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Analyzing the Impacts of Out-of-Market Corrections

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Abstract

The electric power grid is one of the most complex engineered systems today. Managing thousands of transmission assets spanning many miles and interconnecting regions and countries together combined with optimizing many generators with complex operating requirements creates a very challenging scheduling problem. Such a challenging problem becomes even more complex with resource uncertainty and stringent reliability standards. In order to solve such complex optimization problems within reasonable timeframes, approximations are required. The consequence of such approximations, however, is the need to implement out-of-market corrections (uneconomic adjustments). This paper presents an overview of out-of-market corrections, an overview of industry related practices that require out-of-market corrections, multiple algorithms that can be used to determine out-of-market corrections, and the various costs and market implications due to out-of-market corrections.

Nomenclature

Parameters

G	Set of generators
K	Set of all transmission elements, line or transformer
N	Set of nodes
T	Set of time periods
g	Index of generators, $g \in G$
k	Index of transmission lines, $k \in K$
n	Index for buses, $n \in N$
t	Index for time periods, $t \in T$
$\delta^+(n)$	Set of lines specified as to node *n*
$\delta^-(n)$	Set of lines specified as from node *n*
$g(n)$	Set of generators connected to node *n*
$n(g)$	Node location of generator *g*
B_k	Electrical Susceptance of line *k*
c_g	Operation cost ($/MWh)
c_g^{noload}	No-load cost of unit *g*
$c_g^{shutdown}$	Shut-down cost of unit *g*
$c_g^{startup}$	Start-up cost of unit *g*
P_g^{max}	Maximum output of unit *g*
P_g^{min}	Minimum output of generator *g*
P_k^{max}	Capacity of transmission line *k*
R_g^{HR}	Maximum hourly ramp rate of unit *g*
R_g^{10}	Maximum 10-min ramp rate of unit *g*
UT_g	Minimum up time of unit *g*
DT_g	Minimum down time of unit *g*
$\bar{u}_{gt}$	Scheduled unit commitment status of generation unit *g* in period *t*
$\bar{P}_{gt}$	Scheduled real power output of unit *g* in period *t*
$N1_g$	N-1 contingency indicator of unit *g*; 0 when there is a contingency on unit *g*; otherwise, 1.
β_{kt}^c	Parameter related to the direction of line flow on overloaded transmission line *k* in period *t*
$PTDF_{k,n}^{REF}$	Power transfer distribution factor over line *k* for an injection at bus *n* sent to the reference bus *REF*
α_{nt}^c	Parameter to establish the rank for node *n*, contingency *c*, in period *t*
γ_g^c	Parameter to establish the rank for unit *g* in contingency *c*

Variables

u_{gt}	Unit commitment binary variable for generation unit *g* in period *t*
v_{gt}	Start-up binary variable for generation unit *g* in period *t*
w_{gt}	Shut-down binary variable for generation unit *g* in period *t*
P_{gt}	Real power output variable for unit *g* in period *t*
RSV_{gt}	Scheduled spinning reserve for unit *g* in period *t*
P_{kt}	Real power flow through line *k* in period *t*
d_{nt}	Demand at bus *n* in period *t*
θ_{nt}	Voltage angle at node *n* in period *t*
RSV_t^{max}	Required level of spinning reserve in period *t*
s_{kt}^+, s_{kt}^-	Violation in the line flow limits of line *k* in period *t*
s_{nt}	Violation in the node balance constraint at node *n* in period *t*
$\hat{P}_{gt}$	Real power output re-dispatch variable of unit *g* in period *t*

Introduction

Out-of-market corrections (OMC), also referred to as uneconomic adjustments, occur when a dispatch solution must be corrected by the operator in order to satisfy a system requirement that was not implicitly or adequately modeled within the dispatch optimization problem. For instance, nomograms (hyperplanes) are commonly used to approximate the feasible set. Inaccurate nomograms will require the

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solution to be corrected by the operator to ensure a truly feasible solution. Such procedures are taken to simplify the complex combinatorial dispatch problems that are solved daily and, in some locations, hourly, such as unit commitment. While such procedures are currently necessary in order to ensure a solution is obtained within the required timeframe, the resulting out-of-market corrections that are necessary to correct for these approximations are extremely costly. The California Independent System Operator (CAISO) and the Electric Reliability Council of Texas (ERCOT) collectively spent roughly $80 million in 2006 on their out-of-market corrections [1] [2].

In [3]-[6], CAISO, SPP, and ERCOT all state their respective market structures and procedures in allocating awards in the day-ahead and real-time markets. In [3] and [4], CAISO proposes their procedure to minimize price inconsistencies and discloses that they resort to OMCs to attain a feasible solution when economic bids are insufficient. CAISO state**s** their objective is to achieve scheduling and pricing outcomes consistent with good operational practices that support reliable operation of the CAISO transmission system by preventing "unreasonable" price outcomes in the pricing runs. RTOs, such as SPP and ERCOT, also state that they perform OMCs and detail their procedures in [5] and [6], respectively. These organizations maintain that, if a feasible solution cannot be obtained with economic bids alone, the possibility of using OMCs is considered. In [7], the authors present how system reliability and out-of-market corrections impact reserve zone requirements.

OMCs (uneconomic adjustments) are employed by all energy providers: vertically integrated utilities or Independent System Operators (ISO). In particular, implementing OMCs under a deregulated market structure impact the market outcomes for its stakeholders. Performing an OMC changes the original solution, which is considered to be the most economical solution but is infeasible since it does not satisfy the reliability requirements.

This paper seeks to provide a discussion on OMCs and how this procedure affects the outcomes of a unit commitment schedule to meet reliability standards. In the subsequent section, we explain why OMCs occur in industry and provide a simple example to demonstrate how the procedure occurs. In the following section, an OMC procedure is performed on the IEEE-118 test case system [8], after solving the day-ahead unit commitment model. Contingency analysis is then performed and violations, e.g., line overloads, are recorded. Subsequently, an OMC procedure is used to find a reliable unit commitment and dispatch schedule. Finally, the results between the day-ahead unit commitment schedule and the OMC procedure are compared.

