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Offline penalty price determination method for transmission thermal constraint relaxations

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ABSTRACT

This paper proposes an offline penalty price determination process for transmission thermal constraint relaxations. System operators utilize various market models, which are highly complex due to operating requirements as well as physical restrictions of assets, to manage electric energy markets while ensuring a reliable supply of electric power. System operators enable constraint relaxations in market models by allowing certain constraints to be relaxed for penalty prices. Constraint relaxation practices help system operators to cope with model infeasibility, obtain possible gains in market surplus, and cap shadow prices. A proper selection of penalty prices is imperative due to the influence that penalty prices have on generation scheduling and market settlement; however, current industry practices do not consider the true cost of the relaxations. This work introduces a systematic methodology to capture the cost of relaxations considering probabilistic weather conditions and associated conductor degradation risk. The numerical analysis evaluates the effectiveness of the proposed method on an electric energy market; the results show that exercising transmission thermal constraint relaxations with a proper selection of penalty prices can provide net benefits to market participants.

1. Introduction

Power systems are among the largest and most complex systems in the world. System operators must manage generation scheduling while considering complex operational requirements and strict physical restrictions, to ensure a reliable supply of electric energy. To do this, system operators solve various market models, which are typically optimization problems. However, even with an advanced software and algorithmic performance, accurate modeling of every single physical characteristic into an optimization model is not possible nor practical; therefore, market models to date approximate many system conditions. Most common approximations include a linearized direct current power flow, linear ramping constraints, and proxy reserve requirements. Approximated system conditions inherent in market models require additional adjustment processes, including reliability unit commitment and out-of-market corrections [1,2].

Moreover, system operators employ constraint relaxation (CR) practices, which allow certain constraints to be relaxed for penalty prices, in their market models. That is, instead of strictly adhering to all the approximated system conditions, market operators treat certain constraints as soft constraints by adding slack variables into the constraints and penalty term into the objective function. Although system operators employ CR practices on a much broad basis, this paper focuses on transmission thermal constraint relaxation (TCR) that allows line flow to exceed its thermal rating, based on a predefined penalty price. Ref. [3] presents a summary of contemporary CR practices in the industry and investigates the impacts of CR practices on markets and system security.

CR practices provide several benefits to market operators and participants. First, CR practices help market operators to obtain a solution within given time limits even if one or more of original (non-relaxed) constraints cannot be satisfied by available resources. Secondly, CR practices can provide gains in market surplus. For instance, thermal limits for transmission lines are typically determined conservatively while assuming severe weather conditions. Enabling short-term overloading on thermally congested lines may not have significant impacts on the assets during normal weather conditions; however, by doing so, there is the chance to increase market surplus by enhancing the utilization of the transmission asset. Lastly, CR practice allows market operators to limit market prices (shadow prices). The electric energy markets in the US use shadow prices, such as locational marginal prices (LMPs) or flowgate marginal prices (FMPs), for market settlements.

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Nomenclature

C_{gi}^{OP}	Operational cost of unit g ($\$/MWh$) segment i
C_g^{SP}, C_g^{NS}	Spinning and non-spinning reserve cost of unit g
C_g^{NL}	No-load cost of unit g
C_g^{SD}, C_g^{SU}	Shut-down and start-up cost of unit g
C_k^{end}	End-of-service cost of line k
D_{nt}	Demand at bus n in period t
$Deg\left(Y\left(z\right)\vert X_k\right)$	Conductor degradation risk of line k from the operating X_k together with the line temperature state $Y(z)$
F_k^+	Thermal rating of transmission line k
i	Index of generator segments, $i \in I$
k	Index of transmission lines, $k \in K$
n	Index for buses, $n \in N$
p_{git}	Real power output for unit g, segment i, period t
p_{gt}^{total}	Total real power output for unit g in period t
p_{nt}^{inj}	Net power injection at bus n for time period t
P_g^+, P_{gi}^+	Maximum output of unit g and segment i
P_k	Penalty price for relaxing transmission line k
$Pr\left(Y\left(z\right)\vert X_k\right)$	Probability density function of $Y(z)$given X_k
$PTDF_{nk}^{REF}$	Power transfer distribution factor for an injection at n sent to the reference bus, for flow on line k
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 reserve in period t
$Risk\left(X_k\right)$	Expected degradation risk from the operating condition X_k of line k
R_g^{HR}, R_g^{10}	Maximum hourly and 10-min ramp rates of unit g
R_g^{SU}, R_g^{SD}	Maximum start-up and shut-down ramp rates of unit g
s_{kt}	Violation in the flow limits of line k in period t
t	Index for time periods, $t \in T$
$u_{gt}, \bar{U}_{gt}$	Unit commitment variable and schedule for unit g in period t
UT_g, DT_g	Minimum up time and down time of unit g
v_{gt}, w_{gt}	Start-up and shut-down variable for unit g in period t
$\bar{V}_{gt}, W_{gt}$	Start-up and shut-down schedule for unit g in period t
X_k	Operating condition (line flow information) of line k
$Y\left(z\right)$	Line temperature state which is influenced by the operating condition X_k and the weather condition z
z	Index of the weather condition
Ω_G	Set of generators, $g \in \Omega_G$
Ω_G^n	Set of generators connected to bus n
Ω_G^C	Set of conventional generators, $\Omega_G^C \in \Omega_G$
Ω_G^H	Set of hydros, $\Omega_G^H \in \Omega_G$

