Electric Power Systems Research 190 (2021) 106674

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Towards the construction of a class of grid operational flexibility metrics

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ARTICLE INFO

Keywords:
Electricity market and grid operations
Grid operational flexibility
Renewable energy integration impacts

ABSTRACT

The increased net load uncertainty and variability due to higher levels of renewable energy resource integration into grids require the clear understanding and quantification of grid operational flexibility (GOF) and associated impacts. However, there is no widely-accepted methodology to assess flexibility, guide policy formulation and quantify the value of operational flexibility. Recent efforts towards improved flexibility assessment have focused on feasible net load ramps, operational margins and robustness bounds. In this paper, we propose an approach to GOF assessment focused on the economic impacts related to net load variability/uncertainty accommodation. We illustrate the application of the proposed approach through representative study cases on a modified version of the *IEEE* Reliability Test System operated under a multi-settlement system. Our results indicate that the market outcomes provide a concrete basis for GOF assessment in general, and in particular, the impacts due to ramping limitations provide insights into a grid's ability to accommodate net load variability/uncertainty.

1. Introduction

The deepening penetrations of renewable energy resources (RERs) in electric power systems raise major concerns about the ability of the grid to efficiently and effectively accommodate the resultant net load profiles characterized by increased variability/uncertainty. Such ability, often referred to as GOF, entails the harnessing of the various supply- and demand-side services offered to the grids through the day-ahead markets (DAMs) and their real-time markets (RTMs). The efficient and effective accommodation of the variable and uncertain net loads that result from the higher levels of RER integration is a daunting challenge in grid operations and associated markets in light of the required clear understanding and appropriate quantification of flexibility requirements and associated impacts of their provision. Nonetheless, a formal GOF definition directly relatable to measurable quantities, as well as a widely-accepted methodology for flexibility assessment and to explicitly express the value of GOF in today's increasingly complex grids is yet to be established. The intrinsic challenges of flexibility assessment arise from GOF's multi-dimensional and multi-time-scale aspects embedded within an uncertain decision-making context, in which various interdependent operational constraints and forecasts with distinct time-dependent accuracies must be explicitly represented.

For day-ahead grid and market operations, RER forecasts lack accuracy and have rather rough time granularity. Therefore, the design of appropriate ancillary service provision/acquisition via markets and the specification of the corresponding requirements pose challenges due to the conflicting impacts on market efficiency and operational margins. In contrast to day-ahead operations, real-time operations benefit from forecasts with shorter lead times that can provide higher accuracy. RTMs aim to clear the energy imbalances due to the imperfect information used in the DAMs clearing. Real-time locational marginal price (LMP) volatility arises due to the possibly large energy imbalances from day-ahead decisions and may be exacerbated by the RTM shorter lead times, as many controllable resources (CRs) require several hours to startup and shutdown. Consequently, large energy imbalances from DAMs expose market participants to more volatile real-time LMPs and indicate that the DAM cannot provide financial certainty nor economically efficient decisions to accommodate the variable and uncertain net loads.

Price volatility across network locations may occur in both the DAMs and the RTMs as a consequence of transmission transfer capability constraints. Spatial price volatility may increase with net load uncertainty, as the independent grid operator (IGO) may require transmission transfer capability margins to ensure robust dispatch decisions. Flexibility scarcity entails price volatility across time, a phenomenon closely related to the physical capabilities of CRs. More specifically, the ramping capabilities, the minimum up/down times and the startup costs of CRs contribute to price volatility across both temporal and spatial dimensions, particularly under highly variable net loads. Typically, the net loads become significantly variable due to the more pronounced role of RERs in the provision of energy. A direct implication is on the utilization of CRs, which are either committed to operate

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https://doi.org/10.1016/j.epsr.2020.106674
Received 4 October 2019; Received in revised form 11 March 2020; Accepted 1 August 2020
Available online 08 August 2020

just above their minimum output limits or are decommitted and become unable to respond to short-term net load changes so as to not violate minimum up/down time constraints. Clearly, IGOs avoid to decommit an excessive amount of CRs in order to exercise control over supply and demand balance in the grid. Therefore, IGOs commit CRs close to their minimum output limits to ensure that these CRs can adequately respond to fast net load changes. In such cases, it may happen that the LMP at a CR bus falls below the CR's minimum offer price even once the resource is cleared in the market [1]. Consequently, such a CR becomes eligible to receive uplift payments to recover the incurred expenditures – including lost opportunity costs – to follow the IGO dispatch instructions. The increased net load variability may also require the more frequent startup and shutdown of CRs. Thus, the additional startup costs lead to increased uplift payments. Some electricity markets socialize uplift costs among loads along cost-causation principles [2].

In light of the various implications and complexities of variable and uncertain net load accommodation, it is clear that GOF is inexorably linked to the physical limitations of the grid's resource mix, the transmission transfer capability, the underlying market design, and the effectiveness of the grid's operational paradigm with respect to the management of the effects of the various sources of uncertainty which include RER outputs, demands and CR availabilities. In this paper, we refer to flexibility assessment as the evaluation of a grid's ability to accommodate the variable and uncertain net loads over a specified period. Due to the complex nature of GOF, past flexibility assessment methods frequently focused on operational margins or on the consequences of flexibility deficiency, such as marked frequency excursions, load shedding, RER output curtailment, additional payments due to real-time decisions, increased uplift payments, and acute price volatility across time and space [3]. A wide variety of flexibility metrics and assessment methodologies has been proposed in the literature along with distinct approaches to the classification of GOF metrics. One approach classifies flexibility metrics based on whether they pertain to planning or short-term operations and on the provided information with respect to flexibility requirements, resource flexibility provision or overall grid flexibility [4].

