases $\mathbb{P}^{57}_{0,0}$, $\mathbb{P}^{57}_{0,1}$ and $\mathbb{P}^{57}_{0,10}$ at bus 12. We note the load variability in the winter week, shown in Fig. 4.5, and consequently the price fluctuations, shown in Fig. 4.4, are less pronounced than those of the summer

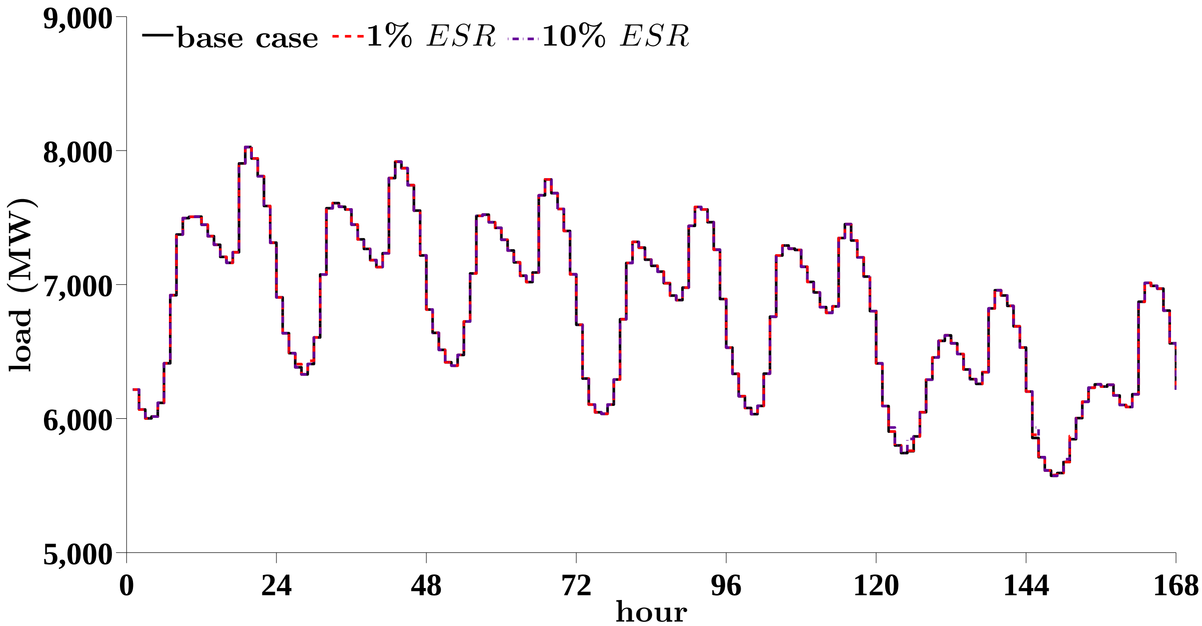

Figure 4.5: The hourly loads for the week of Dec. 13–19, 2010, on the MTS_{57}

week discussed above. In fact, the maximum peak to off-peak load ratio and maximum peak to off-peak price difference do not exceed 1.5 and \$30, respectively, in case $\mathbb{P}^{57}_{0,0}$. The lack of a significant peak to off-peak price difference and the low peak to off-peak load ratio leave fewer opportunities for *ESR*s to reduce *ABLMP*s. Because the *ESR*s have a round trip efficiency of less than one, 0.8 in our studies, each charge and discharge cycle results in some lost energy. To overcome the cost of the lost energy, there must be a differential between the maximum *ESR* charge price and the minimum *ESR* discharge price. Clearly, the minimum differential is not often met in the winter weeks, as is clear from the limited *ABLMP* reductions which result from the utilization of *ESR*s in the winter week and the similarity between the load shape in each of the cases shown in Fig. 4.5.

Table 4.3 summarizes the average buyer *LMP* reductions for deepening penetrations of *ES* resources seasonally and annually for the MTS_{118}. Figure 4.6 depicts the annual *ABLMP*s for deepening *ESR* penetrations. We note in Fig. 4.6, as before in Fig. 4.1, the annual *ABLMP*s decreases monotonically with deepening *ESR* penetration, but at a decreasing rate. The seasonality effects on the *ABLMP* impacts of *ESR* integration are even more pronounced in the MTS_{118} cases than they are in the MTS_{57} cases. The highest *ABLMP* reduction in the summer period is around 15% with respect to a 20% or deeper *ESR* penetration. The annual

Table 4.3: The seasonal and annual $ABLMP$ reductions for deepening penetrations of ESRs on the MTS_{118}

ESR penetration (%)	average buyer LMP reduction (%) spring	summer	fall	winter	annual
1	0.77	1.96	1.77	1.10	1.46
2	1.54	3.66	3.51	2.03	2.76
5	2.63	8.26	6.79	4.32	5.81
8	3.24	11.40	8.54	5.37	7.61
11	3.50	13.11	9.41	5.50	8.41
14	3.74	13.92	9.69	5.79	8.86
17	3.79	14.50	10.30	5.55	9.08
20	3.78	14.97	10.37	5.51	9.25
25	3.73	14.80	10.38	5.63	9.22
30	3.28	14.98	10.63	5.39	9.18

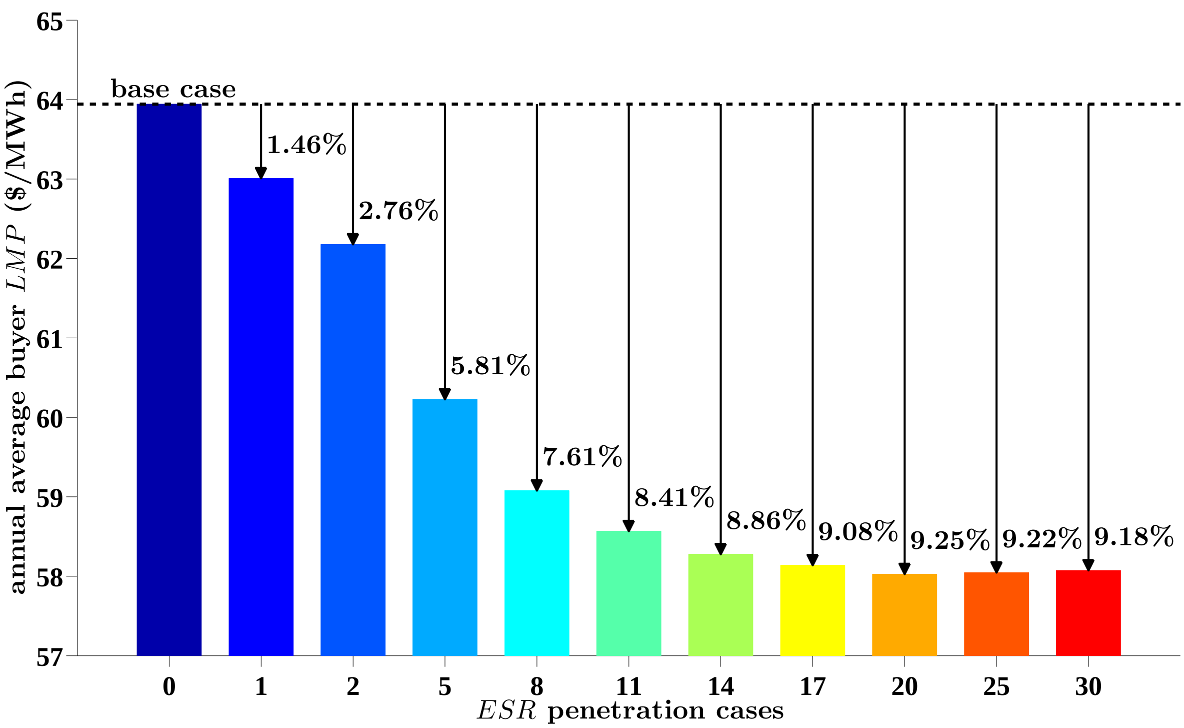

Figure 4.6: The annual $ABLMP$ for deepening penetrations of ESRs on the MTS_{118}

$ABLMP$ reduction with ESRs is around 9.2% and remains so for penetrations deeper than 20%, indicating that the peak to off-peak price differentials required for economic storage operation are no longer present at these penetrations. The $ABLMP$ reductions in the fall are similar to those of the summer. However, in the winter and spring periods the *ABLMP*s impacts of *ESR*s are less than half those of the fall and summer. The *ABLMP* reductions

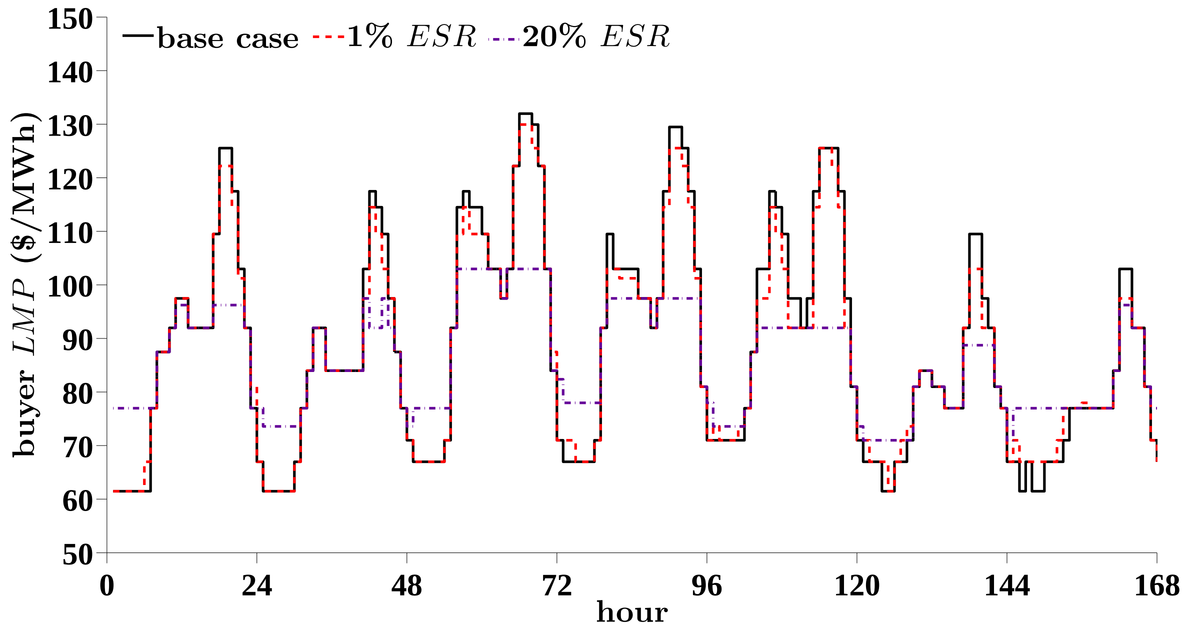

Figure 4.7: The hourly *LMP*s at bus 59 for the week of Dec. 13–19, 2010, on the MTS_{118}

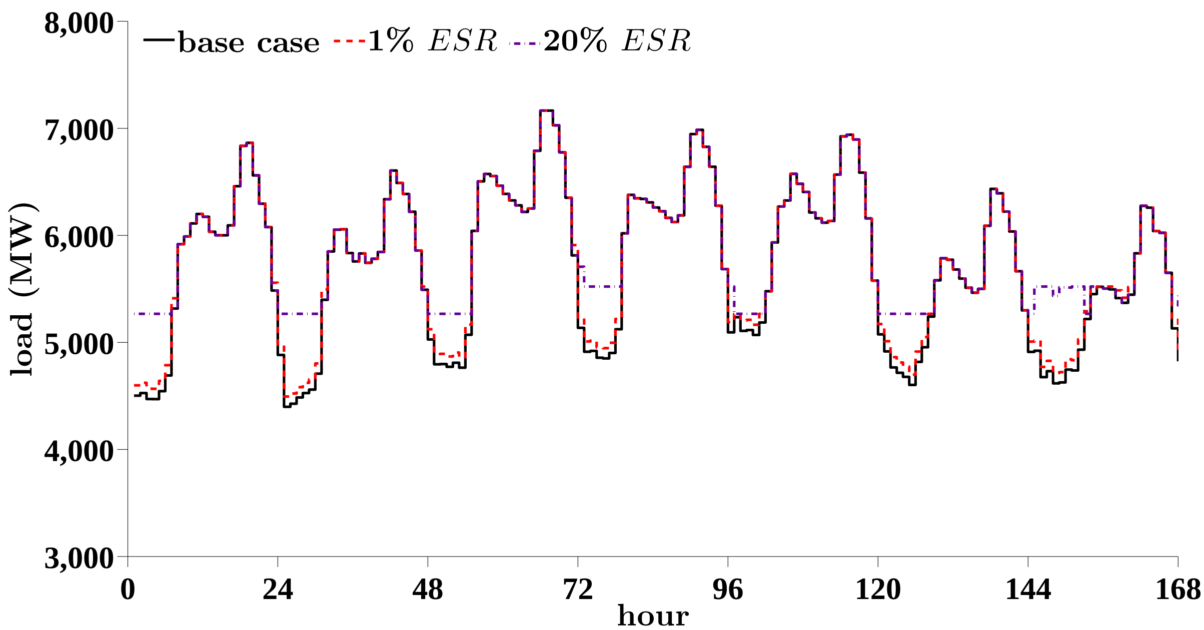

Figure 4.8: The hourly loads at bus 59 for the week of Dec. 13–19, 2010, on the MTS_{118}

in all of the seasons can be explained using the same rationale as we used for the MTS_{57} cases.

