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Multi-Year Stochastic Transmission Network Expansion Planning Considering Line Uprating

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ABSTRACT Transmission network expansion planning (TNEP) has become increasingly challenging due to the worldwide transformation of power systems, with the fast deployment of renewable energies as one of the key drivers. Given current socio-environmental concerns, building new lines to integrate new renewable energy sources may take several years and has a significant risk of delays and cost overruns. A sound strategy to achieve a more adapted expansion plan is to include the option of uprating existing lines among planning candidates. This paper presents a novel model for multi-year stochastic TNEP considering line uprating options, such as line reconductoring, voltage uprating, and adding series compensation, along with adding new lines, simultaneously. Compared to adding new lines, line uprating can be performed with low out-of-time service and has lower socio-environmental impact, thus being a cost-effective alternative, especially in cases where acquiring new right-of-ways is difficult and expensive. Illustrative results demonstrate that including line uprating options within the TNEP problem allows us to obtain more economic expansion plans with fewer new line projects in comparison to traditional approaches. This in turn results in less environmental impact of the optimal expansion plan, which makes construction permissions easier to obtain, thus reducing the risk of having delays and cost overruns. Additionally, considering line uprating options also helps the integration of renewable energies by deferring investment decisions until more information regarding future development of renewable energies becomes available.

INDEX TERMS Line uprating, power system modeling, power system planning, solar energy, wind energy.

NOMENCLATURE

A. SETS AND ACTIONS

$(A, E_{j,k})$	Add element $E_{j,k}$ to the network
$(R, E_{j,k})$	Remove element $E_{j,k}$ from the network
$\Omega_{p_i}^{dep}$	Set containing dependencies of project p_i
Ω_G	Set of conventional generators, indexed g
Ω_G^b	Set of conventional generators connected to bus b
Ω_{E^0}	Set of existing network elements
Ω_B	Set of network buses, indexed b
Ω_P^{excl}	Set of mutually exclusive projects
Ω_O	Set of operating conditions, indexed o
Ω_P	Set of projects
Ω_P^{RC}	Set of projects for reconductoring
Ω_P^{VU}	Set of projects for voltage uprating
Ω_S	Set of scenarios, indexed s
Ω_L	Set of transmission lines
Ω_T	Set of transformers
Ω_Y	Set of years under consideration, indexed y

B. PARAMETERS

$W_b^{s,y,o}$	Available renewable energy injection at bus b (MW)
$y_{p_i}^0$	Built time of project p_i (years)
$c_{E_{j,k}}$	Construction cost of element $E_{j,k} \in \Omega_L \cup \Omega_T$ (\$)
c_W	Cost of renewable energy curtailment (\$/MWh)
Γ_{p_i}	Investment costs of project p_i (\$)

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$T_{E_{j,k}}$	Lifetime of element $E_{j,k} \in \Omega_L \cup \Omega_T$ (years)
c_U	Load shedding cost (\$/MWh)
$\bar{P}_g$	Maximum generation for unit g (MW)
$D_b^{s,y,o}$	Power demand at bus b (MW)
Υ_{p_i}	Possible commissioning delay of project p_i (years)
μ_s	Probability of scenario s
c_g	Production cost of conventional generator g (\$/MWh)
$r\left(E_{j,k}\right)$	Receiving-end busbar of element $E_{j,k} \in \Omega_L \cup \Omega_T$
$s\left(E_{j,k}\right)$	Sending-end busbar of element $E_{j,k} \in \Omega_L \cup \Omega_T$
$B_{E_{j,k}}$	Susceptance of element $E_{j,k} \in \Omega_L \cup \Omega_T$ (p.u.)
σ_o	Weighting factor of operating condition o
$y^0_{E_{j,k}}$	Year of construction of existing element $E_{j,k} \epsilon \Omega_{E^0}$

C. NETWORK ELEMENTS

B_n^v	Busbar at substation n with voltage v
$E_{i,k}$	i-th network element of type k (line or transformer)
$L_{i,k}^v$	i-th line with conductor type k and voltage v
$T_{i,k,n}^{v1,v2}$	i-th transformer of type k in bus n, voltages $v1$ and $v2$

D. DECISION VARIABLES

$\delta_{p_i}^{s,y}$	Binary variable for building project p_i
$\Delta_{p_i}^{s,y}$	Binary variable signifying the aggregated decision of building project p_i in scenario s up to year y
$z_{p_i,y_n,s}^{p_d,y_m,s}$	Binary variable signifying that project p_i is built in year y_n and p_d is built in year y_m (in scenario s)
$c_{p_i}^{s,y}$	Cost of project p_i if built in scenario s and year y
$r_b^{s,y,o}$	Load shed at bus b
$p_g^{s,y,o}$	Power injected by generator g
$f_{E_{j,k}}^{s,y,o}$	Power flow through element $E_{j,k} \in \Omega_L \cup \Omega_T$
$w_b^{s,y,o}$	Renewable energy curtailment at bus b
$\theta_b^{s,y,o}$	Voltage angle at bus b

I. INTRODUCTION

Several power systems around the globe are experiencing a rapid deployment of renewable energy sources (RES) such as photovoltaic and wind generation. While this trend represents a unique opportunity to effectively combat climate change, it also poses significant challenges in power system planning and operation [1]. Compared to conventional generating units, power plants based on RES are typically located in different parts of the network, often in weak areas of the system with sparse transmission capacity and have shorter construction times. Additionally, the large-scale integration of RES in power systems has been characterized by significant levels of uncertainty regarding both future capacity and allocation of new generating units [2] and the generation feed-in of RES [3]. The restructuring of power markets also increased and diversified the sources of uncertainty regarding generation expansion, since it is no longer coordinated with transmission expansion [4]. Consequently, network planners are facing a significant challenge to achieve a more adapted expansion plan, which involves a timely and cost-effective increase of the transmission capacity to accommodate future RES while providing secure and reliable electricity service to customers, enhancing competition and ensuring market efficiency [4]. The paradigm shift in energy supply towards electricity systems dominated by RES requires a gradual breakaway from the essential pillars on which TNEP has been based. It is no longer enough to respond to system evolution by simply adding new transmission lines. We need to conceive a new way of planning future network infrastructure in which the challenges related to high levels of RES are inherently recognized through more advanced generation and transmission expansion planning models and strategies [5]. Only by this we will be able to adapt our power systems and achieve a seamless transition to future low-carbon power systems.

Within the transmission network expansion planning (TNEP) problem, the traditional approach for increasing the transmission capacity has been to build new lines. However, the process of building new transmission lines may take several years and is becoming more difficult nowadays given current social and environmental concerns, especially when new right-of-ways (ROW) are required [6]. For instance, project permitting can take up to 10 years in the U.S and even up to 20 years in Europe [7]. This situation can result in delays, cost overruns and even cancellation of transmission expansion projects [8], thus not only affecting the power system economics and social welfare, but also proper RES integration.

In response to this new challenge, recent works have included flexible assets within the multi-year TNEP problem in order to increase the use of existing network infrastructure and facilitate RES integration. Examples of these technologies are phase-shifting transformers [2], [9], storage devices [2], [10], [11] demand-side management [2] and special protection schemes [12]. These works show that, by providing congestion management and corrective control, investment in flexible assets increases power system operational flexibility, which ultimately allows deferring line reinforcements to the future and to obtain more cost-efficient expansion plans. Furthermore, the works in [2] and [9] show that the value of flexible technologies increases with explicit recognition of uncertainty, among others due to the reduced build times of flexible assets. Although these technologies increase the system's ability to accommodate new RES, they may not always be able to provide the required transmission capacity in case of a large-scale RES deployment. Another strategy is to increase the transmission capacity of existing assets through line uprating. Promising line uprating options are line reconductoring, voltage uprating, adding series compensation to lines (static [13] or thyristor-controlled [14], [15]) and conversion of HVAC lines into HVDC [16]. The advantages of performing line uprating to accommodate new RES are numerous. On the one hand, many of these options can be performed with minimal structural modifications and low out-of-time service [17]– [19], thus making them a cost-effective alternative to adding new lines [17]. On the other hand, line uprating options allow us to increase the transmission capacity in an existing ROW with only a small increase in footprint, or in some cases none at all, rendering construction permits easier to obtain [20]. They also exhibit shorter construction lead times compared to building new lines, which can be crucial for achieving a time-effective increase of the transmission capacity to accommodate new RES. Shorter construction lead times have also a significant value when the network planner faces uncertainty regarding future generation deployment, since investment commitments can be deferred until more information is available, thus reducing the risk of premature lock-in to sub-optimal investments in case of unfavorable scenario realizations [2]. Finally, in some cases the conductors being replaced may still have residual lifetime. In these cases, the industry practice is to sell or reuse the old conductors to lower the overall costs of the project. For example, in a reconductoring project in Chile in 2015, the old conductors were sold at about 1 \$/kg [21]. Even though line uprating options have been widely deployed in several power systems around the world and their advantages are well-known, their deployments have been decided based on planner experience and expertise, but not optimized within a TNEP approach. Only few works have included line uprating within the multi-year TNEP problem. To the best of our knowledge, the only ones are [13], [15], [16], [22], and [23]. The main difficulty of considering line uprating options endogenously within TNEP models is that some line uprating options change technical parameters of the resulting line, in particular the reactance. Therefore, including them among expansion candidates requires one to account for these changes in the reactance, which is not straightforward using existing models. In [13], a multi-year TNEP model that includes fixed series compensation to lines is proposed. The model also considers N-1 security constrains. The main limitation of this model is that it uses a single disjunctive parameter (big-M) that is large-enough so that no implicit bounds over voltage angle difference will exist, but it may negatively affect the convergence of the proposed method. In addition, it considers only three stages (years) within the planning horizon, the TNEP model is deterministic and it only considers one operating condition for each stage. These latter two characteristics mean that the model is not able to consider either the uncertainty regarding future generation scenarios or different generation patterns that result from RES. In [16], a multi-year TNEP model that includes HVAC to HVDC conversion is proposed. Among others, the model allows converting single/double circuit HVAC lines into single/double circuit HVDC bipolar HVDC line. Since the HVAC to HVDC conversion does not change the reactance of the line, a traditional disjunctive formulation is used. Two limitations of [16] is that it uses a deterministic approach, and it does not consider the construction lead times of expansion alternatives. Both characteristics limit the value of HVAC to HVDC conversion that can be captured within the proposed model. Note that in [13] and [16], only one type of uprating option is considered. In [15], a deterministic multi-year TNEP model including thyristor-controlled series compensation (TCSC) to enhance line transmission capacity, and superconducting fault current limiters (SFCL) to control short-circuit levels is proposed. The TNEP problem is formulated as a mixed-integer non-linear programming model (MINLP), where nonlinearities are mainly caused by the fact that impedances are variables from the addition of TCSCs and SFCLs. To solve the model, the authors linearize the problem using first order Taylor series expansion around a base point and implemented a solution technique based on Benders decomposition that iteratively updates the base point and re-linearizes non-linear functions accordingly. Finally, [22] and our previous work [23] present a proposal for considering several line uprating options simultaneously within the multi-year TNEP. Even though both works show the benefits of including several line uprating options within the multi-year TNEP problem simultaneously, their solution approach is based on an expert system [22] and a meta-heuristic solution technique [23]. This means that both proposals only allow obtaining efficient solutions, but not the optimal one. In addition, both works consider a deterministic approach, neglecting the uncertainty regarding future generation capacity. It is worth mentioning that a few works have also considered line uprating options, but within a static approach (e.g., single year). Examples of these works are [6], where line reconductoring along with thermal constraint relaxation was investigated; and [24], where a model and solution methodology for solving the static TNEP problem considering conductor proposals with different wire size and technology is presented. Finally, a model for evaluating different voltage levels in projected corridors was proposed in [25]. However, no voltage uprate of existing lines was considered.