In the planning context, reliability assessment methods and indices have inspired various overall grid flexibility metrics based on operational margins [5–7]. A tool that evaluates the flexibility supply based on CR operational constraints is proposed in [5]. The tool generates a curve of RER capacity share versus the fraction of operating hours with insufficient ramping capability. A flexibility measure inspired by the widely deployed loss of load expectation is proposed in [6]. The metric is insufficient ramping resource expectation and it is computed through the comparison between the observations of a probability distribution of operational margins and a given series of net load ramps. The expected unserved ramping metric was proposed in [7], as the flexibility analogue of the expected unserved energy metric. Metrics for flexibility requirements within different time scales were proposed in [8] and flexibility indices based on the physical capabilities of CRs were defined in [9].

Robustness-based flexibility metrics that aim to provide awareness for real-time operations have been explored as well in [10–12]. In [10], energy limitations of CRs are explicitly considered and a visualization tool is presented to compare the "required flexibility", the "aggregated flexibility" and the "remaining flexibility" metrics. The flexibility metrics proposed in [10] relate to capacity, ramp rate and energy limitations of supply-side resources. A deterministic flexibility metric focused on the range of net load values that the system can accommodate in the near future is proposed in [11]. Such range of net load values is determined subject to an upper cost limit. In [12], the lack of ramp probability is proposed under the assumption of a Gaussian distribution for the net load forecast error. The application of robust optimization determines the dispatch of units in a way that ensures sufficient reserves to accommodate net load values within a specified confidence interval. The approach explicitly considers zonal transmission constraints and provides dispatch instructions that constrain the maximum lack of ramp probability based on the assumption of Gaussian net load forecast errors.

The metrics proposed in the literature provide useful insights into the ability of a grid to accommodate deepening RER penetrations with a focus on operational capabilities and associated margins. However, they provide no measurable economic information associated with the impacts of flexibility provision to market outcomes. Since the objective of grid operations is to meet the rapidly changing net loads as economically as possible, quantification of the economic impacts is essential in GOF assessment.

In this paper, we propose a general flexibility analysis and assessment approach that quantifies the economic impacts of ramping limitations on CR output changes, the essential source of flexibility. We use the proposed approach to construct a class of GOF metrics based on the comparison of market outcomes under different operational constraints to evaluate the economic impacts of CR ramping limitations in a grid over a specified time period. The class of metrics defined under this approach provide quantitative answers to various *what if* questions and have a broad range of applications, from operational analysis to planning, investment evaluation and policy formulation. We illustrate the effectiveness of the approach on representative study cases performed on the *IEEE* Reliability Test System with wind and solar resources [13]. The significance of our work lies in the provision of a class of metrics that provide valuable insights into the economic aspects of GOF. The paper represents an advancement of the state of the art in GOF to report on the construction of appropriate economic metrics that extensively use the performance of the grid and market operations in meaningful ways for GOF assessment. Our results indicate that the market performance outcomes provide a concrete basis for GOF assessment and that the impacts due to CR ramping limitations provide insights into a grid's ability to accommodate net load variability.

This paper contains four additional sections. In Section 2, we present our flexibility assessment approach. We devote section 3 to the description of the proposed class of *GOF* metrics. In Section 4, we describe the nature and scope of the broad range of case studies and present the analysis of the representative study results. We summarize the paper and discuss future work directions in Section 5. The paper has three appendices that describe the notation, market-clearing problem (MCP) statements and uplift payment computation, respectively.

2. Proposed approach

Due to the economic implications to accommodate variable and uncertain net loads, market performance outcomes can quantitatively reflect whether or not GOF scarcity exists. In a market environment, the IGO aims to securely meet demand as economically as possible and, consequently, the impacts of GOF provision on market outcomes are of utmost importance. Our GOF assessment focuses on the economic dimensions of flexibility to gain insights into the repercussions of GOF scarcity. In the following, we describe our proposed approach to production-costing-based simulation, including the evaluation of the impacts due to CR ramping limitations.

The proposed approach is based on a side-by-side comparison between the market outcomes that stem from two distinct production-costing modules – a reference module and a modified module. The reference module utilizes a faithful grid representation and the modified module uses relaxed versions of specific constraints related to CR output level changes. The differences between the market performance outcomes of the two modules represent the economic impacts of the CR ramping limitations and we use these differences as the GOF metrics. We remark that, in our analysis, the GOF of a specific grid is conditioned to the grid's generation and transmission resources, operational paradigm, net loads and its various forecasts with distinct lead-time-dependent accuracies.