To illustrate the impacts of the multi-day storage schedule and the *ESR* efficiency, we depict in Figs. 4.7 and 4.8 the hourly *LMP*s and the hourly loads for the representative winter week of December 13–19, 2010, for cases $\mathbb{P}^{118}_{0,0}$, $\mathbb{P}^{118}_{0,1}$ and $\mathbb{P}^{118}_{0,20}$ at bus 59. The ratio of peak to off-peak load in the winter week of case $\mathbb{P}^{118}_{0,0}$, depicted in Fig. 4.8, is approximately 1.5, a value similar to the winter week in $\mathbb{P}^{57}_{0,0}$. In addition, the peak to off-peak period price difference for case $\mathbb{P}^{118}_{0,0}$ is approximately \$70 as seen in Fig. 4.7. Though the winter week peak to off-peak load ratio on the MTS_{118} is similar to that of the winter week on the MTS_{57}, the peak to off-peak price differential is nearly twice as large on the MTS_{118}. The greater price differential allows the *ESR*s to overcome the efficiency losses to operate and account for the higher winter week *ABLMP* reductions observed in MTS_{118} compared to MTS_{57} with deepening *ESR* penetrations. Though the *ESR*s typically do not operate without a minimum peak to off-peak price differential in the *DAM*s, we observe cases where this tenant is violated.

Due to the multi-day *ESR* schedule, described in Section 3.1.2, there are days when the *ESR*s operate uneconomically in order to take advantage of higher prices on future days. Figures 4.9 and 4.10 provide a closer look at the hourly *LMP*s and the hourly loads for December 19, 2010, at the same bus.

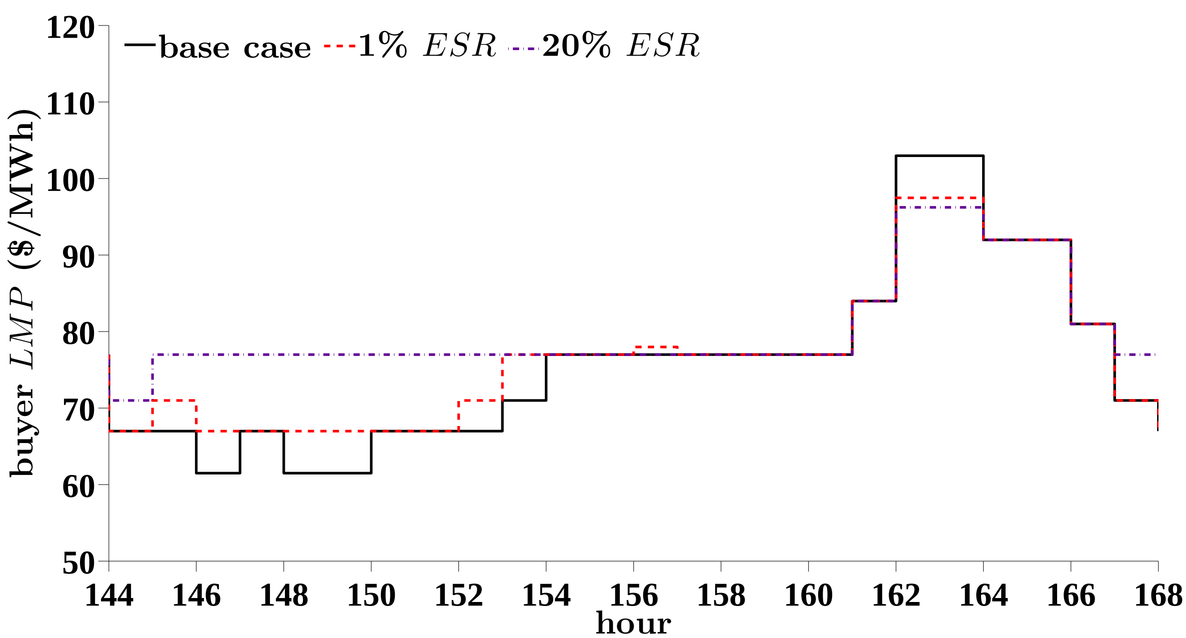

Figure 4.9: The hourly bus 59 *LMP*s for December 19, 2010, on the MTS_118

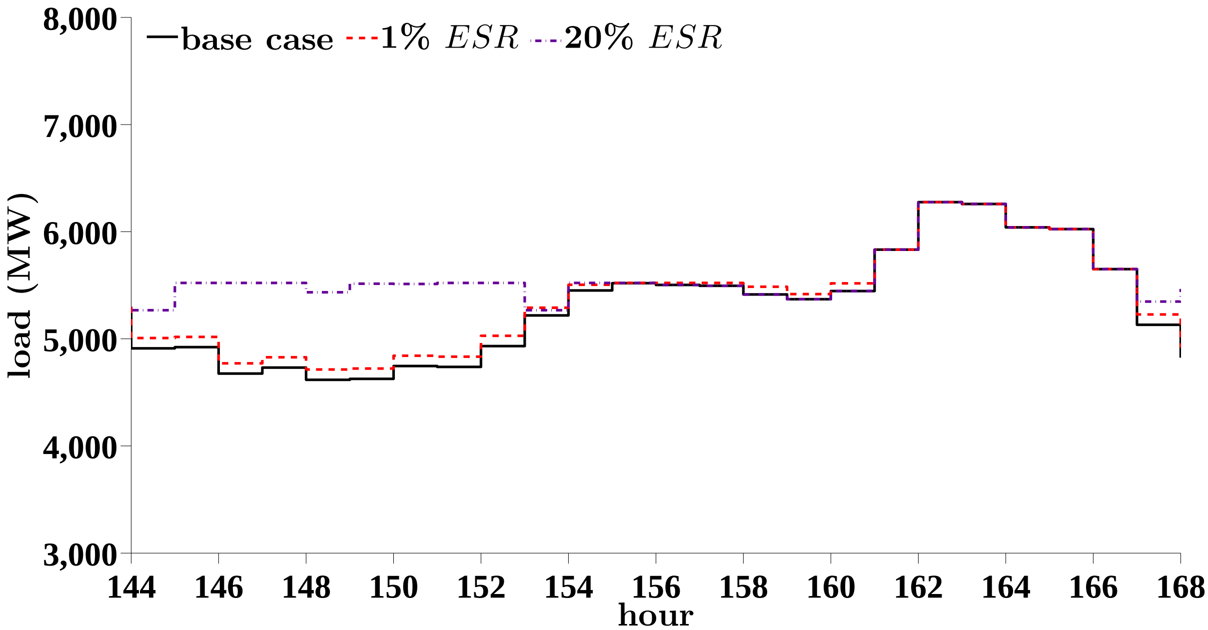

Figure 4.10: The hourly loads for December 19, 2010, on the $MTS_1 18$

As shown in Fig. 4.9, the *LMP*s are mostly impacted in the off-peak hours indicating the *ESR*s are primarily charging. The *LMP* changes are reflected in the load increases from charging in those hours in Fig. 4.10. Clearly, the payments for charge energy are greater than the payments received for discharge on December 19th since there are only two hours of discharge. However, we note the periodic nature of the prices. In Fig. 4.7, for example, the prices on Monday and Tuesday, the first and second days depicted, are greater than the prices on Sunday, the seventh day depicted. The three-day *ESR* schedule performed on December 19th, a Sunday, includes price information for following two days, a Monday and Tuesday, and thus the units maintain a higher stored energy on the 19th, resulting in net payments by the *ESR*s for purchased energy, such that they have the capability to discharge in more hours on the 20th and 21st when the prices are higher. While this information results in short-term uneconomic *ESR* operation, without a multi-day look ahead for the *ESR* schedule, such opportunities to store energy on a day with lower prices to discharge on a future day with higher prices, and therefore realize a greater amount of the economic potential of *ESR*s , would be lost.

From these results we conclude that significant price variations from peak to off-peak driven in part by a high ratio of peak to off-peak loads are the principal contributing factors to the larger reductions in *ABLMP*s seen in the summer period at all penetrations of *ESR* as compared to other seasons. Overall, we observe annual *ABLMP* reductions of at most 2.39% at 13% *ESR* penetration and 9.25% at 20% *ESR* penetration on the MTS_{57} and the MTS_{118}, respectively. In the following section, we discuss the impact of the generator offers in greater detail where we compare the systematic differences between the MTS_{57} and the MTS_{118} which lead to the differences in the *ESR ABLMP* impacts.

4.3 System Properties Contributing to the Price Impacts of *ESR*s

The *ABLMP* reduction impacts of *ESR* on the MTS_{57} are around a quarter of the those for each *ESR* penetration level on the MTS_{118}. The systematic differences between the impacts in the two systems suggest there are some underlying system characteristics which effect the price impacts of integrated *ESR*s. In this section we compare the supplier offers and the load shapes from each system for representative winter and summer months to identify the system characteristics which lead to the differences in *ABLMP* reduction impacts and draw some conclusions about the properties of systems in which *ESR*s will have a higher impact on the *ABLMP*s.

The analysis in the section 4.2 suggests that the key factors driving the impacts of *ESR* on *ABLMP*s are the price reductions (increases) and the load facing those prices. Tables 4.4 and 4.5 summarize the base case average peak and off-peak *LMP*s and loads on the MTS_{57} and MTS_{118}, respectively. These price differences and load ratios represent the potential for *ABLMP* reductions on each respective system. From Tables 4.4 and 4.5 we see that the annual average peak to off-peak price difference and load ratio on the MTS_{118} are $28.58 and 1.28, respectively, while on the MTS_{57} the annual average peak to off-peak price difference and load ratio are $8.49 and 1.17. The potential for reduced annual *ABLMP* is greater on the MTS_{118} both in terms of the price differential and load ratio—which supports the higher *ABLMP* reductions we observe in our case studies on the MTS_{118} compared to the MTS_{57}. Furthermore, the seasonal differences in the peak to off-peak price differences and load ratios are consistent with our observations in Section 4.2.

We have explored the impact of the peak to off-peak load ratio and the peak to off-peak

Table 4.4: The base case seasonal and annual average peak and off-peak *LMP*s and loads on the MTS_{57}

	average *LMP* (\$/MWh)			average load (MW)		
	peak	off-peak	difference	peak	off-peak	ratio
spring	52.54	48.99	3.55	5778	5040	1.15
summer	65.56	45.69	19.87	7616	5918	1.29
fall	48.62	45.13	3.49	5999	5141	1.17
winter	75.66	69.71	5.95	6543	5999	1.09
annual	61.24	52.75	8.49	6485	5523	1.17

Table 4.5: The base case seasonal and annual average peak and off-peak *LMP*s and loads on the MTS_{118}

	average *LMP* (\$/MWh)			average load (MW)		
	peak	off-peak	difference	peak	off-peak	ratio
spring	43.73	34.87	8.86	5480	4396	1.25
summer	102.36	48.10	54.26	7039	5131	1.37
fall	51.71	34.22	17.49	5706	4456	1.28
winter	99.20	71.09	28.11	6190	5152	1.20
annual	76.50	47.92	28.58	6104	4782	1.28

price differences on the *ABLMP*s. However, the extent to which load impacts prices is dependent upon the seller offers.[1] As described in section 4.1, the seller offer curve for a month in our sensitivity cases is representative of the respective average *ISO* offer curve for the same month. To illustrate the impact of the seller offers, *MISO*-representative offer curves for August and December 2010 are shown in Fig. 4.11.

As depicted in Fig. 4.11, the offer curves are very flat over a wide range of load values which results in off-peak prices which differ very little from peak prices in those hours where both the peak and off-peak load are served by suppliers whose offers lie in this flat segment of the offer curve. A lack of peak to off-peak period price differentials and similar peak and off-peak supply elasticities are the main factors contributing to the lower impacts of *ESR*s on the *ABLMP*s in the MTS_{57} at all penetration levels in the spring, fall and winter. For example, in December 2010, we see from points C and D in Fig. 4.11 that there is a difference

[1]The price impacts are also dependent upon buyer bids. However, we have assumed the buyers have an arbitrarily high willingness to pay and that the supply is always equal to the demand and so only the seller offers are at play in the extent to which the load impacts the prices.

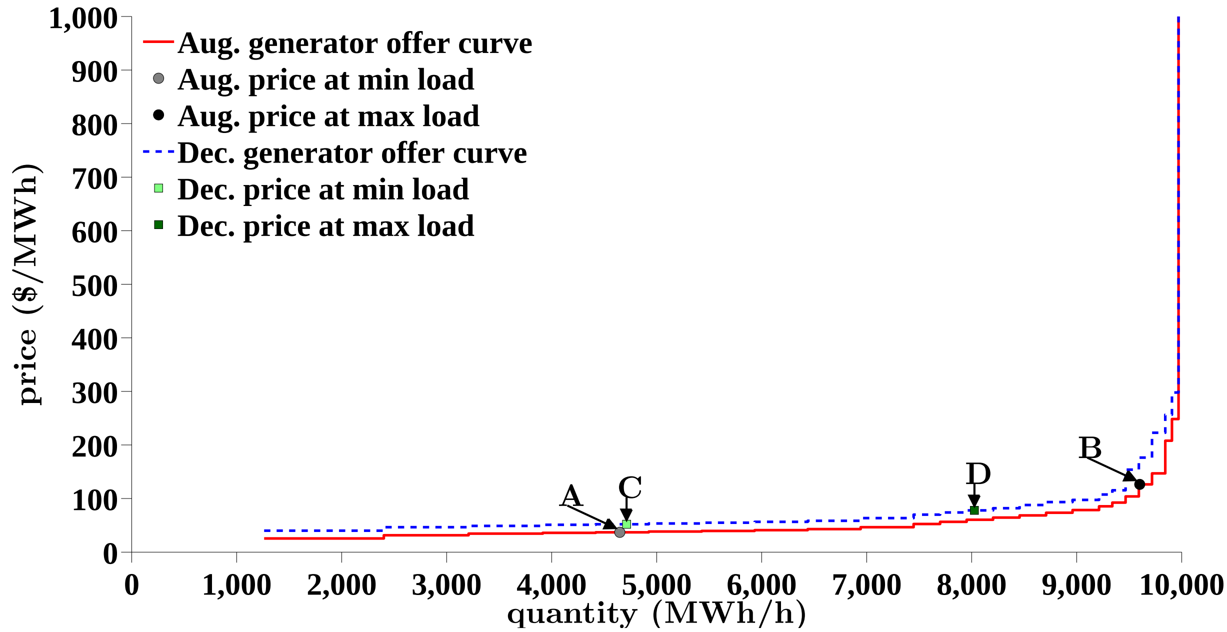

Figure 4.11: *MISO*-representative offer curves for Aug. and Dec. 2010

of around $30 between the price in the hour with the maximum load, around point D, and the price in hour with the minimum load, around point C. Both points C and D are in the flat portion of the offer curve, where the elasticity of supply is high. Similarity between the supply elasticity at points C and D combined with the low winter price differential are the reasons for the modest *ABLMP* impacts reported in Table 4.2 for the spring, fall, and winter.

