

Co-Optimization of Multi-Stage Transmission Expansion Planning and Grid Operation

Marco Franken, Alexander B. Schrief, Hans Barrios, Ralf Puffer, Albert Moser
 Institute for High Voltage Equipment and Grids, Digitalization and Energy Economics (IAEW)
 RWTH Aachen University
 Aachen, Germany
 m.franken@iaew.rwth-aachen.de

Abstract—The ongoing transformation of the power system characterized by an increased share of renewable energy sources requires additional transmission capacities. Nevertheless, the need for new transmission capacities can be reduced by optimizing grid operation. This contribution presents a novel approach to the co-optimization of multi-stage transmission expansion planning and grid operation within a mixed-integer linear programming formulation. The expansion via AC systems and phase shifting transformers (PSTs) is combined with the control of PSTs and the determination of congestion management interventions such as redispatch of power plants or curtailment of renewable energies. The number of potential expansion candidates is reduced by linear programming relaxations. Exemplary results based on a synthetic test system containing 120 buses evidence the impact of the proposed approach on overall system costs. The proposed co-optimization reduces the total costs by 16.5 % when applied instead of the sole expansion via AC technology.

Index Terms—Congestion management, multi-stage expansion planning, phase shifting transformer, transmission expansion planning, transmission grid operation.

NOMENCLATURE

Sets

K	Set of buses k
L_0, L_c	Set of existing lines l_0 / expansion line candidates l_c
L	Set of all lines l ($L = L_0 \cup L_c$)
$L_{0,k}, L_{c,k}$	Set of existing lines l_0 / expansion line candidates l_c connecting bus k with other buses
I, J	Set of conventional power plants i / renewable generation units j
G	Set of generation units g ($G = I \cup J$)
G_k, I_k	Set of generation units g / conventional power plants i connected to bus k
S	Set of stages s within the planning horizon with $ S $ as the number of analyzed stages
U_s	Set of grid snapshots analyzed at stage s

Functions

IC_s, OC_s	Investment cost / total operational cost at stage s
OC_s^I	Operational cost for installed assets at stage s
OC_s^{Slack}	Slack cost at stage s
OC_s^{CM}	Congestion management cost at stage s

Parameters

M	Sufficiently large constant
a	Annual discount factor
b_s	Present value factor for operational cost taken into account at stage s
T_s	Operation year of stage s
c_r	Cost for load shedding and generation curtailment
$c_{l_c}^{AC}$	Cost for new line l_c
c_l^{PST}	Cost for new PST connected in series to line l
c^{OP}	Yearly operational cost factor per asset
c_i^{PP}	Marginal cost of power plant i
c^{RES}	Cost for feed-in management of renewable energies
$w_{CM,s}, w_{CM,u}$	Stage-specific weighting factor / grid snapshot-specific weighting factor of congestion management costs
$\bar{f}_{l_0}^{AC}, \bar{f}_{l_c}^{AC}$	Limit of active power flow on line l_0 / on line l_c
$\gamma_{l_0}^{AC}, \gamma_{l_c}^{AC}$	Susceptance of line l_0 / of line l_c
θ_{max}^{PST}	Maximum angle of PSTs
g_g^{max}, g_g^{min}	Maximum / minimum active power output of generation unit g

Variables

$y_{l_c,s}^{AC}$	Binary variable representing construction of line l_c at stage s
$y_{l,s}^{PST}, y_{l_c,s}^{PST}$	Binary variable representing construction of PST connected in series to line l / line l_c at stage s
$\theta_{k,s,u}, \theta_{l_f/t,s,u}$	Voltage phase angle at bus k / from/to bus of line l at stage s in grid snapshot u (at the time s/u)

$g_{k,s,u}, g_{g,s,u}$	Active power generation at bus k / of generation unit g at the time s/u
$d_{k,s,u}$	Active power demand at bus k at the time s/u
$r_{k,s,u}^g, r_{k,s,u}^d$	Generation curtailment / load shedding at bus k at the time s/u
$f_{l,s,u}^{AC}, f_{l_c,s,u}^{AC}$	Active power flow on line l / on line l_c at the time s/u
$\theta_{l,s,u}^{PST}, \theta_{l_c,s,u}^{PST}$	Angle of PST connected in series to line l / line l_c at the time s/u
$\Delta p_{g,s,u}^+, \Delta p_{g,s,u}^-$	Positive redispatch (generation increase) / negative redispatch (generation decrease) of generation unit g at the time s/u
C_s^{CM}	Congestion management cost at stage s in the case of resolving all bottlenecks only with congestion management measures

I. INTRODUCTION

The decarbonization of the European energy system characterized by an increased integration of renewable generation results in augmented volatile power flows as well as transport of electrical energy over long distances. Therefore, maintaining system security requires additional transmission capacities and further operational flexibility for overcoming contingency situations. Both requirements can be met by considering power flow controlling devices such as phase shifting transformers (PSTs) besides conventional AC expansion measures in the expansion portfolio. Power flow controlling devices are particularly suitable for utilizing existing transmission capacities more efficiently and hence overcoming the lack of social and public acceptance assigned to new transmission lines. Furthermore, such components can be integrated into a grid fast enough to reduce operational congestion management costs. The duration of planning and approval processes gains in importance in the context of determining the intertemporal transformation path of grid structures in the case of analyzing multiple planning stages. While a secure and reliable grid operation has to be ensured at each stage, expansion measures characterized by long planning and approval processes will be available only at a later stage. Therefore, identifying cost-optimal structures requires an overall investigation of both short- and long-term measures. Otherwise, intertemporal and technological interdependencies are modeled inadequately, leading to suboptimal solutions.

Determining expansion paths requires the analysis of multi-stage transmission expansion planning (TEP) formulations, which have been addressed in several studies [1], [2]. First approaches focus on a pseudo-dynamic formulation aiming at a sequential solving of single-stage expansion problems [1]. However, intertemporal interdependencies are not modeled adequately. Further methods that simultaneously investigate all planning horizons and thus capture intertemporal interdependencies generally consider only the network expansion enabled by AC technologies [3], [4]. Few approaches focus on power flow controlling devices in a multi-stage expansion framework, neglecting further AC systems within the expansion portfolio: while [5] investigates PSTs, [6] and [7] deal with series compensators. However, multi-stage network

expansion analyzing both short-term measures such as PSTs and long-term measures such as AC systems has not been analyzed yet. Furthermore, identifying cost-optimal expansion plans requires the optimization of grid operation including controlling PSTs and congestion management interventions. Optimizing the grid operation enables avoiding potentially cost-intensive expansion measures and overcoming congestions that arise only at single stages (e.g. years) or even single grid snapshots. Co-optimizing expansion planning and grid operation has primarily been investigated for single-stage approaches [8], [9].

This paper presents a novel multi-stage expansion approach considering AC systems and PSTs as well as operational congestion management interventions. The TEP problem is formulated as a mixed integer linear programming (MILP) problem using DC power flow equations. The required expansion measures at each stage are simultaneously determined by capturing the interdependencies between multiple stages, technologies and congestion management interventions. To keep the optimization problem still tractable regarding its applicability to large-scale grid structures, we propose a heuristic framework for reducing the set of expansion candidates.

II. METHODOLOGY

The methodology is divided into four parts: the formulation of the multi-stage approach containing only AC expansion measures, the modeling of PSTs, the integration of congestion management interventions into the TEP model and a method for selecting suitable expansion candidates to reduce the computational effort. The multi-stage approach including only AC expansion measures is referred to as the base case formulation and combines the multi-stage approach presented in [10] with the detailed modeling of expansion costs described in [11]. All proposed model extensions are presented with respect to the base case formulation.

A. Multi-stage transmission expansion model (base case)

The multi-stage TEP model determining the required expansion measures is formulated as a MILP problem using DC power flow equations. AC system modeling differentiates between reinforcement and expansion measures. Expansion measures require the construction of both new poles and circuit conductors, whereas reinforcement measures require only the installation of new circuit conductors using existing poles. The installation of transformers in parallel to existing ones completes the expansion portfolio. In the following, the multi-stage TEP problem is described for a set of stages S and a set of grid snapshots U_s per stage s , compare (1)-(15).

The objective function shown in (1)-(6) aims to minimize overall investment costs (capital expenditures) and operational costs (operational expenditures). Operational costs contain costs for load shedding and generation curtailment as well as yearly operational costs for installed assets, compare (3)-(5). Load shedding and generation curtailment are integrated into the formulation as node-specific slack variables for ensuring its solvability and should not be part of the final solution. For this purpose, operational costs for the period between two stages are

assumed to be constant. Due to the different stages within the planning horizon, investment and operational costs have to be discounted to their present value. Fig. 1 visualizes the discounting process for corresponding costs. Investment costs are directly discounted to their present value. Operational costs until the next stage are summed up and discounted to their present value in a further step, compare (6). To address the long depreciation period of expansion measures comprising several decades as well as their technical lifetime, which frequently exceeds the economic lifetime [12], the operational costs of the last stage are calculated as perpetual annuity.

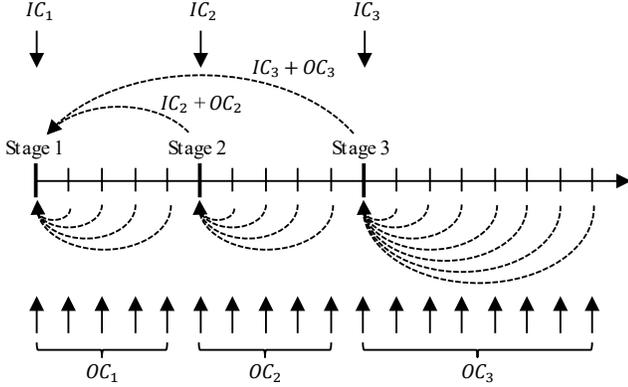


Figure 1. Discounting process of investment and operational costs.

$$\min v = \sum_{s \in S} \frac{IC_s + OC_s}{(1+a)^{(T_s - T_1)}} \quad (1)$$

$$IC_s = \begin{cases} \sum_{l_c \in L_c} c_{l_c}^{AC} y_{l_c, s}^{AC}, & \text{if } s = 1 \\ \sum_{l_c \in L_c} c_{l_c}^{AC} (y_{l_c, s}^{AC} - y_{l_c, s-1}^{AC}), & \text{if } s > 1 \end{cases} \quad (2)$$

$$OC_s = b_s (OC_s^I + OC_s^{Slack}) \quad (3)$$

$$OC_s^I = c^{OP} \sum_{l_c \in L_c} c_{l_c}^{AC} y_{l_c, s}^{AC} \quad (4)$$

$$OC_s^{Slack} = c_r \sum_{u \in U_s} \sum_{k \in K} (r_{k, s, u}^d + r_{k, s, u}^g) \quad (5)$$

$$b_s = \begin{cases} 1 + \frac{(1+a)^{(T_{s+1} - T_s - 1)} - 1}{a(1+a)^{(T_{s+1} - T_s - 1)}}, & \text{if } s \neq |S| \\ 1 + \frac{1}{a}, & \text{if } s = |S| \end{cases} \quad (6)$$

The constraints of the multi-stage TEP problem are presented in (7)-(15).

$$\sum_{l_c \in L_{c,k}} f_{l_c, s, u}^{AC} + \sum_{l_0 \in L_{0,k}} f_{l_0, s, u}^{AC} + g_{k, s, u} - r_{k, s, u}^g = d_{k, s, u} - r_{k, s, u}^d, \quad \forall k \in K, \forall s \in S, \forall u \in U_s \quad (7)$$

$$f_{l_0, s, u}^{AC} - \gamma_{l_0}^{AC} (\theta_{l_0, f, s, u} - \theta_{l_0, t, s, u}) = 0, \quad \forall l_0 \in L_0, \forall s \in S, \forall u \in U_s \quad (8)$$

$$\left| f_{l_c, s, u}^{AC} - \gamma_{l_c}^{AC} (\theta_{l_c, f, s, u} - \theta_{l_c, t, s, u}) \right| \leq M(1 - y_{l_c, s}^{AC}), \quad \forall l_c \in L_c, \forall s \in S, \forall u \in U_s \quad (9)$$

$$\left| f_{l_0, s, u}^{AC} \right| \leq \bar{f}_{l_0}^{AC}, \quad \forall l_0 \in L_0, \forall s \in S, \forall u \in U_s \quad (10)$$

$$\left| f_{l_c, s, u}^{AC} \right| \leq \bar{f}_{l_c}^{AC} y_{l_c, s}^{AC}, \quad \forall l_c \in L_c, \forall s \in S, \forall u \in U_s \quad (11)$$

$$y_{l_c, s-1}^{AC} - y_{l_c, s}^{AC} \leq 0, \quad \forall l_c \in L_c, \forall s \in S, s > 1 \quad (12)$$

$$0 \leq r_{k, s, u}^g \leq g_{k, s, u}, \quad \forall k \in K, \forall s \in S, \forall u \in U_s \quad (13)$$

$$0 \leq r_{k, s, u}^d \leq d_{k, s, u}, \quad \forall k \in K, \forall s \in S, \forall u \in U_s \quad (14)$$

$$y_{l_c, s}^{AC} \in \{0, 1\}, \quad \forall l_c \in L_c, \forall s \in S \quad (15)$$

Kirchhoff's current law is represented by (7) and Kirchhoff's voltage law for existing and new circuits is described by (8) and (9). Equations (10) and (11) limit power flows on existing as well as on new circuits to their thermal line rating. The expansion decisions between two planning stages are coupled by (12). An asset constructed at one stage has to be constructed at each following stage and cannot be deconstructed. Generation curtailment and load shedding are defined for each grid snapshot at each stage by (13) and (14), respectively. The voltage angle at the reference bus is set to zero. The differentiation between reinforcement and expansion measures is enabled by separating expansion costs into costs for poles and circuits, compare [11].

B. Modeling phase shifting transformers

PSTs enable the alleviation of congestions by controlling power flows and hence utilizing existing transmission capacities more efficiently. Generally, the electrical characteristics of PSTs can be described by a reactance and a phase shift connected in series to a transmission line. Within the proposed approach, the operational flexibility of PSTs is modeled as a variable phase angle, neglecting the effect of the additional reactance as it is done in several works [5], [13]. The operating point of PSTs is endogenously determined within the optimization problem. The extended calculation for investment and operational costs is presented in (16) and (17), respectively.

$$IC_s = \begin{cases} \sum_{l_c \in L_c} c_{l_c}^{AC} y_{l_c, s}^{AC} + \sum_{l \in L} c_l^{PST} y_{l, s}^{PST}, & \text{if } s = 1 \\ \sum_{l_c \in L_c} c_{l_c}^{AC} (y_{l_c, s}^{AC} - y_{l_c, s-1}^{AC}) + \sum_{l \in L} c_l^{PST} (y_{l, s}^{PST} - y_{l, s-1}^{PST}), & \text{if } s > 1 \end{cases} \quad (16)$$

$$OC_s^I = c^{OP} (\sum_{l_c \in L_c} c_{l_c}^{AC} y_{l_c, s}^{AC} + \sum_{l \in L} c_l^{PST} y_{l, s}^{PST}) \quad (17)$$

