A Comparative Assessment of Demand Response and Energy Storage Resource Economic and Emission Impacts

Kai Van Horn and George Gross
Department of Electrical and Computer Engineering
University of Illinois at Urbana-Champaign

*Abstract***— Over the past decade, there has been a resurgence of interest among system operators, policy makers and other grid stakeholders in the expanded utilization of energy storage (*ES*) and demand response resources (*DRR*s) to address power system economic and environmental concerns. In this work, we construct a general *ES* resource (*ESR*) model, which encompasses *DRR*s as a special case and explicitly represents the physical and economic attributes of integrated grid-scale *ES* and *DRR*s and aggregations of smaller-scale *ES* and *DRR*s. We deploy this model in a market simulation framework to perform a systematic side-by-side comparison of the economic and emission impacts of *ES* and *DRR*s in networks operated/controlled by an independent system operator/regional transmission organization and in its associated day-ahead markets.**

This analysis points out the limits to the penetrations below which an added MW of *ES* or *DRR* no longer brings about decreases in buyer payments and that the benefits that accrue to *DRR*s are disproportionately larger than the benefits to buyers and *ESR*s. Further, we find that *ES* and *DRR*s have little impact on reducing system-wide emissions. In fact, we find that their utilization may even result in emission increases in some cases. These findings provide insights into nature of the *ES* and *DRR* market impacts which are useful for grid stakeholders interested in the integration of appropriate penetrations of such resources.

Introduction

Electricity generation and delivery is a prototypical just-in-time manufacturing system due to the limited means to economically store electricity on a large-scale basis. As such, electricity must be consumed as soon as it is produced. In regions of the U.S. with competitive electricity markets, independent system operators (*ISO*s)/regional transmission operators (*RTO*s)-run day-ahead electricity markets (*DAM*s) to determine which resources will meet the demand, and to ensure adequate capacity is committed so as to meet the supply-demand balance around the clock. System operators, generally, meet the demand by controlling the output of the supply-side resources. Until recently, there has been a limited amount of grid-scale energy storage (*ES*) in operation 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 may result, at times, in high prices, marked price volatility, and even price spikes and has associated emission impacts. These price issues, and the emergence of policies aimed at emission reductions, along with advances in storage and communication technology, have reinvigorated the drive of policy makers, system operators, private investors and other electricity grid stakeholders to expand the utilization of demand response (*DR*) and *ES* resources (*ESR*s) to reliably and effectively meet the supply-demand balance.

DR resources (*DRR*s) are consumers of electricity who provide reductions in the consumption of electric energy through load curtailments, at specified times, in response to incentive payments. *ESR*s are devices that have the capability to store electric energy at one time, acting as a load, and discharge the energy at other times, acting as a generator. We focus on grid-scale *DRR*s and *ESR*s as singular resources or as aggregations of such distributed resources. Grid-scale *ESR*s have the capability to store energy for discharge over periods of hours, such as large-scale battery storage, compressed air energy storage or pumped-hydro storage.

In the restructured electricity system, *ES* and *DRR*s can participate in the *ISO*/*RTO*-run *DAM*s. With their participation, the *ISO*/*RTO* has the ability to shape the load through demand reductions at peak load times or the transfer of demand from peak to off-peak hours. *ES* and *DRR*s may also provide ancillary services. The appropriate use of *ES* and *DRR*s for load shaping will lead to attenuated *DAM* price volatility; increased reliability via increased reserve margins and resource flexibility; reduced pollutant emissions; delayed or eliminated need for investment in additional transmission and generation due to a reduced system peak load met by the supply-side; and will provide ISO/RTOs a means by which to manage the impacts of the intermittency and variability from renewable resource generation [1]–[4]. In this paper, our focus is on the economic and emission impacts of *ES* and *DRR*s on the *DAM* outcomes. We assess the impacts on market performance, generation dispatch, transmission usage, emissions and other system variable effects.

A number of papers has focused on the conceptual aspects of *ES* and *DRR*s operating in electricity markets [3]–[6]. These works, however, have not discussed their commonalities. Several models have been proposed to represent *ES* and *DRR*s in the wholesale electricity market environment [7]–[9]. Further, several studies have been conducted, which quantify the economic impacts of *ES* and *DRR*s [10]–[13]. These studies provide insights into the price reductions which may be achieved by deepening penetrations of *ES* and *DRR*s in the wholesale electricity markets. However, they do not quantify the emission impacts of *ES* and *DRR*s, nor do they provide a consistent basis upon which to compare their respective

978-1-4799-0199-9/13/ $31.00

economic impacts. This lack of a common basis motivates our construction of a unified methodology and our side-by-side comparison.

In this work, we construct a general *ESR* model, which captures the physical and economic aspects of *ESR*s. In this model, we represent *DRR*s as a special case of *ESR*s. We incorporate the *ESR* model into a market clearing model that represents the transmission constrained *DAM*s. This *DAM* clearing model forms the basis of our simulation approach. We deploy the simulation approach to perform a systematic comparative assessment on a consistent basis of the economic and emission impacts of *ES* and *DRR*s participating in the *DAM*s.

The remainder of the paper is organized into three sections. In the next section, we give an overview of the *ESR* model and the simulation approach. In the subsequent section, we describe the nature of the simulation studies and present the key findings. We use a number of representative studies to describe the nature of the results. In the final section, we draw broad conclusions about the *DAM* economic and emission impacts of *ESR*s and *DRR*s and discuss the implications of those impacts.

A Unified *ES* and *DRR* *DAM* Modeling and Simulation Approach

In this section, we develop an *ESR* model, which captures the salient aspects of *ESR*s, and describe how the model can be used to represent *DRR*s as a special case of *ESR*s. We then describe the incorporation of the *ESR* model into a standard *DAM*s clearing model and the application of the resulting, extended model to create a simulation approach. We begin by describing the *ESR* model.

Our work is independent of the *ESR* technology and focuses on the interactions of *ESR*s with the grid and other resources. We consider a set of U storage units $\mathscr{U} = \{u_1, u_2, \ldots, u_U\}$. Each unit u is fully specified by four parameters: the upper and lower bounds on its charge and discharge capacity, in *MW*, the upper and lower bounds on its 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 quantities and define a set of H hours $\mathscr{H}_k = \{h_1, h_2, \ldots, h_H\}$ and a set of K days $\mathscr{K} = \{k_1, k_2, \ldots, k_K\}$. 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 model 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 the 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. Further, we define $\eta^u_r = \eta^u_c \eta^u_d$ to be the *ESR* overall cycle efficiency. Our aim is to develop an *ESR* model which will be integrated into a standard market clearing model and so we formulate a set of constraints to represent the key aspects of *ESR*s in the *DAM*s. The *ESR* capacity constraints are

$$c^u_m[h] \le c^u[h] \le c^u_M[h] \tag{1}$$
$$d^u_m[h] \le d^u[h] \le d^u_M[h] \tag{2}$$

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 capability, or stored energy, constraints are

$$y^u_m[h] \le y^u[h] \le y^u_M[h] \tag{3}$$

The capability constraints introduce inter-hourly dependence into the *DAM* model. We pay close attention this this aspect of *ESR*s in the simulation approach. Further, to provide an additional degree of freedom in the *ESR* model, we introduce a constraint which governs the energy required to be in the storage reservoir in hour h_H

$$\sum_{h \in \mathscr{H}} \left(\eta^u_d c^u[i] - \frac{\alpha^u_k d^u[i]}{\eta^u_d} \right) = 0 \tag{4}$$

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. These capacity, capability, and final stored energy constraints capture the key characteristics of *ESR*s that impact the *DAM*s outcomes. We now turn to the application of the *ESR* model to represent *DRR*s.

In line with the representation of *DRR*s in [14], we define the set of buyers $\mathscr{B}$ and segment it into two non-overlapping subsets to delineate the set of *DRR*s. We denote the subset of buyers operating as pure buyers, those without the capability to provide *DR*, 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 $p^{\tilde{b}}[h] \ge \tilde{p}^{\tilde{b}}[h]$. Each *DRR* $\tilde{b}$ is fully specified by the upper and lower bounds on its curtailment and recovery capacity, in *MW*, the upper and lower bounds on its capability to provide sustained energy consumption reductions, in *MWh*, and its energy recovery percentage.

On close examination, we see that the parameters of *DRR*s have commonalities with those of *ESR*s. The *DRR* curtailment bound (energy recovery bound) is analogous to the *ESR* discharge bound (charge bound) and the *DRR* energy recovery percentage is analogous to the inverse of the *ESR* overall cycle efficiency. Furthermore, the sustained capability of *DRR*s to provide energy consumption reductions is the analogous to the *ESR* energy storage capability bounds. Table I summarizes these commonalities.

TABLE I: *DRR* and *ESR* commonalities

ESR	***DRR***
discharge bound	curtailment bound
charge bound	recovery bound
inverse of overall cycle efficiency	energy recovery percentage
MWh capability bounds	capability to provide sustained energy consumption reductions

It follows, then, from the commonalities between *ES* and *DRR*s, that we may represent *DRR*s with the *ESR* model by replacing u with $\tilde{b}$ in each of the constraints formulated in Eqs. (1–4).

The *ES* and *DRR* constraints and decision variables are incorporated into a standard, DC optimal power flow (*OPF*)-based transmission-constrained *DAM* clearing model (*MCM*) to formulate the extended transmission-constrained market clearing model (*EMCM*). The objective of the *EMCM* is the maximization of the social welfare function and the decision variables are the hourly generator outputs, the *ES* and *DRR* charge (recovery) and discharge (curtailment) quantities. The *EMCM*, formulated in the Appendix, is the basic building block of our *ES* and *DRR* economic and emission impact simulation approach. We now give a brief overview of the development of our simulation approach. For a more detailed description of the simulation approach see [15].

In our simulation approach, we assume the system is in steady-state in each hour and that, throughout the simulation period, the resource mix, the transmission grid, the market structure, and the operating policies remain unchanged. Moreover, we assume that a forecast of the aggregate system load is specified for the simulation period and that the load submits fixed-price bids with an arbitrarily high willingness to pay. To simplify the discussion, we consider the supply system to consist of only controllable, i.e., dispatchable units, and assume that the units are all committed so as to evaluate the impacts of *ES* and *DRR*s on the economic dispatch. We consider a pool market structure with a uniform price auction. Also, we assume that *DRR*s and *ESR*s are operated as a system resource to maximize the social welfare. We also assume that suppliers do not engage in anti-competitive behavior. To facilitate the calculation of the CO_2 emission in our approach, we assume a price-based loading order in which nuclear units are the first to be loaded, followed by hydro units. Coal-fired units are assumed to be loaded third followed by natural-gas-fired units and oil-fired units based on the relative costs of their fuel sources.

We consider *ES* and *DRR*s operating in the *DAM*s and so we adopt a chronological simulation approach in which an hour is the smallest indecomposable unit of time and, due to the inter-hourly dependence introduced by the *ESR* capability constraints, the 24 hourly *DAM*s must be cleared simultaneously. As such, a day is the basic time unit of simulation. We also note the inter-temporal dependencies in *ESR* operation may require the simulation of longer than a single day. However, the simulation approach has the capability to represent multi-day schedules through the application of the *EMCM* over multi-day periods. We adopt a two day *ESR* scheduling period and restrict the hours of charge/discharge and the stored energy at the end of each day in the *DAM*s to that which is determined by the two-day schedule.

For each day in the simulation period, the *OPF* defined by the *EMCM* is solved, for a given system topology and with a given set of resources, to evaluate the market outcomes in each hour. These market outcomes facilitate the assessment of the metrics used in the comparison of the *ES* and *DRR* impacts. The metrics of interest are the total cleared load, the average *LMP*s (*ALMP*s), defined as the total buyer annual payments divided by the total annual cleared load and the average *DRR*/*ESR* and buyer benefits. We define the buyer average benefits as the *ALMP* reductions and consider a *positive* buyer benefit to be an *ALMP reduction*. The *ESR* average benefits are defined to be the total *ESR* profits divided by the total cleared load and the *DRR* average benefits are the total *DRR* profits plus the value of the forgone energy consumption divided by the total cleared load. We also focus on the total congestion rents and the average CO_2 emission, defined as the total annual CO_2 emission divided by the total annual cleared load. The mathematical formulation of the hourly metrics is given in the Appendix.