We use production-costing modules that represent both DAMs and RTMs to capture the effects of day-ahead decisions on the real-time outcomes. DAMs solve a MCP with H periods per day. For the RTMs, we represent K RTM periods within each DAM period. Each module takes the same set of buses, transmission lines, generation resources and demand/RER output information to produce a set of optimal DAM and RTM decisions. The reference module faithfully represents the grid under study and its constraints related to the accommodation of net load variability and uncertainty. The modified module, on the other hand, relaxes the constraints on CR output level changes across time so as to provide a set of decisions that represent how the grid would operate if its CRs could change power outputs faster.

The proposed economic-impact-based flexibility assessment enables us to effectively distill multi-temporal, multi-dimensional aspects into meaningful and intuitive scalar metrics that are independent of the market implementation. More specifically, the proposed metrics may be applied to any market implementation that explicitly represents CR output level changes in ramping constraints. Moreover, metrics based on market outcomes need not be one-dimensional and may provide insights with respect to GOF deliverability and time dependence. We note that, while the proposed approach focuses on the economic impacts of the CR ramping constraints, its application to GOF assessment in grids with integrated demand response resources (DRRs) and energy storage resources (ESRs) and interconnections with other IGOs is entirely feasible, as the proposed side-by-side comparison approach can be applied to grids with an arbitrary resource mix and interconnections. Moreover, the presence of ESRs and DRRs in the resource mix as well as interconnections may be viewed as additional sources of GOF and their flexibility provision impacts the GOF that is supplied by the CRs. Thus, the proposed approach is suitable to assess GOF in grids with additional sources of flexibility.

3. Proposed class of flexibility metrics

To define a class of metrics that reflect the overall economic impacts of CR ramping limitations, we parametrize the ramping constraints on CRs. We introduce the parameter $\alpha \in [0, 1]$ to modify the term that represents the output level change between periods. In the proposed ramping constraint definition, $g_c[k]$ refers to the output level of CR c at period k in *MW* and the up (down) ramp product, up (down) frequency regulation and T^{ς}-minute spinning reserves provided by c at period k are given by $\rho_c^{\uparrow}[k]$ ($\rho_c^{\downarrow}[k]$), $\phi_c^{\uparrow}[k]$ ($\phi_c^{\downarrow}[k]$) and $\varsigma_c[k]$, respectively. We denote the up (down) ramp limit of resource c in *MW/min* by $\rho_c^{\uparrow M}$ ($\rho_c^{\downarrow M}$), the period length in minutes by τ, the ramp production duration in minutes by T^{ρ}, and the ramp rate coefficient for frequency regulation service by ζ^{ϕ}. The up and down CR ramping constraints follow:

$$\alpha\frac{g_c[k]-(g_c[k-1]-T^{\rho}\rho_c^{\downarrow}[k-1])}{\tau}+\frac{1}{T^{\varsigma}}\varsigma_c[k]+\rho_c^{\uparrow}[k] + \zeta^{\phi}\phi_c^{\uparrow}[k]\leq\rho_c^{\uparrow M},$$

$$-\alpha\frac{g_c[k]-(g_c[k-1]+T^{\rho}\rho_c^{\uparrow}[k-1])}{\tau}+\rho_c^{\downarrow}[k]+\zeta^{\phi}\phi_c^{\downarrow}[k]\leq\rho_c^{\downarrow M}.$$

The term multiplied by α corresponds to the up (down) change in output level given that the ramp down (up) product from the previous period may have been fully utilized. Therefore, when $\alpha = 1$, the impacts due to CR output level changes between consecutive periods are left unchanged. When α approaches zero, such impacts diminish. The comparison between the market outcomes when $\alpha = 1$ and when $\alpha \in [0, 1)$ enables us to evaluate the net load variability impacts on the market performance outcome. Therefore, for the reference production-costing module, we set $\alpha = 1$ and for the modified module, $\alpha \in [0, 1)$.

The proposed class of metrics is based on the relative change of various market outcomes with respect to the relaxation carried out via the parameter α. We denote the optimal objective value of a production-costing module with given value of α over a specific time as $C(\alpha)$ in dollars ($). Analogously, we refer to the corresponding total RER energy curtailment in *MWh* as $\mathcal{E}(\alpha)$ and the total uplift payments in $ as $\mathcal{U}(\alpha)$. We construct a class of metrics based on the comparison of these market outcomes under different values of α.

To evaluate the GOF-related impacts to the total operational cost, we define

$$\mathcal{M}_C(\alpha)=\frac{C(1)-C(\alpha)}{C(1)}\times 100\,\%. \tag{1}$$

For a given value of $\alpha \in [0, 1)$, the magnitude of $\mathcal{M}_C(\alpha)$ indicates the relative impacts to the market outcome C. For example, a null $\mathcal{M}_C(0)$ implies that $C(0) = C(1)$, and the relaxation imposed by $\alpha = 0$ does not impact the total production cost for a particular study. The higher the value of $\mathcal{M}_C(0)$, the larger the change in total production cost due to ramping constraints.

To investigate the impacts to RER curtailment, we define $\mathcal{M}_{\mathcal{E}}(\alpha)$ under the assumption that there is RER curtailment for the grid under study when no relaxation is imposed:

$$\mathcal{M}_{\mathcal{E}}(\alpha)=\frac{\mathcal{E}(1)-\mathcal{E}(\alpha)}{\mathcal{E}(1)}\times 100\,\%. \tag{2}$$

Analogously, we use $\mathcal{M}_{\mathcal{U}}(\alpha)$ to assess the GOF-related impacts to uplift payments:

$$\mathcal{M}_{\mathcal{U}}(\alpha)=\frac{\mathcal{U}(1)-\mathcal{U}(\alpha)}{\mathcal{U}(1)}\times 100\,\%. \tag{3}$$

The proposed class of metrics enables us to assess how net load variability impacts the electricity market outcomes. Furthermore, the metrics may be applied to systematically evaluate how a particular change to the grid affects the market outcomes related to GOF.