Industry Examples

Out-of-market corrections (or uneconomic adjustments) are almost always required. The most common situation is that the direct current optimal power flow (DCOPF) solution is not AC feasible. An operator will examine the constraint violations within the AC problem and determine to re-dispatch generators accordingly. At times, this involves examining the power transfer distribution factors (PTDFs) for lines that have flows that exceed its flow limit and identifying a set of generators that can be re-dispatched in order to reduce the flow violation.

Another reason out-of-market corrections are needed is that many operators do not solve a full network flow model when solving day-ahead unit commitment. The system operator may ignore line flow limits for most of the transmission lines when solving the day-ahead unit commitment model. Once the unit commitment solution is obtained, the operator will perform a check on the base case (no-contingency) DCOPF and select post-contingency DCOPF cases, which is known as contingency analysis. The branch flow violations are noted and, with time permitting, unit commitment is resolved while imposing the branch flow limits of the previously violated constraints determined by contingency analysis. Contingency analysis is repeated to identify further branch flow violations. Finally, the operator must implement out-of-market corrections in order for the resulting unit commitment solution to have a feasible N-1 solution (this is required due to time limitations as, otherwise, this iterative process could be repeated until no violations exist).

Even if a full DCOPF formulation is used, out-of-market corrections may still be required. Modern reserve requirements do not guarantee an N-1 reliable solution, as they do not take into consideration the deliverability, or locational aspect of reserve (the exception to this is when a stochastic programming framework is used). Although an operator may acquire reserve equal to the largest single contingency, this does not guarantee an N-1 reliable solution, since congestion can prevent the deliverability of reserve.

To illustrate an example of an OMC, a simple 3-bus example is used in Figure 1. In this example, ramp rate and minimum up-time and down-time constraints are ignored. The constraints imposed include a transmission line constraint on line 1, minimum generation constraints on units A and B, and a reserve requirement equal to the largest generator. For the most economical solution, the generator at node C is the cheapest unit with an offer of $10/MWh and, as a result, is dispatched at 90 MW. Generator B is also dispatched at 10 MW to meet the reserve requirement. With this dispatch, the system is not congested and, hence, the locational marginal prices (LMP) are the same, at $10/MWh.

When performing N-1 contingency analysis, if a contingency on unit C occurs, the system becomes unreliable because unit B can only deliver 60 MW due to the transmission limit of line 1 (note that the solution can reliably respond to an outage of unit B or any single transmission outage). To ensure reliability, an OMC is performed where unit A is turned on to meet N-1 reliability. This dispatch solution deviates from its original economic solution. However, the 3-bus system is now

N-1 reliable. With this new solution, the LMPs have stayed the same as before the OMC correction, at $10/MWh. The two solutions can be viewed in Table 1.

In this simple example, an additional expensive unit is dispatched. In reality, an operator working with a much larger and more complicated system would rely on her or his own experience when dispatching additional units to bring the system to a reliable state. However, there are various criteria that the operator could utilize to choose these additional units, such as turning on the cheapest or the largest unit that has not already been committed. Another approach is turning on the closest unit to the location of load shedding.

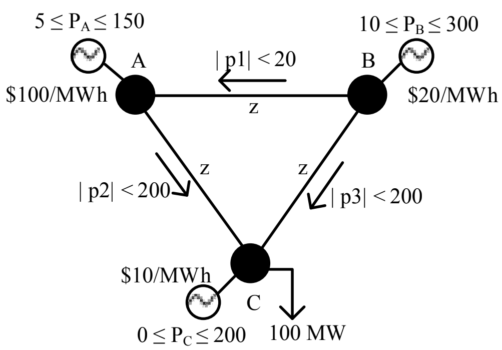

Fig. 1. A simple 3-bus system example.

TABLE 1
RESULTS FOR THE 3-BUS SYSTEM

Original Solution			Reliable Solution		
Unit	Status	Output	Unit	Status	Output
P_A	Off	0	P_A	On	5
P_B	On	10	P_B	On	10
P_C	On	90	P_C	On	85
Cost	$1,100		Cost	$1,550	

Problem Formulation and Model Description

To replicate a similar approach that an ISO (or a vertically integrated utility) might perform, a day-ahead unit commitment model is solved utilizing the IEEE-118 test case [8]. The result is a unit commitment schedule for generator units, which is subsequently tested for reliability by performing N-1 contingency analysis; note that the unit commitment model incorporates contingency based reserve requirements. Using different OMC procedures, this paper seeks to demonstrate the implications on the unit commitment schedule and resulting impacts due to out-of-market corrections.

Contingency analysis is performed by testing whether the system can avoid involuntary load shedding when there is a loss of any single generator or non-radial transmission asset (line or transformer). Within the contingency analysis framework, generator outputs must be within a 10-minute ramping limit with respect to their market solution's dispatch level, i.e., this captures a 10-minute operating reserve restriction, and post-contingency line flows are allowed to reach up to their short-term emergency limits. The testing of these contingencies is performed with two different methods. The first method is to allow for infinite transmission capability by adding slack variables to the transmission line constraints and the problem then minimizes the line overloads. The other method utilized is to allow for load shedding by adding a slack variable to each node balance constraint and then the total load shedding is minimized. Based on the specific OMC algorithm used, one of these two methods is employed to perform the contingency analysis.

With both methods for contingency analysis, if the slack variables are greater than zero, then a violation is recorded for that contingency in that particular hour. Violations indicate that the system is not N-1 reliable for that given contingency. Hence, the unit commitment market solution must be modified by out-of-market corrections in order to generate an N-1 reliable solution. At that time, the various OMC algorithms are initiated and additional units are committed to help ensure a reliable solution. Since new units are committed by the OMC algorithm, an optimal power flow problem that minimizes costs is solved after the OMC process. This step is required to ensure a feasible dispatch since turning on units through the OMC process requires the dispatch of the previously committed units (by the market solution) to be adjusted. N-1 contingency analysis is again conducted to ensure the final commitment, dispatch, and reserve schedule is N-1 reliable. If it is not, then the process repeats by initiating the OMC algorithm again. The day-ahead scheduling procedure with out-of-market corrections can be viewed in Figure 2. For this paper, we are assuming that the day-ahead unit commitment model is solved at most once, which is what is displayed by Figure 2.