Conversely, in August 2010, we see from points A and B in Fig. 4.11 that there is a difference of around $75 between the price in the hour with the peak load, around point B, and the price in hour with the base load, around point A. In August, the offers of the suppliers which serve the peak load are in the steeper portion of the offer curve, i.e., where the elasticity of supply is lower. In general, if there is a sufficient difference between the peak and off-peak prices to overcome the cost of *ESR* efficiency losses, *ESR*s will be effective if the offers of suppliers which serve the load in peak periods are in the steeper portion of the offer curve, while the offers of suppliers which serve the off-peak load are in the flatter portion of the offer curve.

Many *ISO* offer curves have a similar shape to the *MISO*-representative curves in Fig. 4.11 where the elasticity of supply decreases as the quantity increases. However, the monotonic decrease of supply elasticity is not always the case for *ISO* supplier offer curves.

The *ISO-NE*-representative offer curves are an example of offers curves which have segments where the supply elasticity increases with increasing quantity. *ISO-NE*-representative offer curves for July and December 2010 are shown in Fig. 4.12. Unlike the single flat seg-

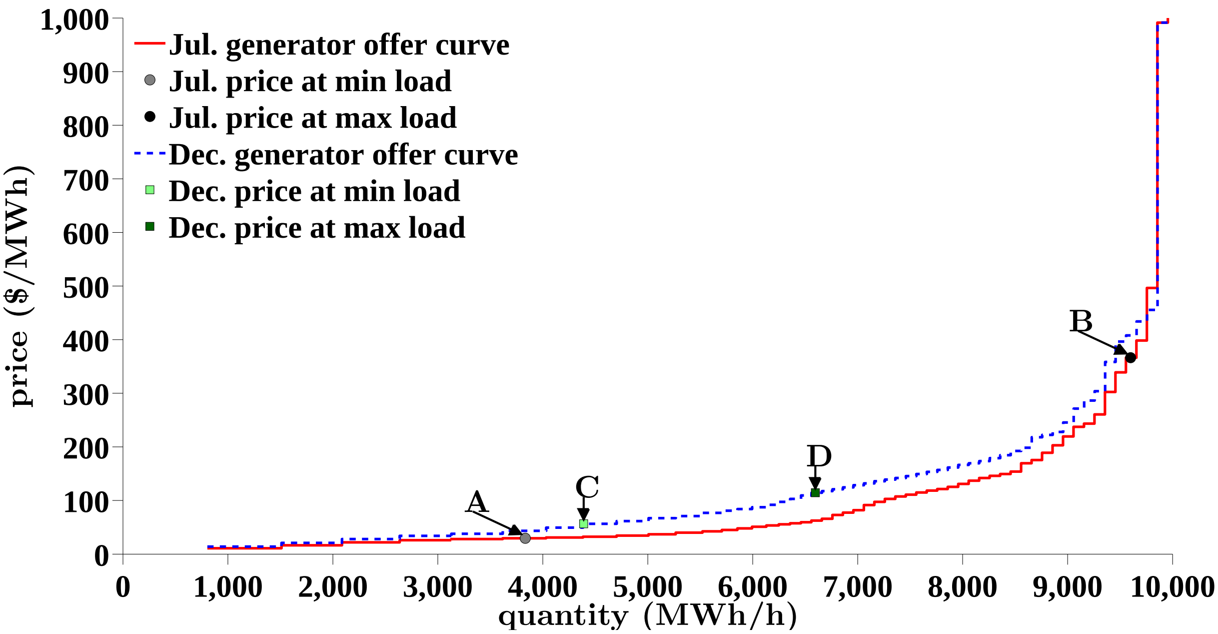

Figure 4.12: *ISO-NE*-representative offer curves for Jul. and Dec. 2010

ment of the *MISO*-representative offer curves, the *ISO-NE*-representative offer curves have two relatively flat segments with an additional steepening portion between 6500 and 7500 MW. The existence of this second steeper portion in the curve is the principal reason for the modest winter and spring *ABLMP* impacts we reported in Table 4.3 compared to the other seasons. In the month of July, we see from points A and B in Fig. 4.12 that the elasticity of supply is clearly less than in the peak periods, around point B, than in the off-peak periods, around point A. In the month of December, the supply elasticity in the peak periods, around point D, is similar to the supply elasticity in the off-peak periods, around point C. With relatively similar supply elasticities between the peak and off-peak periods and low differential between peak and off-peak prices, the *ESR* integration impacts on the *ABLMP*s are modest in the winter period on the MTS_{118}.

From this discussion we conclude that for *ESR*s to be effective at reducing *ABLMP*s, the elasticity of supply must be less in the discharge periods than in the charge periods. The differential in the peak to off-peak elasticity of supply depends on the ratio of peak to off-peak load. Deepening penetration of integrated *ESR*s pushes the points for peak and off-peak periods, depicted in Figs. 4.11 and 4.12 towards each other along the offer curve. The limitations of the *ABLMP* impacts of deepening *ESR* penetrations are driven by the differences between the prices, the elasticity of supply and the load in the peak and off-peak periods.

4.4 The Economic Impacts of *DRR*s

In Chapter 1 we discussed the aspects of *DR* and *ES* resources which led us to the conclusion that we may view *DRR*s as a special case of *ESR*s and represent them as such. Both *DR* and *ES* resources may provide the same energy market service and may therefore be viewed as substitutable resources. If *DR* and *ES* resources are substitutable, the question arises: Which resource is more effective at providing the energy storage service to the system? In this section we discuss the economic impacts of deepening *DRR* penetration and explore the limits of the benefits in reduced *ABLMP*s that *DRR*s may bring to the system and compare them to those of *ESR*s.

Table 4.6 summarizes the *ABLMP* reductions for deepening penetrations of *DRR*s seasonally and annually on the MTS_{57}. Figure 4.13 depicts the annual *ABLMP*s for deepening *DRR* penetrations. From Fig. 4.13 we see that the highest annual reduction in *ABLMP*s with *DRR*s is achieved at a penetration of 2% and the *ABLMP*s begin to increase at penetrations of 9% or deeper. In case $\mathbb{P}^{57}_{10,0}$ the *ABLMP*s increase by approximately 0.65%. In addition, on the MTS_{57}, the highest annual *ABLMP* reduction is 0.64% for case $\mathbb{P}^{57}_{2,0}$, a factor of two less than the 1.27% annual *ABLMP* reduction in $\mathbb{P}^{57}_{0,2}$.

To explain the impacts of *DRR*s on reducing *ABLMP*s we depict the hourly *LMP*s and the hourly loads for the representative summer week of August 9-15, 2010, at bus 12 in Figs. 4.14 and 4.15, respectively, for $\mathbb{P}^{57}_{0,0}$, $\mathbb{P}^{57}_{1,0}$ and $\mathbb{P}^{57}_{10,0}$. *DRR* curtailments reduce the loads in the peak periods and, when curtailed energy is recovered, increase the loads in the off-peak periods, decreasing the ratio of peak to off-peak load. The load shifts may result in price

Table 4.6: The seasonal and annual $ABLMP$ reductions for deepening penetrations of DRRs on the MTS_{57}

DRR penetration (%)	average buyer LMP reduction (%)				
	spring	summer	fall	winter	annual
1	0.13	1.45	0.13	-0.19	0.40
2	0.17	2.63	0.16	-0.54	0.64
3	0.13	3.19	0.03	-1.00	0.61
4	0.03	3.69	-0.13	-1.33	0.60
5	-0.06	3.99	-0.32	-1.62	0.54
6	-0.11	4.05	-0.50	-2.00	0.39
7	-0.22	4.23	-0.62	-2.32	0.30
8	-0.36	4.23	-0.88	-2.87	0.04
9	-0.51	4.02	-1.22	-3.46	-0.30
10	-0.73	3.86	-1.53	-4.11	-0.65

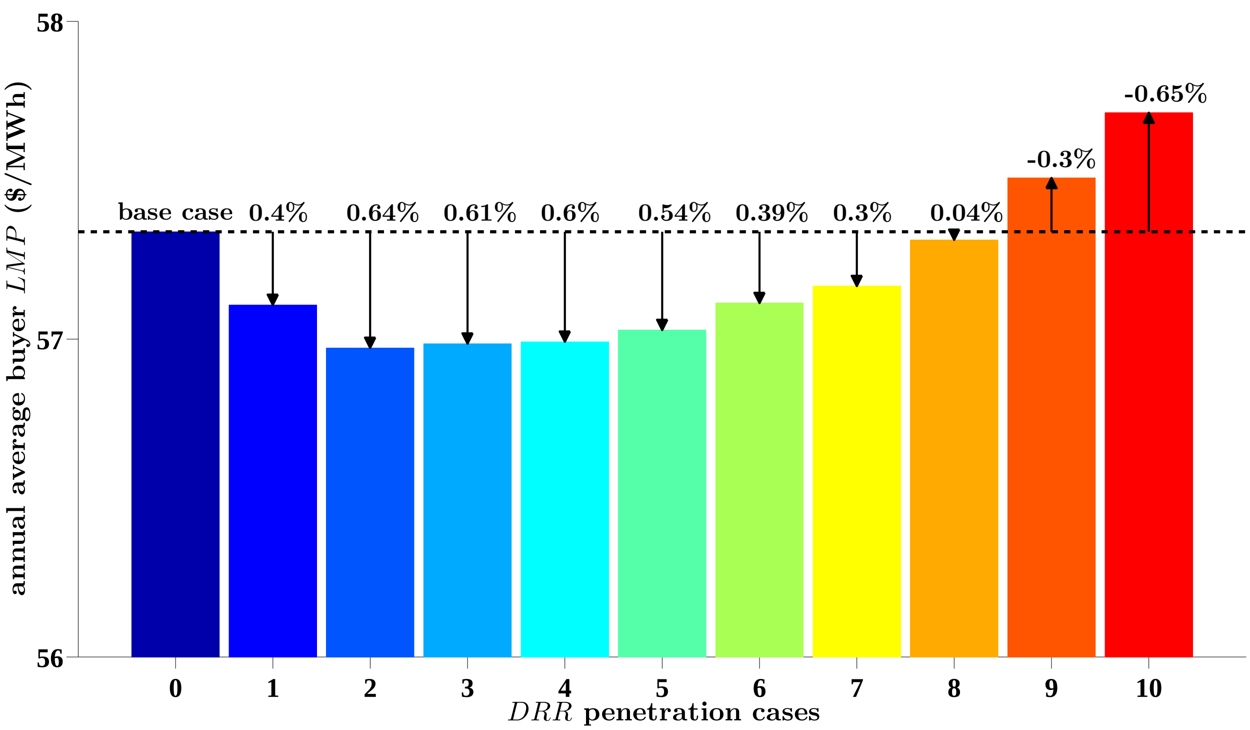

Figure 4.13: The annual $ABLMP$ for deepening penetrations of DRRs on the MTS_{57}

reductions in peak periods for those remaining loads and price increases in off-peak periods for the loads and DRRs recovering energy. We see the impacts of this load shifting in Fig. 4.15. In case $\mathbb{P}^{57}_{1,0}$ the load is impacted very little by the DRR curtailments and recovery, while in case $\mathbb{P}^{57}_{10,0}$ we see a significant impact on the load and the formation of new load

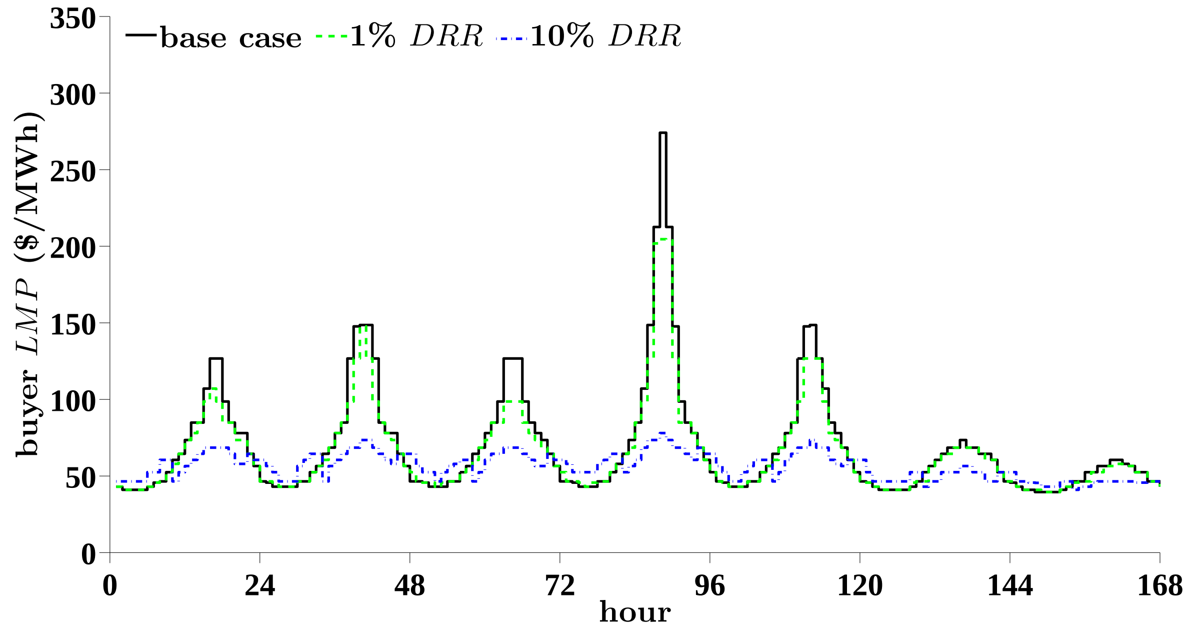

Figure 4.14: The hourly LMPs at bus 12 for the week of Aug. 9–15, 2010, on the MTS_{57}