4. Representative results

We illustrate the evaluation of the proposed metrics on the *IEEE* Reliability Test System with wind and solar resources described in [13]. The network under study consists of 120 transmission lines and 73 buses that are separated into 3 areas. As described in [14], the line lengths from the *IEEE* Reliability Test System 1996 were used to determine geographical distances among nodes and establish a fictitious grid in the southwestern region of the United States, for which synchronized wind, solar, hydro and regional demand profiles are available. We represent all the resources modeled in [14] except for the high-voltage *DC* link that connects areas 1 and 3, the 200-MW concentrated solar power plant, the 50-MW storage resource and the three synchronous condensers. The resulting grid contains 153 generation resources that add up to 14.3 GW of installed capacity. The resource mix consists of 74 thermal resources (8,076 MW), 22 run-of-river hydro resources (1 GW), 4 wind power plants (2,507 MW), 26 utility-scale photovoltaic (PV) plants (1,555 MW), and 31 behind-the-meter distributed *PV* (DPV) aggregations (1,161 MW).

We introduce specific assumptions on the MCP problem formulation so as to allow the side-by-side comparison of different flexibility-related market outcomes for a grid. For simplicity, we assume demand is inelastic in both the DAMs and the RTMs. We utilize hourly DAM periods and 5-minute RTM periods so that $H = 24$ and $K = 12$. As the focus of this investigation is limited to GOF, we assume that the required ancillary services to meet contingency-based security criteria have already been procured and, therefore, we do not consider any contingency constraints in our MCP statement. We further assume that the ancillary services available in both DAMs and RTMs are 10-minute spinning reserves in *MW* and up/down frequency regulation service, which we defined as amounts of *MW* that must be deliverable within 5 minutes so that $\zeta^{\phi} = 1/5$. Up/down ramp products in *MW/min*, which must be sustainable for at least 20 minutes, are present in the DAMs to account for less accurate net load forecasts and coarser time resolution. The utilized notation, MCP statements and uplift payment computation

Table 1
Overall market outcomes for $\alpha = 1$.

η [%]	DPV capacity [MW]	$\mathcal{C}(1)$ [$]	$\mathcal{E}(1)$ [MWh]	$\mathcal{U}(1)$ [$]
0	0	17,435,316	12,325	77,161
20	233	17,245,100	12,941	83,703
40	467	17,058,690	13,600	84,919
60	700	16,912,387	14,446	158,755
80	933	16,779,116	16,376	246,594
100	1161	16,661,675	16,747	219,225

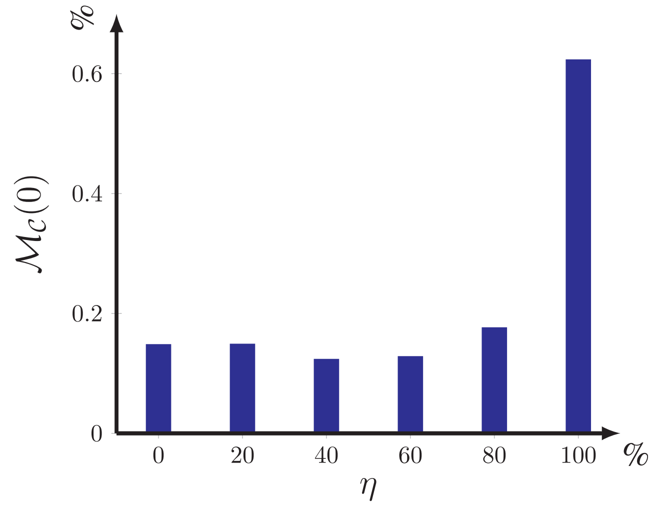
methodology are presented in detail in Appendix A, Appendix B and Appendix C, respectively.

The study is performed for the first week of August 2020, when the net load is expected to be extremely variable due to air-conditioning loads and PV production. To investigate how distinct RER penetration levels affect the measured impacts, we apply the metrics to the grid under various levels of DPV integration. We define η to be the parameter which we use to scale the DPV capacity in the grid. We express η in % and let it vary from 0 % to 100 %, where $\eta = 0\,\%$ ($\eta = 100\,\%$) corresponds to 0 (1,161) MW of installed DPV capacity. The DPV output profiles are also scaled by η so as to appropriately represent the time-dependent behavior of the DPV outputs, which we assume cannot be curtailed. Table 1 summarizes the market outcomes for 6 specific values of η under $\alpha = 1$.