Equations (18)-(23) show the restrictions added to the base case approach by the integration of PSTs into the TEP formulation.

$$f_{l_0, s, u}^{AC} - \gamma_{l_0}^{AC} (\theta_{l_0, f, s, u} - \theta_{l_0, t, s, u} + \theta_{l_0, s, u}^{PST}) = 0, \quad \forall l_0 \in L_0, \forall s \in S, \forall u \in U_s \quad (18)$$

$$\left| f_{l_c, s, u}^{AC} - \gamma_{l_c}^{AC} (\theta_{l_c, f, s, u} - \theta_{l_c, t, s, u} + \theta_{l_c, s, u}^{PST}) \right| \leq M(1 - y_{l_c, s}^{AC}), \quad \forall l_c \in L_c, \forall s \in S, \forall u \in U_s \quad (19)$$

$$\left| \theta_{l, s, u}^{PST} \right| - \theta_{max}^{PST} y_{l, s}^{PST} \leq 0, \quad \forall l \in L, \forall s \in S, \forall u \in U_s \quad (20)$$

$$y_{l_c, s}^{PST} - y_{l_c, s}^{AC} \leq 0, \quad \forall l_c \in L_c, \forall s \in S \quad (21)$$

$$y_{l, s-1}^{PST} - y_{l, s}^{PST} \leq 0, \quad \forall l \in L, \forall s \in S, s > 1 \quad (22)$$

$$y_{l, s}^{PST} \in \{0, 1\}, \quad \forall l \in L, \forall s \in S \quad (23)$$

Equation (18) and (19) show Kirchhoff's voltage law extended by the PST phase angle representing the corresponding operational flexibility. The operating range of PSTs is limited by (20) to the maximum phase angle. PSTs in series to new circuits can be placed only in the case of installing the corresponding

new circuit. This order is maintained by (21). Equation (22) ensures similarly to (12) that assets placed at one stage have to be constructed within the following stages. Here, it is assumed that PSTs are installed for all parallel lines. Furthermore, all parallel PSTs operate with the same phase shift.

C. Modeling congestion management interventions

Widely used congestion management approaches are formulated as mixed-integer unit commitment problems including network constraints as well as system balance equations [14]. All contingencies are alleviated while minimizing overall operational costs for redispatching conventional power plants and curtailing renewable energy sources (RES). Due to long planning horizons within TEP, the level of detail is reduced within the proposed approach. Therefore, all generation constraints requiring binary variables are neglected.

The calculation of operational costs for grid operation described by (3)-(5) is extended by costs for network-related redispatch interventions and curtailment of renewable energies. Negative redispatch of conventional power plants (reduction of generation) results in financial returns determined by reduced feed-in and marginal costs. All other redispatch interventions result in additional operational costs determined by marginal costs or technology-specific cost coefficients for curtailment of renewable energies. The analysis of both the costs of network expansion measures depreciated over several decades and the congestion management costs of single grid snapshots requires weighting the congestion management costs within the objective function. It has to be taken into account that only representative grid snapshots are investigated. Therefore, a grid snapshot specific factor $w_{CM,u}$ is introduced that weights the operational costs of the analyzed grid snapshots for capturing the operational costs of the whole year. It also has to be taken into account that expansion measures amortize over a long period of several decades, whereas congestion management costs describe operational costs for only one single year. Furthermore, the investigated stages often do not represent a continuous period (representing, for example, a single year every five or ten years). This requires an adequate estimation of congestion management costs in between the stages and after the last stage. Therefore, the development in between two stages is modeled by a linear interpolation of the congestion management costs. For this purpose, operational costs required for resolving all bottlenecks without installing any expansion measures are calculated for the stage itself (C_s^{CM}) and the stage that follows (C_{s+1}^{CM}). The resulting cost difference between the stages is used to linearly interpolate the congestion management costs for the years between the stages, compare (24). The total costs taken into account at a stage for the stage itself and the period until the next stage are calculated as a present value factor as shown in (24). Similarly to the consideration of operational costs of installed assets, compare (6), the development of congestion management costs after the last stage ($s = |S|$) is assumed to be constant. Therefore, the corresponding development is modeled via perpetual annuity. The present value is integrated into the TEP formulation by multiplying the factor $w_{CM,s}$ with unit-specific costs and volumes of congestion management interventions as