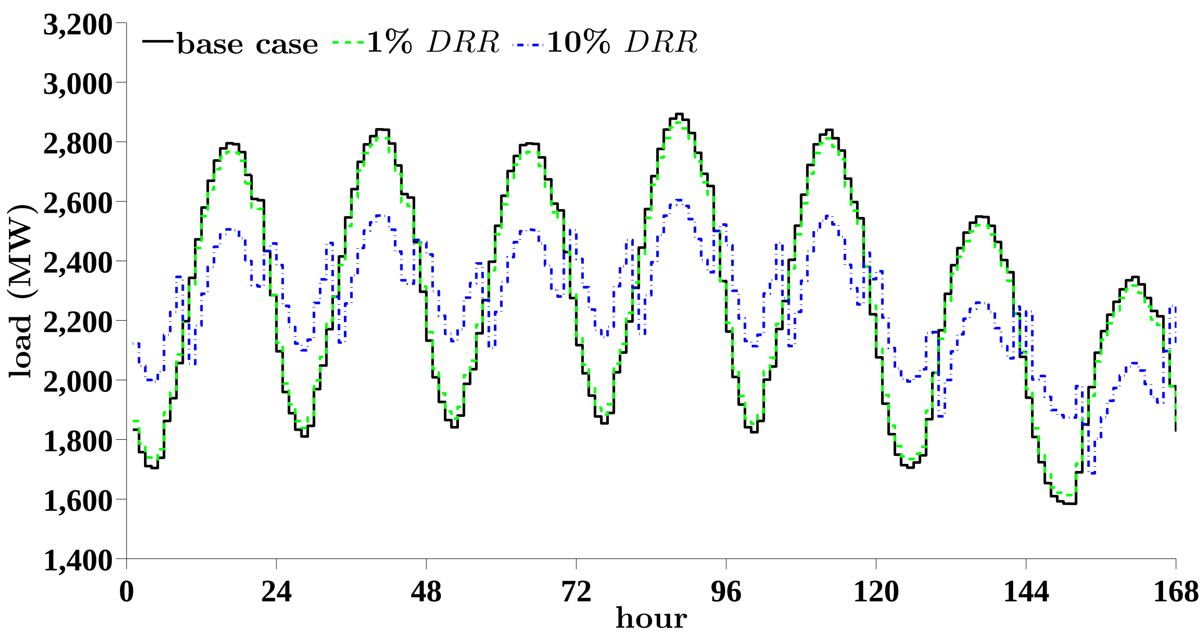

Figure 4.15: The hourly loads at bus 12 for the week of Aug. 9–15, 2010, on the MTS_{57}

peaks in the shoulder hours of the day in which the load is nearly as great as the load in the $\mathbb{P}^{57}_{0,0}$ peak hours. The price impacts of these shoulder hour peak loads may be seen in Fig. 4.14. For case $\mathbb{P}^{57}_{1,0}$ we see price reductions in the peak periods and minor price increases in the recovery periods. However, in case $\mathbb{P}^{57}_{10,0}$, while the prices are reduced in the peak hours of the day as a result of the DRR curtailments, the off-peak period prices spike in the shoulder hours where the new peaks have formed. The additional payments in the shoulder hours overtake the peak period savings, resulting in the $ABLMP$ increases we report in Table 4.6 for DRR penetrations of 9% or deeper. The formation of shoulder hour load peaks causing

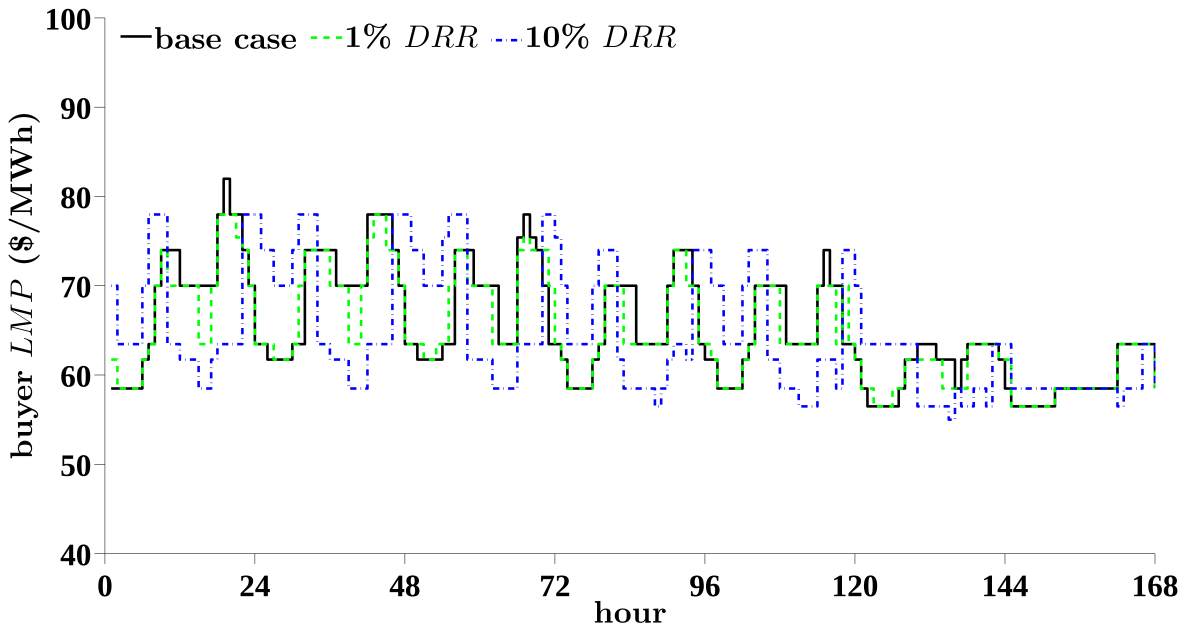

Figure 4.16: The hourly *LMPs* at bus 12 for the week of Dec. 13–19, 2010, on the MTS_{57}

off-peak period LMP spikes is particularly acute in the winter period. Figure 4.17 depicts the loads for the winter week of December 13–19, 2010, at bus 12. Again, the impacts of DRR integration on the loads, and consequently the LMPs, for case $\mathbb{P}^{57}_{1,0}$ are relatively minor. However, in the deep DRR penetration case $\mathbb{P}^{57}_{10,0}$, the load shape is nearly inverted, causing what were previously the off-peak loads to be peak loads at load levels even higher than the previous weekly peak load. These new load peaks drive the price peaks shown in Fig. 4.16. We focus on the day of December 15, 2010, in Figs. 4.18 and 4.19 to see the load and LMP impacts more clearly. The load in shoulder hours, particularly hours 9 and 22, shown in Fig. 4.19 for case $\mathbb{P}^{57}_{10,0}$, is higher than the peak loads in case $\mathbb{P}^{57}_{0,0}$. The impact of these drastic load changes on the LMPs may be seen in Fig. 4.18. In case $\mathbb{P}^{57}_{10,0}$, we observe LMP increases of nearly \$30 in some of the shoulder hours, resulting in new peaks for case $\mathbb{P}^{57}_{10,0}$ which, like the load, are even higher than the peak prices in case $\mathbb{P}^{57}_{0,0}$. The result of these winter load and corresponding LMP spikes is the increased $ABLMP$s at all penetrations of

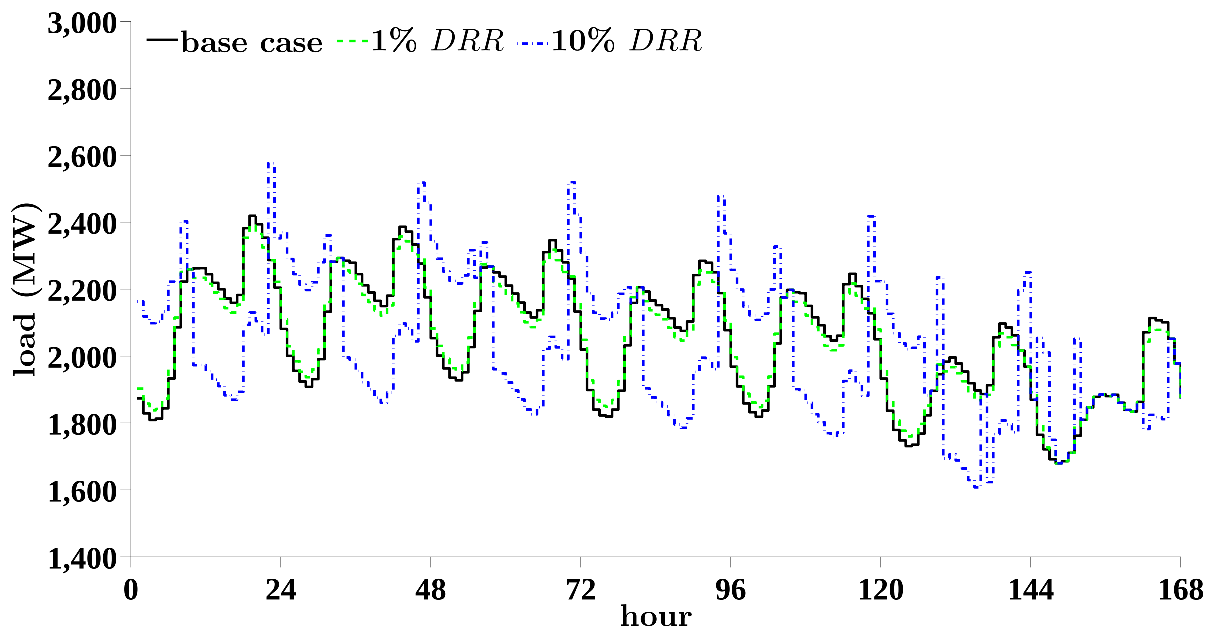

Figure 4.17: The hourly loads at bus 12 for the week of Dec. 13–19, 2010, on the MTS_{57}

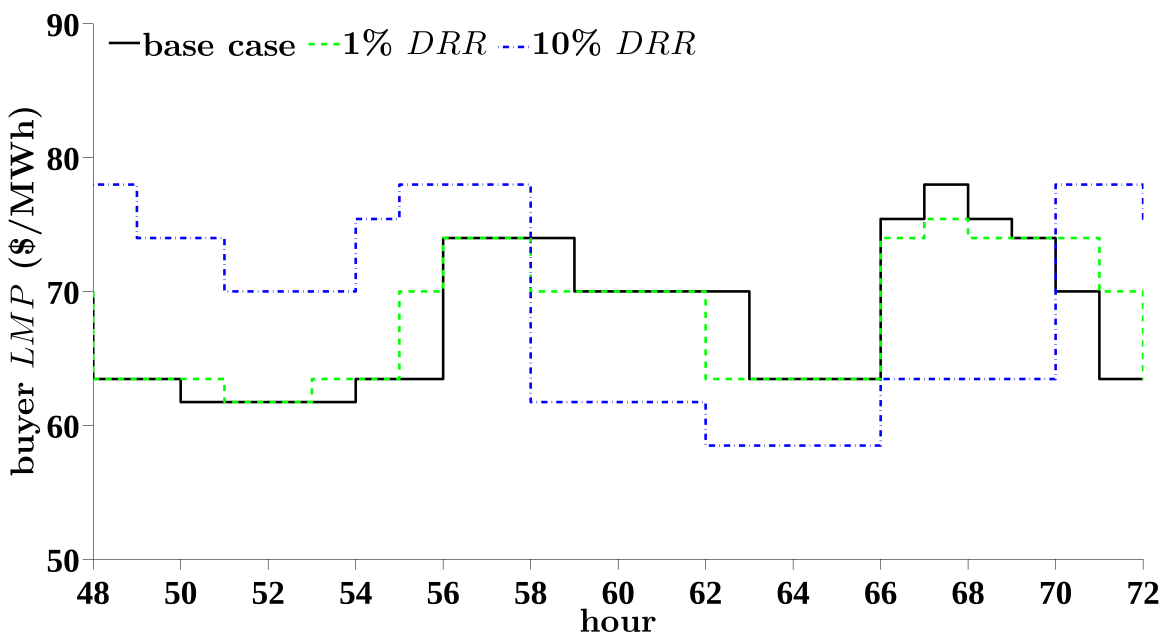

Figure 4.18: The hourly LMPs at bus 12 for December 15, 2010, on the MTS_{57}

DRR in the winter months reported in Table 4.6..

Table 4.7 summarizes the $ABLMP$s reductions for deepening penetrations of DRRs seasonally and annually for the MTS_{118}. Figure 4.20 depicts the annual $ABLMP$s reductions for deepening DRR penetrations.

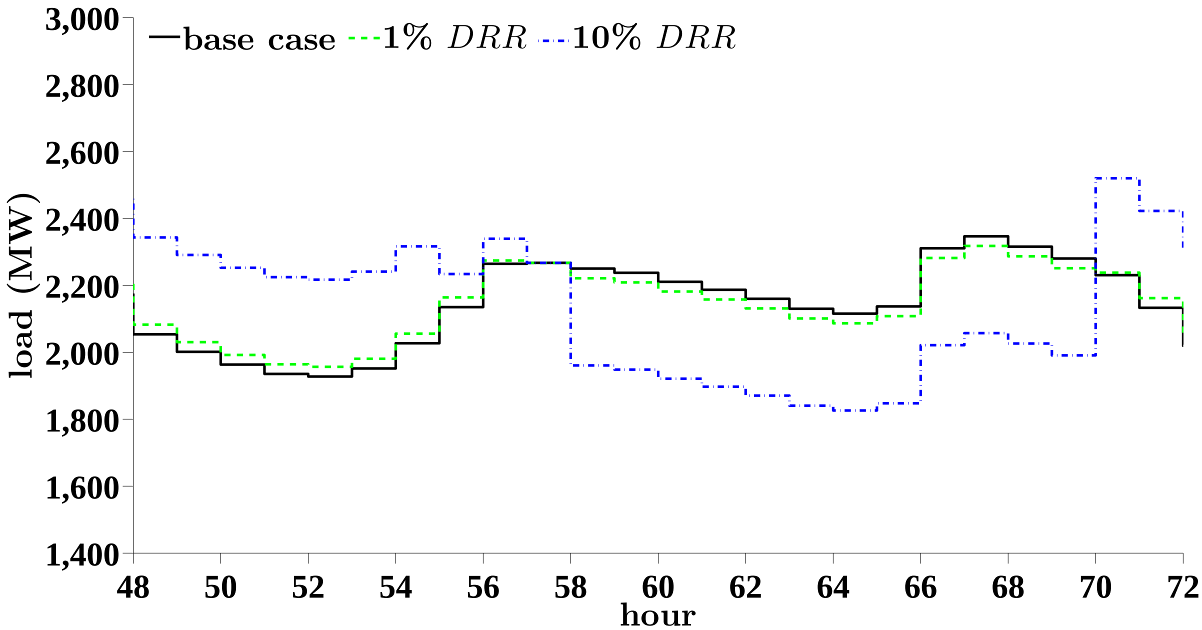

Figure 4.19: The hourly loads at bus 12 for December 15, 2010, on the MTS_{57}

Table 4.7: The seasonal and annual $ABLMP$ reductions for deepening penetrations of DRRs on the MTS_{118}

DRR penetration (%)	average buyer LMP reduction (%)				
	spring	summer	fall	winter	annual
1	0.25	1.30	0.76	0.46	0.77
2	0.43	2.40	1.79	0.75	1.45
3	0.68	3.63	1.98	0.92	2.01
4	0.79	4.65	2.09	0.95	2.40
5	0.76	5.44	2.04	0.92	2.66
6	0.65	5.94	1.46	0.98	2.75
8	0.33	6.64	-0.31	0.39	2.46
10	-0.16	6.50	-3.97	-0.35	1.50
12	-0.88	3.92	-9.64	-1.08	-0.67

From Fig. 4.20 we see that DRRs are more effective at reducing $ABLMP$s on the MTS_{118} than they are on the MTS_{57}—consistent with our findings for ESRs. However, the highest annual $ABLMP$ reduction is still only 2.75% at a 6% DRR penetration. Even in the summer period, the highest $ABLMP$ reduction with integrated DRRs is only 6.64% at 8% penetration. In all seasons with the exception of the summer period, the $ABLMP$s increase in case $\mathbb{P}^{118}_{10,0}$ and annually the $ABLMP$s increase in case $\mathbb{P}^{118}_{12,0}$. This contrasts with ESRs

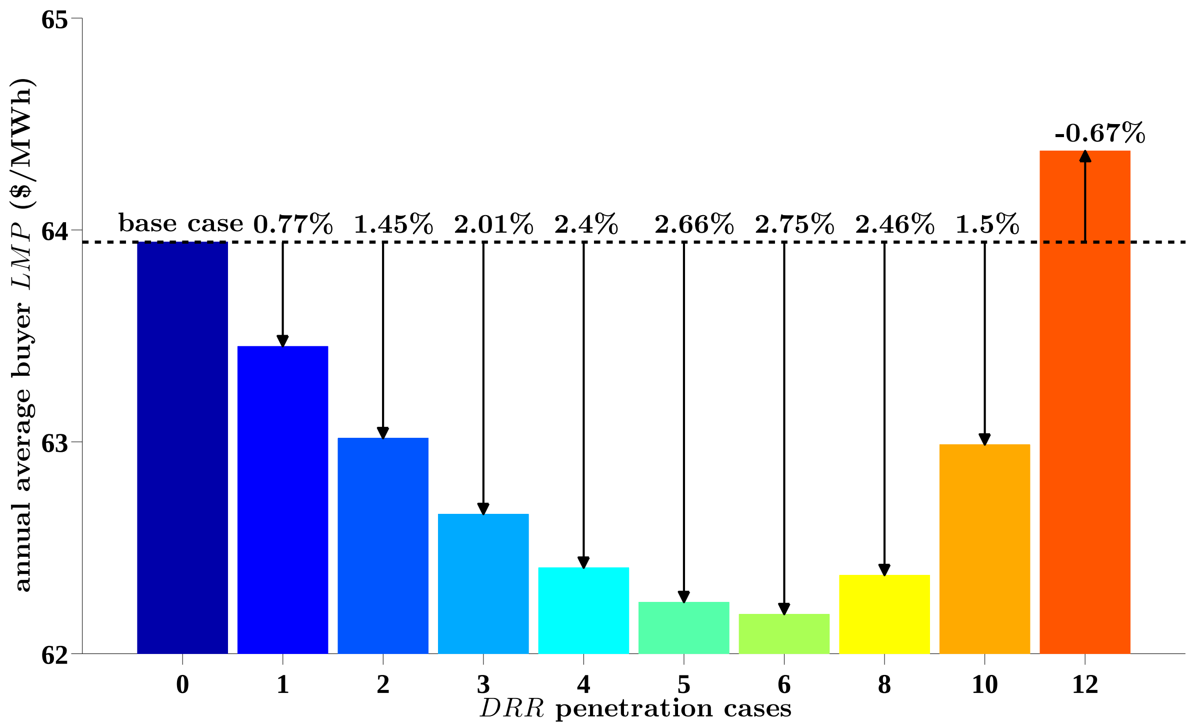

Figure 4.20: The annual $ABLMP$ for deepening penetrations of DRRs on the MTS_{118}

which reduce $ABLMP$s in all cases.

Overall, we observe annual $ABLMP$ reductions of at most 0.64% at 2% DRR penetration and 2.75% at 6% DRR penetration on the MTS_{57} and the MTS_{118}, respectively. In the following section we further explore the factors, such as the curtailed energy recovery requirement, which contribute to the reduced price impacts of DRRs compared to ESRs.

4.5 DRR Limitations

From our discussion in Sections 4.2 and 4.4 we concluded that ESRs are more price effective than DRRs at each penetration level. The reduced price impacts of DRRs compared to ESRs we observe in the case studies is a direct result of the our representation of the requirements of $FERC$ Order No. 745 in the simulation methodology and the additional constraints imposed upon DRRs in the model described in Chapter 2 to represent the physical and operational limitations of DRRs. In this section we describe two key reasons for the limited price impacts of DRRs:

- the "billing unit effect", and
- the constraints on the operation of DRRs imposed by the requirements of $FERC$ Order No. 745 and in particular the application of a system-wide threshold price.

When DRR curtailments take place, the remaining loads make an additional payment to compensate DRRs for their curtailments. The increase in prices resulting from these incentive payments is the billing unit effect [7]. The price reductions caused by the DRR curtailment must be sufficient to cover the compensation of the DRR if the curtailment is to be cost-effective. The billing unit effect dampens the price reductions impacts of DRR curtailments for all penetrations of DRRs integration and may even lead to situations where DRR curtailment results in an increase in $ABLMP$. We observe the billing unit effect by

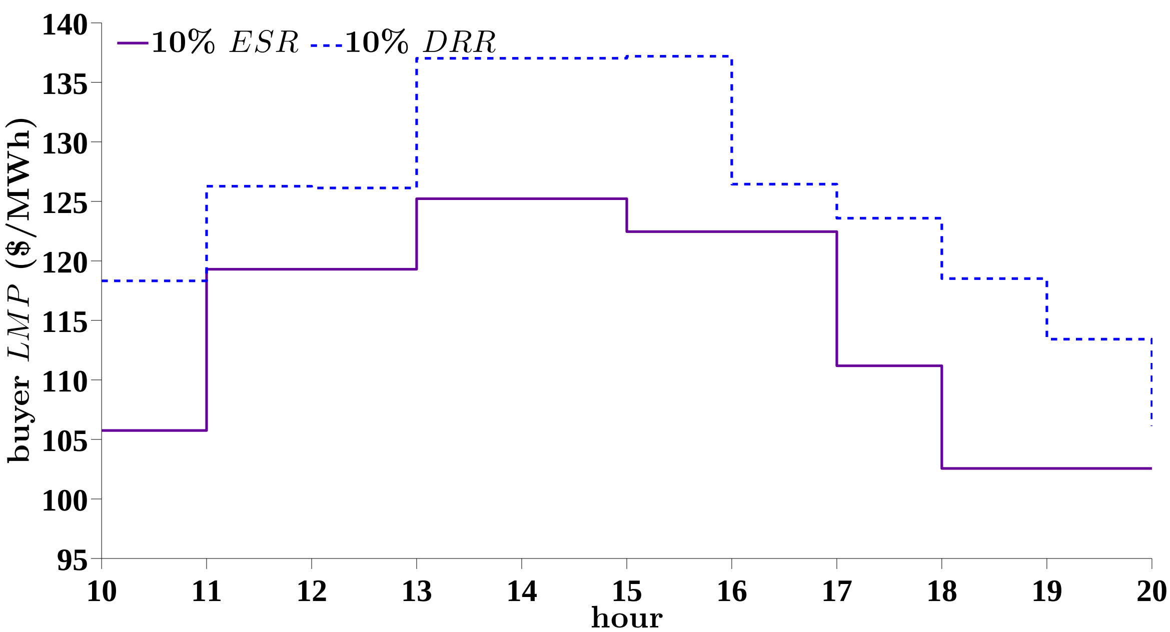

Figure 4.21: The hourly LMPs at bus 59 for the peak hours on July 16, 2010, on the MTS_{118}

comparing the buyer LMPs between $\mathbb{P}^{118}_{0,10}$ and $\mathbb{P}^{118}_{10,0}$ in those hours where $DR(ES)$ resources are curtailed (discharging) at full capacity in Fig. 4.21 and the buyer LMPs with and without the additional incentive payment for DRR curtailments for the same set of hours in Fig. 4.22. We note in Fig. 4.21 that the prices with ESRs are always less than the prices with DRRs as a result of the additional incentive payment buyers make to DRRs, derived in

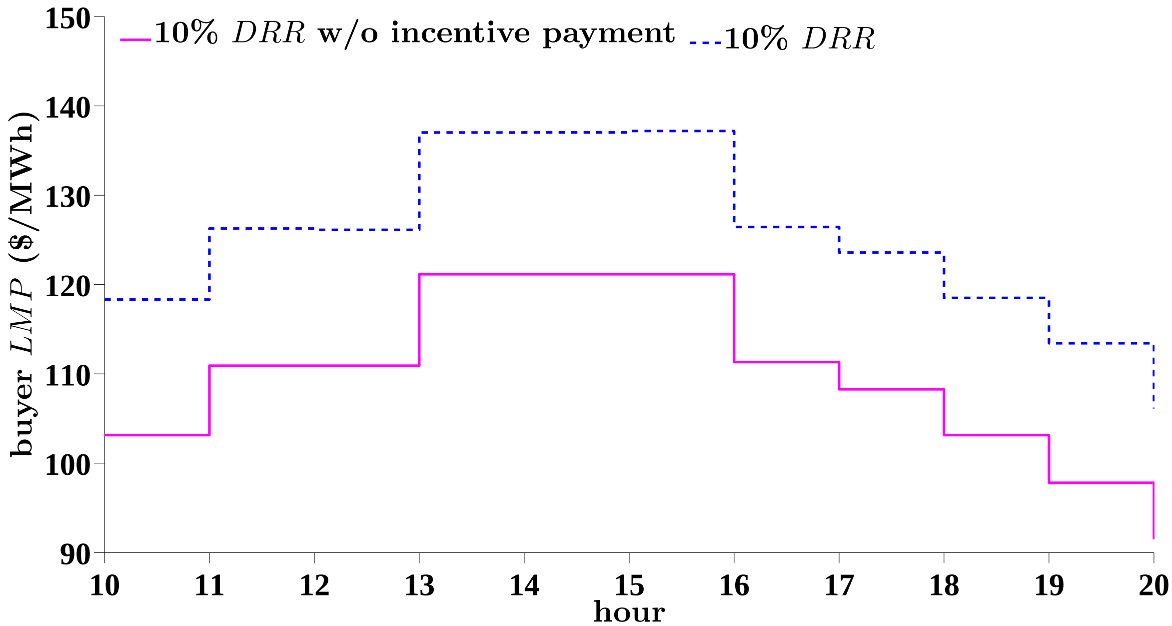

Figure 4.22: The hourly *LMP*s at bus 59 with and without the *DRR* incentive payment for the peak hours on July 16, 2010, on the MTS_{118}

Eq. (2.2). In Fig. 4.22 we show the impact this incentive payment has on the buyer *LMPs*. Clearly, the payments made by the remaining buyers to compensate a 10% *DRR* penetration for curtailments provided have a significant impact on the buyer *LMP*s, increasing them by around 10%, and hence dampen the *ABLMP* reduction impacts of *DRR*s.

The second key driver of the reduced price impacts of *DRR*s is the system-wide threshold price requirement of *FERC* Order No. 745. The threshold price is a measure of the cost effectiveness of *DRR*s—when the threshold price is met, *DRR* curtailments are assumed to be cost effective.

According to our assumptions, the *DRR* curtailments are restricted to occur between the hours of 10:00 a.m. and 10:00 p.m. and *DRR*s curtail at full capacity whenever they are accepted for curtailment. In the absence of *DRR* curtailed energy recovery, these full capacity curtailments exacerbate the billing unit effect in the shoulder hours. However, when the curtailed energy is recovered according to the constraint in Equation (2.4), which also is also applied to *DRR*s, the recovery of curtailed energy may also cause buyer *LMP* increases in the hours in which energy is recovered. Furthermore, we assume the *DRR*s recover the curtailed energy in the same day. Our assumptions and the application of the recovered energy constraint result in the shoulder hour price spikes we observe in Figs. 4.16 and 4.18.

If the *DRR* curtails in every peak hour of the day and recovery is assumed to occur at a capacity no greater than the curtailment, the shoulder hour load spikes, and the resulting price spikes, are an inevitable consequence of curtailed energy recovery, since the *DRR* must recover at full capacity in every recovery hour to ensure the recovered energy constraint is not violated. *ESR*s, on the other hand, operate at less than full capacity in the shoulder hours of the peak and off-peak periods. This operational aspect of *ESR*s is exemplified by Fig. 4.4 for case $\mathbb{P}^{57}_{0,10}$ where the *LMP*s in the charge hours never exceed the *LMP*s in the discharge hours, which is in direct contrast to the shoulder hour *LMP* spikes we see in Fig. 4.16 for case $\mathbb{P}^{57}_{10,0}$. The difference between the load shape and the *LMP* impacts of *DR* and *ES* resources in these two cases is a result of the energy recovery constraints enforced for each resource in the *EMCP*.

Due to the threshold criteria, *DRR*s offer the *ISO* fewer degrees of freedom than *ESR*s. The hours and capacity of curtailment are fixed variables in the *MCP* for *DRR*s whereas the *ESR* discharge variables are decision variables in the *EMCP*. The only degrees of freedom for *DRR*s are the hours and capacities of recovery, which are also somewhat restricted by the amount of curtailed energy that must be recovered. The reduced number of degrees of freedom that *DRR*s offer to the *ISO* and the damping effects of the billing unit effect on *ABLMP* reductions resulting from *DRR* curtailments are the key aspects which limit the *DRR*s impacts on the *ABLMP*s.

4.6 Summary

In this chapter we summarized the results of our extensive studies with illustrative sensitivity cases from the MTS_{57} and the MTS_{118}. We focused on the impacts of *DR* and *ES* resources on *ABLMP*s and developed intuition about the characteristics of systems in which *DR* and *ES* resources have greater price impacts.

It is clear from our sensitivity studies that *ESR* have a greater impact than *DRR*s at reducing *ABLMP*s. Furthermore, we find that *DRR*s become uneconomic at relatively low penetrations when the recovery of curtailed energy is taken into account. We summarize our key insights as follows:

- *ABLMP*s reductions are the highest on the MTS_{57} for *DR* and *ES* resource penetrations of 2% and 9%, respectively;

- *ABLMP*s reductions are the highest on the MTS_{118} for *DR* and *ES* resource penetrations of 6% and 20%, respectively;

- the shape of the offer curve is an important factor determining the price impacts of *DR* and *ES* resources: systems with a lower ratio of the elasticity of supply in the curtailment/discharge periods to the elasticity of supply in the recover/charge periods can accommodate deeper penetrations of *DR* and *ES* resources;

- the load shape is important factor determining the price impacts of *DR* and *ES* resources: systems with a higher ratio of load in peak periods to load off-peak periods can accommodate deeper penetrations of *DR* and *ES* resources; and

- the requirements of *FERC* Order No. 745, which limit the number of degrees of freedom *ISO*s have in controlling *DRR*s by prescribing a system-wide curtailment threshold price, along with the billing unit effect, which dampens the *ABLMP* impacts of *DRR* curtailments, are two principal factors in the reduced price impacts of *DR* as compared to *ES* resources.

Clearly, there are limitations to the *ABLMP* reductions which result from deepening *ES* and *DR* penetrations. The results of the studies presented in this chapter are useful to guide policies which incentivize appropriate penetrations of *DR* and *ES* resources and demonstrate the usefulness of the flexible market simulation framework presented in this work. In the following chapter we summarize the work presented this thesis and point out directions for future research.

CHAPTER 5

CONCLUSIONS

5.1 Summary

In this work we have provided a comparative economic assessment of the impacts of *DR* and *ES* resources participating in the *DAM*s. In order to perform the assessment, we constructed a flexible simulation approach which represents the salient aspects of the *DAM*s and the current regulatory environment. The engine of our approach is the *EMCP* framework developed in Chapter 2. In the *EMCP* framework, we explicitly account for *ES* and *DR* resources and the transmission-constrained network. Furthermore, we represent *DRR*s as a special case of *ESR*s, which allows for the comparison of *ES* and *DR* resources on equal footing. Our approach also allows the assessment of the impacts of *DRR* recovery energy—an important, and often ignored, component of economic impacts of *DRR*s on the *DAM*s.

We applied the simulation approach to perform the comparative economic assessment of the impacts of deepening capacity penetrations of *ES* and *DR* resources with their explicit participation in *DAM*s using data from the *ISO-NE* and *MISO*. In our studies, we investigated the reductions in the *ABLMP* which result from the participation of *ES* and *DR* resources with capacities penetrations in the 0% to 30% of system peak load range.

We found the deployment of *ESR*s has a greater impact on reducing the *ABLMP* than *DRR*s at each penetration investigated, reducing the *ABLMP*s by as much as 9.2% compared to the base case system with no deployed *DR* or *ES* resources. *DRR*s, on the other hand, resulted in *ABLMP* reductions of at most 2.7% compared to the base case due to the additional regulatory constraints in place for *DRRs*. Furthermore, we find that *DRR*s cause increases in the *ABLMP* at relatively low penetrations when *DRR* energy recovery is taken into account—contrary to the results of other studies which have investigated the economic impacts of *DRR*s in the market environment. Additionally, we find that systems which experience a greater difference between the average peak and off-peak locational marginal prices (*LMP*s) and/or a higher ratio of average peak to off-peak loads accommodate deeper penetrations of *ES* and *DR* resources before the *ABLMP* reductions are saturated with respect to *ES* and/or *DR* resources—the sensitivity of the *ABLMP* reductions compared to the base case to an additional MW of *ES* and *DR* resource capacity becomes zero or negative. We find that the economic impacts of *DRR*s on the *ABLMP*s saturate at 2%–6% penetration while those of *ESR*s saturate at 9%–20% penetration.

The results of such studies provide useful information for planning, the development of operational procedures, the formulation of effective policy and other electricity grid stakeholder decision making processes. Furthermore, the flexible market simulation approach developed in this work provides electricity grid stakeholders a means to perform a number of "what if" studies to analyze the economic impacts of the various aspects of *ES* and *DR* resources on the *DAM*s.

The prominent role of the electricity sector in addressing global climate change necessitates understanding on the part of all stakeholders of the greenhouse gas emissions impacts of resource deployment decisions. An extension of this work is the application of the framework to investigate the greenhouse gas emissions impacts of *DR* and *ES* resources participating in the *DAM*s.

Another extension of this work is the integration of the variable and intermittent renewable energy sources and their associated uncertainty as well as other sources of uncertainty, such as resource and line availability, in the simulation framework. Representing sources of uncertainty would allow the framework to be applied to an even wider range of "what if" questions.

In this work we have considered *ES* and *DR* resources operated by the *ISO* as a system resource. A further extension is the application of the simulation approach to study the impacts of private *ES* and *DR* resource providers on the *DAM*s.

APPENDIX A

ACRONYMS AND NOTATION

A.1 Acronyms

ABLMP	Average buyer locational marginal price
ARRA	American Recovery and Reinvestment Act
CSP	Curtailment service provider
DAM	Day-ahead market
DR	Demand response
DRR	Demand response resource
DSM	Demand-side management
DOE	U.S. Department of Energy
EMCP	Extended transmission-constrained market clearing problem
EPAct	U.S. Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ES	Energy storage
ESR	Energy storage resource
ESP	Energy service provider
FERC	Federal Energy Regulatory Commission
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
LMP	Locational marginal price
MCP	Transmission-constrained market clearing problem

MISO	Midwest Independent System Operator
PJM	Pennsylvania-New Jersey-Maryland Interconnection

A.2 Notation

The following are the key aspects of the notation used

- all variables are in italics
- all vectors and matrices are in **bold** and <u>underline</u>
- all optimal solutions are represented with the notation $[\cdot]^\star$
- all network-related indices are in subscripts

The simulation time-related notation is given as follows

$\mathscr{T}$	:	index set of simulation periods
T	:	$\lvert\mathscr{T}\rvert$
t	:	simulation period with values $1, \ldots, T$
$\mathscr{K}_t$	:	index set of daily subperiods from simulation period t
K	:	$\lvert\mathscr{K}\rvert$
k	:	daily subperiod with values $k_1, \ldots, k_K$
$\mathscr{H}_k$	:	index set of hourly subperiods from daily subperiod k
H	:	$\lvert\mathscr{H}\rvert$
h	:	hourly subperiod with values $h_1, \ldots, h_H$
m	:	number of days in the multi-day *ESR* schedule minus one

The seller-related notation for hour h is

$\mathscr{S}$	:	set of sellers

$$
\begin{aligned}
S &: \quad |\mathscr{S}| \\
s &: \quad \text{seller index with values } s_1, \ldots, s_S \\
p^s[h] &: \quad \text{output of seller } s \text{ in period } h \\
\mathcal{C}^s\left(p^s[h]\right) &: \quad \text{integral of the offer function of a seller } s \text{ to output } p^s[h] \\
p^s_M[h] &: \quad \text{upper bound on the capacity offered by seller } s \\
p^s_m[h] &: \quad \text{lower bound on the capacity offered by seller } s \\
p^g_n[h] &: \quad \text{sum of the injections into node } n
\end{aligned}
$$

The buyer-related notation for an hour h is

$$
\begin{aligned}
\mathscr{B} &: \quad \text{set of buyers} \\
B &: \quad |\mathscr{B}| \\
b &: \quad \text{buyer index with values } b_1, \ldots, b_B \\
p^b[h] &: \quad \text{demand of buyer } b \text{ in period } h \\
\mathcal{B}^b\left(p^b[h]\right) &: \quad \text{integral of the bid function of a buyer } b \text{ to demand } p^b[h] \\
p^s_M[h] &: \quad \text{upper bound on the capacity bid for by buyer } b \\
p^s_m[h] &: \quad \text{lower bound on the capacity bid for by buyer } b \\
p^d_n[h] &: \quad \text{sum of the withdrawals from node } n
\end{aligned}
$$

The network-related notation for an hour h is

$$
\begin{aligned}
\mathscr{N} &: \quad \text{set of nodes} \\
N &: \quad |\mathscr{N}| - 1 \\
n &: \quad \text{node index with values } 0, 1, \ldots, N \\
\mathscr{J} &: \quad \text{set of lines} \\
J &: \quad |\mathscr{J}| \\
j &: \quad \text{line index with values } 1, 2, \ldots, J
\end{aligned}
$$

$\boldsymbol{A}$: reduced network incidence matrix without the column for the slack bus, $\boldsymbol{A} \in \mathbb{R}^{J\times(N)}$

$\boldsymbol{B}$: reduced branch susceptance matrix, $\boldsymbol{B} \in \mathbb{R}^{N\times N}$

$\boldsymbol{B}_d$: diagonal branch susceptance matrix, $\boldsymbol{B}_d \in \mathbb{R}^{J\times J}$

$\boldsymbol{b}_0$: vector of susceptances for branches between each node and the slack node, $\boldsymbol{b}_0 \in \mathbb{R}^{N+1}$

$\boldsymbol{\theta}[h]$: vector of nodal voltage angles (excluding the slack node) in hour h, $\boldsymbol{\theta}[h] \in \mathbb{R}^{N}$

$f_j[h]$: flow on line j in hour h

$f_j^M[h]$: upper bound on positive flow on line j

$f_j^m[h]$: lower bound on negative flow on line j

The *ESR*-related notation for an hour h is

$\mathscr{U}$: set of storage units

U : $|\mathscr{U}|$

u : storage unit index with values $u_1, \ldots, u_U$

$p^u[h]$: scheduled charge/discharge quantity of storage unit u

$c^u[h]$: charge capacity scheduled for storage unit u

$d^u[h]$: discharge capacity scheduled for storage unit u

$d^u_M[h]$: upper bound on the discharge capacity of storage unit u

$d^u_m[h]$: lower bound on the discharge capacity of storage unit u

$c^u_M[h]$: upper bound on the charge capacity of storage unit u

$c^u_m[h]$: lower bound on the charge capacity of storage unit u

$y^u[h_0]$: initial stored energy of storage unit u

$y^u[h]$: stored energy of storage unit u

$y_M^u[h]$: upper bound on the storage capability of storage unit u

$y_m^u[h]$: lower bound on the storage capability of storage unit u

η_c^u : charge efficiency of storage unit u, $\eta_c^u \in [0, 1]$

η_d^u : discharge efficiency of storage unit u, $\eta_d^u \in [0, 1]$

η_r^u : roundtrip efficiency of storage unit u, $\eta_r^u \in [0, 1]$

α_k^u : ratio of charged to discharged energy in unit u at the end of the daily subperiod

$c_n^{\mathscr{U}}[h]$: sum of the storage charging at node n

$d_n^{\mathscr{U}}[h]$: sum of the storage discharging at node n

The *DRR*-related notation for an hour h is

$\bar{\mathscr{B}}$: subset of buyers in $\mathscr{B}$ operating as pure buyers

$\tilde{\mathscr{B}}$: subset of buyers in $\mathscr{B}$ capable of acting as a *DRR*s

$\mathscr{B}$: $\tilde{\mathscr{B}} \cup \bar{\mathscr{B}}$, $\tilde{\mathscr{B}} \cap \bar{\mathscr{B}} = \emptyset$

$p^{\bar{b}}[h]$: load of pure buyer $\bar{b}$

$\tilde{p}^{\tilde{b}}[h]$: curtailment/recovery of *DRR* $\tilde{b}$

$p^{\tilde{b}}[h]$: load of buyer $\tilde{b}$ in hour h, $p^{\tilde{b}}[h] \geq \tilde{p}^{\tilde{b}}[h]$