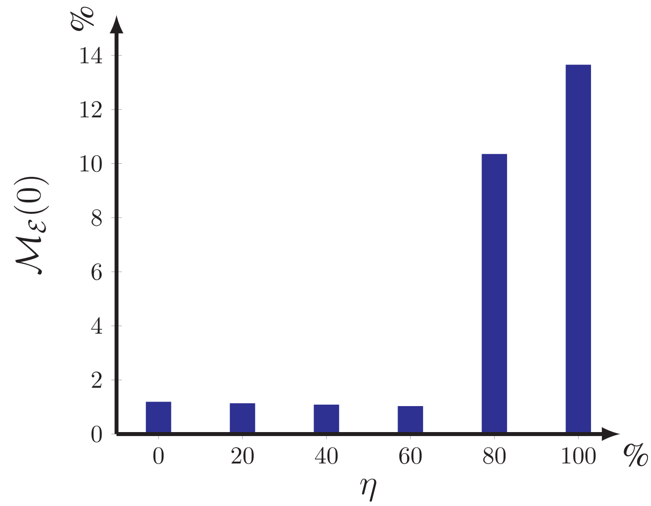
The objective of this study is to analyze the impacts of CR ramping limitations on market outcomes and determine whether relevant flexibility metrics may be derived from these impacts. We first focus on the impacts to the total operational costs. We compute the reference cost $\mathcal{C}(1)$ through the addition of the operational costs of each RTM period for each day of the week under study. The cost under relaxed ramping constraints is computed analogously, with $\alpha = 0$. The results, presented in Fig. 1a, indicate that operational cost impacts due to ramping limitations are small up to $\eta = 80\,\%$. For $\eta = 100\,\%$, the impacts due to CR ramping limitations reach 0.6 % of the total production costs. Fig. 1a indicates that the integration of DPV affects the GOF metric defined in (1) significantly above a certain integration level. Therefore, it is reasonable to expect that the grid will experience GOF scarcity under DPV integration levels above $\eta = 100\,\%$, as the impacts of CR ramping limitations on production costs become more prominent. We note that, as Table 1 indicates, the total production costs decrease with deepening penetrations of DPV since these resources offer energy at zero marginal cost. However, the impacts on the total production costs due to CR ramping limitations tend to increase with higher levels of DPV integration.

Fig. 1 b shows that the grid experiences large impacts to RER curtailment for $\eta \geq 80\,\%$. For lower levels of DPV integration, the CR ramping limitations have little effect on the total RER curtailment. The results indicate that, for $\eta = 80\,\%$, RER curtailment increases by roughly 10 % due to CR ramping limitations even though the impacts to total production costs remain small. For $\eta = 100\,\%$, impacts on RER curtailment increase significantly and the impacts to the total production costs experience a threefold increase if compared to the results for $\eta = 80\,\%$. Thus, the results indicate that until a certain level of DPV integration, the IGO uses RER curtailment to follow the net load and avoid significant changes to the clearing of CRs. However, to accommodate the net loads that result from deeper DPV penetrations, the IGO also needs to clear additional CRs with higher operational costs.

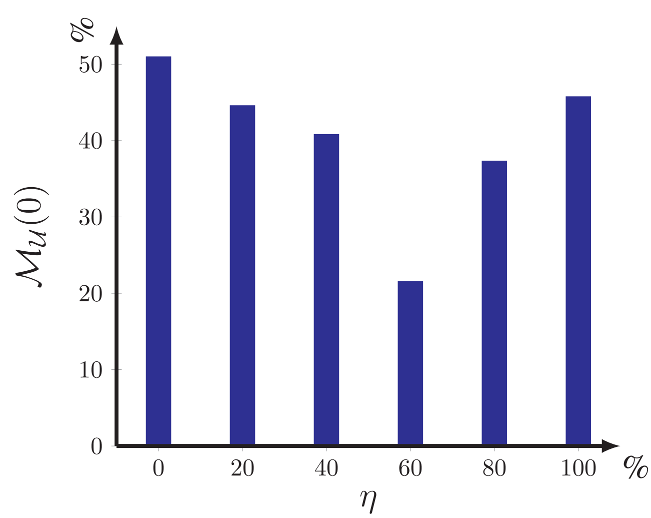
With respect to uplift payments, the outcomes displayed in Table 1 indicate that uplift payments tend to increase along with DPV penetrations, as expected. However, in Fig. 1c, the results for the uplift payment metric defined in (3) do not show a clear relation between DPV penetration and CR ramping limitations to uplift payments. While the impacts to uplift payments increase with DPV integration levels above $\eta = 60\,\%$, such trend does not hold for $\eta \leq 40\,\%$. This result is



(a) Overall production cost metric as a function of η.



(b) *RER* curtailment metric as a function of η.



(c) Uplift payment metric as a function of η.

Fig. 1. Proposed metrics for $\alpha = 0$ at various levels of DPV integration expressed in terms of η.

reasonable in light of the fact that the pricing scheme within our market-clearing simulation is based on marginal prices and, even though startup costs of CRs are represented in the market-clearing formulation, the LMPs do not reflect startup costs. There is ongoing research on distinct pricing schemes that aim to minimize uplift payments [15], but pricing methodologies are beyond the scope of this paper. A possible explanation is that uplift payments decrease with DPV penetration for small values of η as the DPV resources lower the peak net load and, consequently, prevent the commitment of expensive peakers. For $\eta > 60\,\%$, the ramping challenges due to deep DPV penetrations require fast responses from CRs and entail an increase in uplift payments.

Our study indicates that the economic impacts of CR ramping limitations become more prominent under deeper RER penetrations and, in fact, such impacts may be used to assess GOF in an economically meaningful manner. The proposed approach may be used to quantify the impacts of CR ramping limitations and investigate how these impacts change as a function of RER penetrations.

5. Concluding remarks

In this paper, we propose a class of metrics for the assessment of GOF based on the comparison between the market outcomes of a faithful grid representation and a modified version in which ramping constraints are relaxed. We model the grid operations under a multi-settlement system involving DAMs, RTMs and an uplift payment computation scheme so as to capture the effects of the DAM decisions on real-time operations and market outcomes. The proposed approach provides a systematic method to quantify the impacts of CR ramping capability under different RER penetration levels and has a broad range of applications, from operational analysis to planning, investment evaluation and policy formulation. We illustrate the application of the proposed approach on the *IEEE* Reliability Test System with wind and solar resources described in [13] to evaluate the economic impacts due to ramping constraints under different RER penetration levels.

Future work directions include the extension of the proposed class of metrics to incorporate additional metrics based on LMPs and congestion so as to gain insights into the deliverability of GOF. In addition, we aim to apply the proposed approach to compare how different operational paradigms — such as the use of different time resolutions, robust optimization and stochastic optimization — affect the economic impacts related to GOF provision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personel relationships that could have appeared to influence the work reported in this paper.

Appendix A. Notation

In this appendix, we define the notation used in the paper. The sets we utilize follow.

$\mathscr{K}$ time periods, $\mathscr{K} = \{k: k = 1, ..., |\mathscr{K}|\}$
$\mathscr{A}$ areas, $\mathscr{A} = \{a: a = 1, ..., |\mathscr{A}|\}$
$\mathscr{N}$ nodes, $\mathscr{N} = \{n: n = 1, ..., |\mathscr{N}|\}$
$\mathscr{L}$ branches, $\mathscr{L} = \{\ell: \ell = 1, ..., |\mathscr{L}|\}$
$\mathscr{S}$ supply resources, $\mathscr{S} = \{s: s = 1, ..., |\mathscr{S}|\}$
$\mathscr{C}$ CRs, $\mathscr{C} = \{c: c = c_1, ..., c_{|\mathscr{C}|}\} \subset \mathscr{S}$
$\mathscr{V}$ RERs, $\mathscr{V} = \{\nu: \nu = \nu_1, ..., \nu_{|\mathscr{V}|}\} \subset \mathscr{S}$
$\mathscr{B}$ DPVs, $\mathscr{B} = \{b: b = b_1, ..., b_{|\mathscr{B}|}\} \subset \mathscr{V}$
$\mathscr{S}_n$ supply resources located at node $n \in \mathscr{N}$
$\mathscr{C}_a$ CRs within area $a \in \mathscr{A}$

We use $\mathcal{S}_s(\cdot)$ to denote the piecewise linear offer curve of resource *s*, n_c to denote the nodal location of CR c and a_c to denote the area of CR c. The utilized decision variables follow.

$g_s[k]$ output of supply resource s in period k
$u_c[k]$ unit commitment status of CR c in period k
$y_c[k]$ startup status of CR c in period k
$z_c[k]$ shutdown status of CR c in period k
$\rho_c^{\uparrow}[k]$ up ramp product of CR c in period k
$\rho_c^{\downarrow}[k]$ down ramp product of CR c in period k
$\phi_c^{\uparrow}[k]$ up frequency regulation service of CR c in period k
$\phi_c^{\downarrow}[k]$ down frequency regulation service of CR c in period k
$\varsigma_s[k]$ spinning reserve of CR c in period k
$p_n[k]$ nodal power injection into node n in period k

The definitions of the problem statement parameters follow.

τ period length
g_c^M maximum output of CR c
g_c^m minimum output of CR c
C_c startup cost of CR c
T_c minimum up time of CR c
$\bar{T}_c^z$ minimum down time of CR c
φ_ℓ^n injection shift factor of line ℓ with respect to node n
f_ℓ^M *MW*-flow limit of line ℓ

T^{ς} spinning reserve deployment time
T^{ρ} ramp product duration
ζ^{ϕ} ramp rate allocation coefficient for $\phi^{\uparrow}$ and $\phi^{\downarrow}$
$r_{\nu}[k]$ forecasted output of ν in period k
$d_n[k]$ demand at node n in period k
$\varrho_a^{\varsigma}[k]$ spinning reserves requirements in area a in period k

The total requirements for the grid-wide ancillary services $\rho^{\uparrow}[k]$, $\rho^{\downarrow}[k]$, $\phi^{\uparrow}[k]$ and $\phi^{\downarrow}[k]$ are denoted by $\varrho^{\rho^{\uparrow}}[k]$, $\varrho^{\rho^{\downarrow}}[k]$, $\varrho^{\phi^{\uparrow}}[k]$ and $\varrho^{\phi^{\downarrow}}[k]$, respectively.