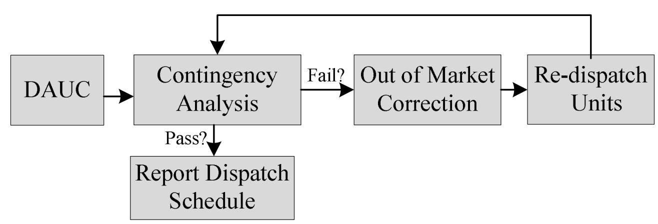

Fig. 2. Day-ahead scheduling procedure with OMC.

Day-Ahead Unit Commitment

The day-ahead unit commitment (DAUC) formulation, which is a security constrained unit commitment (SCUC) model, is a traditional multi-period unit commitment model with a DCOPF formulation, which is a linear approximation of an alternating current optimal power flow (ACOPF) formulation. The objective of the day-ahead unit commitment model is to minimize the total system cost (or maximize the total market surplus when demand participates in the market by bidding). It provides the most economical solution for the forecasted demand in the test case, but this solution is not guaranteed to be N-1 reliable. The model accounts for generator capacity, transmission capacity, node balance, and reserve requirement constraints. For simplicity, only spinning reserve is modeled to capture the operating reserve requirements. The reserve requirement for each period, depending on which value is higher, must exceed the largest generator output or 7% of the demand during that period.

Minimize: $\sum_t \sum_g c_g P_{gt} + c_g^{noload} u_{gt} + c_g^{startup} v_{gt} + c_g^{shutdown} w_{gt}$ (1)

$P_{gt} \geq P_g^{min} u_{gt} \quad \forall\, g, t$ (2)

$P_{gt} + RSV_{gt} \leq P_g^{max} u_{gt} \quad \forall\, g, t$ (3)

$\sum_{s=t-UT_g-1}^{t} v_{gs} \leq u_{gt} \quad \forall\, g, t$ (4)

$\sum_{s=t-DT_g-1}^{t} w_{gs} \leq 1 - u_{gt} \quad \forall\, g, t$ (5)

$v_{gt} - w_{gt} = u_{gt} - u_{gt-1} \quad \forall\, g, t$ (6)

$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall\, k, t$ (7)

$-P_k^{max} \leq P_{kt} \leq P_k^{max} \quad \forall\, k, t$ (8)

$\sum_{k\in\delta^+(n)} P_{kt} - \sum_{k\in\delta^-(n)} P_{kt} + \sum_{g\in g(n)} P_g = d_{nt} \quad \forall\, n, t$ (9)

$R_g^{HR} \geq P_{gt} - P_{gt-1} \quad \forall\, g, t$ (10)

$R_g^{HR} \geq P_{gt-1} - P_{gt} \quad \forall\, g, t$ (11)

$RSV_t^{max} \leq \sum_g RSV_{gt} \quad \forall\, t$ (12)

$RSV_t^{max} \geq \sum_n 0.07 d_n \quad \forall\, t$ (13)

$RSV_t^{max} \geq P_{gt} + RSV_{gt} \quad \forall\, g, t$ (14)

$RSV_{gt} \leq R_g^{10} u_{gt} \quad \forall\, g, t$ (15)

$u_{gt} \in \{0,1\}; 0 \leq v_{gt}, w_{gt} \leq 1 \quad \forall\, g, t$ (16)

Contingency Analysis

The test system examined in this paper is the IEEE-118 test case [8] and the emergency limits, for the transmission lines, are assumed to be 125% of their rated values. Using the dispatch results from the day-ahead unit commitment model, an N-1 contingency analysis is performed. In this particular contingency analysis model, the system is allowed to violate its transmission limits, which is accomplished by adding slack variables to the transmission line limit constraints. This contingency analysis model aims to minimize violations across all transmission lines. The program (17)-(25) is solved for each N-1 contingency and for each time period. Note that the formulation below is for a generator outage; for simplicity, the formulation for a transmission outage is not presented in this paper.

Minimize: $\sum_k s_{kt}^+ + s_{kt}^-$ (17)

$\hat{P}_{gt} \leq \bar{u}_{gt} N1_g \left(\bar{P}_{gt} + R_g^{10}\right) \quad \forall\, g$ (18)

$\hat{P}_{gt} \geq \bar{u}_{gt} N1_g \left(\bar{P}_{gt} - R_g^{10}\right) \quad \forall\, g$ (19)

$\hat{P}_{gt} \leq P_g^{max} \bar{u}_{gt} N1_g \quad \forall\, g$ (20)

$\hat{P}_{gt} \geq P_g^{min} \bar{u}_{gt} N1_g \quad \forall\, g$ (21)

$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall\, k$ (22)

$-P_k^{max} - s_{kt}^- \leq P_{kt} \leq P_k^{max} + s_{kt}^+ \quad \forall k$ (23)

$\sum_{k\in\delta^+(n)} P_{kt} - \sum_{k\in\delta^-(n)} P_{kt} + \sum_{g\in g(n)} \hat{P}_{gt} = d_{nt} \quad \forall n$ (24)

$s_{kt}^+ \geq 0\,,\ s_{kt}^- \geq 0 \quad \forall k$ (25)

The second contingency analysis model allows for load shedding, which is accomplished by adding a slack variable to the node balance constraints. The dispatch results from the day-ahead unit commitment model are utilized for this N-1 contingency analysis model, as well. Emergency limits of the transmission lines are still assumed to be 125% of their rated values. This model seeks to minimize load shedding. If any load shedding occurs, a violation is recorded. The program (26)-(35) is solved for each N-1 contingency and for each time period. Note that the formulation below is for a generator outage; for simplicity, the formulation for a transmission outage is not presented in this paper.