$\alpha_k^{\tilde{b}}$: ratio of recovered to curtailed energy by *DRR* $\tilde{b}$ at the end of the daily subperiod

$\mathscr{E}$: set of resources offering energy storage services to the system, $\mathscr{U} \cup \tilde{\mathscr{B}}$

e : index of elements of $\mathscr{E}$

The market-related notation for an hour h is

$\lambda_n[h]$: post-curtailment *LMP* at node n

$\bar{\lambda}_n[h]$: pre-curtailment *LMP* at node n

$\lambda^r[h]$: threshold price

$\rho^{\mathscr{S}}[h]$: the payments to sellers

$\rho^{\bar{\mathscr{B}}}[h]$: the by pure buyer payments

$\rho_d^{\mathscr{U}}[h]$: the payments to storage units

$\rho_c^{\mathscr{U}}[h]$: the payments by storage units

$\rho_d^{\tilde{\mathscr{B}}}[h]$: the payments to DRRs

$\rho_c^{\tilde{\mathscr{B}}}[h]$: the payments by DRRs

$\bar{\mathscr{N}}[h]$: subset of nodes of $\mathscr{N}$ where $\lambda_n[h] \leq \bar{\lambda}_n[h]$

$\upsilon_n[h]$: additional charge to buyers at node n for DRR curtailment incentive payments

APPENDIX B

TEST SYSTEM DATA

Table B.1: Monthly threshold prices for the MTS_{57} and MTS_{118}, respectively

	threshold price ($/MWh)	
month	MTS_{57}	MTS_{118}
Jan.	72.35	114.74
Feb.	78.70	105.70
Mar.	43.54	51.16
Apr.	58.91	39.01
May	60.43	45.28
Jun.	49.70	48.21
Jul.	43.95	47.50
Aug.	44.30	34.64
Sep.	43.39	31.06
Oct.	42.19	26.18
Nov.	59.34	33.74
Dec.	60.41	82.32

Table B.2: MTS_{118} line data

from	to	x (Ω)	line limit (MW)	from	to	x (Ω)	line limit (MW)
1	2	9.99	545	35	37	4.97	545
1	3	4.24	545	33	37	14.2	599
4	5	0.798	545	34	36	2.68	545
3	5	10.8	545	34	37	0.94	545
5	6	5.4	545	38	37	3.75	545
6	7	2.08	545	37	39	10.6	545
8	9	3.05	545	37	40	16.8	545
8	5	2.67	1061	30	38	5.4	2502
9	10	3.22	545	39	40	6.05	545
4	11	6.88	545	40	41	4.87	545
5	11	6.82	545	40	42	18.3	545
11	12	1.96	545	41	42	13.5	545
2	12	6.16	545	43	44	24.54	545
3	12	16	545	34	43	16.81	545
7	12	3.4	545	44	45	9.01	545
11	13	7.31	545	45	46	13.56	545
12	14	7.07	545	46	47	12.7	545
13	15	24.44	545	46	48	18.9	545
14	15	19.5	545	47	49	6.25	545
12	16	8.34	545	42	49	32.3	545
15	17	4.37	545	42	49	32.3	545
16	17	18.01	545	45	49	18.6	545
17	18	5.05	545	48	49	5.05	545
18	19	4.93	545	49	50	7.52	545

Table B.2: MTS_{118} line data (cont.)

from	to	x (Ω)	line limit (MW)	from	to	x (Ω)	line limit (MW)
19	20	11.7	545	49	51	13.7	545
15	19	3.94	545	51	52	5.88	545
20	21	8.49	545	52	53	16.35	545
21	22	9.7	545	53	54	12.2	545
22	23	15.9	545	49	54	28.9	545
23	24	4.92	877	49	54	29.1	545
23	25	8	545	54	55	7.07	545
26	25	3.82	545	54	56	0.955	545
25	27	16.3	545	55	56	1.51	545
27	28	8.55	545	56	57	9.66	545
28	29	9.43	545	50	57	13.4	545
30	17	3.88	545	56	58	9.66	545
8	30	5.04	2068	51	58	7.19	545
26	30	8.6	545	54	59	22.93	545
17	31	15.63	545	56	59	25.1	545
29	31	3.31	545	56	59	23.9	545
23	32	11.53	545	55	59	21.58	545
31	32	9.85	545	59	60	14.5	545
27	32	7.55	545	59	61	15	545
15	33	12.44	599	60	61	1.35	545
19	34	24.7	599	60	62	5.61	545
35	36	1.02	545	61	62	3.76	545
63	59	3.86	545	90	91	8.36	545
63	64	2	545	89	92	5.05	545
64	61	2.68	545	89	92	15.81	545
38	65	9.86	2275	91	92	12.72	545
64	65	3.02	599	92	93	8.48	545
49	66	9.19	545	92	94	15.8	545
49	66	9.19	545	93	94	7.32	545
62	66	21.8	545	94	95	4.34	545
62	67	11.7	545	80	96	18.2	545
65	66	3.7	545	82	96	5.3	545
66	67	10.15	545	94	96	8.69	545
65	68	1.6	1554	80	97	9.34	545
47	69	27.78	545	80	98	10.8	545
49	69	32.4	545	80	99	20.6	545
68	69	3.7	545	92	100	29.5	545
69	70	12.7	545	94	100	5.8	545
24	70	41.15	599	95	96	5.47	545
70	71	3.55	599	96	97	8.85	545
24	72	19.6	599	98	100	17.9	545
71	72	18	599	99	100	8.13	545
71	73	4.54	545	100	101	12.62	545
70	74	13.23	545	92	102	5.59	545
70	75	14.1	545	101	102	11.2	545
69	75	12.2	545	100	103	5.25	545
74	75	4.06	545	100	104	20.4	545
76	77	14.8	545	103	104	15.84	545
69	77	10.1	545	103	105	16.25	545
75	77	19.99	545	100	106	22.9	545
77	78	1.24	545	104	105	3.78	545
78	79	2.44	545	105	106	5.47	545
77	80	4.85	545	105	107	18.3	545
77	80	10.5	545	105	108	7.03	545
79	80	7.04	545	106	107	18.3	545
68	81	2.02	1167	108	109	2.88	545
81	80	3.7	1167	103	110	18.13	545
77	82	8.53	545	109	110	7.62	545
82	83	3.665	545	110	111	7.55	545
83	84	13.2	545	110	112	6.4	545
83	85	14.8	545	17	113	3.01	545
84	85	6.41	545	32	113	20.3	545
85	86	12.3	545	32	114	6.12	545
86	87	20.74	545	27	115	7.41	545
85	88	10.2	545	114	115	1.04	545
85	89	17.3	545	68	116	0.405	545
88	89	7.12	545	12	117	14	545
89	90	18.8	545	75	118	4.81	545
89	90	9.97	545	76	118	5.44	545

Table B.3: Load distribution data for the for the MTS_{118}

buyer bus and buyer load (% of total hourly load)																			
bus	load	bus	load	bus	load	bus	load	bus	load	bus	load	bus	load	bus	load	bus	load	bus	load
1	1.2	13	0.8	25	0.0	37	0.0	49	2.1	61	0.0	73	0.1	85	0.6	97	0.4	109	0.2
2	0.5	14	0.3	26	0.0	38	0.0	50	0.4	62	1.8	74	1.6	86	0.5	98	0.8	110	0.9
3	0.9	15	2.1	27	1.7	39	0.6	51	0.4	63	0.0	75	1.1	87	0.0	99	1.0	111	0.0
4	0.9	16	0.6	28	0.4	40	1.6	52	0.4	64	0.0	76	1.6	88	1.1	100	0.9	112	1.6
5	0.0	17	0.3	29	0.6	41	0.9	53	0.5	65	0.0	77	1.4	89	0.0	101	0.5	113	0.1
6	1.2	18	1.4	30	0.0	42	2.3	54	2.7	66	0.9	78	1.7	90	3.8	102	0.1	114	0.2
7	0.4	19	1.1	31	1.0	43	0.4	55	1.5	67	0.7	79	0.9	91	0.2	103	0.5	115	0.5
8	0.7	20	0.4	32	1.4	44	0.4	56	2.0	68	0.0	80	3.1	92	1.5	104	0.9	116	4.3
9	0.0	21	0.3	33	0.5	45	1.2	57	0.3	69	0.0	81	0.0	93	0.3	105	0.7	117	0.5
10	0.0	22	0.2	34	1.4	46	0.7	58	0.3	70	1.6	82	1.3	94	0.7	106	1.0	118	0.8
11	1.7	23	0.2	35	0.8	47	0.8	59	6.5	71	0.0	83	0.5	95	1.0	107	1.2		
12	1.1	24	0.3	36	0.7	48	0.5	60	1.8	72	0.3	84	0.3	96	0.9	108	0.0		

Table B.4: Offer data for the for the MTS_{118} for the months of Jan.–Jun. 2010

		monthly seller offer prices ($)					
seller bus	seller quant. (MW)	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
69	804.5	13.5	12.7	10.5	10	10	11.5
89	706.4	20.2	19.1	15.7	15	15	17.2
80	576.5	27	25.5	21	20	20	23
10	549.5	35	31.5	25	23	23	27
66	491.6	39.5	35.5	27.5	25	25.5	29
65	490.6	43.5	39.5	30	27	28	31
26	413.6	51	44.5	32	29	30	33
100	351.7	56	48	34	31.5	32	34.5
25	319.7	60	51	36.5	33.5	33.5	36.5
49	303.7	65	54.5	38.5	35.5	35.5	39.5
61	259.8	69	58	40.5	37.5	37	42
59	254.8	74	63	43	39.5	39	44
12	184.8	80.5	68	45.5	41	41	46
54	147.9	87.5	72.5	47.5	42	43	48
103	139.9	94	78	50	43.5	45	50
111	135.9	97.5	83.5	52	45	47	53
46	118.9	100	88	53.5	46.5	49	56.5
31	106.9	103.5	92	56.5	48	51	59
87	103.9	107.5	95.5	61	49.5	54	61
1	99.9	110.5	99	64	52.5	59	63
4	99.9	112.5	103.5	69	56.5	61	65
6	99.9	114	108.5	79.5	60	62.5	68
8	99.9	116	110.5	87.5	64	64.5	71.5
15	99.9	118.5	112	96.5	67.5	73	76
18	99.9	121	113	100.5	75	81	84.5
19	99.9	123	114.5	107.5	88	89	90.5
24	99.9	125	116	111	96.5	94.5	99
27	99.9	127	118	113	101.5	99.5	106.5
32	99.9	129	120	115	110	105.5	110
34	99.9	131.5	122	118	113	110	112
36	99.9	134	124	121	115.5	112	114
40	99.9	137.5	126.5	123	121.5	114	116
42	99.9	142.5	131	125	124.5	116.5	118.5
55	99.9	146.5	135	128	127	120.5	121.5
56	99.9	150	139.5	132.5	129	124.5	126.5
62	99.9	153.5	144	139	132.5	128.5	132.5
70	99.9	164	148	142.5	139	132.5	139
72	99.9	175.5	152	145.5	144.5	139	145.5
73	99.9	195.5	169	148.5	147.5	146	150.5
74	99.9	200	186	152.5	151	153.5	169
76	99.9	211.9	196.9	180	162.5	168	183.5
77	99.9	230	201.9	198.5	199.5	191.5	198.5
85	99.9	235	229	219	229	216	218.4
90	99.9	246	232.9	232.9	233.4	229.5	230
91	99.9	251.9	236	237.4	243.4	232.9	235
92	99.9	281	246.4	246.9	252.4	245	249.5
99	99.9	288.4	260	259.5	266.4	260	270
104	99.9	346.4	290	287.9	296.9	278.4	327.9
105	99.9	372.9	357.9	373.9	380	329.5	347.4
107	99.9	396.9	381.4	394.5	395.9	394.5	368.4
110	99.9	466.4	453.4	465.9	437.9	453.9	435.9
112	99.9	587.8	520.5	528.4	530	528.4	517.9
113	99.9	991.3	990.8	991.3	991.3	991.3	991.3
116	99.9	1004.4	1004.4	1004.4	1004.4	1004.4	1004.4