Appendix B. Market-clearing problems

In this appendix, we provide the market-clearing formulations we used to clear the DAMs and corresponding RTMs. The unit commitment (UC) model we use in day-ahead operations is similar to the one discussed in [16] and the proposed ramping constraints are built upon constraints from [3]. The utilized day-ahead market-clearing formulation follows.

$$\min_{\substack{p_n[k],\, g_s[k],\, u_c[k],\, z_c[k],\, y_c[k],\\ \varsigma_c[k],\, r_c^{\uparrow}[k],\, r_c^{\downarrow}[k],\, \phi_c^{\uparrow}[k],\, \phi_c^{\downarrow}[k]}} \sum_{t\in\mathscr{K}} \left(\sum_{s\in\mathscr{S}} \mathcal{S}_s(g_s[t]) + \sum_{i\in\mathscr{C}} C_i y_i[t] \right)$$

subject to

$$g_c[k] + T^{\rho}\rho_c^{\uparrow}[k] + \phi_c^{\uparrow}[k] + \varsigma_c[k] \le g_c^M u_c[k], \tag{4}$$

$$g_c[k] - T^{\rho}\rho_c^{\downarrow}[k] - \phi_c^{\downarrow}[k] \ge g_c^m u_c[k], \tag{5}$$

$$\alpha(g_c[k] - (g_c[k-1] - T^{\rho}\rho_c^{\downarrow}[k-1]))/\tau + \frac{1}{T^{\varsigma}}\varsigma_c[k] + \rho_c^{\uparrow}[k] + \zeta^{\phi}\phi_c^{\uparrow}[k] \le \rho_c^{\uparrow M}, \tag{6}$$

$$-\alpha(g_c[k] - (g_c[k-1] + T^{\rho}\rho_c^{\uparrow}[k-1]))/\tau + \rho_c^{\downarrow}[k] + \zeta^{\phi}\phi_c^{\downarrow}[k] \le \rho_c^{\downarrow M}, \tag{7}$$

$$u_c[k] - u_c[k-1] - (y_c[k] - z_c[k]) = 0, \tag{8}$$

$$y_c[k] + z_c[k] \le 1, \tag{9}$$

$$\sum_{t=k-T_c+1}^{k} u_c[t] \ge z_c[k] T_c, \tag{10}$$

$$\sum_{t=k-\bar{T}_c+1}^{k} 1 - u_c[t] \ge y_c[k]\bar{T}_c, \tag{11}$$

$$g_{\nu}[k] \le r_{\nu}[k], \tag{12}$$

$$g_b[k] = r_b[k], \tag{13}$$

$$\sum_{i\in\mathscr{S}_n} g_i[k] - d_n[k] = p_n[k], \tag{14}$$

$$\sum_{i\in\mathscr{N}} p_i[k] = 0, \tag{15}$$

$$\sum_{i\in\mathscr{N}} \varphi_{\ell}^{i} p_i[k] \le f_{\ell}^{M}, \tag{16}$$

$$-\sum_{i\in\mathscr{N}} \varphi_{\ell}^{i} p_i[k] \le f_{\ell}^{M}, \tag{17}$$

$$\sum_{i\in\mathscr{C}} \rho_i^{\uparrow}[k] \ge \varrho^{\rho^{\uparrow}}[k], \tag{18}$$

$$\sum_{i\in\mathscr{C}} \rho_i^{\downarrow}[k] \ge \varrho^{\rho^{\downarrow}}[k], \tag{19}$$

$$\sum_{i\in\mathscr{C}} \phi_i^{\uparrow}[k] \ge \varrho^{\phi^{\uparrow}}[k], \tag{20}$$

$$\sum_{i\in\mathscr{C}} \phi_i^{\downarrow}[k] \ge \varrho^{\phi^{\downarrow}}[k], \tag{21}$$

$$\sum_{i\in\mathscr{C}_a} \varsigma_i[k] \ge \varrho_a^{\varsigma}[k], \tag{22}$$

$$g_s[k],\ r_c^{\uparrow}[k],\ r_c^{\downarrow}[k],\ \phi_c^{\uparrow}[k],\ \phi_c^{\downarrow}[k],\ \varsigma_c[k] \geq 0, \tag{23}$$

$$u_c[k],\ y_c[k],\ z_c[k] \in \{0, 1\}, \tag{24}$$

for all $k \in \mathscr{K}$, $a \in \mathscr{A}$, $n \in \mathscr{N}$, $\ell \in \mathscr{L}$, $c \in \mathscr{C}$, $v \in \mathscr{V}$ and $b \in \mathscr{B}$. The initial conditions $p_c[0]$, $\rho_c^{\uparrow}[0]$, $\rho_c^{\downarrow}[0]$ and $u_c[t]$ for $t < 1$ are given for all $c \in \mathscr{C}$.

The LMPs $\lambda_n[k]$ are the dual variables associated with the nodal injection constraints. The prices for the ancillary services are the dual variables associated with their requirement constraints.

In the real-time markets, the commitment status variables $u_c[k]$ are given and the resulting real-time market-clearing formulation follows:

$$\min_{\substack{p_n[k],\, g_s[k],\, \varsigma_c[k],\\ r_c^{\uparrow}[k],\, r_c^{\downarrow}[k],\, \phi_c^{\uparrow}[k],\, \phi_c^{\downarrow}[k]}} \sum_{t\in\mathscr{K}} \sum_{s\in\mathscr{S}} \mathcal{S}_s(g_s[t])$$

subject to constraints (4) through (7) and (12) through (23) for all $k \in \mathscr{K}$, $a \in \mathscr{A}$, $n \in \mathscr{N}$, $\ell \in \mathscr{L}$, $c \in \mathscr{C}$, $v \in \mathscr{V}$ and $b \in \mathscr{B}$.