Minimize: $\sum_n s_{nt}$ (26)

$\hat{P}_{gt} \leq \bar{u}_{gt} N1_g \left(\bar{P}_{gt} + R_g^{10}\right) \quad \forall g$ (27)

$\hat{P}_{gt} \geq \bar{u}_{gt} N1_g \left(\bar{P}_{gt} - R_g^{10}\right) \quad \forall g$ (28)

$\hat{P}_{gt} \leq P_g^{max} \hat{u}_{gt} N1_g \quad \forall g$ (29)

$\hat{P}_{gt} \geq P_g^{min} \hat{u}_{gt} N1_g \quad \forall g$ (30)

$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall k$ (31)

$-P_k^{max} \leq P_{kt} \leq P_k^{max} \quad \forall k$ (32)

$\sum_{k\in\delta^+(n)} P_{kt} - \sum_{k\in\delta^-(n)} P_{kt} + \sum_{g\in g(n)} \hat{P}_{gt} = d_{nt} - s_{nt} \quad \forall n$ (33)

$s_{nt} \geq 0 \quad \forall n$ (34)

$s_{nt} \leq d_{nt} \quad \forall n$ (35)

Out of Market Correction Procedures

After recording the violations from the contingency analysis, several OMC procedures are tested. Each OMC procedure modifies the dispatch schedule such that an N-1 compliant solution is obtained. The first two OMC procedures utilized were based on simple heuristics, which could be used by an operator to bring the system to an N-1 compliant state. There are two primary ways to correct the solution; the operator can re-dispatch committed units and the operator can also turn on additional units. In this paper, the OMC procedures are designed to first identify units to commit. Once those units are identified, there is a re-dispatch procedure for all committed units (including the units that were committed by the OMC procedure). At that time, if N-1 reliability is not achieved, then the process repeats. Note that the proposed algorithms do not consider OMC procedures that *only* re-dispatch the units committed by the market solution; the OMC procedures *will* commit additional units that were not committed by the market solution and then re-dispatch the committed units.

The first simple heuristic commits the cheapest generator available to bring the system into N-1 compliance (SH – Cheapest). The second simple heuristic uses a similar approach, by committing the closest unit to the location of the load shedding in order to bring the system into N-1 compliance (SH-Closest). The final OMC procedure is based upon examining the power transfer distribution factors (PTDF) for lines that have post-contingency overloads (beyond their emergency rating). Generators that are not committed by the market solution are ranked based on their ability to reduce the post-contingency line overloads if they were to be committed. Each technique is an iterative technique where the process is repeated until the solution is N-1 compliant. As a part of these different OMC procedures when checking for N-1 compliance, fast-start units are allowed to be dispatched to help satisfy N-1.

Simple Heuristic – Cheapest Unit

With this simple heuristic, the cheapest available generator, based on operating cost, is committed and then the system is checked to determine whether the particular violation has been mitigated. The heuristic selects multiple generators until that particular violation is mitigated, which is needed because the next cheapest generator might not be the most effective unit in mitigating the particular violation. The result of the heuristic is a list of generators to be added to the dispatch schedule, which is then re-tested for N-1 compliance. The model used for testing N-1 compliance is the contingency analysis model allowing for infinite transmission, which can be seen in (17)-(25) above.

Simple Heuristic – Closest Unit

For the second simple heuristic, generators closest to a particular violation are committed. Hence, the contingency analysis model that allowed load shedding is utilized because violations are reported based on location. The dispatch schedule is then modified and this process is repeated until all violations are mitigated. This modified dispatch schedule is again tested for N-1 compliance using (26)-(35) above.

PTDF Heuristic Formulation

The third heuristic is based upon examining the power transfer distribution factors (PTDF) for the transmission lines that have overloads from the contingency analysis. Using equations (17)-(25), violations are recorded and, more specifically, the overloaded transmission lines for each contingency are identified. To correct for an overloaded transmission line, the corresponding PTDFs for that line are examined; generators located at buses that have large PTDFs associated to that line are positioned higher in the rank list. The specific goal is to determine which generators to turn on in order to reduce the line's flow as much as possible.

For situations where there is a contingency that causes multiple lines to be overloaded, generators are ranked by accounting for their ability to reduce the flows on all of the violated lines. To determine this ranking, (36) and (37) are used. For overloaded transmission lines, buses are ranked based on the sum of the PTDF values, multiplied by a parameter β_{kt}^{c}. When the desire is to have negative PTDFs, β_{kt}^{c} is set to be -1. When the desire is to have positive PTDFs, β_{kt}^{c} is set to be 1. Note that β_{kt}^{c} is set to be 0 for lines that are not overloaded. Since this heuristic is being used to determine additional units to commit, the desire is to have negative PTDFs when the flow exceeds its maximum limit and the desire is to have positive PTDFs when the flow exceeds its minimum limit. Once these α_{nt}^{c} values are determined, the offline generators are ranked from most likely to reduce the post-contingency overload to least likely. The ranking is established by (37); the values of α_{nt}^{c} are added up across all periods for generator *g*, which is located at node *n*, for the periods that it is off. This value is then normalized by the number of periods it is offline. This produces γ_{g}^{c}, which reflects the cumulative α_{nt}^{c} value for each generator averaged by the number of periods the unit is offline. γ_{g}^{c} is then used to create the ranking list. Note that since there might be multiple available generators at a particular bus, the generators at that bus are ranked based on their operating costs to have the cheaper unit be committed first. This process can be viewed in Figure 3.

$$\alpha_{nt}^{c} = \sum_{k} PTDF_{k,n}^{REF} \beta_{kt}^{c} \qquad \forall n, t, c \qquad (36)$$

$$\gamma_{g}^{c} = \frac{\sum_{t} \alpha_{n(g),t}^{c} (1-\bar{u}_{gt})}{\sum_{t}(1-\bar{u}_{gt})} \qquad \forall g, c \qquad (37)$$