Originally, many independent system operators (ISOs) employed bid caps to limit market prices; however, this practice does not place a maximum cap on the dual variables (e.g., LMPs). Instead, by employing CR practices, the shadow prices are capped by the assigned penalty price [3]. For instance, when a node balance constraint is relaxed, its LMP will be limited by the assigned penalty price.

Due to the influence that penalty prices have on generation scheduling and market settlement, it is important to ensure that system operators choose penalty prices such that economic (price) signals avert market inefficiencies. This research aims to further enhance the potential benefits of CR practices by proposing a penalty price determination model that captures the true cost of relaxations. The research motivation emerged from the fact that the current industry practices for determining penalty prices are neither transparent nor systematic; rather, the current process relies on operators' judgment and stakeholders' agreement. For example, in Ref. [4], the market monitoring report states that the Pennsylvania-New Jersey-Maryland Interconnection has been using CR practices; however, public information regarding a detailed description or penalty price is limited. Moreover, in the mid-continent ISO (MISO) system, TCRs occur frequently within their market models. While they often correct for many of these relaxations out of the market, there are frequent real-time (actual), short-term TCRs that occur. MISO operators often try to avoid this from happening by manually de-rating the line's capacity. That is, the real-time market security constrained economic dispatch (SCED) tool will have an artificial rating chosen by the operator [5]. Therefore, it is crucial to develop a systematic penalty price determination methodology. This paper aims to propose an offline based methodology to determine penalty prices while, again, only focusing on TCR.

Although such a TCR concept is not new, limited work has been done to propose a systematic methodology to determine associated penalty prices. Table 1 compares the proposed penalty price determination model with the current industry practices and compatible works in the literature. First, all ISOs in the US employ TCR practices; however, there is little to no methodology or engineered approach around the determination of the penalty prices [6–10]. Ref. [11] presents a penalty function-based TCR method for an optimal power flow (OPF) model. The proposed method investigates the dual of transmission thermal constraints and determines lower bounds of penalty prices such that constraint violations will only be exercised when the original OPF is infeasible; for the application of only handling infeasibilities, an intuitively large enough price is sufficient. The present paper takes the approach to handling the cost trade off due to relaxing transmission thermal constraints in association to the actual impact on the assets. Ref. [12] proposes an approximated conductor degradation model to determine penalty prices for TCR within a long-term transmission expansion planning model that investigates various options to increase transmission system capacity while preserving right-of-ways. However, the presented market model is too complex due to the added constraints associated with the line temperature and degradation effect estimation. Also, the model only considers a deterministic ambient weather condition. Ref. [13] proposes a risk-based TCR process for SCED to cope with the model infeasibility, without exogenously selecting penalty prices. However, the method is not scalable due to the added complexity in a SCED model along with the iterative process. System operators can achieve the same goal (and more benefits), without adding such complexities to the optimization model, by exercising TCR with properly selected penalty prices. The present approach does not affect the complexity of existing market models by determining penalty prices on an offline basis. Ref. [14] presents a risk-based penalty price determination approach based on the forced outage probability and post-contingency flow violation analysis. This work classifies transmission lines into three risk classes, high, medium, and low risk, and assigns fixed penalty prices accordingly. What decisively marks off the present paper from this prior work is that the penalty price determination is based on the impact overloading can have on the residual life of the line.

This research attempts to identify soft spots of the current industry practices and proposes an innovative and systematic methodology to improve overall efficiency and transparency of power system operations. The contribution of this paper includes: