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Analysis of reserve relaxations in electric energy markets

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ABSTRACT

Electric power grids are some of the most complex engineering systems today. System operators must manage generation fleets with complex operating requirements and transmission assets spanning thousands of miles, while maintaining synchronism and meeting strict reliability criteria. Given the limited computational capabilities of modern computers, the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) cannot fully integrate all of these complexities in their market model. Thus to ensure scalability, ISOs and RTOs employ a number of approximations within their market models, including proxy reserve requirements that attempt to achieve, but does not guarantee, $N-1$ reliability. Since the market model is an approximate model itself, and the solution needs to be corrected nevertheless, market management tools allow select constraints to be relaxed for a set penalty price. This paper examines the impacts of different penalty price schemes, for relaxation of reserve requirements, on system $N-1$ reliability and market outcomes. In particular, the post contingency network violations for the relaxed and non-relaxed market solutions are compared. Moreover, the final cost after making necessary corrections to arrive at the $N-1$ secure solutions are presented and compared for the relaxed and non-relaxed cases. The paper demonstrates that reserve relaxation does not significantly increase post contingency violations for the market solution or the total system cost after the adjustment phase. Thus, if performed for appropriate reasons such as controlling price or achieving feasibility, reserve relaxation is a justifiable practice in power system operations.

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1. Introduction

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) employ market management system (MMS) software to solve unit commitment and determine dispatch decisions. The MMS utilizes a mixed integer linear program that approximates the power system under the ISO or RTO's control. Despite the advancement in hardware and software, the market model within the MMS cannot fully capture all the complexities involved in operating the power system. For example, linear direct-current power flow (DCPF) is used rather than the more accurate alternating-current power flow (ACPF). This approximation facilitates fast computation by changing the problem from a non-linear program (NLP) to a linear program (LP). Other approximations include linear ramping constraints and proxy reserve requirements instead of explicitly modeling all contingencies existing in the MMS. Additional complexities result from load uncertainty and, more recently, intermittent generation.

Since the market model abstracts from the complexities of power systems, the ISO needs to adjust the day-ahead market solution to ensure AC feasibility and reliability. Thus, the day-ahead solution is corrected during an adjustment period, or post-processing phase, due to the approximations and inaccuracies inherent in market solutions. This approximate problem may be infeasible at times. To guarantee feasibility, ISOs and RTOs allow select constraints to be violated or relaxed in their market models, a practice known as constraint relaxation. By adding a slack variable to a specific constraint, constraint relaxations are incorporated within the market model. The relaxed problem no longer strictly enforces these constraints, and as a result model feasibility is guaranteed. Note that since the market model is an approximate problem itself, there is no reason to strictly enforce the approximate constraints in an imprecise problem.

Including constraint relaxation practices in market models provides several benefits. They allow market operators to manage prices, such as limiting the price of energy in the market. Previous market designs only included a bid cap, which does not limit the market's locational marginal prices (LMPs). To limit the LMP a

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Nomenclature

Indices and sets

g	index of generators, $g \in G$
$g(n)$	set of generators connected to node n
$H(g)$	set of hydro-generators
i	index of generator segments, $i \in I$
j	index of line outage element for LODF formulation, $j \in J$
k	index of transmission lines, $k \in K$
n	index for buses, $n \in N$
t	index for time periods, $t \in T$
x	index of staircase-penalty price segments, $x \in X$

Parameters

B_k	electrical susceptance of line k
CRP	percentage of the largest possible contingency used to identify the required reserves
c_{gi}^{OP}	operational cost of unit g ($/MWh) segment i
c_g^{NL}	no-load cost of unit g
c^{NS}	penalty price for non-spinning reserve; fixed-price relaxations
c_q^{NS}	penalty price for non-spinning reserve; staircase-price relaxations
c_g^{SD}, c_g^{SU}	shutdown and startup cost of unit g
c^{SP}	penalty price for spinning reserve; fixed-price relaxations
c_q^{SP}	penalty price for spinning reserve; staircase-price relaxations
d_{nt}	demand at bus n in period t
FS_g	indicator for unit g as a fast-start unit
$LODF_{kj}$	line outage distribution factor for flow on line k with the loss of line j
$N1_g$	$N-1$ contingency indicator of unit g; 0 for a contingency on unit g; otherwise, 1
P_{gi}^{Limit}	max output of unit g for segment i
P_g^{min}, P_g^{max}	min and maximum output of unit g
$\bar{P}_{gt}$	scheduled real power output of unit g in period t
P_k^{max}, $P_k^{max,C}$	normal and emergency rating of transmission line k
$PTDF_{nk}^{REF}$	power transfer distribution factor for an injection at n sent to the reference bus, for flow on line k
R_g^{HR}, R_g^{10}	max hourly and 10-min ramp rates of unit g
R_g^{SU}, R_g^{SD}	max startup and shutdown ramp rates of unit g
$\overline{R_{gt}^{SP}}$, $\overline{R_{gt}^{NS}}$	scheduled operating reserve for unit g in period t
SRP	spinning reserves a percentage of the total required reserves
UT_g, DT_g	minimum up time and down time of unit g
α	percent of total supply required for operating reserve for period t
β	percent of non-hydro supply required for operating reserve for period t