From the above review it can be seen that, despite its benefits, few works have included line uprating options simultaneously within a multi-year TNEP. In addition, current proposals are deterministic, thus neglecting the uncertainty of future generation capacity, especially from RES. In the aforementioned context, in this article we present a novel stochastic model for multi-year TNEP that enables us to consider several line uprating options along with adding new lines simultaneously. To model the uncertainty of future generation capacities we formulate a two-stage stochastic problem using a scenario fan. Branching only occurs during the base year (root node) [26]. First-stage investment decisions (*here-and-now*) in the short run must be made before future information materializes and considers the build time of each project including possible commissioning delays. Second-stage investment decisions (*wait-and-see*) in the long run can be deferred to once future information materializes [27], and are therefore be made specifically for each scenario realization. Non-anticipativity constraints are introduced for each investment alternative using a scenario-variable approach [26]. This enables us to extract the benefits of shorter built times and commissioning delays for line uprating options.

The main contributions of this article are:

1) To present a novel stochastic model for multi-year TNEP that allows us to consider several line uprating options simultaneously. To this end, the model includes a novel (tight) representation of the expansion alternatives, where the values of the disjunctive parameters (big-M) associated with each network element are minimized. As shown in the result section, the proposed (efficient) representation of the disjunctive parameters significantly improves the convergence of the proposed model, thus rendering valuable benefits in terms of practicability and scalability.
2) To demonstrate that including several line uprating options simultaneously within the TNEP facing uncertainties has significant benefits. Our results show that an optimal combination of line uprating options along with traditional expansion alternatives allows us to lower total investment costs, defer first-stage investment commitments to later stages and reduce the ROW required to deploy the optimal expansion plans. In particular, being able to identify cost-efficient network reinforcements with less requirements of new ROWs acquisition (and thus with lower socio-environmental impact) is of major importance nowadays and may prove to be vital for obtaining practical, timely and efficient solutions with less risk of suffering delays and cost overruns.

Finally, it is worth mentioning that the proposed model presented in this article is the first one that allows us to optimally solve the multi-year TNEP problem facing uncertainties considering several line uprating options, along with adding new lines, simultaneously.

The rest of this paper is organized as follows. Section II presents an analysis of selected uprating options used in this article. Section III presents the approach for modeling expansion alternatives introduced in [23], and is described here for completeness. Section IV presents the problem formulation and the solution approach. Section V presents the case study and the results. In Section VI, we conclude.

II. SELECTED LINE UPRATING OPTIONS

A. LINE RECONDUCTORING

Line reconductoring consists of changing the type of conductor in an existing line to another with higher current-handling capability. This can be done by replacing the existing conductor by a conventional one with bigger diameter, or by replacing it with a High Temperature Low Sag (HTLS) conductor [28]. The disadvantage of increasing the conductor diameter is that larger conductors usually involve higher mechanical load on the structure and therefore either the structure may need extensive upgrades or it has to be fully replaced [28]. On the other hand, HTLS conductors with the same or even lower weight and diameter as conventional conductors are able to conduct higher currents. Therefore, reconductoring can be performed with little or no modifications to the supporting structures [28]. Reconductoring can be an effective strategy for increasing the power transfer in short lines (typically below 80 km), where the main limiting factor is the thermal rating of the conductor. It might not be as effective for long lines, where the main limiting factors are either voltage drop limits or small-signal stability limits [29]. Another advantage of line reconductoring is that it can be performed quickly (within few months) and even under energized conditions, i.e. with low or no out-of-time service. This was the case in the USA, where reconductoring the 52 km 345 kV LaCygne –Stillwell line while energized took 5 months [30].

B. VOLTAGE UPRATING

Voltage uprating consists of increasing the rated voltage of the transmission line to the next standard voltage level. This enables higher power transfers without increasing the current. Voltage uprating is generally the most effective way of providing large step change in transmission capacity [17]. Technical factors that need to be evaluated when considering voltage uprating are those associated with their insulation (e.g. switching surge performance) and conductor characteristics (e.g. radio influence and current carrying capacity) [31]. In the past, it was not unusual to design some lines considering the possibility of voltage uprate in the future, i.e., they were overbuilt [17]. In these best cases, voltage uprating can be performed with the existing conductor configuration and with relatively small marginal costs for the line reconfiguration [17]. Real case studies have found that under these circumstances, the costs of voltage uprating are around 20% of the costs of a new line for a 100% increase in transmission capacity [17]. In the worst case, voltage uprating involves changing the conductors (for larger ones or bundle conductors), install new towers or upgrade existing ones. In addition, an expansion of the existing ROW may be required to keep the corona and the electromagnetic field contamination within acceptable values, unless using a compact design is technically feasible [20]. Even in a worst-case, voltage uprating has the advantage of spreading out an existing ROW rather than acquiring a new one, thus lowering the footprint of the line, which makes construction permits easier to obtain.

C. ADDING SERIES COMPENSATION

Compensating a line with series capacitors reduces the transfer reactance between the buses where the line is connected, increasing in turn the maximum power that can be transmitted. This option is especially suitable in long lines (above 80 km), where the limiting factors for the power transfer are either voltage drops or steady-state stability limits. The amount of series compensation is typically selected between 20% and 80% of the line inductive reactance [32].

III. GENERAL FRAMEWORK AND PROPOSED MODELING APPROACH OF EXPANSION ALTERNATIVES

A. GENERAL FRAMEWORK

In this article, we assume a deregulated environment with a centralized network planning. The task of the central planer is to expand or reinforce the current transmission infrastructure in order to economically serve the projected load and maximize expected social welfare. We also assume that the planner faces a significant exogenous uncertainty regarding future generation capacity, which is accounted for through a discrete set of credible generation expansion scenarios Ω_S, each one of them assigned to a certain probability of occurrence μ_s. To increase transmission network capacity, the network planner identifies feasible network expansions or reinforcement options and defines a set of expansion candidates. Each candidate is characterized by its deployment costs, the transmission capacity of the resulting line, and the expected construction lead times. The challenge of the network planner is to optimally select which expansion candidates to deploy and when.

In the aforementioned context, the proposed TNEP model aims to be a useful tool for the network planner to determine an optimal investment path. Input data of the TNEP model are the current infrastructure, the projected load, the discrete set of generation expansion scenarios and the predefined set of expansion alternatives.

Remark 1: in real-world planning practices, the scenarios for future generation capacity and their probability of occurrence are usually the product of expert opinion, industry surveys and analysis of the underlying market dynamics [2]. In this article, the scenarios adopted are for illustrative purpose only. The generation of such scenarios is out of the scope of this paper. It is also worth mentioning that in our proposed methodology the definition of scenarios is not restricted to future generation capacities. Other sources of uncertainties such as load growth and fuel prices can be considered as well.

Remark 2: regarding the expansion candidates, it is worth mentioning that many jurisdictions incorporate a consultative process as well, allowing different actors to also propose expansion alternatives. The generation of expansion candidates is also out of the scope of this paper. The transmission network expansion candidates used in this paper are also for illustrative purposes only, and were developed considering technical characteristics of each expansion alternative and using deployment costs from the literature. It is assumed that the deployment of each expansion alternative is technically feasible.