The daily outcomes are aggregated over the simulation period to determine the total *ES* and *DRR* impacts on the market outcomes. Our simulation approach captures the economic and emission impacts of *ES* and *DRR* participation in the *DAM*s over multiple time scales and is adaptable to a wide range of resource types and a broad spectrum of systems.

A Comparison of *ESR* and *DRR DAM* Economic and Emissions Impacts

In this section, we deploy our simulation framework to explore the economic and emission impacts on the *DAM*s outcomes brought about by deepening *DR* and *ESR* capacity penetrations with a set of sensitivity studies. The objectives of the sensitivity studies are to investigate the limitations of the *ES* and *DRR* economic and emission impacts and to compare the respective impacts of *ES* and *DRR*s. The studies are backcast scenarios for the year 2010 with deepening penetrations of *ES* and *DRR*s assuming perfect knowledge of the load. We focus on a single year to draw attention to important aspects of the *DR* and *ESR* impacts and to reduce the impacts of uncertainty.

The illustrative results we present in this work are drawn from case studies on modified *IEEE* 57- and 118-bus test systems (which we refer to as S_{57} and S_{118}, respectively) [16]. We use 2010 market and load data from the *MISO* on the S_{57} and from the *ISO-NE* on the S_{118} [17], [18]. For a detailed description of the test systems and data see [15]. 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 with capacity in proportion to the bus peak load. We place four equal capacity and capability *ESR*s at each of the four buses with the largest load concentration in each system. We summarize test system characteristics in Table II.

TABLE II: Test system characteristics

	test system	
system property	S_{57}	S_{118}
offer & load data source	*MISO*	*ISO-NE*
# of generator buses	25	54
# of load buses	42	99
# of lines	80	186
ESR buses	6, 8, 9, 12	15, 59, 80, 116

The *ISO*-representative generation mix used in each test system is shown in Table III. To translate the generator outputs into CO_2 emission in each case, we use CO_2 emission rates of 1.02, 0.51 and 0.76 *tonnes/MWh* for coal-, natural-gas- and oil-fired generation, respectively [19].

TABLE III: Test system generation mixes

	generation capacity % by fuel source				
test system	nuclear	hydro	coal	natural gas	oil
S_{57}	6	9	52	26	7
S_{118}	15	12	8	43	22

We perform *ES* and *DRR* capacity sensitivity studies for penetrations in the range of [0,15] % on the S_{57} and S_{118} systems. The total *ES* and *DRR* capacity penetrations in each case are calculated as a percentage of the annual peak load. Each simulation does not account for any sources of uncertainty and so all the case studies presented are deterministic.

We perform two sensitivity studies. In the first study, we investigate the impacts of deepening *DRR* capacity in the absence of *ESR*s. We restrict *DRR* curtailments to between the hours of 12:00 p.m. and 10:00 p.m. To account for the limited capability of loads to provide sustained consumption reductions, we also assume that *DRR*s may provide total curtailments of no more than four times their capacity in the ten potential curtailment hours each day. Furthermore, we assume *DRR*s are operated under the requirements of the recent *FERC* Order No. 745 [20]. *DRR*s are assumed to recover energy at a capacity no greater than their curtailment capacity and we assume 100 % of curtailed energy is recovered in the same 24 hour period (midnight to midnight) in which it was curtailed.

In the second study, we investigate the impacts of deepening *ESR* capacity in the absence of *DRR*s. The storage capability of the *ESR*s is considered to be 12 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 storage facilities [2]. Further, we select a two-day, moving-window scheduling period to determine *ESR* *DAM*s schedules. The case with no *DR* or *ESR*s is taken as the reference case scenario for each system. Table IV shows the reference case metrics for the S_{57} and S_{118}, respectively. We begin our assessment with an analysis of the economic impacts of deepening *DRR* and *ESR* penetration.

TABLE IV: reference case metrics

	test system	
metric	S_{57}	S_{118}
buyer payments ($*M*)	3,015	3,049
cleared load (*MWh*)	$52,600,000$	$47,700,000$
ALMP ($/*MWh*)	57.3	63.9
congestion rents ($*M*)	26.7	33.9
CO_2 emission (*Mtonnes*)	41.8	19.7

The Economic Impacts of Deepening ESR and DRR Penetration

We first compare the impacts of deepening *ESR* and *DRR* penetration on the *ALMP*. Figures 1 and 2 depict the change in the annual *ALMP* for deepening *DRR* and *ESR* penetrations on the S_{57} and S_{118}, respectively.

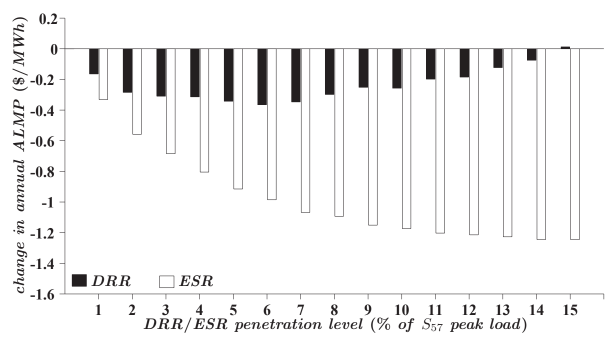

Fig. 1: The change in the annual *ALMP* for deepening penetrations of *ES* and *DRR*s on the S_{57}

The *ALMP* impacts of *ES* and *DRR*s are similar on both of the systems. In each system, *ESR* utilization reduces the *ALMP* by at least a factor of two more than *DRR* utilization and both the *ES* and *DRR* impacts exhibit diminishing marginal returns, i.e., each additional percent *ES* or *DRR* penetration results in lower additional *ALMP* reductions.