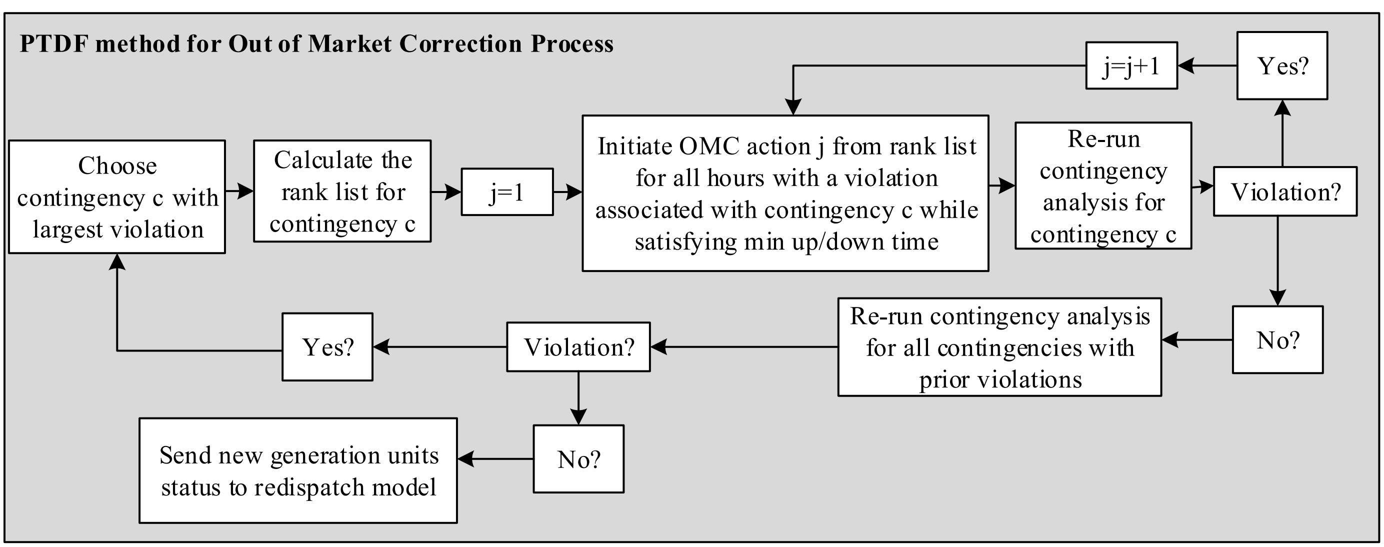

Fig. 3. OMC process using the PTDF-based heuristic method.

Results

The use of the IEEE-118 test case [8] allowed for the evaluation of the different OMC procedures. The original unit commitment output from the day-ahead unit commitment model, which does not provide an N-1 reliable solution, has the lowest primal objective value, which is generation operating cost. Comparatively, the total system cost results for the different OMC methodologies (simple heuristic cheapest, simple heuristic closest, and PTDF heuristic) are all higher; however, these results are N-1 compliant.

The additional units committed for each OMC method increased the costs to the entire system, but also decreased the load payment, generation revenue, congestion rent, and generation rent due to lower locational marginal prices (LMPs); however, note that there is no guarantee that these values will always decrease due to OMC. In particular, the OMC solution method with the PTDF heuristic lowered the LMPs on average by approximately $2.90 across all time periods, whereas the LMPs of the OMC methods for simple heuristic cheapest and simple heuristic closest were lowered on average by approximately $6.59 and $5.43 respectively across all the buses and time periods. The difference between the day-ahead unit commitment model and different OMC methods can be viewed in Table 2.

The simple heuristic that commits the cheapest units turned on the most additional generators to bring the system into N-1 compliance. With this OMC method, five units that were previously completely uncommitted in the schedule from the day-ahead unit commitment model were dispatched. Furthermore, an additional seven units had their dispatch schedules modified by either being committed earlier and/or committed for an extended period of time. The modified dispatch schedule for this OMC methodology can be viewed in Figure 4. The implementation of this simple heuristic was ineffective because the next cheapest available generator is not guaranteed to be in an effective location to deliver power to mitigate the contingency. Hence, multiple generators are needed to mitigate a certain contingency.

For the simple heuristic methodology of turning on the closest generator, fewer generation units were committed to bring the system into N-1 compliance. With this method, only one unit was committed and dispatched that was previously completely uncommitted in the day-ahead unit commitment model, which was generator unit 1. This simple heuristic also modified the dispatch schedule of five other units that were previously committed in the day-ahead unit commitment model. These modified units include units 30, 31, 33, 34, and 41. The modified dispatch schedule for the simple heuristic for the closest can be viewed in Figure 5. This simple heuristic was more effective in mitigating violations because dispatching a generator close to the location of the violation will likely mitigate the violation.

From the original unit commitment schedule, the OMC methodology using the PTDF heuristic modified the dispatch of only five generators. Figure 6 displays the generating units with modified schedules. Generators number 33, 41, 52, and 54 were previously scheduled, but were dispatched earlier by the PTDF heuristic to ensure N-1 reliability. The PTDF heuristic turned only one additional generation that was not previously scheduled, which was unit 1.

In general, these OMC methods typically decreased the Location Marginal Prices (LMPs), which affect the pricing results for the system. This depends on whether the market operator uses the original unit commitment schedule to determine LMPs or the modified schedule based on the OMC procedure. In general, these OMC procedures lower the load payments and generation revenue compared to the original dispatch schedule.

When comparing the LMPs at specific buses, similar results are observed. For example, bus 66 in the IEEE-118 test system has three generators connected to that bus, which are units 30 to 32. When comparing the LMPs for the cheapest simple heuristic, closest simple heuristic, and PTDF heuristic, they were all lower than the original unit commitment schedule (see Figure 7). As a result, the generators at bus 66 earn lower generator revenue, which increases the uplift payments to the generators. The uplift payments required for each unit at bus 66 according to the OMC dispatch solution can be viewed in Table 3.

TABLE 2
COMPARISON OF RESULT BEFORE AND AFTER OMC

Dispatch Solution	Original Unit Commitment	PTDF Heuristic	Simple Heuristic – Cheapest	Simple Heuristic – Closest
Load Payment	$ 2,503,023.96	$ 2,202,767.73	$ 1,867,281.24	$ 1,974,537.37
Generation Revenue	$ 2,323,286.18	$ 2,053,903.98	$ 1,724,672.11	$ 1,833,762.79
Gen. Operating Cost	$ 1,226,129.17	$ 1,262,299.70	$ 1,387,712.89	$ 1,295,154.93
Congestion Rent	$ 179,737.78	$ 148,863.76	$ 142,609.13	$ 140,774.59
Gen. Profit	$ 1,097,157.01	$ 791,604.28	$ 336,959.22	$ 538,607.86
Difference in Operating Cost with Original UC	-	$ 36,170.52	$ 161,583.72	$ 69,025.76

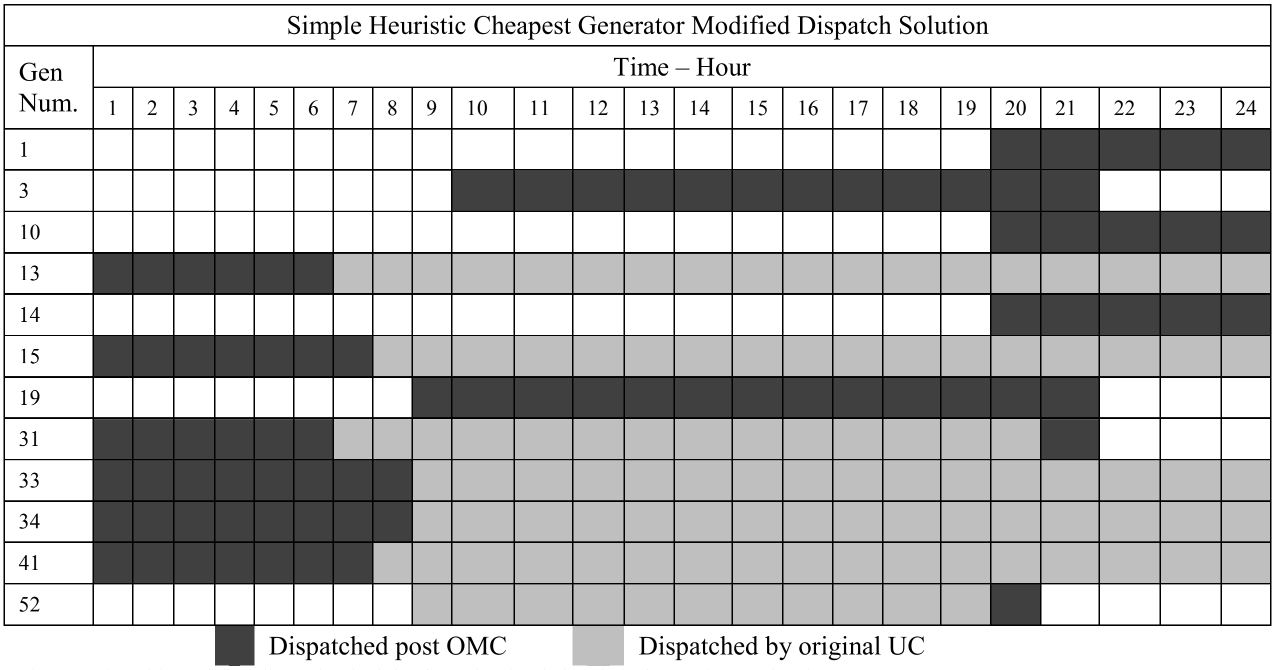

Fig. 4. Units with modified dispatch schedules from the simple heuristic for turning on the cheapest generator.

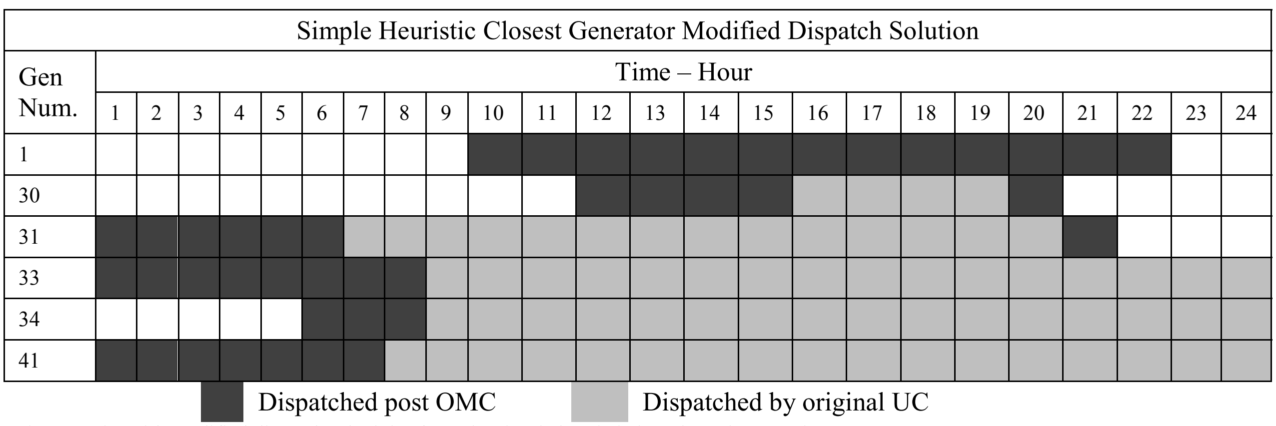

Fig. 5. Units with modified dispatch schedules from the simple heuristic based on closest unit.

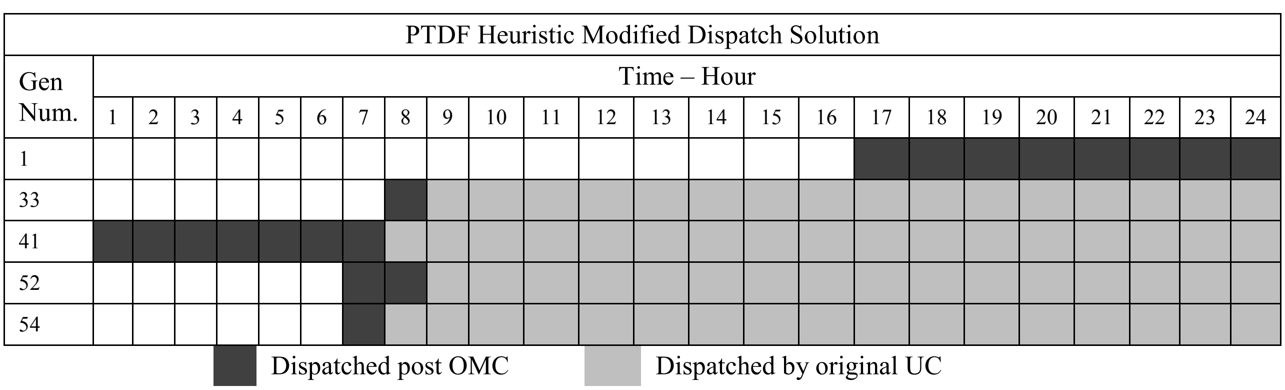

Fig. 6. Units with modified dispatch schedules from the PTDF based heuristic.

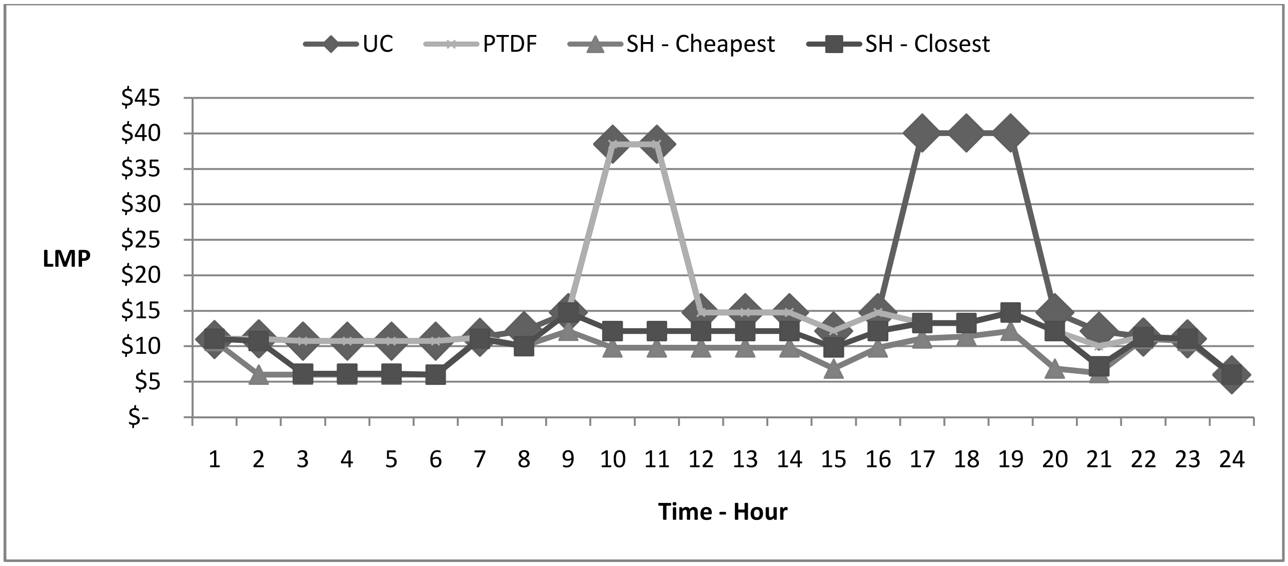

Fig. 7. LMPs at bus 66 based on the different dispatch solution.

TABLE 3
UPLIFT PAYMENTS FOR THE DIFFERENT DISPATCH SOLUTIONS

Uplift Payments to Generators at Bus 66 based on Dispatch Solution				
Gen.	Original UC Dispatch	PTDF Dispatch	SH – Cheapest	SH - Closest
30	$ 1,007.96	$ 1,197.14	$ 1,224.94	$ 2,041.82
31	-	$ 1,877.19	$ 7,552.07	$ 6,973.85
32	-	-	-	-
Total	$ 1,007.96	$ 3,074.33	$ 8,777.01	$ 9,015.67

Similar results can also be observed at bus 90, which serves a maximum load of 440 MW. This bus has lower LMPs in comparison to the modified dispatch schedule from the PTDF heuristic and simple heuristics to the original unit commitment schedule, which can be viewed in Figure 8. For example, the dispatch schedule from the PTDF heuristic lowers the load payment at bus 90 by $40,990.33 compared to the original unit commitment solution. The load payment for the simple heuristic solutions, where the cheapest unit and closest unit are used to resolve N-1 violations, are also lower compared to the original unit commitment schedule. The load payment for different dispatch schedules can be viewed in Table 4.

Another interesting bus for comparison of LMPs is bus 77, serving a load with a maximum of 61 MW. The LMPs produced by the simple heuristics and the PTDF heuristic are very similar to that of the original dispatch solution. However, there are periods of the day when LMPs of these different OMC solutions are higher when compared to the original unit commitment, which is an anomaly because typically the different OMC solutions lowered the LMPs. Therefore, the PTDF heuristic and the simple heuristics required the load to pay higher LMPs during certain periods of the day, which can be viewed in Figure 9. Overall, at bus 77 compared to the original dispatch, the PTDF heuristic increased the load payment over the entire 24 hour period by $244.60. Over the same time period, the simple heuristics solutions also increased the load payment at bus 77. These results can be viewed in Table 5.

TABLE 4
LOAD PAYMENT AT BUS 90

Dispatch Result from	Load Payment at Bus 90	Difference with Original UC
Original UC	$ 349,388.82	-
PTDF	$ 308,398.49	$ (40,990.33)
SH – Cheapest	$ 277,628.81	$ (71,760.01)
SH – Closest	$ 285,729.77	$ (63,659.05)