Variables

P_{git}	real power output for unit g, segment i, period t
P_{gt}	total real power output for unit g in period t
$\hat{P}_{gt}$	real power re-dispatch output of unit g in period t
P_{kt}	power flow through line k in period t
P_{nt}^{inj}	net power injection at bus n for time period t
r_{gt}^{NS}	non-spinning reserve for unit g in period t
r_{gt}^{SP}	spinning reserve for unit g in period t
r_t^{req}	required level of operating reserve in period t
s_{kt}^{+}, s_{kt}^{-}	violation in the flow limits of line k in period t
s_t^{SP}, s_t^{NS}	violation in the operating reserve in period t for fixed-price relaxations
s_{tq}^{SP}, s_{tq}^{NS}	violation in the operating reserve in period t for penalty price q for staircase-price relaxations
u_{gt}	unit commitment binary variable for unit g in period t
v_{gt}, w_{gt}	startup and shutdown variables for unit g in period t
θ_{nt}	voltage angle at bus n in period t
λ_{nt}	locational marginal price at bus n in period t

constraint relaxation on the node balance constraint is included by first adding a slack variable to the objective function multiplied by a pre-determined penalty price. Then, this slack variable is added to the node balance constraint. Consequently, the highest LMP that the market will have is the pre-determined penalty price associated with that slack variable in the objective.

Another benefit is that even small relaxations could potentially allow for substantial gains in market surplus. Requiring approximate market models to strictly enforce approximated constraints in the market can significantly increase costs. Since the market model is inexact, there is no need to strictly enforce approximated constraints. By allowing for constraint relaxations, when the day-ahead market is solved, the market is allowed to choose to relax constraints. However, the model will not readily do so unless the benefit of added flexibility, i.e., the value of the associated dual variable, is greater than the cost of the relaxation.

The effect of constraint relaxations on market outcomes [1] as well as system security performance [2] due to line and nodal constraint relaxations in the market solution has been investigated in previous work. References [3,4], studied the effects of modifying the day-ahead market solution to obtain an $N-1$ secure solution. Finally, in [5] the effects of pre- and post-contingency transmission line relaxations were investigated.

ISOs and RTOs differ in their market practices regarding constraint relaxations, outlined in [1]. Some utilize a fixed-price penalty price scheme in their market models, but others prefer a staircase penalty price function [6]. Also as stated previously in [1], NYISO utilizes a staircase function for its reserve requirement penalty price scheme. MISO also uses a staircase penalty price scheme for relaxation of its reserve requirements [7]. The penalty prices are different for the variety of reserve products that are available. MISO refers to the penalty price schemes as “operating reserve demand curve”, which determines the monetary impacts of not meeting the reserve requirements.

In this paper, both of these penalty price schemes are examined for relaxations of the reserve requirement constraints. Note that reserve requirements are proxy constraints used in the market model that attempt to attain an $N-1$ secure solution, which is a NERC criterion [8,9]. However, these constraints are approximations and do not explicitly model $N-1$ contingency scenarios and therefore cannot guarantee the $N-1$ security requirement. This is one reason why constraint relaxations are allowed when it comes to the reserve requirements. Furthermore, there is the notion that some constraints should be modeled as soft constraints because they are approximations. The reserve requirement constraint is one approximation that could lead to model infeasibilities. In this work, the effect that reserve relaxations have on market outcomes and potential $N-1$ violations will be examined.

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