Table B.5: Offer data for the for the MTS_{118} for the months of Jul.–Dec. 2010

		monthly seller offer prices ($)					
seller bus	seller quant. (MWh/h)	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
69	804.3	11	9.7	9.7	8.5	10.5	14
89	706.2	16.5	14.6	14.6	12.7	15.7	21
80	576.4	22	19.5	19.5	17	21	28
10	549.4	26	24.5	22	20.5	24	34
66	491.5	28	26.5	24	22	26	38
65	490.5	29.5	28	25.5	24	28	43.5
26	413.5	31	29.5	27.5	25.5	30	49.5
100	351.6	32.5	31	29.5	27.5	32	56.5
25	319.7	34.5	32.5	31.5	30	35.5	61.5
49	303.7	37	35	33.5	32	39	67
61	259.7	40	38	35	34	42.5	71
59	254.7	42.5	41.5	37.5	36.5	47.5	77
12	184.8	45	45	40	39	52.5	81
54	147.8	48	48.5	43	41.5	55	84
103	139.8	51	51	46	44.5	56.5	87.5
111	135.9	53.5	52.5	48.5	47	58.5	92
46	118.9	55.5	54	50.5	49	60	97.5
31	106.9	57.5	56	52.5	51	62	103
87	103.9	59.5	58	54.5	53	64.5	109.5
1	99.9	62.5	60.5	56	55	67	114.5
4	99.9	66	63.5	58	57.5	69.5	117.5
6	99.9	73	68	60.5	60.5	74	121
8	99.9	77.5	72.5	65	69	81.5	124.5
15	99.9	82	77.5	71.5	77	84	128.5
18	99.9	91.5	87	80	83	91	132
19	99.9	97.5	96	93.5	94	108	136
24	99.9	103	101.5	97.5	100	117	139
27	99.9	107.5	108.5	106	110.5	122.5	142
32	99.9	111	114.5	113	116.5	127.5	145.5
34	99.9	115	118	118	120	131.5	149.5
36	99.9	118.5	121.5	121	124.5	135.5	153.5
40	99.9	121.5	125	124.5	129	140	157
42	99.9	125.5	129	129.5	133.5	144.5	161.5
55	99.9	131	133.5	134	138.5	148	166.5
56	99.9	137	139	139.5	144	154.5	169.5
62	99.9	142	145	145	150.5	159.5	173.5
70	99.9	146	150.5	151.5	157	167.5	179
72	99.9	149.5	152.5	156.5	162	172.5	184.5
73	99.9	154	155.5	169	180	194.5	192.4
74	99.9	169.5	168.5	184.5	196	197.4	198.5
76	99.9	175.5	179	196.5	198.5	207.4	217.9
77	99.9	189	196	199.5	217.9	226.4	222.4
85	99.9	202.9	216.4	216.9	244.5	246.4	227.9
90	99.9	219.5	236.4	245	247.9	249.5	245.5
91	99.9	237.4	239	247.4	251	262.9	271.4
92	99.9	243.4	252.4	250	261.9	277.9	286.4
99	99.9	260.5	284	282.9	279.5	301.4	303.9
104	99.9	302.4	315.5	315	302.4	356.4	358.4
105	99.9	338.9	352.9	361.9	362.4	394.5	396.4
107	99.9	366.4	373.4	375	391.9	398.4	407.9
110	99.9	398.4	395.5	394.5	396.9	413.4	433.9
112	99.9	496.4	478.9	449.5	413.9	448.9	455.5
113	99.9	991.3	991.3	991.3	991.3	991.3	991.3
116	99.9	1004.4	1004.4	1004.4	1004.4	1004.4	1004.4

Table B.6: MTS_{57} line data

from	to	x (Ω)	line limit (MW)	from	to	x (Ω)	line limit (MW)
1	2	2.8	958	7	29	6.48	639
2	3	8.5	639	25	30	20.2	639
3	4	3.66	639	30	31	49.7	639
4	5	13.2	639	31	32	75.5	639
4	6	14.8	639	32	33	3.6	639
6	7	10.2	639	34	32	95.3	639
6	8	17.3	639	34	35	7.8	639
8	9	5.05	447	35	36	5.37	639
9	10	16.79	255	36	37	3.66	223
9	11	8.48	255	37	38	10.09	335
9	12	29.5	255	37	39	3.79	223
9	13	15.8	255	36	40	4.66	639
13	14	4.34	958	22	38	2.95	639
13	15	8.69	958	11	41	74.9	639
1	15	9.1	702	41	42	35.2	639
1	16	20.6	702	41	43	41.2	639
1	17	10.8	958	38	44	5.85	639
3	15	5.3	766	15	45	10.42	275
4	18	55.5	639	14	46	7.35	639
4	18	43	639	46	47	6.8	639
5	13	7.32	639	50	51	22	639
12	13	5.8	1373	10	51	7.12	639
12	6	6.41	639	47	48	2.33	639
7	8	7.12	639	48	49	12.9	319
10	12	12.62	639	49	50	12.8	639
11	16	8.13	639	13	49	19.1	639
12	17	17.9	639	29	52	18.7	639
14	15	5.47	639	52	53	9.84	639
18	19	68.5	639	53	54	23.2	639
19	20	43.4	639	54	55	22.65	639
21	20	77.67	639	11	43	15.3	639
21	22	11.7	639	44	45	12.42	262
22	23	1.52	639	40	56	119.5	639
23	24	25.6	702	56	41	54.9	639
24	25	118.2	255	56	42	35.4	639
24	25	123	255	39	57	135.5	639
24	26	4.73	255	57	56	26	639
26	27	25.4	958	38	49	17.7	639
27	28	9.54	639	38	48	4.82	639
28	29	5.87	639	9	55	12.05	639

Table B.7: Load distribution data for the for the MTS_{57}

buyer bus and buyer load (% of total hourly load)											
bus	load	bus	load	bus	load	bus	load	bus	load	bus	load
1	4.4	11	0	21	0	31	0.5	41	0.5	51	1.4
2	0.2	12	30.1	22	0	32	0.1	42	0.6	52	0.4
3	3.3	13	1.4	23	0.5	33	0.3	43	0.2	53	1.6
4	0	14	0.8	24	0	34	0	44	1	54	0.3
5	1	15	1.8	25	0.5	35	0.5	45	0	55	0.5
6	6	16	3.4	26	0	36	0	46	0	56	0.6
7	0	17	3.4	27	0.7	37	0	47	2.4	57	0.5
8	12	18	2.2	28	0.4	38	1.1	48	0		
9	9.7	19	0.3	29	1.4	39	0	49	1.4		
10	0.4	20	0.2	30	0.3	40	0	50	1.7		

Table B.8: Offer data for the for the MTS_{57} for the months of Jan.–Jun. 2010

		monthly seller offer prices ($)					
seller bus	seller quant. (MWh/h)	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
8	1261.4	48.5	54	24.5	38.5	41	31
1	1139.7	55	60.5	31.5	45.5	46.5	36.5
12	807.3	57.5	63	33.5	48	49	39
3	706.4	59	64.5	35.5	49.5	50.5	40.5
2	504.5	60.5	66	37	51	51.5	42
6	504.5	62	67.5	38	52	52.5	43
9	504.5	64	69.5	39.5	53.5	54	44
48	504.5	66.5	72.5	41.5	55	55.5	46
45	504.5	73.5	78	45	57.5	58	48.5
41	504.5	83	85.5	50.5	62.5	64	54.5
36	504.5	92	94	57	68.5	69.5	61
37	252.3	96.5	97.5	60	71.5	72.5	65
32	252.3	102	102	64	74.5	76	69
56	252.3	106	107	67.5	78	80	74
49	252.3	110.5	112	72	81	83.5	78.5
43	252.3	115.5	116.5	77.5	84.5	87	83.5
24	252.3	126.5	125	83.5	90.5	92.5	88.5
14	252.3	142.5	136.5	93.5	99.5	102.5	99
25	126.1	156.5	145.5	101	104.5	108	107
26	126.1	176	166	134	128.5	119	118
54	126.1	201.5	197.9	157.5	160	152.5	144
38	126.1	232.9	229	192.9	203.5	196.9	194.5
15	126.1	281.9	279.5	232.9	248.4	237.9	224.5
18	63.1	328.9	317.9	288.4	294	291.4	278.4
29	63.1	1049.4	1054.4	1024.4	1039.4	1039.4	1029.4

Table B.9: Offer data for the for the MTS_{57} for the months of Jul.–Dec. 2010

		monthly seller offer prices ($)					
seller bus	seller quant. (MWh/h)	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
8	1261.4	25	25.5	24.5	24	40.5	40
1	1139.7	31	31.5	31	31	46	46.5
12	807.3	33.5	34.5	34	33.5	48.5	49
3	706.4	35.5	36	35.5	35.5	50.5	51
2	504.6	37	37	37	36.5	52	52
6	504.6	38	38.5	38	38	53.5	53.5
9	504.6	39	39.5	39.5	39.5	55	55
48	504.6	40.5	41	41	41	56.5	56.5
45	504.6	43	43	42.5	43.5	59	58.5
41	504.6	47.5	46.5	45.5	46.5	62.5	63.5
36	504.6	54	52.5	50	51	68.5	70
37	252.3	58.5	56.5	54.5	54	71.5	74
32	252.3	62	60.5	58	57.5	75.5	78
56	252.3	65.5	64.5	61.5	62	79	82
49	252.3	70.5	68.5	65.5	65.5	82.5	88
43	252.3	74.5	73.5	69.5	68.5	87	93.5
24	252.3	79	78.5	75.5	74	92	97.5
14	252.3	87.5	85.5	81	81	99.5	107.5
25	126.1	94	92.5	88	89.5	109	115.5
26	126.1	102	104	98	113	148.5	154
54	126.1	125	126.5	136	156.5	172	176.5
38	126.1	168.5	147	164	189	211.9	222.9
15	126.1	211.9	207.9	215	228.4	249	256.4
18	63.1	259.5	248.4	268.4	317.9	327.9	297.9
29	63.1	1024.4	1024.4	1024.4	1022.7	1039.4	1039.4

APPENDIX C

ADDITIONAL STUDY RESULTS

Tables C.1–C.4 contain a complete set of *ABLMP* results from the studies discussed in Chapter 4.

Table C.1: The seasonal and annual *ABLMP* reductions for deepening penetrations of *ESR*s on the MTS_{57}

ESR penetration (%)	average buyer *LMP* reduction (%) spring	summer	fall	winter	annual
1	0.06	1.97	0.07	0.08	0.61
2	0.13	3.34	0.14	0.13	1.04
3	0.16	4.14	0.14	0.12	1.27
4	0.21	4.86	0.16	0.17	1.51
5	0.22	5.54	0.22	0.23	1.74
6	0.30	5.88	0.25	0.19	1.85
7	0.30	6.39	0.29	0.22	2.02
8	0.31	6.71	0.27	0.19	2.10
9	0.32	6.90	0.30	0.20	2.17
10	0.32	7.22	0.38	0.25	2.29
11	0.31	7.40	0.34	0.16	2.31
12	0.31	7.44	0.33	0.24	2.35
13	0.30	7.60	0.33	0.23	2.39
14	0.30	7.47	0.31	0.25	2.36
15	0.29	7.54	0.39	0.23	2.39

Table C.2: The seasonal and annual $ABLMP$ reductions for deepening penetrations of DRRs on the MTS_{57}

DRR penetration (%)	average buyer LMP reduction (%)				
	spring	summer	fall	winter	annual
1	0.13	1.45	0.13	-0.19	0.40
2	0.17	2.63	0.16	-0.54	0.64
3	0.13	3.19	0.03	-1.00	0.61
4	0.03	3.69	-0.13	-1.33	0.60
5	-0.06	3.99	-0.32	-1.62	0.54
6	-0.11	4.05	-0.50	-2.00	0.39
7	-0.22	4.23	-0.62	-2.32	0.30
8	-0.36	4.23	-0.88	-2.87	0.04
9	-0.51	4.02	-1.22	-3.46	-0.30
10	-0.73	3.86	-1.53	-4.11	-0.65
11	-0.94	3.52	-1.81	-4.92	-1.10
12	-1.07	3.12	-2.09	-5.63	-1.52
13	-1.19	2.70	-2.42	-6.48	-2.00
14	-1.39	2.04	-2.91	-7.50	-2.65
15	-1.61	1.42	-3.28	-8.63	-3.30

Table C.3: The seasonal and annual $ABLMP$ reductions for deepening penetrations of ESRs on the MTS_{118}

ESR penetration (%)	average buyer LMP reduction (%) spring	summer	fall	winter	annual
1	0.77	1.96	1.77	1.10	1.46
2	1.54	3.66	3.51	2.03	2.76
3	2.11	5.34	4.71	2.88	3.91
4	2.56	6.84	5.91	3.63	4.94
5	2.63	8.26	6.79	4.32	5.81
6	2.96	9.44	7.38	4.89	6.55
7	3.05	10.45	7.90	5.16	7.08
8	3.24	11.40	8.54	5.37	7.61
9	3.27	12.07	8.92	5.49	7.94
10	3.37	12.77	9.12	5.70	8.30
11	3.50	13.11	9.41	5.50	8.41
12	3.61	13.56	9.72	5.67	8.68
13	3.72	13.66	9.72	5.65	8.73
14	3.74	13.92	9.69	5.79	8.86
15	3.76	13.93	9.99	5.55	8.83
16	3.80	14.31	10.08	5.46	8.95
17	3.79	14.50	10.30	5.55	9.08
18	3.83	14.61	10.30	5.60	9.15
19	3.82	14.97	10.43	5.57	9.28
20	3.78	14.97	10.37	5.51	9.25
21	3.84	14.77	10.54	5.50	9.20
22	3.77	14.99	10.54	5.50	9.28
23	3.72	15.24	10.41	5.56	9.37
24	3.66	15.04	10.56	5.20	9.18
25	3.73	14.80	10.38	5.63	9.22
26	3.57	14.93	10.04	5.32	9.08
27	3.57	15.15	10.27	5.28	9.19
28	3.70	14.68	10.40	5.38	9.09
29	3.60	14.80	10.56	5.29	9.12
30	3.28	14.98	10.63	5.39	9.18
31	3.62	14.67	10.73	5.62	9.22
32	3.28	7.10	9.52	2.00	5.04
33	3.17	6.90	9.51	1.20	4.68
34	3.82	13.96	10.30	5.39	8.85
35	3.69	14.33	10.54	5.24	8.95

Table C.4: The seasonal and annual $ABLMP$ reductions for deepening penetrations of DRRs on the MTS_{118}

DRR penetration (%)	average buyer LMP reduction (%)				
	spring	summer	fall	winter	annual
1	0.25	1.30	0.76	0.46	0.77
2	0.43	2.40	1.79	0.75	1.45
3	0.68	3.63	1.98	0.92	2.01
4	0.79	4.65	2.09	0.95	2.40
5	0.76	5.44	2.04	0.92	2.66
6	0.65	5.94	1.46	0.98	2.75
7	0.51	6.33	0.65	0.68	2.63
8	0.33	6.64	-0.31	0.39	2.46
9	0.01	6.59	-1.75	-0.03	2.02
10	-0.16	6.50	-3.97	-0.35	1.50
11	-0.44	6.25	-6.78	-0.75	0.78
12	-0.88	3.92	-9.64	-1.08	-0.67
13	-1.55	3.02	-13.29	-1.52	-1.82
14	-1.91	2.07	-16.63	-2.17	-2.97
15	-2.59	0.06	-20.42	-2.68	-4.55

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