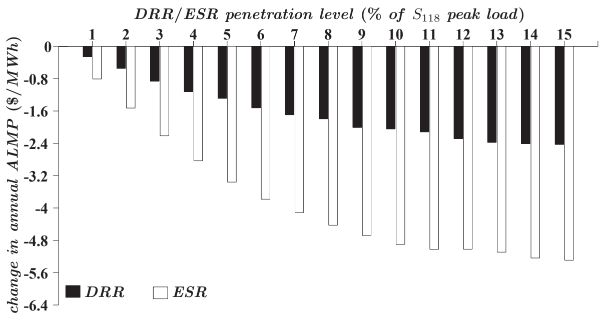

Fig. 2: The change in the annual *ALMP* payments for deepening penetrations of *ES* and *DRR*s on the S_{118}

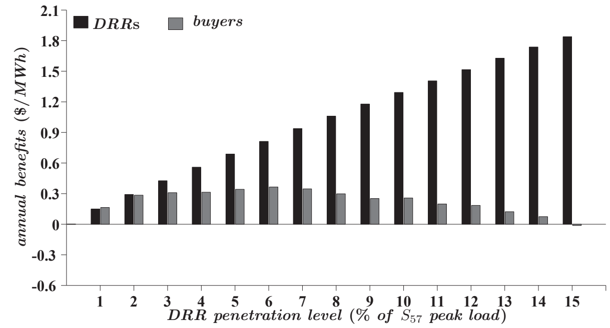

Fig. 3: The change in the annual *DRR* and buyer average benefits for deepening penetrations of *DRR*s on the S_{57}

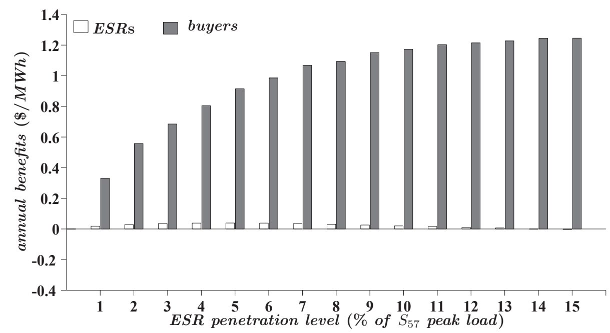

Fig. 4: The change in the annual *ESR* and buyer average benefits for deepening penetrations of *ESR*s on the S_{57}

The highest impact of *DRR*s on reducing the *ALMP* is attained at 6 % penetration in the S_{57} cases and at 15 % penetration for *ESR*s in the same cases. *DRR*s even result in *ALMP* increases for the 15 % *DRR* penetration case, shown in Fig. 1. Such an increase indicates that, at 15 % *DRR* penetration, the load would be more economically served by the generators in the system rather than the *DRR*s—a clear departure from the intended *DRR* economic impacts and from the goals of effective *DRR* integration. On the S_{118}, the highest impact of *ES* and *DRR*s on reducing the *ALMP* is at 15 % penetration for both resource. At this penetration, however, the marginal returns of deeper resource penetrations have fallen to near zero.

Our studies show that the *ALMP* impacts of *ESR*s and *DRR*s can be significant if there are abundant arbitrage opportunities, as in the cases on the S_{118}. Two broad conclusions can be drawn from our results. The first is that there are limitations to the penetration of *DRR*s and *ESR*s above which they result in economic benefits and that these limits are system dependent. The second is that the *ALMP* reduction benefits of *ESR*s participation are higher than those for *DRR*s and the limits are reached for *DRR*s at lower penetrations than for *ESR*s.

We next explore the impacts of deepening *DRR* and *ESR* penetration on the benefits that accrue to the various market players. The benefits provide insight into the incentives for each market player to participate and differ considerably between the buyers, *ESR*s and *DRR*s. Figures 3 and 4 show the buyer average benefits and *DRR* and *ESR* average benefits, respectively, for the S_{57} cases and Figs. 3 and 4 show the same for the S_{118} cases. It is clear from Figs. 3–6 that the *DRR* benefits are higher than the buyer and *ESR* benefits in nearly all cases. Further, we see that *ESR*s result in higher buyer average benefits than *DRR*s at every penetration level. The disproportionately large *DRR* benefits are due to the additional benefit *DRR*s receive on top of the incentive payments at the *LMP*: the savings from forgone energy consumption. This forgone energy consumption benefit is large due to the large price reductions which result from *DRR* curtailments in peak hours and makes up the majority of the *DRR* benefits in most cases. A key feature of the *DRR* benefits observed in our case studies is that they increase monotonically as the *DRR* penetration deepens, even when the buyer benefits have begun to decrease or the buyer benefits have been reduced to zero or become negative. These low *ESR* benefits are the result

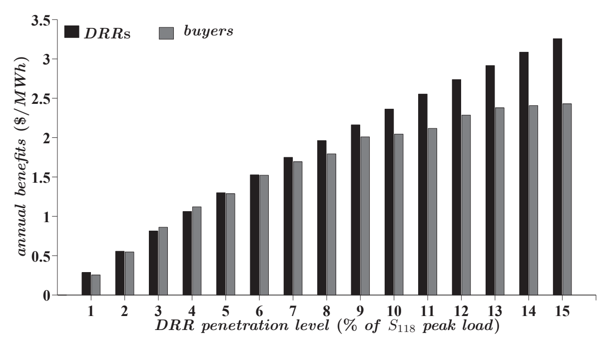

Fig. 5: The change in the annual *DRR* and buyer benefits for deepening penetrations of *DRR*s on the S_{118}

of the *ESR* operating as a system resource. In such cases, the *ESR* benefits approach zero with deepening penetration as the arbitrage opportunities are exhausted.