B. PLANNING PROJECTS

In this proposal, the expansion options are modeled through planning projects. A planning project consists of a set of actions and network elements. Actions can be to either *add a network element* (denoted by A) to or *remove a network element* (denoted by R) from the network. To illustrate an example, assume that a certain corridor $\bar{k}$ connecting buses s and r has two lines, $L^{v1}_{1,c1}$ and $L^{v1}_{2,c1}$, with a conductor type c_1, and with a rated voltage v_1. Further on, assume that to increase the transmission capacity of the corridor, the network planner identifies the following four expansion candidates: 1) add a third line $L^{v1}_{3,c1}$ using the same conductor; 2) perform reconductoring with a HTLS conductor c_2 in both lines; 3) add series compensation to the existing lines; and 4) increase the rated voltage from v_1 to v_2 (voltage uprating). Within our proposal, the network planner can model the aforementioned expansion candidates as follows:

$$p_1 = \left\{\left(A, L^{v1}_{3,c1}\right)\right\}. \tag{1}$$

$$p_2 = \left\{\left(R, L^{v1}_{1,c1}\right), \left(R, L^{v1}_{2,c1}\right), \left(A, L^{v1}_{1,c2}\right), \left(A, L^{v1}_{2,c2}\right)\right\}. \tag{2}$$

$$p_3 = \left\{\left(R, L^{v1}_{1,c1}\right), \left(R, L^{v1}_{2,c1}\right), \left(A, L^{v1}_{1,c4}\right), \left(A, L^{v1}_{2,c4}\right)\right\}. \tag{3}$$

$$p_4 = \left\{\left(A, B^{v2}_{s}\right)\right\}, \tag{4}$$

$$p_5 = \left\{\left(A, B^{v2}_{r}\right)\right\}, \tag{5}$$

$$p_6 = \left\{\left(A, T^{v1,v2}_{1,t_1,s}\right)\right\}, \tag{6}$$

$$p_7 = \left\{\left(A, T^{v1,v2}_{1,t_1,r}\right)\right\}, \tag{7}$$

$$p_8 = \left\{\left(R, L^{v1}_{1,c1}\right), \left(R, L^{v1}_{2,c1}\right), \left(A, L^{v2}_{1,c3}\right), \left(A, L^{v2}_{2,c3}\right)\right\}. \tag{8}$$

Project p_1 consists of adding a third line using the same conductor. Project p_2 models the option of reconductoring and consists of removing the two existing lines and adding two lines with HTLS conductors. Project p_3 models the option of adding series compensation and consists of removing the two existing lines and adding two compensated lines with the corresponding conductor type $c4$. Finally, the voltage uprating option is modeled with projects $p_4 - p_8$ as follows: projects p_4 and p_5 build the busbars with voltage v_2 at both ends of the line; projects p_6 and p_7 build the transformers; and project p_8 replaces the line with another one with the corresponding conductor type c_3. Modeling voltage uprating options through different projects instead of just one big project has the advantage of providing flexibility to the model and avoids duplicating investments. To illustrate this advantage, assume that performing voltage uprating option in an adjacent corridor connecting buses r and $\tilde{r}$, is also among the expansion candidates, as shown in Fig. 1. Modeling this option requires adding following projects to the aforementioned candidates:

$$p_9 = \left\{\left(A, B^{v2}_{\tilde{r}}\right)\right\}, \tag{9}$$

$$p_{10} = \left\{\left(A, \tilde{T}^{v1,v2}_{1,t_1,\tilde{r}}\right)\right\}, \tag{10}$$

$$p_{11} = \left\{\left(R, \tilde{L}^{v1}_{1,c1}\right), \left(R, \tilde{L}^{v1}_{2,c1}\right), \left(A, \tilde{L}^{v2}_{1,c3}\right), \left(A, \tilde{L}^{v2}_{2,c3}\right)\right\}. \tag{11}$$

Project p_9 builds the busbar with voltage v_2 at the connecting bus $\tilde{r}$; projects p_{10} builds the transformer; and project

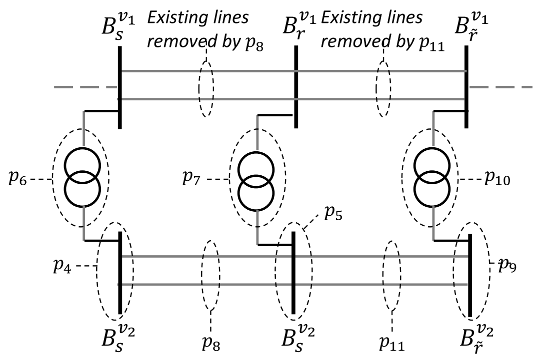

FIGURE 1. Illustration of candidate projects for modeling voltage uprating in adjacent corridors.

p_{11} replaces the lines $\tilde{L}_{1,c1}^{v1}$ and $\tilde{L}_{2,c1}^{v1}$ with another one with the corresponding conductor type c_3. Notice that projects for building a new substation and a transformer in bus r do not need to be defined again, since they were already defined in projects p_5 and p_7. One feasible solution could be to perform voltage uprating in both corridors simultaneously, in which case all projects $p_4 - p_9$ are deployed the same year. However, another feasible solution could be to first perform voltage uprating between buses r and $\tilde{r}$ and then in a later year perform voltage uprating between buses r and s. In this case, for performing voltage uprating between buses r and $\tilde{r}$ would require the deployment of projects p_5, p_7, p_9, p_{10} and p_{11}, while projects p_4, p_6, p_8 can be deployed in a later year.

C. EXCLUSIONS AND DEPENDENCIES

When considering line uprating options, the exclusions and dependencies of any project must be considered. For instance, in the aforementioned example, the first set of expansion candidates available to increase the transmission capacity in corridor $\bar{k}$ are adding a third line using the conventional conductor c_1 (project p_1), changing the conductor of the two existing lines with HTLS conductors c_2 (project p_2), adding series compensation to the lines (project p_3), and increasing the operating voltage (p_8 and the projects needed for ensuring the connectivity of the new lines). These projects are mutually exclusive, since only one of them can be built. On the other hand, if for example reconductoring of the two existing lines is performed, a third line with the new conductor can be added in a later year. This is dependent on the building of an earlier reconductoring project of the two existing lines. Regarding voltage uprating, the project that changes one line for another with higher voltage (project p_8) can only be built if the projects that ensure its connectivity have been already built (p_4, p_5 for the busbars and p_6, p_7 for the transformers). Exclusions and dependencies among projects considering scenarios of future generation capacity can be modeled as follows:

$$\Delta_{p_i}^{s,y} = \sum_{y_n \leq y} \delta_{p_i}^{s,y_n}, \; \Delta_{p_i}^{s,y} \in \{0, 1\}, \quad \forall p_i \in \Omega_P, \times y \in \Omega_Y, \mathrm{s} \in \Omega_S \tag{12}$$

$$\Delta_{p_i}^{s,y} = 0, \forall \mathrm{y} < y_{p_i}^0, p_i \in \Omega_P, \mathrm{s} \in \Omega_S \tag{13}$$

$$\Delta_{p_i}^{s,y} - \sum_{p_d \in \Omega_{p_i}^{dep}} \Delta_{p_d}^{s,y} \leq 0, \forall p_i \in \Omega_P, y \in \Omega_Y, \mathrm{s} \in \Omega_S \tag{14}$$

$$\sum_{y \in \Omega_Y} \Delta_{p_i}^{s,y} + \Delta_{p_j}^{s,y} \leq 1, \forall \left(p_i, p_j\right) \in \Omega_P^{excl}, \mathrm{s} \in \Omega_S \tag{15}$$

$$\Delta_{p_i}^{s_j,y} = \Delta_{p_i}^{s_k,y}, \quad \forall p_i \in \Omega_P, \; \forall y \leq y_{p_i}^0 + \Upsilon_{p_i}, \quad \forall \mathrm{s}_j, \mathrm{s}_k \in \Omega_S \tag{16}$$

Constraint (12) states the aggregated decision of building project p_i over all previous years in the corresponding scenario. It ensures that each candidate project can only be built once in each scenario. The earliest year that a project can be built is restricted in (13). Constraint (14) ensures that a project p_i can be built in a certain year and scenario only if at least one of its dependent projects has already been built in the same scenario. Constraint (15) ensures that, for each pair of projects that is mutually exclusive, at the most one of them can be built in each scenario. Constraint (16) contains the non-anticipativity conditions of the investment decisions and includes possible commissioning delays. They ensure that first-stage investment decisions (*here-and-now* decisions) adopt the same value in all scenarios. To exemplify this, assume that the build time of a project is expected to take 3 years ($y_{p_i}^0 = 3$), but the network planner envisions possible commissioning delays of 2 years ($\Upsilon_{p_i} = 2$) to secure permissions. The decision-making problem faced by the planner is the following: at the start year, the network planner needs to decide whether or not to commit to the investment for building the project, in which case the project can be in operation anytime between years 3 and 5 (according to the expected construction lead times and possible delays). This is the first-stage decision (*here-and-now*) and is independent from the scenario realization, according to (16). Notice that the first-stage decision of this project spans 5 years. On the other hand, if the project needs to be in operation any time after year 5, then the investment commitment can be deferred to the future, since there is no need to start immediately with the process for securing planning permissions. These are second-stage decisions and can be made specifically for each scenario realization. Notice that within this scenario-variable formulation, the timespan (years) of first- and second-stage decisions may vary among projects, since it depends on the expected construction lead times and possible delays of each project specifically. For example, if the construction lead time of a reconductoring project is expected to be 1 year and the risk of delays is minimum, then the timespan of the first-stage decision is only 1 year. Dealing with possible delays in the regulatory process is of major concern nowadays, which justifies its incorporation into the model.