Appendix C. Uplift payments

We devote this appendix to describe the procedure we use to compute the uplift payments in the DAMs. To make the notation more compact, we define bold letters to represent arrays in $\mathbb{R}^{|\mathscr{K}|}$. Let the prices for up ramp product, down ramp product, up frequency regulation, down frequency regulation and spinning reserves in each area a along the day to given by $\boldsymbol{\xi}^{\rho^{\uparrow}}$, $\boldsymbol{\xi}^{\rho^{\downarrow}}$, $\boldsymbol{\xi}^{\phi^{\uparrow}}$, $\boldsymbol{\xi}^{\phi^{\downarrow}}$ and $\boldsymbol{\xi}_a^{\varsigma}$, respectively. We assume the generators' offers reflect their costs and define their profits given the cleared prices as

$$\pi_c(\boldsymbol{g}_c, \boldsymbol{\rho}_c^{\uparrow}, \boldsymbol{\rho}_c^{\downarrow}, \boldsymbol{\phi}_c^{\uparrow}, \boldsymbol{\phi}_c^{\downarrow}, \boldsymbol{\varsigma}_c, \boldsymbol{u}_c, \boldsymbol{y}_c) = \boldsymbol{\lambda}_{n_c}^{\top}\boldsymbol{g}_c + \boldsymbol{\xi}_{\rho}^{\uparrow\top}\boldsymbol{\rho}_c^{\uparrow} + \boldsymbol{\xi}_{\rho}^{\downarrow\top}\boldsymbol{\rho}_c^{\downarrow} + \boldsymbol{\xi}_{\phi}^{\uparrow\top}\boldsymbol{\phi}_c^{\uparrow} + \boldsymbol{\xi}_{\phi}^{\downarrow\top}\boldsymbol{\phi}_c^{\downarrow} + \boldsymbol{\xi}_{a_c}^{\varsigma\top}\boldsymbol{\varsigma}_c - \sum_{k\in\mathscr{K}} (\mathcal{S}_c(g_c[k]) + C_c y_c[k]).$$

Given the prices $\boldsymbol{\lambda}_{n_c}$, $\boldsymbol{\xi}^{\rho^{\uparrow}}$, $\boldsymbol{\xi}^{\rho^{\downarrow}}$, $\boldsymbol{\xi}^{\phi^{\uparrow}}$, $\boldsymbol{\xi}^{\phi^{\downarrow}}$ and $\boldsymbol{\xi}_{a_c}^{\varsigma}$, resource c seeks to maximize profits by solving

$$\pi_c^* = \max_{\substack{\boldsymbol{u}_c, \boldsymbol{y}_c, \boldsymbol{z}_c, \boldsymbol{g}_c,\\ \boldsymbol{\varsigma}_c, \boldsymbol{\rho}_c^{\uparrow}, \boldsymbol{\rho}_c^{\downarrow}, \boldsymbol{\phi}_c^{\uparrow}, \boldsymbol{\phi}_c^{\downarrow}}} \pi_c(\boldsymbol{g}_c, \boldsymbol{\rho}_c^{\uparrow}, \boldsymbol{\rho}_c^{\downarrow}, \boldsymbol{\phi}_c^{\uparrow}, \boldsymbol{\phi}_c^{\downarrow}, \boldsymbol{\varsigma}_c, \boldsymbol{u}_c)$$

subject to constraints (4) through (11), (23) and (24) for all $k \in \mathscr{K}$. If the underlying market-clearing problem is convex, the market-clearing prices support an optimal solution of the individual profit-maximization problem in the sense that, given the clearing prices, resource c can maximize its profit by producing the amount of energy and ancillary services that were cleared in the market. However, if the market-clearing problem includes non-convexities, the market-clearing prices may not support a solution of the individual profit-maximization problem. Consequently, resource c receives uplift payments to become indifferent with respect to whether it follows its individual profit-maximizing solution or the solution of the market-clearing problem. Therefore, the uplift payment υ_c is given by

$$\upsilon_c = \pi_c^* - \pi_c(\bar{\boldsymbol{g}}_c, \bar{\boldsymbol{\rho}}_c^{\uparrow}, \bar{\boldsymbol{\rho}}_c^{\downarrow}, \bar{\boldsymbol{\phi}}_c^{\uparrow}, \bar{\boldsymbol{\phi}}_c^{\downarrow}, \bar{\boldsymbol{\varsigma}}_c, \bar{\boldsymbol{u}}_c),$$

where $(\bar{\boldsymbol{g}}_c, \bar{\boldsymbol{\rho}}_c^{\uparrow}, \bar{\boldsymbol{\rho}}_c^{\downarrow}, \bar{\boldsymbol{\phi}}_c^{\uparrow}, \bar{\boldsymbol{\phi}}_c^{\downarrow}, \bar{\boldsymbol{\varsigma}}_c, \bar{\boldsymbol{u}}_c)$ are the quantities cleared in the DAM for resource c.

We do not compute uplift payments in the RTMs, as the underlying market clearing mechanism we utilized is based on the solution of a convex optimization problem [15].

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