We now turn to the impacts of deepening *ES* and *DRR* penetration on the total congestion rents. The congestion rents are an indication of the market efficiency and high congestion rents indicate a large market efficiency loss. Congestion rents arise when a there is a binding transmission constraint. Such constraints result in the dispatch of generator(s) which are not the least costly generators in the system capable of serving the next *MWh* of load, but rather the least costly generator(s) which can supply the next *MWh* of load without

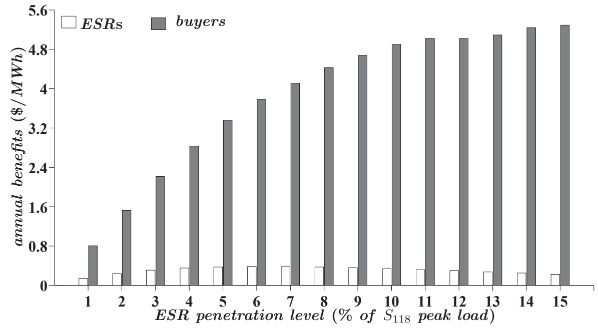

Fig. 6: The change in the annual *ESR* and buyer benefits for deepening penetrations of *ESR*s on the S_{118}

violating such a constraint. The congestion rents are paid by the buyers and any reduction in the congestion rents reduces buyer payments and improves the market efficiency. *ES* and *DRR*s change the network flows and have an impact on congestion and, consequently, the congestion rents. Figs. 7 and 8 show the total congestion rents for the S_{57} and S_{118} cases, respectively. We note that, in every case studied, *ES* and *DRRs* reduce the congestion rents. As such, the utilization of *ES* and *DRR*s improves the market efficiency. On the S_{57}, for penetrations of *ES* or *DRR*s in the [1,9] % range, these resources provide congestion rent reductions from 4–10 % compared to the reference case. However, as the penetration deepens below 9 % the *ESR* congestion rent reductions remain roughly constant—consistent with the *ESR* impact on the buyer benefits at such penetrations—while the *DRR* congestion rent reductions approach zero—consistent with diminishing buyer benefits associated with *DRR*s at such penetrations. On the S_{118}, where there are ample arbitrage opportunities resulting from significant peak-hour congestion, *DRR*s provide higher reductions in the congestion rents than *ESR*s at every penetration level. We observe that the distributed nature of *DRR*s, in our cases the *DRR*s are located at all load buses, as compared to the *ESR*s, which are concentrated at four buses, results in the higher impacts of *DRR*s on the congestion rents shown in Figs. 7 and 8.

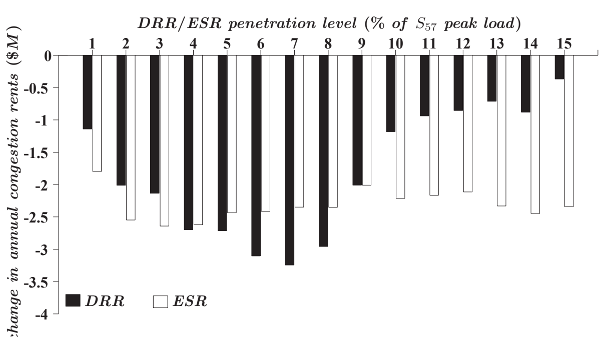

Fig. 7: The change in the annual congestion rents for deepening penetrations of *ES* and *DRR*s on the S_{57}

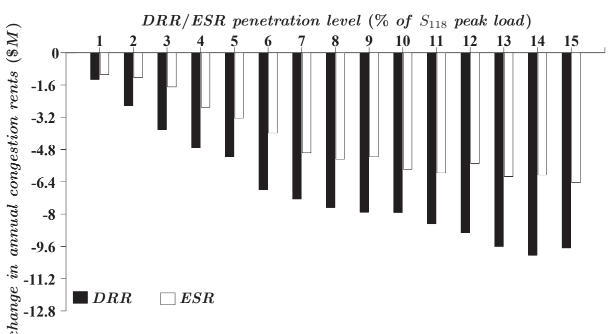

Fig. 8: The change in the annual congestion rents for deepening penetrations of *ES* and *DRR*s on the S_{118}

We conclude from the results of our studies that both *DRR*s and *ESR*s have a significant impact impact on reducing the congestion rents and that distributed *ES* and *DRR*s may have a higher impact on reducing congestion rents than *ES* or *DRR*s which are concentrated at a small number of buses. We now turn to the comparative emission impacts of deepening *ES* and *DRR* penetration.

The Emission Impacts of Deepening ESR and DRR Penetration

The emission impacts of *ES* and *DRR*s depend on the generator fuel mix in the system in which they operate. Figures 9 and 10 show the percent change in annual average CO_2 emission for the S_{57} and S_{118} cases, respectively. The generation mix of the S_{57} system is dominated by coal-fired generation, which represents more than half of the capacity in the system. In the

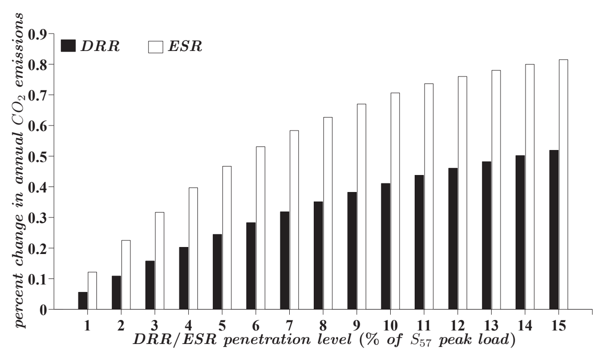

Fig. 9: The percent change in the annual CO_2 emission for deepening penetrations of *ES* and *DRR*s on the S_{57}

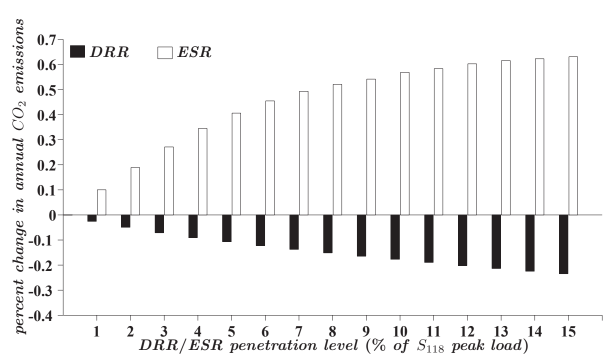

Fig. 10: The percent change in the annual CO_2 emission for deepening penetrations of *ES* and *DRR*s on the S_{118}

curtailment (discharge) hours, the marginal generators, those which will provide the next MW of capacity, are often natural-gas-fired units, which, according to the price-based loading order, are loaded after the coal-fire units. Consequently, much of the generation offset by *DRR* curtailments is from natural-gas-fired units, while the additional load for energy recovery (charge) is served by coal-fired units, which have roughly twice the CO_2 emission rate of natural-gas-fired units per MWh of generation. The results of shifting energy from low emission rate generators to those with higher emission rates are the S_{57} system average per MWh CO_2 emission increases, compared to the reference case, at all *ESR*/*DRR* penetration levels shown in Figure 9.