IV. MULTI-YEAR TNEP MODEL: MATHEMATICAL FORMULATION AND SOLUTION METHODOLOGY

The objective of the multi-year TNEP problem facing uncertainties is to minimize the expected net present value (NPV) of the investment and operating costs of the power system throughout the whole horizon under study. This problem

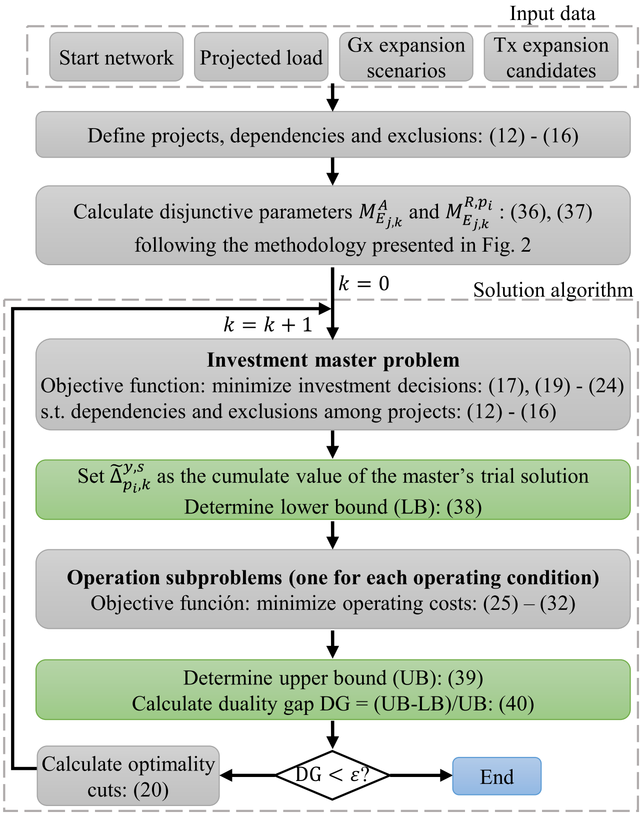

FIGURE 2. **General framework of the proposed model and solution technique.**

is a mixed-integer large-scale optimization problem, where the number of variables and constraints grows rapidly with an increasing number of investment decisions, years, and scenarios. To keep the problem tractable in terms of memory requirements, we use a two-level formulation for the multi-year TNEP and use a multicut Benders decomposition technique to solve it iteratively, similar to the one proposed in [2]. Note that, if sufficient memory is available, the proposed TNEP model can be solved using a single MILP formulation. The general structure of the proposed solution technique is presented in Fig. 2. At each iteration, we solve the investment master problem, formulated as a mixed integer linear programming (MILP) problem, and send the optimal solution to the operational subproblems (one for each year, operating condition and scenario), which are formulated as a linear programming (LP) problem. The result of the operational subproblems in each iteration k is a set of $|\Omega_S|\,|\Omega_Y|\,|\Omega_O|$ optimality cuts, one for each scenario, year, and operating condition. These cuts are added to the master problem. Consequently, operation costs are taken into account in the master problem through a cutting plane approximation. This procedure is performed until a convergence criterion is met.

A. INVESTMENT MASTER PROBLEM

The investment master problem considers only investment decisions and constraints among planning projects. The value of the operation subproblem is approximated using scalar decision variables $\alpha_{y,s,o}$.

$$\underset{\delta_p}{\boldsymbol{min}} \sum_{s\in\Omega_S} \sum_{y\in\Omega_Y} \frac{\mu_s}{q^{y-y_0}} \left(\sum_{p_i\in\Omega_P} c^{s,y}_{p_i} + \sum_{o\in\Omega_O} \sigma_o \cdot \alpha_{s,y,o} \right) \tag{17}$$

where

$$c^{s,y}_{p_i} = \delta^{s,y}_{p_i} \cdot \Gamma_{p_i} - \sum_{y_m \leq y} \sum_{\substack{p_i \epsilon \Omega^{RC}_P \cup \Omega^{VU}_P \\ p_d \epsilon \Omega_p, (R, E_{j,k}) \\ \in p_i (A, E_{j,k}) \in p_d}} \delta^{s,y}_{p_i} \cdot \delta^{s,y_m}_{p_d} \cdot RV^{y,y_m}_{E_{j,k}} \tag{18}$$

$$RV^{y,y_m}_{E_{j,k}} = \begin{cases} c_{E_{j,k}} \left(1 - \frac{y-y_m}{T_{E_{j,k}}}\right) \mathit{if}\ \left(A, E_{j,k}\right) \epsilon \Omega_P \\ c_{E_{j,k}} \cdot max \left\{1 - \frac{y-y_0^{E_{j,k}}}{T_{E_{j,k}}}, 0\right\} \mathit{otherw.} \end{cases} \tag{19}$$

Subject to
Constraints (12) – (16) among planning projects

$$\alpha_{s,y,o} \geq \omega^{k-1}_{s,y,o} + \sum_{p_i\in\Omega_P} \lambda^{k-1}_{p_i,s,y,o} \left(\Delta^{s,y}_{p_i} - \tilde{\Delta}^{s,y}_{p_i,k-1} \right), \quad \forall y,\ \forall s,\ \forall o \tag{20}$$

where q represents the discount rate and y_0 the base year. The objective function (17) represents the expected present value of the total system cost over the study period. The system investment costs are calculated using the variables $c^{s,y}_{p_i}$, which represent the cost of project p_i if built in scenario s and year y. Notice that constraints (12) and (16) force first-stage investment decisions to be the same for all scenarios. Consequently, $\forall y \leq y^0_{p_i} + \Upsilon_{p_i}$, $c^{s,y}_{p_i}$ is the same for all scenarios and is therefore independent from the scenario realization. The reason for adopting this formulation is to include the residual value of elements being removed within reconductoring or voltage uprating projects. These residual values are subtracted from the total project cost since they can be sold. The residual value of a network element in a certain year depends on its construction year, useful lifetime, annual depreciation, as well as other specific market considerations. The values of $c^{s,y}_{p_i}$ are calculated using (18) and (19). In (18), Γ_{p_i} represents the investment cost of project p_i and $RV^{y,y_m}_{E_{j,k}}$ is the residual value of element $E_{j,k}$ if built in year y_m and removed in year y. Notice that $RV^{y,y_m}_{E_{j,k}}$ are scalar values which are calculated beforehand and therefore no nonlinearities are involved in this part. In (19) we applied a linear depreciation method, but any other depreciation method to reflect specific market considerations can be used as well. This residual value is restricted to reconductoring and voltage uprating options only. For projects that add series compensation, the investment costs are those associated with the series capacitors. There is no residual value, since no line is removed. In (18), if project p_i is not built in scenario s and year y ($\delta^{s,y}_{p_i} = 0$), then the costs of the project in that year is zero. If project p_i is built in scenario s and year y ($\delta^{y,s}_{p_i} = 1$), then according to the dependencies and exclusions between projects, every removed element must have been already built within another (dependent) project. In (19), for network elements that already existed in the initial network, y_m is replaced by the year it was built. To include the residual value of network elements being removed is relevant to fully explore the benefits of uprating options and reflect industry practices. Constraints (12) – (16) among planning projects limit the search space to feasible regions according to the exclusions and dependencies among projects. Constraints (20) are the Benders cuts appended to the master problem. These cuts are calculated using the dual variables of the subproblems $\lambda^{k-1}_{p_i,s,y,o}$ and provide a lower bound estimate for each operating condition.

The formulation in (18) is non-linear due to the product of the decision variables. To linearize it, we use auxiliary variables $z^{p_d,y_m,s}_{p_i,y,s}$ meaning that projects p_i and p_d are built in years y and y_m, respectively (both in scenario s). The linearized form is:

$$c^{y,s}_{p_i} = \delta^{y,s}_{p_i} \cdot \Gamma_{p_i} - \sum_{y_m \leq y} \sum_{\substack{p_i \epsilon \Omega^{RC}_P \cup \Omega^{VU}_P \\ p_d \epsilon \Omega_p, (R,E_{j,k}) \in p_i \\ (A,E_{j,k}) \in p_d}} z^{p_d,y_m,s}_{p_i,y,s} \cdot RV^{y,y_m}_{E_{j,k}} \tag{21}$$

$$z^{p_d,y_m,s}_{p_i,y,s} \leq \delta^{y,s}_{p_i} \tag{22}$$

$$z^{p_d,y_m,s}_{p_i,y,s} \leq \delta^{y_m,s}_{p_d} \tag{23}$$

$$\delta^{y,s}_{p_i} + \delta^{y_m,s}_{p_d} - z^{p_d,y_m,s}_{p_i,y,s} - 1 \leq 0 \tag{24}$$

B. OPERATION SUBPROBLEMS

At each iteration k, the operation subproblems (one for each operating condition) use the cumulate value of the master's trial solution $\tilde{\Delta}^{y,s}_{p_i,k}$ and determines the optimal generation dispatch.

$$\omega^k_{s,y,o} = \min_{p_g} \left\{ \sum_{\forall g} c_g p^{s,y,o}_g + \sum_{\forall b} \left(c_U r^{s,y,o}_b + c_W w^{s,y,o}_b \right) \right\} \tag{25}$$

Subject to

$$\Delta^{s,y}_{p_i} = \tilde{\Delta}^{s,y}_{p_i,k} : \lambda^k_{p_i,s,y,o}, \forall p_i \in \Omega_P \tag{26}$$

$$\sum_{g \epsilon \Omega^b_G} p^{s,y,o}_g - \sum_{s(E_{j,k})=b} f^{s,y,o}_{E_{j,k}} + \sum_{r(E_{j,k})=b} f^{s,y,o}_{E_{j,k}} + r^{s,y,o}_b - w^{s,y,o}_b = D^{s,y,o}_b - W^{s,y,o}_b, \forall b \epsilon \Omega_B \tag{27}$$

$$0 \leq r^{s,y,o}_b \leq D^{s,y,o}_b, \forall b \epsilon \Omega_B \tag{28}$$

$$0 \leq w^{s,y,o}_b \leq W^{s,y,o}_b, \forall b \epsilon \Omega_B \tag{29}$$

$$0 \leq p^{s,y,o}_g \leq \bar{P}_g, \forall g \epsilon \Omega_G \tag{30}$$

$$\left| f^{s,y,o}_{E_{j,k}} \right| \leq f^{max}_{E_{j,k}} \cdot \left(\sum_{(A,E_{j,k}) \epsilon p_i} \Delta^{s,y}_{p_i} - \sum_{(R,E_{j,k}) \epsilon p_i} \Delta^{s,y}_{p_i} \right) \quad \forall E_{j,k} \epsilon \Omega_L \cup \Omega_T \tag{31}$$

$$\left| f^{s,y,o}_{E_{j,k}} - B_{E_{j,k}} \left(\theta^{s,y,o}_{s(E_{j,k})} - \theta^{s,y,o}_{r(E_{j,k})} \right) \right| \leq M^A_{E_{j,k}} \left(1 - \sum_{(A,E_{j,k}) \epsilon p_i} \Delta^{s,y}_{p_i} \right) + \sum_{(R,E_{j,k}) \epsilon p_i} M^{R,p_i}_{E_{j,k}} \cdot \Delta^{s,y}_{p_i}, \forall E_{j,k} \epsilon \Omega_L \cup \Omega_T \tag{32}$$

The objective function (25) includes the generation costs, the load-shedding costs and the costs of RES curtailment. Constraint (26) forces the subproblem auxiliary investment decision variables $\Delta^{s,y}_{p_i}$ to be equal to the optimal decisions $\tilde{\Delta}^{s,y}_{p_i,k}$ supplied by the master problem at iteration k. The resulting Lagrange multipliers $\lambda^k_{p_i,s,y,o}$ are used to construct the Benders cut to be appended in the master problem in the next iteration. Constraint (27) models the power balance at each bus, considering each existing and projected line independently (element $E_{j,k}$ denotes the j-th parallel line with conductor type k); (28) represents the limits for the load shedding at each bus, (29) the limits for RES curtailment and (30) provides limits on generation dispatch. Constraint (31) sets the power flow limits for lines and transformers, which depends on whether or not the elements exist in the network for the corresponding year. Constraint (32) correlates the power flow of lines and transformers with the voltage angle at the busbars using our proposed disjunctive approach. In (32), two types of disjunctive parameters (big-M) associated with each network element $E_{j,k}$ are used: one type associated with projects that add the corresponding element to the network, $M^A_{E_{j,k}}$, and another one associated with projects that removes the element from the network, $M^{R,p_i}_{E_{j,k}}$. Note that, by construction of the exclusions between projects in (15), at most one disjunctive parameter will be active at each time. In addition, there is no need to calculate the parameter $M^A_{E_{j,k}}$ for existing lines in the starting network, since these lines are always built before the first year. Notice that the operational subproblems are always feasible due to the use of slack variables for load-shedding and RES curtailment. Consequently, the cuts generated are optimality cuts and define the objective value associated with feasible integer solutions (e.g. expansion plans). There are no feasibility cuts in our formulation.

The efficient solution to the problem (25)–(32) depends on the values of the disjunctive parameters. Bigger coefficients give less tight polyhedrons, worse optimal values [33], and may introduce numerical instabilities in practical applications [34]. Therefore, the objective is to find minimum appropriate values. In the next subsection we provide a strategy for determining efficient values of the disjunctive parameters, based on already existing network restrictions over voltage angle differences and considering the candidate expansion projects. Notice that the values of these parameters are calculated outside (before) the optimization process.

The main contribution of our proposed methodology is that it provides the corresponding authority with a practical tool for designing grid code requirements systematically for FFR capability in RES and therefore ensures a flawless and secure integration of these types of generating technology.

One area of improvement that will be addressed in a future work is to include load dynamics in the reduced-order representation of system frequency dynamics. This may lead to less conservative and thus more economic reserve reallocation solutions that allow the avoidance of the activation of UFLSSs in case of extreme contingencies.

C. PROPOSAL FOR CALCULATING DISJUNCTIVE PARAMETERS

For a classical TNEP model which only considers adding new lines, an efficient approach to determine the disjunctive parameters $M^{A}_{E_{j,k}}$ for each candidate circuit $E_{j,k}$ is to use the existing network restrictions over voltage angle differences [34]. In this case, the minimal existing limit of the voltage angle difference between buses $s = s\left(E_{j,k}\right)$ and $r = r\left(E_{j,k}\right)$ can be determined by solving the following shortest path problem using the Dijkstra algorithm:

$$c^{base}_{s,r} = \min_{x_{E_{t,u}} \in \{0,1\}} \left\{ \sum_{E_{t,u} \in \Omega_{E0}} \frac{f^{max}_{E_{t,u}}}{B_{E_{t,u}}} x_{E_{t,u}} \right\} \tag{33}$$

s.t.:

$$\sum_{\substack{E_{t,u}\in\Omega_{E0}\\ b=s(E_{t,u})}} x_{E_{t,u}} - \sum_{\substack{E_{t,u}\in\Omega_{E0}\\ b=r(E_{j,k})}} x_{E_{t,u}} = \begin{cases} 1 & \text{if } b = s \\ -1 & \text{if } b = r \\ 0 & \text{otherwise.} \end{cases} \tag{34}$$

Note that $c^{base}_{s,r}$ represents the largest voltage angle difference between the connecting buses s and r in the existing network. Once (33)–(34) is solved, the disjunctive parameters $M^{A}_{E_{j,k}}$ for each candidate circuit $E_{j,k}$ can be set to:

$$M^{A}_{E_{j,k}} = B_{E_{j,k}} \cdot c^{base}_{s,r},\ s = s\left(E_{j,k}\right),\ r = r\left(E_{j,k}\right) \tag{35}$$

When including line uprating options, the existing limit $c^{base}_{s,r}$ over the voltage angle difference may no longer be valid, since replacing the lines for other ones with different technical characteristics may result in higher values. This could be the case when series compensation or voltage uprating in adjacent corridors occurs. To consider this fact, we introduce the variable $c^{z}_{s,r}$ that represents the maximum voltage angle difference if a candidate element of type z is built between buses s and r. The value of $c^{base}_{s,r}$ must also be re-calculated in order to include the influence of building uprating projects. Then we determine proper values for $M^{A}_{E_{j,k}}$ and $M^{R,p_i}_{E_{j,k}}$ based on $c^{z}_{s,r}$ and the adjusted value of $c^{base}_{s,r}$, using the methodology presented in Fig. 3. This algorithm allows us to compute the values without having to consider all possible combinations of candidate planning projects, thus reducing significantly the

Obtain set $\Omega_{P,s,r}$ of eligible projects in corridor between nodes (s, r)
$\forall p_i \in \Omega_{P,s,r} \cup p_0 = \{\emptyset\}$ do
- Build project p_i in the start network. The resulting network is denoted N_{E_0,p_i} (p_0 means no project is built)
- Set $z = k \,/\, \left(A, E_{j,k}\right) \in p_i, \forall i \neq 0; z = base \text{ if } i = 0$
- Solve the shortest-path problem (33) –(34) using N_{E_0,p_i}
- Set $c^{z}_{s,r}$ as the largest voltage angle difference obtained
- Get set $V_{s,r}$ with visited corridors (edges) other than (s, r)
- Obtain set $\Omega_{P,V}$ of eligible projects to be built in the network N_{E_0,p_i} that add lines in corridors belonging to $V_{s,r}$
- Obtain set $\mathfrak{T}$ with all possible eligible project combinations in the set $\Omega_{P,V}$ to be built in network N_{E_0,p_i}
- $\forall \mathfrak{T}_j \epsilon \mathfrak{T}$ do
  - Build projects belonging to $\mathfrak{T}_j$ in the network N_{E_0,p_i}
  - Solve the shortest-path problem (33) – (34) using the resulting network. The result is denoted $c^{z,j}_{s,r}$
  - Set $c^{z}_{s,r} = max\{c^{z}_{s,r}, c^{z,j}_{s,r}\}$
- end

end

FIGURE 3. Methodology for calculating the values of $c^{base}_{s,r}$ and $c^{z}_{s,r}$ between busbars s and r.

required computational time. Note that for each variable the influence of building other projects in different corridors is considered as well. Once the new values of $c^{base}_{s,r}$ and $c^{z}_{s,r}$ are computed, the parameters $M^{A}_{E_{j,k}}$ and $M^{R,p_i}_{E_{j,k}}$ are set to:

$$M^{A}_{E_{j,k}} = \begin{cases} B_{E_{j,k}} \cdot \max\limits_{\substack{\forall z/(A,E_{j,z})\varepsilon\Omega_P\\ z\neq k}} \left\{c^{base}_{s,r}, c^{z}_{s,r}\right\} & \text{if } j = 1 \\ B_{E_{j,k}} \cdot \max\limits_{\forall z/(A,E_{j,z})\varepsilon\Omega_P} \left\{c^{base}_{s,r}, c^{z}_{s,r}\right\} & \text{if } j > 1 \end{cases}$$
$$\times \left(A, E_{j,k}\right) \epsilon \Omega_P,\ s = s\left(E_{j,k}\right),\ r = r\left(E_{j,k}\right) \tag{36}$$

$$M^{R,p_i}_{E_{j,k}} = B_{E_{j,k}} \cdot c^{z}_{s,r}\ \left(R, E_{j,k}\right) \epsilon p_i,$$
$$\times \left(A, E_{j,z}\right) \epsilon p_i,\ s = s\left(E_{j,k}\right),\ r = r\left(E_{j,k}\right) \tag{37}$$

To illustrate this with an example, assume that for a given corridor between buses s and r the initial network has one existing line with a conventional conductor c_1, denoted $E_{1,1}$. To increase its transmission capacity, the network planner can build up to two lines, opting between adding a second parallel line with the same conductor, $E_{2,1}$, performing reconductoring and change the conductor to c_2 (candidate lines are $E_{1,2}$ and $E_{2,2}$), or performing voltage uprating and change the conductor to c_3 (candidate lines are $E_{1,2}$ and $E_{2,2}$). For the existing line $E_{1,1}$, only the disjunctive parameters $M^{R,p_i}_{E_{j,k}}$ for the uprating projects must be determined. If the line is removed by the reconductoring project, the maximum voltage angle difference between the connecting buses will be $c^{2}_{s,r}$. Indeed, $c^{2}_{s,r}$ was calculated by replacing the existing line with $E_{1,2}$ using the HTLS conductor, and includes building every other eligible project combination in the neighborhood that may affect this maximum voltage angle difference. Note that there is no need to consider $c^{3}_{s,r}$, given that the voltage uprating project cannot be built if the reconductoring project is built. Consequently, the disjunctive parameter

$M_{E_{1,1}}^{R,p_i} = B_{E_{1,1}} \cdot c_{s,r}^2$ is the minimum value that does not pose any implicit restriction over the voltage angle difference. The same holds for the voltage uprating project, in which case possible transformer combinations are also explored. For the projected line $E_{2,1}$, if it is not built, the maximum voltage angle difference between the connecting buses will be $c_{s,r}^{base}$, if no uprating project is built; $c_{s,r}^2$, if the reconductoring project is built; or $c_{s,r}^3$, if the voltage uprating project is built. Since all possibilities can occur, $M_{E_{2,1}}^A$ must be calculated considering the maximum voltage angle difference obtained from all three options. If the second line $E_{2,1}$ is built and later removed by the uprating project p_i, then the corresponding value of the disjunctive parameter $M_{E_{1,2}}^{R,p_i}$ is the same as the one for the existing line $M_{E_{1,1}}^{R,p_i}$, since the maximum voltage angle difference that may occur is the same if project p_i is built.

In regard to the first projected line using the HTLS conductor $E_{1,2}$, as long as is not built, if the voltage uprating project has not been built either, the maximum voltage angle difference will be $c_{s,r}^{base}$. Otherwise, if the voltage uprating project was built, the maximum voltage angle different will be $c_{s,r}^3$. Therefore, the maximum voltage angle difference for calculating $M_{E_{1,2}}^A$ corresponds to the maximum value between $c_{s,r}^{base}$ and $c_{s,r}^3$. There is no need to consider $c_{s,r}^2$, because once the reconductoring project is built then the disjunctive parameter $M_{E_{1,2}}^A$ is no longer active. This formulation does not consider removing lines from uprating projects. However, the formulation can be easily extended to consider these cases using the same criteria. Regarding the second projected line using a HTLS conductor, $E_{2,2}$, as long as it has not been built, the maximum voltage angle difference will be $c_{s,r}^{base}$ if none of the uprating projects have been built either; $c_{s,r}^2$, if the project for reconductoring the existing line is built; or $c_{s,r}^3$, if the project for voltage uprating is built. Therefore, in this case the maximum value of the voltage angle difference to be considered is the maximum value of all three possibilities. The same holds for the disjunctive parameters of candidate lines built within the voltage uprating projects.

D. CONVERGENCE CRITERION

The convergence criterion is defined based on the upper and lower bounds of the problem according to (38)–(40).

$$Z_k^{lower} = \sum_{s\in\Omega_S}\sum_{y\in\Omega_Y}\frac{\mu_s}{q^{y-y_0}}\left(\sum_{p_i\in\Omega_P} c_{p_i}^{s,y} + \sum_{o\in\Omega_O}\sigma_o\cdot\alpha_{s,y,o}\right) \tag{38}$$

$$Z_k^{upper} = \sum_{s\in\Omega_S}\sum_{y\in\Omega_Y}\frac{\mu_s}{q^{y-y_0}}\left(\sum_{p_i\in\Omega_P} c_{p_i}^{s,y} + \sum_{o\in\Omega_O}\sigma_o\cdot\omega_{s,y,o}^k\right) \tag{39}$$

$$\frac{Z_k^{upper} - Z_k^{lower}}{Z_k^{upper}} \le \varepsilon \tag{40}$$

The threshold ε should be chosen close to zero to in order to ensure close matching between the bounds of the problem.

V. CASE STUDIES

In this section we present the studies carried out to i) validate the model, ii) analyze the results and identify the benefits of line uprating options and iii) examine the computational performance and scalability of the proposed model. To this end, we implemented our model in a tailor-made 7-bus test system and in the IEEE 118-bus test system. In both cases we assumed two scenarios of large-scale incorporation of renewable energies. Full data of both test systems can be found in [35].

To identify the benefits of including line uprating options and evaluate the scalability of our proposal, in each system we tested four different TNEP models, as described in Table 1. In the first two cases we solved a deterministic planning task, i.e., for each scenario independently, with and without uprating options (cases D-UR and D-B, respectively). In the last two cases we solved the stochastic planning task, also with and without uprating options (cases S-UR and S-B, respectively). For illustrative purposes, in the stochastic formulations we considered construction lead times including commissioning delays of three years for building new lines and of one year for uprating projects. We also assumed that all projects could be built by the first year under consideration. The proposed model was implemented in Matlab R2017 using the solver Xpress 8.2. Simulations were done in a computer with 2 Intel Xeon E5-2630 (12 cores), 2.4 GHz and 32 GB of RAM. The relative gap to reach convergence was set equal to 10^{-4} in all simulations.

TABLE 1. TNEP models.

Case	Description
D-B	Deterministic optimization without uprating options
D-UR	Deterministic optimization including uprating options
S-B	Stochastic optimization without uprating options
S-UR	Stochastic optimization including uprating options

A. 7 BUS TEST SYSTEM

This test system consists of seven buses, six existing lines, five demands points, and three conventional generators, as shown in Fig. 4. The planning task consists of determining the optimal expansion plan with yearly resolution over a time horizon of 5 years, assuming an annual load growth of 4%. We assumed two scenarios of large-scale incorporation of wind and solar energy with equal probability of occurrence. Scenario S1 envisages a strong wind incorporation at bus 6, with a final value of 400 MW by year 5 and a moderate incorporation of solar capacity in bus 7, with a final value of 125 MW by year 5. Scenario S2 envisages a strong solar incorporation at bus 6, with a final value of 400 MW by

TABLE 2. Optimal expansion plans taylor-made 7-bus test system.

	D-B	D-UR	D-B	D-UR	S-B		S-UR	
Year	S1		S2		S1	S2	S1	S2
1	2-6 (L_2^{C1}) 2-6 (L_3^{C1}) 3-5 (L_2^{C1})	2-6 (L_1^{C3}) – VU 1-4 ($L_1^{C4,50\%}$) – SC 3-5 (L_2^{C1})	2-3 (L_2^{C1}) 2-6 (L_2^{C1}) 3-5 (L_2^{C1})	2-3 (L_1^{C2}) – RC 2-6 (L_1^{C2}) – RC 3-5 (L_2^{C1})	2-3 (L_2^{C1}) * 3-5 (L_2^{C1}) * 2-6 (L_2^{C1}, L_3^{C1}) *		2-3 (L_2^{C1}) * 3-5 (L_2^{C1}) * 2-6 (L_2^{C2}) – RC *	
2			5-7 (L_2^{C1})		5-7 (L_2^{C1}) *			5-7 (L_1^{C3}) – VU 1-4 ($L_1^{C4,50\%}$) – SC
3			5-7 (L_3^{C1})	5-7 (L_1^{C3}) – VU				
4	5-7 (L_2^{C1})	5-7 ($L_1^{C4,50\%}$) – SC	5-7 (L_4^{C1})		2-6 (L_4^{C1})	5-7 (L_3^{C1}) 5-7 (L_4^{C1})	4-6 (L_1^{C1}, L_2^{C1}) 5-7 ($L_1^{C4,50\%}$) – SC	
5	2-6 (L_4^{C1})							
#NL	5	1	6	1	6	7	4	2
+ROW	910.8 ha	238.8 ha	1359.6 ha	195.6 ha	1016.4 ha	1518 ha	514.8 ha	301.2 ha

* New buses and transformers for voltage uprating are omitted for brevity purposes. #NL indicates the number of new lines built. "+ROW" indicates the additional ROW requirements (in hectares)

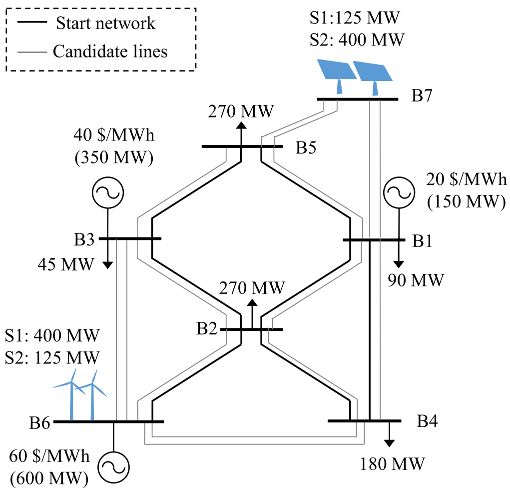

FIGURE 4. Diagram of the tailor-made 7-bus system. Capacities of renewable generators and loads are for year 5. For simplicity purposes, only two lines are shown for each corridor.

year 5 and a moderate incorporation of wind capacity in bus 6, with a final value of 125 MW by year 5. To capture different operating conditions, in each year and scenario we used five representative days (120 h in total): one for each calendar season and one to capture yearly demand peak conditions.

For the TNEP problem, we considered three types of conductors: one conventional conductor for 110 kV (C1), one HTLS conductor (C2), and one conventional conductor for 220 kV (C3). In addition, we considered series compensation of 25% and 50% for long lines (C4,25% and C4,50%, respectively). The investment costs of new lines using conventional conductors were calculated assuming nominal values of 2400 $/MW-km for 110 kV lines and 1400 $/MW-km for 220 kV lines. For the HTLS conductor C2, a nominal value of 2880 $/MW-km was assumed. The costs of 110/220 kV transformers were assumed to be 7,250 $/MVA and the costs of new busbars with 220 kV voltage were set to 1.5 M$. For series compensation, the capacitor unitary cost for compensating 110 kV lines was set to 10,000 $/MVA. We allowed building up to three new lines in each corridor.

The optimal expansion plans for each case are presented in Table 2. Here, the expansion options are indicated by the indexes of the interconnected buses, followed by the line within brackets. Each line is described by its parallel index (subscript) and the conductor type (superscript). Uprating projects are highlighted at the end, where "VU" denotes voltage uprating project, "RC" reconductoring, and "SC" series compensation. For the stochastic models, first-stage decisions are indicated by an asterisk ($*$) at the end of each project. At the end of the table we present the number of new lines built (#NL) and the additional ROW requirements of each expansion plan (+ROW). Table 3 summarizes the costs of each optimal expansion plan.

The deterministic cases (D-B and D-UR) show the optimal expansion plans assuming perfect information regarding future capacities of renewable energies. For scenario S1, if no uprating options are available, the optimal expansion plan consists of adding three lines the first year, two in corridor (2-6) and one in corridor (3-5), adding one line in corridor (5-7) in year 4, and adding one line in corridor (2-6) in year 5. The net present value (NPV) of the total system cost of this solution is 364 M$. In contrast, when line uprating options are considered, the optimal solution for scenario S1 requires adding only one new line in corridor (3-5) in the first year. The rest of the required transmission capacity is obtained by performing voltage uprating in corridor (2-6) and adding series compensation of line of corridor (1-4) in year 1, and by adding 50% series compensation in the line of corridor (5-7) in year 4. The NPV of the total system cost in this case is 338 M$, which is around 7% less compared to the optimal solution without uprating options. As for scenario S2, the optimal plan without line uprating consists of building 6 new lines (3 lines in year 1, and 1 line in years 2, 3 and 4). The NPV of the total system cost of this solution is 382.1 M$. In contrast, the optimal plan considering line uprating requires building only one new line in corridor (3-5) in year 1. The rest of the transmission capacity is obtained by performing two reconductoring projects in year 1: in the lines connecting corridors (2-3) and (2.6), and by performing voltage uprating in the line of corridor (5-7) in year 3. In this

TABLE 3. Net present value (NPV) of the total costs.

		IC	OC	TC	E{TC}
D-B	S1	51.5	312.5	364.0	373.1
	S2	78.7	303.3	382.1	
D-UR	S1	28.7	309.9	338.6	350.9
	S2	56.9	306.3	363.2	
S-B	S1	61.9	304.4	366.3	379.7
	S2	87.5	305.5	393.0	
S-UR	S1	42.4	304.1	346.5	354.8
	S2	58.7	304.4	363.1	

IC, OC and TC are the investment, operation, and total costs, respectively. E{} is the expected operator.

latter case, the NPV of the total system cost is 306.3 M$, thus allowing a cost reduction of 5%, compared to the case where no line uprating is considered. From these results it can be seen that considering line uprating options enables to reduce both the number of new lines to be build and the total system costs. In terms of additional ROW requirements, assuming typical ROW widths of 33 m and 42 m for 100 kV and 220 kV lines, respectively [18], the optimal expansion plans without uprating options require total ROWs of 910.8 and 1359.6 hectares for scenarios S1 and S2, respectively. On the other hand, the optimal expansion plans with line uprating require additional ROWs of 238.8 and 195.6 hectares for scenarios S1 and S2, respectively. This means that ROW requirements are reduced in factors of around 4 and 7 times in scenarios S1 and S2, respectively, compared to the optimal expansion plans without line uprating options. These results demonstrate that line uprating options may also allow a significant reduction in the environmental impact of optimal expansion alternatives, which makes construction permissions easier to obtain, thus reducing the risk of having delays and cost overruns.

The results of the stochastic formulation (cases S-B and S-UR) enable us to also extract the value of shorter build time of line uprating options, compared to building new lines. While the optimal plan without line uprating requires the network planner to commit to build 5 new lines in the first-stage (4 of them in years 1 and one in year 2), the optimal plan with line uprating requires the network planner to commit to first-stage investments in only 3 projects, all of them in the first year (among them, one reconductoring project). Notice that the two line uprating options deployed in year two for scenario S2 are second-stage decisions, since it was assumed that they could be built within 1 year. Considering line uprating enables us to reduce the NPV of the total expected system costs from 379.7 M$ to 354.8 M$, i.e. a reduction of 6.5%. In terms of first-stage decisions, while the NPV of first-stage investment commitments of the optimal expansion plan without line uprating is 54.7 M$, the NPV of fist-stage investment commitments is reduced to only 26.4 M$ when considering line uprating (around 48% reduction). This shows the significant benefits of considering line uprating options within TNEP under uncertainty; shorter construction lead times of line uprating options compared to building new lines allows the network planner to significantly reduce first-stage investment commitments and defer them to later years, where more information regarding future RES capacity is available. Finally, in terms of additional ROW requirements, the optimal plan without uprating options requires requesting a total of 858 hectares in ROWs within first-stage decisions (i.e., projects built independently from both scenarios) and additional 158.4 hectares of ROWs in case of realization of scenario S1 (in year 4) and 660 hectares 195.6 hectares of ROW in case of realization of scenarios S2 (also in year 4). In contrast, the optimal expansion plan considering line uprating requires requesting a total of 211.2 hectares of ROWs within first-stage decisions. If scenario S1 is materialized, the optimal plan requires a total of 303.6 hectares for building two lines connecting buses (4-6) in year 4, and if scenario S2 is materialized, the optimal plan requires additional 90 hectares of ROW for performing voltage uprating in corridor (5-7) in year 2. These results show that including line uprating options not only allows us to reduce the requirements of additional ROW to deploy the optimal expansion plan, but also to defer its commitment to later years.

B. MODIFIED IEEE 118-BUS TEST SYSTEM

The IEEE 118-bus system consists of 118 buses, 186 lines, 54 generators and 91 loads [36]. A single-line diagram of the system is presented in Fig. 5. To determine the transmission capacities of each line (existing and candidates) we first calculated the Surge Impedance Loading (SIL) using the reactance and susceptance values given in [36] and determined that the thermal rating of the lines are 3.5 times their corresponding SIL. Then, we calculated the transmission capacity of each line using its length and the Saint Claire curves according to [37]. These curves estimate the transmission capacity of lines considering operational constraints.

For the planning task, we assumed a yearly load growth of 4% and considered a time horizon of 10 years with yearly resolution. A 10% discount rate was assumed. We assumed two possible scenarios of large-scale incorporation of wind and solar energy, as summarized in Table 4 and presented in detail in [35]. As shown in Fig. 5, for the case studies we assume large potential of wind energy in region 2 (left part of the network depicted in Fig. 5) and large potential of solar energy in region 3 (on the bottom-right part in the network depicted in Fig. 5). To capture different operating conditions, in each year and scenario we used four representative days, one for each calendar season, with hourly resolution (96 h in total). Wind and solar profiles were extracted from [38]. To increase the transmission capacity we considered 50 projects for adding conventional lines and 31 projects for line uprating (including substations and transformers). Based on [39], we calculated the investment costs of new lines by using nominal values of 1800 $/MW-km and 1100 $/MW-km for 138 kV and 345 kV lines, respectively (which includes the costs of acquiring new ROWs). Additionally, we applied 1.5 and 1.2 penalty factors in the investment costs for lines shorter than 5 and 15 kilometers, respectively, according to [39]. As for the voltage uprating of existing lines (from

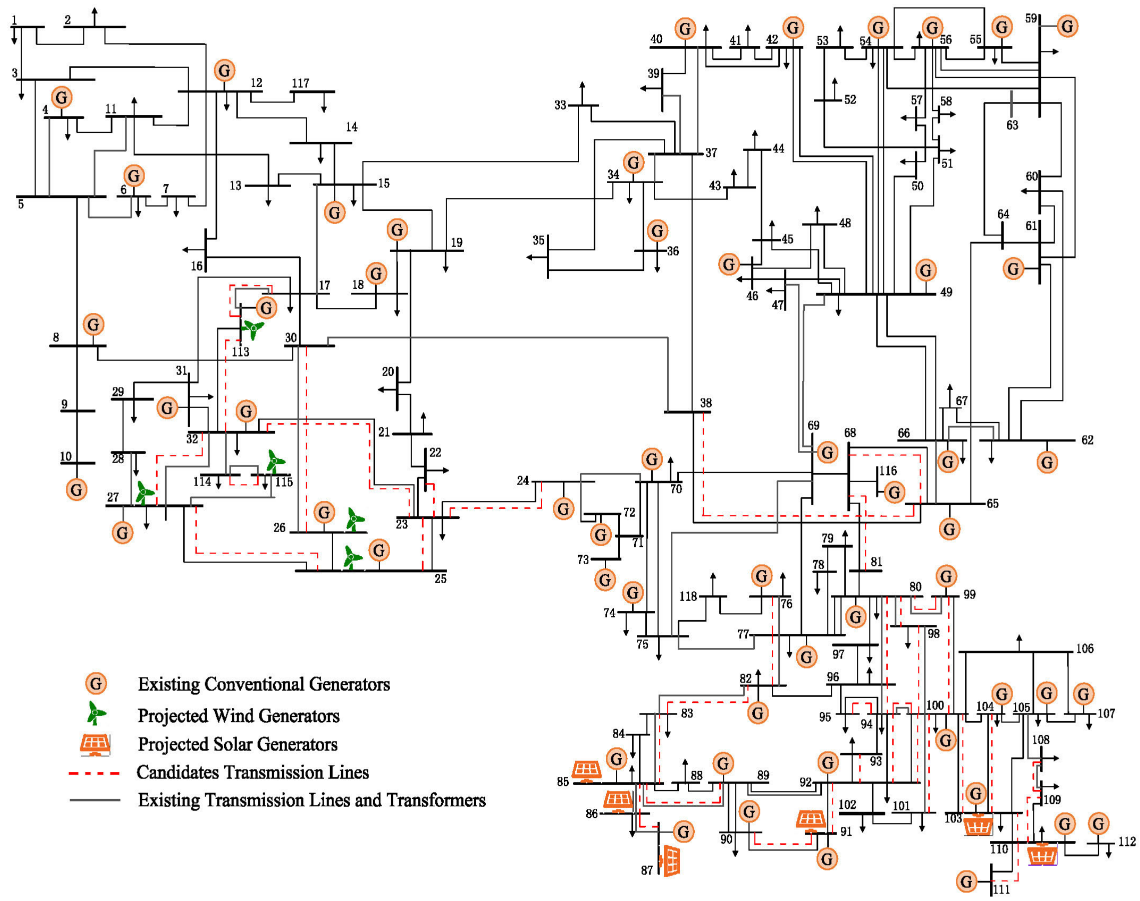

FIGURE 5. Diagram of the modified IEEE 118-bus test system used for the case studies. Load, conventional generators and existing lines and transformers were extracted from [33]. Future RES generation capacities as well as detailed candidate transmission lines and transformers can be found in [32]. Parallel circuits as expansion candidates are omitted for brevity purposes.

TABLE 4. Scenarios.

Scenario	Weight	Wind	Solar	RES share
S1 (high wind)	0.5	1875	450	47%
S2 (high solar)	0.5	750	1200	39%

Wind and solar capacities at year 10 are in MW

TABLE 5. Results for the modified IEEE 118-bus system.

		#NL	#UR	+ROW	IC	OC	TC	E{TC}
D-B	S1	6	-	4897	254.2	1306.4	1560.6	1582.4
	S2	10	-	8085	319.5	1284.6	1604.1	
D-UR	S1	2	2	3670	204.0	1276.6	1480.6	1470.0
	S2	2	4	1352	182.5	1276.8	1459.3	
S-B	S1	8	-	7493	377.1	1272.8	1649.9	1636.9
	S2	11 *3	-	8293	339.3	1284.5	1623.8	
S-UR	S1	2	6	2974	289.6	1260.7	1550.3	1506.0
	S2	2 *0	5 *1	1352	192.0	1269.6	1461.6	

#NL and #UR are the number of new lines and uprating projects, respectively. (*) indicates the number of first-stage decisions. "+ROW" indicates the additional ROW requirements (in hectares). Full details of the investment decisions from each case study can be found in [36].

138 kV to 345 kV), we assumed that a change of conductor as well as tower upgrading was needed. The construction costs comprise therefore the costs of the lines, transformers, and substations. The costs of 138/345 kV transformers were set at 10,350 \$/MVA and the cost of new 345 kV busbars at 1.5 M\$ [39]. The cost of series capacitors was set at 31,000 \$/MVA [39]. We considered a compensation of 50%. For line reconductoring, only the cost of the new conductor was considered (i.e. no additional infrastructure is needed).

A summary of the results is presented in Table 5. The first two columns of this table show the number of new lines (#NL) and the number of uprating projects (#UR) of the corresponding optimal expansion plan. For the stochastic optimization (cases S-B and S-UR) the number of first-stage decisions is indicated with an asterisk. The results show that, for the deterministic case without uprating options, a total of 6 new lines are built in S1 and 10 new lines in S2. The total expected system costs are 1582.4 M\$. Notice that both scenarios S1 and S2 were optimized independently. Including line uprating options enables us to reduce the number of new lines built to 2 in both scenarios. The additional transmission capacity can be obtained by deploying 2 uprating projects in scenario S1 and 4 uprating options in scenario S2. Total savings (in net present value) of 80 M\$ (5.1%) can be achieved in case of scenario S1 and 144.8 M$ (9.0%) in case of scenario S2. An interesting feature of these results is that different line uprating options can be successfully combined to meet the required capacity in a cost-effective way. For example, the uprating projects built in scenario S1 consist of adding series compensation in the line between buses 26-30 (in year 2) and performing reconductoring in the line between buses 17-113 (in year 9). In scenario S2, the uprating projects are one project for voltage uprating in the line between buses 86-87 (in year 1), one project for voltage uprating in the line between buses 85-86 (in year 5), and adding series compensation in lines between buses 98-100 and 83-85 (both in year 5).

Regarding the stochastic case studies, the benefits of including line uprating options are even more significant: the number of new lines to be built is reduced from 8 and 11 in scenarios S1 and S2, respectively, to only 2 in both scenarios. This is achieved by building a total of 6 uprating projects in scenario S1 and 5 in scenario S2. Total expected savings of 130.9 M$ can be achieved (8.0%). This case study also reveals that, due to shorter build times, line uprating options allow us to defer investment decisions until more information regarding new renewable generation is available. While without uprating options the network planner must commit to invest in three projects in the first stage (here-and-now), including line uprating options allows the network planner to only commit investments in one project in the first stage, which is to perform voltage uprating in the line between buses 86-87. Full details of the optimal expansion plan for each case study and scenario can be found in [35]. As it can be seen, including line uprating options not only enables us to reduce the investment and total system costs, but also to reduce the number of new lines built.

Regarding the environmental impact of the optimal expansion plans, the additional ROW (in hectares) required to develop each expansion plan presented in Table 5 also reveals significant benefits when considering line uprating options. While for scenarios S1 and S2 without uprating options additional ROW of 4897 ha and 8085 ha are required, the optimal expansion plans considering line uprating options only require additional ROW of 3670 ha and 1352 ha for scenarios S1 and S2, respectively. This means a reduction of the additional ROW in around 25% and 83% for scenarios S1 and S2, respectively. The stochastic case studies (cases S-B and S-UR) show similar results, where the required ROW can be reduced by 60% and 84% for scenarios S1 and S2, respectively, when considering line uprating options. The significant reduction in the ROW required for increasing the transmission capacity that can be achieved throughout the deployment of line uprating options can play a key role in the successful integration of renewable energies in power systems. Reducing the environmental impact of the expansion options reduces the risk of having delays in securing permissions, which are usually associated with cost overruns. In addition, delays in expanding the grid may cause congestions in the power system, which not only lead to a constrained access to merit plants but may reduce the utilization of renewable energies. In summary, considering line uprating options not only allows us to achieve more economic expansion plans and to defer first-stage investment decisions, but also to significantly reduce the environmental impact of the grid.

C. COMPUTATIONAL PERFORMANCE AND IMPACT OF THE VALUES OF THE DISJUNCTIVE PARAMETERS

The computing time required to reach convergence for each case study is presented in Table 6. From this table it can be seen that, for the deterministic cases (D-B and D-UR), including line uprating options increased the computing time in factors of 1.4 and 2.2 for scenarios S1 and S2, respectively. For the stochastic one, including line uprating options increased the computing time by a factor of around 7.7. In spite of the higher computing times, these additional requirements are reasonable and do not compromise the practicability of the proposal. Notice that the number of projects increased from 50 to 81when considering uprating options.

TABLE 6. **Computational performance.**

Model	Scenario	Time (s)
D-B	S1	359
	S2	152
D-UR	S1	498
	S2	343
S-B	S1+S2	911
S-UR	S1+S2	7057

Finally, in order to evaluate the performance of having a tight representation of the disjunctive parameters, we solved the TNEP problems considering line uprating options with different (higher) values of the disjunctive parameters for each model and scenario. Concretely, we multiplied the efficient disjunctive parameters by factors ranging from 1.5 up to 5. The results obtained are presented in Fig. 6. This figure shows that the time required for solving each TNEP model increases significantly if inefficient values of the disjunctive parameters are used. The worst case in terms

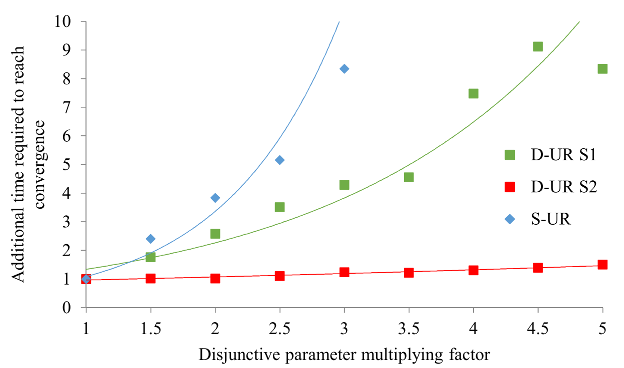

FIGURE 6. **Additional computational time required to reach convergence for different Big-M multiplying factors.**

of computational performance was obtained by the model S-UR. In this case, if the values of the disjunctive parameters were 4 times higher than the tight ones, the solver required 50 times to solve the optimization problem (95 hours instead of 1.9 hours).

VI. CONCLUSION

This paper presents a novel model for multi-year stochastic TNEP that allows the consideration of several line uprating options, such as line reconductoring, voltage uprating, and adding series compensation, along with adding new lines, simultaneously. To this end, the model includes a tight representation of the expansion alternatives, where the values of the disjunctive parameters (big-M) associated with each network element are minimized. As shown in the previous section, the proposed representation of the disjunctive parameters significantly improves the convergence of the proposed model, thus rendering valuable benefits in terms of practicability and scalability.

Numerical studies carried out in a system based on the IEEE 118-bus system for a 10-year planning task with two possible scenarios (S1 and S2) for large-scale RES integration demonstrated the benefits and practicability of our model. We showed that an optimal combination of line uprating options along with traditional expansion alternatives allowed us to lower total investment costs, defer first-stage investment commitments to later stages and reduce the new ROWs required to deploy the optimal expansion plans. Concretely, for the deterministic case, total savings of 80 M$ (5.1%) and 144.8 M$ (9.0%) were achieved for scenarios S1 and S2, respectively. For the stochastic one, total expected savings of 130.9 M$ (8.0%) was achieved. The stochastic case study also revealed that line uprating options allowed us to defer first-stage investment decisions from 3 to only 1, until more information regarding future generation capacity is available. Finally, from a socio-environmental viewpoint, including line uprating options allowed us to reduce the number of new lines to be built from 6 and 10 for scenarios S1 and S2, respectively, to only 2 in both scenarios. For the stochastic case, the number of new lines to be built could be reduced from 8 and 11 for scenarios S1 and S2, respectively, to also only 2 in both scenarios. In particular, being able to identify cost-efficient network reinforcements with less requirements for new ROW acquisition is of major importance nowadays and may prove to be vital for obtaining practical, timely and efficient solutions with less risk of suffering delays and cost overruns. Delays in expanding the grid may cause congestions in the power systems, which not only lead to a constrained access to merit plants, but may reduce the utilization of renewable energies (energy spillage). In summary, the benefits of considering line uprating options within the TNEP are many-fold: it allows us to achieve more economic expansion plans, to defer first-stage investment decisions, to significantly reduce the environmental impact of the grid, and to foster the integration of renewable energies.

Although line uprating options are used as short-term adjustment measures in real-world transmission networks, being able to incorporate them at the TNEP level allows us to integrate them with a systemic approach and with greater benefits for society (reduction of marginal costs, less congestion, lower transmission costs, reduced socio-environmental impact, among others). A detailed study of the economic effect of this proposal on current regulatory schemes for transmission planning is proposed as future research. In addition, future work will focus on the implementation of a multi-objective problem formulation to explicitly include the environmental impact of the expansion plan, as well as the implementation of other optimization techniques to improve computational performance.

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