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Demand side management in power grid enterprise control: A comparison of industrial & social welfare approaches

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HIGHLIGHTS

- We model, simulate and compare two demand side management market designs.
- We holistically address unit commitment, economic dispatch, and regulation service.
- We show the industrial baseline errors result in higher energy consumption and costs.
- We show quantitatively higher industrial baseline errors require higher regulating reserves.

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ABSTRACT

Despite the recognized importance of demand side management (DSM) for mitigating the impact of variable energy resources and reducing the system costs, the academic and industrial literature have taken divergent approaches to DSM implementation. The prequel to this paper has demonstrated that the net-load baseline inflation – a feature particular to the industrial DSM unit commitment formulation – leads to higher and costlier day-ahead scheduling compared to the academic social welfare method. This paper now expands this analysis from a single optimization problem to the full power grid enterprise control with its multiple control layers at their associated time scales. These include unit commitment, economic dispatch and regulation services. It compares the two DSM formulations and quantifies the technical and economic impacts of industrial baseline errors in the day-ahead and real-time markets. The paper concludes that the presence of baseline errors – present only in the industrial model – leads to a cascade of additional system imbalances and costs as compared to the social welfare model. A baseline error introduced in the unit commitment problem will increase costs not just in the day-ahead market, but will also introduce a greater netload error residual in the real-time market causing additional cost and imbalances. These imbalances if left unmitigated degrade system reliability or otherwise require costly regulating reserves to achieve the same performance. An additional baseline error introduced in the economic dispatch further compounds this cascading effect with additional costs in the real-time market, amplified downstream imbalances, and further regulation capacity for its mitigation.

1. Introduction

1.1. Motivation

The prequel [1] to this paper explains that the industrial and academic literature are taking divergent approaches to DSM implementation. DSM with its ability to allow customers to adjust electricity consumption in response to market signals provides additional dispatchable resources to mitigate the variable effects of renewable energy [2,3], enhance electrical grid reliability and reduce system costs through load shaping and emergency response [4–9]. Research on DSM has studied the promotion effect of demand response on distributed generation [10], characterized the load shaping behavior of responsive demands in commercial, residential, and water sectors [11–14], and developed algorithms [15,16] to achieve several optimization goals including minimizing customer discomfort and energy consumption [17,18]. Recent studies have also addressed the effect of DSM energy & reserve

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Nomenclature

Sets

b	index of buses
DC	subscript for dispatchable demand units (i.e. participating in DSM)
DS	subscript for stochastic demand units (i.e. conventional load)
GC	subscript for dispatchable generators (e.g. thermal plants)
GS	subscript for stochastic generators (e.g. wind, solar photo-voltaic)
h	index of lines
i	index of dispatchable generators
j	index of dispatchable demand units
k	index of stochastic generators
l	index of stochastic demand unit
t	index of time

Parameters

γ_{bt}	incremental transmission loss factor of bus b at time t
a_{bht}	bus b generation shift distribution factor to line h at time t
A_{DCj}	quadratic utility function coefficients of the jth dispatchable demand unit
$\mathbb{A}_{DCj}$	quadratic cost function coefficient jth virtual generation
A_{GCi}	quadratic cost function coefficient of the ith dispatchable generator
B_{DCj}	linear utility function coefficients of the jth dispatchable demand unit
$\mathbb{B}_{DCj}$	linear cost function coefficient jth virtual generation
B_{GCi}	linear cost function coefficient of the ith dispatchable generator
$\Delta\hat{D}_{bt}$	stochastic demand forecast increments on bus b at time t
$\overline{F_h}$	flow limit of line h
M_{bi}	correspondence matrix of dispatchable generator i to bus b
M_{bj}	correspondence matrix of dispatchable demand unit j to bus b
N_B	number of buses
N_{DC}	number of dispatchable demand units
N_{GC}	number of dispatchable generators
$\underline{P_{DCj}}$	min. capacity of the jth dispatchable demand unit
$\overline{P_{DCji}}$	max. capacity of the jth dispatchable demand unit
$\underline{\tilde{P}_{DCj} - P_{DCj}}$	min. capacity of the jth virtual generator
$\overline{\tilde{P}_{DCj} - P_{DCj}}$	max. capacity of the jth virtual generator
$\underline{P_{GCi}}$	min. capacity of the ith dispatchable generator
$\overline{P_{GCi}}$	max. capacity of the ith dispatchable generator
$\underline{R_{DCj}}$	min. ramping capability of the jth dispatchable demand unit
$\overline{R_{DCj}}$	max. ramping capability of the jth dispatchable demand unit
$\underline{R_{GCi}}$	min. ramping capability of the ith dispatchable generator
$\overline{R_{GCi}}$	max. ramping capability of the ith dispatchable generator
T_{ED}	real-time market time step