Alternatively, the generation mix of the S_{118} system is dominated by natural-gas fired generation and the peak load is met by oil-fired generation. Thus, for *DRR*s we observe emission decreases as load which was served by the oil-fired units in the reference case is shifted and served by natural gas-fired units in the *DRR* cases. In the *ESR*s cases, however, the emission increase at all penetrations. These emission increases are attributable to the *ESR* efficiency losses. Because the *ESR* efficiency is 0.8, an *ESR* must charge 1.25 MWhs for every 1 *MWh* discharged. *DRR*s, on the other hand, recover exactly 1 *MWh* for every MWh provided as a curtailment. The additional off-peak charging due to efficiency losses is the driving force behind the emission increases associate with *ESR*s compared to the emission decreases associated with *DRR*s in the cases shown in Fig. 10.

We note that emission impacts of *ES* and *DRR*s are not necessarily correlated with their economic impacts and that the highest reductions in the *ALMP* may occur at penetrations at which *ES* and *DRR*s result in emission increases. Further, we note the *ES* and *DRR* emission impacts, both increases and decreases, are less than 1 % compared to the reference case in all of our studies indicating that *ES* and *DRR*s alone are not an effective means by which to reduce system-wide CO_2 emission. However, we have not assessed the impacts of *ES* and *DRR*s in systems with large-scale deployment of renewable resources, such as wind generation, which may offer an abundant source of low emission generation in off-peak hours. The symbiotic relationship between wind and *ES* and *DRR*s has the potential to mitigate the emission impacts of off-peak charging and energy recovery. Effective policies, operational strategies and planning aimed at reducing CO_2 emission must focus on the use of *ES* and *DRR*s and renewables together, to harness their symbiosis.

Conclusions

In this work, we harness the commonalities of *ES* and *DRR*s to construct an *ESR* model which includes *DRR*s as a special case. We incorporate this model into a standard market simulation model and construct a simulation approach which captures the impacts of *ESR*s on the transmission-constrained *DAM*s outcomes. We deploy the simulation approach to perform a side-by-side comparison on a consistent basis of the economic and emission impacts of *DR* and *ESR*s. From our comparison, we conclude that:

- There is a limit to the capacity of *ES* or *DRR*s after which additional capacity does not result in additional *ALMP* reductions.
- The capacity at which the limit is reached depends upon the extent of the arbitrage opportunities, but is less for *DRR*s than it is for *ESR*s
- *ESR*s have a greater impact on reducing the *ALMP* than *DRR*s at all penetrations
- The *DRR* benefits are disproportionally larger than the *ESR*s and buyer benefits due to the additional *DRR* benefits of savings from forgone energy consumption
- The deployment of *ES* and *DRR*s alone may not result in emission reductions. In fact, in some systems, their use may result in emission increases.
- The utilization of *ESR*s may also result in emissions increases due to efficiency losses.

ES and *DRR*s are on a path to play an increasingly important role in maintaining the supply-demand balance around the clock. The studies we present provides system operators, policy makers, planners and other grid stakeholders insight into the impacts and limitations of these resources. Moreover, the approach provides these stakeholders a means by which to answer a number of *what-if* questions related to the impacts of the *ES* and *DRR* characteristics on the *DAM*s outcomes which will enable the effective integration of *ES* and *DRR*s.

Future work will include the incorporation of the various sources of uncertainty into our framework so as to quantify the *ES* and *DRR* longer-term impacts and investigate the symbiotic relationships between *ES* and *DRR*s and renewable resources, such as wind and solar generation.

Appendix

In this appendix we describe the incorporation of the *ESR* model into the standard *MCM* to formulate the *EMCM*. We begin by formulating the *MCM*.

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 make the standard assumption for market clearing models that the DC power flow assumptions hold [21]. Further, 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 *MCM* 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 $\mathscr{H}_k$ on a day k. We denote the statement of the *MCM* by $\bar{\mathcal{M}}(\mathscr{H}_k, \mathscr{S}, \mathscr{B})$ and state it as follows

$$\begin{aligned} max \quad & \sum_{h \in \mathscr{H}_k} \left\{ \sum_{b \in \mathscr{B}} \mathcal{B}^b\left(p^b[h]\right) - \sum_{s \in \mathscr{S}} \mathcal{C}^s\left(p^s[h]\right) \right\} \\ s.t. \quad & \end{aligned}$$

$$\begin{array}{ll} \underline{\boldsymbol{p}}^g[h] - \underline{\boldsymbol{p}}^d[h] = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}[h] & \leftrightarrow \underline{\boldsymbol{\lambda}}[h] \\ p_0^g[h] - p_0^d[h] = \underline{\boldsymbol{b}}_0^T \underline{\boldsymbol{\theta}}[h] & \leftrightarrow \lambda_0[h] \\ p_m^s[h] \leq p^s[h] \leq p_M^s[h] & \leftrightarrow \mu_M^s[h],\, \mu_m^s[h] \\ p_m^b[h] \leq p^b[h] \leq p_M^b[h] & \leftrightarrow \mu_M^b[h],\, \mu_m^b[h] \\ \underline{\boldsymbol{f}}^m[h] \leq \underline{\boldsymbol{f}}[h] \leq \underline{\boldsymbol{f}}^M[h] & \leftrightarrow \underline{\boldsymbol{\xi}}^M[h],\, \underline{\boldsymbol{\xi}}^m[h] \end{array} \qquad \text{(A.1)}$$

$$\forall b \in \mathscr{B},\, \forall s \in \mathscr{S},\, \forall h \in \mathscr{H}_k$$

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 injection $p^s[h]$, $\mathcal{B}^b(p^b[h])$ is the integral of buyer b's marginal bid price as a function of scheduled withdrawal $p^b[h]$ 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

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

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. (A.1) are the dual variables of their respective constraints. These variables have important economic interpretations.

To incorporate *ES* and *DRR*s into the *MCM* framework we define $\mathscr{E} = \mathscr{U} \cup \tilde{\mathscr{B}}$ and

$$\begin{aligned} c_n^{\mathscr{E}}[h] &= \sum_{\substack{e \in \mathscr{E}\, is \\ at\, node\, n}} c^e[h] \\ d_n^{\mathscr{E}}[h] &= \sum_{\substack{e \in \mathscr{E}\, is \\ at\, node\, n}} d^e[h] \end{aligned}$$

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

$$\begin{aligned} \underline{\boldsymbol{c}}^{\mathscr{E}}[h] &= \left[c_1^{\mathscr{E}}[h], c_2^{\mathscr{E}}[h], \ldots, c_N^{\mathscr{E}}[h]\right]^T \in \mathbb{R}^N \\ \underline{\boldsymbol{d}}^{\mathscr{E}}[h] &= \left[d_1^{\mathscr{E}}[h], d_2^{\mathscr{E}}[h], \ldots, d_N^{\mathscr{E}}[h]\right]^T \in \mathbb{R}^N \end{aligned}$$

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

$$\left(\underline{\boldsymbol{p}}^g[h] + \underline{\boldsymbol{d}}^{\mathscr{E}}[h]\right) - \left(\underline{\boldsymbol{p}}^d[h] + \underline{\boldsymbol{c}}^{\mathscr{E}}[h]\right) = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}[h] \qquad \text{(A.2)}$$

For simplicity and without loss of generality we assume there are no *ES* or *DRR*s at the slack node. Due to the assumption that *ES* and *DRR*s are utilized as *system resources*, *DR* and *ES* resources are not represented in the objective function of the *EMCM*, which is stated as follows

$$\begin{aligned} \sum_{h \in \mathscr{H}_k} \Bigg\{ & \sum_{\bar{b} \in \bar{\mathscr{B}}} \mathcal{B}^{\bar{b}}\left(p^{\bar{b}}[h]\right) + \sum_{\tilde{b} \in \tilde{\mathscr{B}}} \mathcal{B}^{\tilde{b}}\left(p^{\tilde{b}}[h] - d^{\tilde{b}}[h]\right) \\ & - \sum_{s \in \mathscr{S}} \mathcal{C}^s\left(p^s[h]\right) \Bigg\} \end{aligned} \qquad \text{(A.3)}$$

We also define

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

to simplify the *EMCM* statement notation. To formulate the *EMCM*, we replace the objective of the *MCM* in Eq. (A.1) with Eq. (A.3) and the *MCM* power flow constraint with the modified power flow constraint in Eq. (A.2). With the addition of the constraints in Eqs. (1–4) to represent *ESR*s, and therefore *DRR*s, the statement of the *EMCP* is complete. We denote the statement of the *EMCP* by $\mathcal{M}(\mathscr{H}_k, \mathscr{D})$. The optimal solution to $\mathcal{M}(\mathscr{H}_k, \mathscr{D})$ is, $\forall h \in \mathscr{H}_k$, 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*. These market outcomes are used to calculate the metrics of interest.

The solution of the *EMCP* may be used to calculate the hourly metrics such as the total load, the seller payments, the pure and *DR*-capable buyer payments, the *ALMP*, the *ESR* profits, *DRR* benefits and the congestion rents. For an hour h, the total cleared load is:

$$\ell^{\mathscr{B}}[h] = \sum_{n \in \mathscr{N}} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}[h]\right]^\star\right) \qquad \text{(A.4)}$$

the seller payments are

$$\rho^{\mathscr{S}}[h] = \sum_{n \in \mathscr{N}} \left[p_n^g[h]\right]^\star \cdot \left[\lambda_n[h]\right]^\star \qquad \text{(A.5)}$$

and the *ESR*s profits are

$$\rho^{\mathscr{U}}[h] = \sum_{n \in \mathscr{N}} \left[d_n^{\mathscr{U}}[h]\right]^\star \cdot [\lambda_n[h]]^\star - \left[c_n^{\mathscr{U}}[h]\right]^\star \cdot \left([\lambda_n[h]]^\star + \upsilon_n[h]\right) \tag{A.6}$$

Due to the recent *FERC* Order No. 745, additional considerations must be made to calculate the *DRR* benefits, the buyer payments, congestion rents and the *ALMP*. *FERC* Order No. 745 specifies that *DRR*s be provided incentive payments at the post-curtailment *LMP* whenever the pre-curtailment *LMP* exceeds a system-wide threshold price. Morever, the Order requires the incentive payments to *DRR*s for reductions in demand 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 [20]. To take account of this requirement, we define $\lambda^{r,y}[h]$ to be the system-wide threshold price for an hour h of a month r in year y. A detailed description of the process by which the threshold prices are calculated is given in [22]. Further, we define $\hat{\lambda}_n[h]$ 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 $\lambda_n[h] \leq \hat{\lambda}_n[h]$. With these quantities, we define the additional charge to buyers at node n to provide the *DRR* incentive payments for *DRR* curtailments in an hour h

$$\upsilon_n[h] = \begin{cases} \dfrac{\displaystyle\sum_{n \in \mathscr{N}} \left[d_n^{\tilde{\mathscr{B}}}\right]^\star [\lambda_n[h]]^\star}{\displaystyle\sum_{n \in \hat{\mathscr{N}}[h]} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}\right]^\star\right)} & \text{if } n \in \hat{\mathscr{N}}[h] \\[2em] \dfrac{\displaystyle\sum_{n \in \mathscr{N}} \left[d_n^{\tilde{\mathscr{B}}}\right]^\star [\lambda_n[h]]^\star}{\displaystyle\sum_{n \in \mathscr{N}} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}\right]^\star\right)} & \text{if } \hat{\mathscr{N}}[h] = \emptyset \\[2em] 0 & \text{otherwise} \end{cases}$$

If $\hat{N}[h] = \emptyset$ for an hour h, the costs of *DRR* curtailments are socialized to all loads on a pro-rata basis. With these additional requirements taken into account, the total buyer payments are

$$\rho^{\mathscr{B}}[h] = \sum_{n \in \mathscr{N}} \left(\left[p_n^d[h]\right]^\star - \left[d_n^{\tilde{\mathscr{B}}}[h]\right]^\star\right) \cdot \left([\lambda_n[h]]^\star + \upsilon_n[h]\right) \tag{A.7}$$

the benefits that accrue to *DRR*s are

$$\rho^{\tilde{\mathscr{B}}}[h] = \sum_{n \in \mathscr{N}} \left[d_n^{\tilde{\mathscr{B}}}[h]\right]^\star \cdot [\lambda_n[h]]^\star - \left[c_n^{\tilde{\mathscr{B}}}[h]\right]^\star \cdot [\lambda_n[h]]^\star + \left[d_n^{\tilde{\mathscr{B}}}[h]\right]^\star \cdot \left[\hat{\lambda}_n[h]\right]^\star \tag{A.8}$$

the congestion rents are

$$\kappa[h] = \rho^{\mathscr{B}}[h] - \rho^{\mathscr{S}}[h] \tag{A.9}$$

and the *ALMP* is

$$\bar{\lambda}[h] = \frac{\rho^{\mathscr{B}}[h]}{\ell^{\mathscr{B}}[h]} \tag{A.10}$$

The metrics defined in Eqs. (A.4)–(A.10) are the foundation of our side-by-side comparison of the *ES* and *DRR* economic and emission impacts on the *DAM* outcomes.

References

[1] *DOE*, "Benefits of demand response in electricity markets and recommendations for achieving them," U.S. Department of Energy, A Report to the United States Congress, 2006. [Online]. Available: http://eetd.lbl.gov/ea/ems/reports/congress-1252d.pdf

[2] D. Rastler, "Electricity energy storage technology options: A white paper primer on applications, costs, and benefits," Electric Power Research Institute, White Paper 1020676, 2010.

[3] J. Eyer and G. Corey, "Energy storage for the electricity grid: Benefits and market potential assessment guide," Sandia National Laboratories, Sandia Report SAND2010-0815, 2010. [Online]. Available: http://prod.sandia.gov/techlib/access-control.cgi/2010/100815.pdf

[4] G. Strbac, "Demand side management: Benefits and challenges," *Energy Policy*, vol. 36, pp. 4419–4426, 2008.

[5] D. Kirschen, "Demand-side view of electricity markets," *IEEE Trans. Power Syst.*, vol. 18, no. 2, pp. 520–527, May 2003.

[6] NYISO, "Energy storage in the new york electricity markets," White Paper, Tech. Rep., March 2010.

[7] G. Strbac, E. Farmer, and B. Cory, "Framework for the incorporation of demand-side in a competitive electricity market," *Generation, Transmission and Distribution, IEE Proceedings-*, vol. 143, no. 3, pp. 232 –237, May 1996.

[8] C. Su and D. Kirschen, "Quantifying the effect of demand response on electricity markets," *IEEE Trans. Power Syst.*, vol. 24, no. 3, pp. 1199–1207, Aug. 2009.

[9] E. Karangelos and F. Bouffard, "Towards full integration of demand-side resources in joint forward energy/reserve electricity markets," *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 280–289, Feb. 2012.

[10] "Quantifying demand response benefits in *PJM*," The Brattle Group, Tech. Rep., 2007.

[11] A. Faruqui, R. Hledik, S. Newell, and H. Pfeifenberger, "The power of 5 percent," *The Electricity Journal*, vol. 20, no. 8, pp. 68 – 77, Oct. 2007.

[12] F. Figueiredo, P. Flynn, and E. Cabral, "The economics of energy storage in 14 deregulated power markets," *Energy Studies Review*, vol. 14, no. 2, pp. 131–152, 2006.

[13] R. Sioshansi, P. Denholm, T. Jenkin, and J. Weiss, "Estimating the value of electricity storage in *PJM*: Arbitrage and some welfare effects," *Energy Economics*, vol. 31, no. 2, pp. 269–277, 2009.

[14] A. Kowli, "Assessment of variable effects of systems with demand response resources," Master's thesis, University of Illinois at Urbana Champaign, Urbana, Illinois, 2009.

[15] K. Van Horn, "The comparative economic assessment of the impacts of energy storage and demand response resource participation in the day-ahead electricity markets," Master's thesis, University of Illinois at Urbana Champaign, Urbana, Illinois, 2012.

[16] Power systems test case archive. University of Washington Department of Electrical Engineering. [Online]. Available: http://www.ee.washington.edu/research/pstca/

[17] *MISO* data. [Online]. Available: https://www.midwestiso.org/Library/MarketReports/Pages/MarketReports.aspx

[18] *ISO-NE* data. [Online]. Available: http://www.is-one.com/markets/hrlydata/index.html

[19] *EPA* air emissions data. [Online]. Available: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

[20] *FERC*, "Order No. 745: Demand Response Compensation in Organized Wholesale Energy Markets Final Rule," 134 FERC 61,187, Federal Energy Regulatory Commission, Mar. 2011. [Online]. Available: http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

[21] A. Wood and B. Wollenberg, *Power Generation Operations and Control*, 2nd ed. New York: John Wiley & Sons, Inc., 1996.

[22] I. Castillo, "Assessment of the impacts of demand curtailments in the *DAM*s: Issues in and proposed modifications of the *FERC* Order No. 745," Master's thesis, University of Illinois at Urbana Champaign, Urbana, Illinois, 2012.