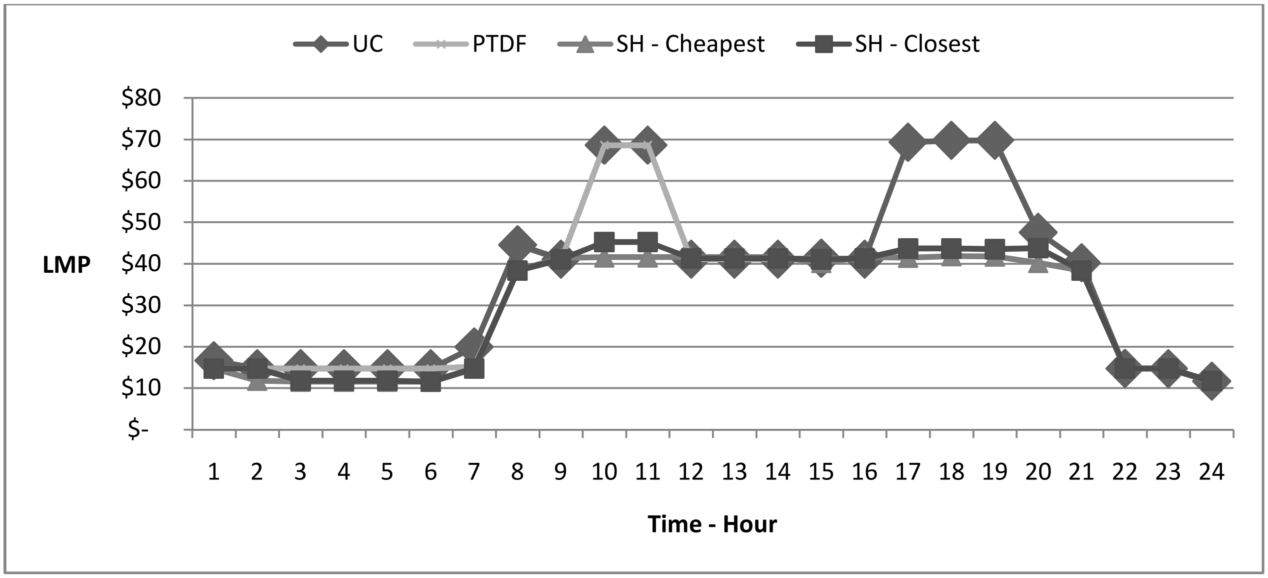

Fig. 8. LMPs at bus 90 based on the different dispatch solution.

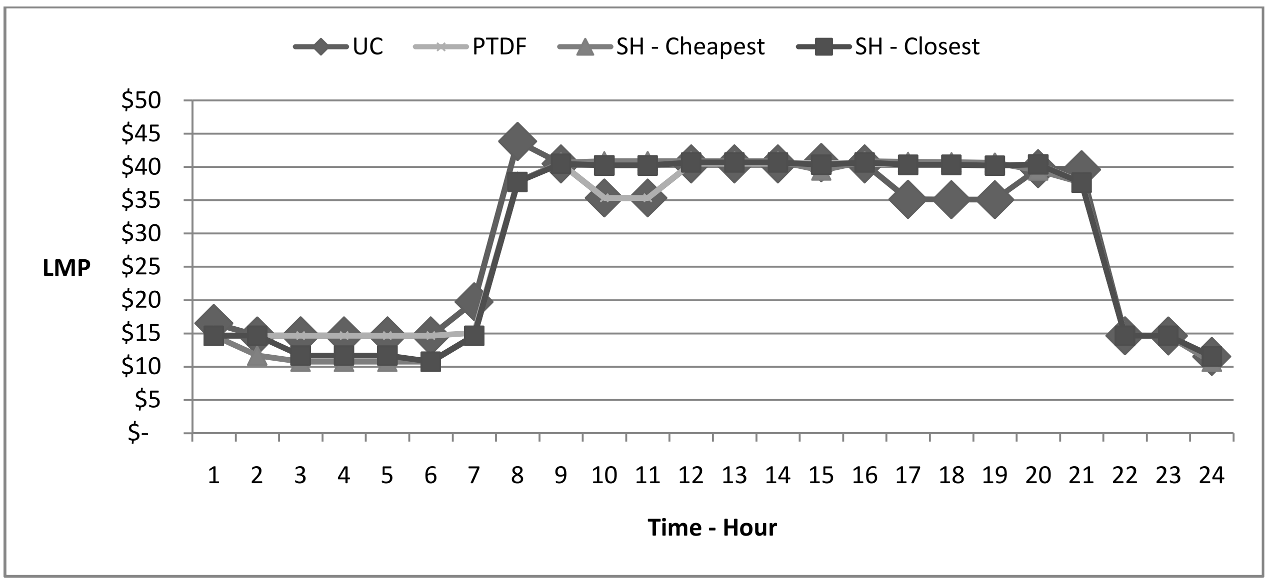

Fig. 9. LMPs at bus 77 based on the different dispatch solution.

TABLE 5
LOAD PAYMENT AT BUS 77

Dispatch Solution	Load Payment for Bus 77	Difference with Original UC
Original UC	$ 37,486.87	-
PTDF	$ 37,731.46	$ 244.60
SH - Cheapest	$ 37,718.39	$ 231.52
SH - Closest	$ 37,869.59	$ 382.72

Conclusions

Out-of-market corrections, otherwise known as uneconomic adjustments, are utilized by all system operators. OMCs are a necessary part of the day-ahead unit commitment process. Due to the computational complexities of day-ahead unit commitment scheduling combined with stringent reliability standards, approximations are made within the optimization problem itself and, thus, the resulting solution must be verified as to whether it is a truly feasible solution, e.g., whether it achieves N-1 reliability. This paper has examined multiple heuristics that mimic strategies that operators will take to modify the DAUC solution in order to achieve N-1 reliability.

For institutions, such as ISOs, OMCs have implications on payments in their deregulated markets. However, OMCs are necessary to ensure reliability standards as well as to achieve AC feasibility. One cause for the need to implement OMCs is to achieve AC feasibility as the unit commitment model is generally solved with a DCOPF framework. Additionally, OMCs are used because some market operators may not include a full representation of the optimal power flow (OPF) problem in their day-ahead unit commitment model. Therefore, the solution obtained must be verified to provide a feasible OPF solution. Furthermore, even if an OPF framework was included, the system might not meet N-1 reliability standards since ensuring N-1 requires implicitly representing the contingencies within the unit commitment structure, which creates a stochastic programming problem.

For this paper, the original unit commitment for the IEEE-118 test case was solved and tested for N-1 reliability. The solution is checked to see if the dispatch can respond to any single N-1 contingency, i.e., the loss of a generator or non-radial transmission, for any hour across the entire 24-hour time period. Reliability violations were recorded and, with the use of different heuristics, new unit commitment schedules were produced that ensured N-1 reliability. The OMC procedures increase the total system cost and, typically, reduced the profits of the generators. The first two methods used to achieve N-1 reliability were simple heuristics; the first heuristic committed the cheapest unit during periods where there were violations resulting from contingency analysis and the second turned on units that were closest to buses that had load shedding. Another heuristic employed to bring the system into N-1 compliance was based upon examining PTDFs; generators that would have the largest influence on reducing post-contingency line overloads were committed one by one until there were no violations. Although the simple heuristics were able to ensure N-1 reliability, the costs were much higher than the PTDF based heuristic. The solutions found with the simple heuristics were, thus, further away from the market solution than the PTDF heuristic dispatch solution and the LMPs for the simple heuristics were further away from the LMPs for the market-based unit commitment solution as compared to the LMPs from the PTDF based heuristic.

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