Decision variables

$\Delta\mathcal{C}_{DCjt}$	incremental cost of the jth virtual generator at time t
$\Delta\mathcal{C}_{GCit}$	incremental cost of the ith dispatchable generator at time t
ΔD_{bt}	dispatchable demand increments on bus b at time t
F_{ht}	power flow level of line h at time t
ΔP_{DCjt}	incremental power consumption at the jth dispatchable demand unit in the tth time interval
ΔP_{GCit}	incremental power generation at the ith dispatchable generator in the tth time interval
ΔP_{bt}	dispatchable generation increments on bus b at time t
P_{DCjt}	dispatched power consumption at the jth dispatchable demand unit in the tth time interval
$\tilde{P}_{DCjt} - P_{DCjt}$	dispatched power generation at the jth virtual generator at time t
P_{GCit}	dispatched power generation at the ith dispatchable generator in the tth time interval
$\Delta\mathcal{U}_{DCjt}$	incremental utility of the jth dispatchable demand unit at time t
$\Delta\mathcal{W}_t$	incremental social welfare at time t

market integration on reliability [19], the incorporation of storage and demand response in optimal power flow and energy hub design [20,21], the scheduling of demand side storage [22–24], and the integration of bus communication [25] and multi-agent systems [26] into DSM.

The demand response market design mostly commonly used among academic researchers [27–35] maximizes social welfare (SW); defined as the benefits from electricity consumption measured as a monetized utility minus the costs of generation [27]. The industrial trend, best exemplified by FERC order 745 [36–38], in contrast, minimizes the costs of generation and the compensation to customers for load reductions from a predefined electricity consumption baseline. Such a baseline is administratively set as the electricity consumption that would have occurred without DSM and is estimated from historical data after enrollment in the DSM program [39,40]. In this way, dispatchable demand reductions are treated as "virtual generators". For the sake of brevity, these two market designs will be called the social welfare and industrial DSM models respectively.

The prequel [1] to this paper emphasized the need to rigorously compare these DSM market designs on an even footing despite their fundamental differences. Fig. 1 contrasts stochastic load and net load curves in the two DSM implementations. In Fig. 1(a), curve **a** represents the stochastic load in the SW model. It consists of the demand forecast from all non-DSM-participating customers. Subtracting the stochastic generation (e.g. wind & solar PV generation) from curve **a** gives curve **b**; representing the stochastic net load in the SW model. Note that this net forecasted time series is composed of two terms, does not include a baseline, and sets the aggregate values to which the controllable generation and demand must dispatch. In Fig. 1(b), curve **c** represents the stochastic net load in the industrial model. It is the sum of curve **a** and the baseline estimation of customers participating in the industrial DSM program. Subtracting stochastic generation from curve **c** results in curve **d**; representing the stochastic net load in the industrial model. Note that this net forecasted time series is composed of three terms, one of which includes the industrial DSM baseline, and sets the aggregate values to which the controllable generation and "virtual" generation must dispatch. In other words, the industrial stochastic net load curve **d** is obtained by adding the industrial DSM baseline to the SW net load curve **b**. In the (likely) event [41,42] that the industrial DSM baseline is erroneously inflated, an error term is