presented in (25). The operational costs of the proposed model are determined by (26), including costs for congestion management interventions, used slack and operational costs for installed assets.

$$w_{CM,s} = \begin{cases} \sum_{t=0}^{T_{s+1}-T_s-1} \frac{1}{(1+\alpha)^t} \left(1 + \frac{C_{s+1}^{CM} - C_s^{CM}}{C_s^{CM}} \frac{t}{T_{s+1}-T_s} \right), & \text{if } s \neq |S| \\ 1 + \frac{1}{\alpha}, & \text{if } s = |S| \end{cases} \quad (24)$$

$$OC_s^{CM} = \sum_{u \in U_s} w_{CM,u} \left(\sum_{i \in I} c_i^{PP} (\Delta p_{i,s,u}^+ - \Delta p_{i,s,u}^-) + \sum_{j \in J} c_j^{RES} \Delta p_{j,s,u}^- \right) \quad (25)$$

$$OC_s = b_s (OC_s^I + OC_s^{Slack}) + w_{CM,s} OC_s^{CM} \quad (26)$$

Constraints affected by integrating congestion management interventions into the proposed TEP approach are shown in (27)-(30). Redispatch interventions per power plant are modeled using two decision variables, one for increasing and the other for reducing feed-in. Modeling curtailment of renewable energies requires only one decision variable. Within the node balance equation (7), the bus-specific generation curtailment is substituted by detailed congestion management interventions affecting power injection and ejection per generation unit, compare (27). Equations (28) and (29) define available redispatch potentials of power plants limited by schedules calculated by market simulation ($g_{g,s,u}$) and maximum as well as minimum power output. The potential for curtailment of renewable energies results from available feed-in, compare (30).

$$\sum_{l_c \in L_{c,k}} f_{l_c,s,u}^{AC} + \sum_{l_0 \in L_{0,k}} f_{l_0,s,u}^{AC} + g_{k,s,u} + \sum_{i \in I_k} \Delta p_{i,s,u}^+ = d_{k,s,u} - r_{k,s,u}^d + \sum_{g \in G_k} \Delta p_{g,s,u}^- \quad (27)$$

$$\forall k \in K, \forall s \in S, \forall u \in U_s$$

$$0 \leq \Delta p_{i,s,u}^+ \leq g_i^{max} - g_{i,s,u}, \forall i \in I, \forall s \in S, \forall u \in U_s \quad (28)$$

$$0 \leq \Delta p_{i,s,u}^- \leq g_{i,s,u} - g_i^{min}, \forall i \in I, \forall s \in S, \forall u \in U_s \quad (29)$$

$$0 \leq \Delta p_{j,s,u}^- \leq g_{j,s,u}, \quad \forall j \in J, \forall s \in S, \forall u \in U_s \quad (30)$$

D. Selection of expansion candidates

One of the main drivers of the size and the complexity of TEP problems is the number of expansion candidates. Particularly with regard to the application of TEP approaches to large-scale grid structures, the number of expansion candidates and hence the computational effort increases significantly. To keep the optimization problem still tractable, analyzing only a reduced set of expansion candidates is a suitable strategy and already proofed [15]-[18].

In the following, a new method is proposed for selecting suitable expansion candidates by a linear programming (LP) relaxation that is integrated into a heuristic framework. The LP relaxation is based on the approaches described in [15] and [16] for reducing the candidate pool of AC systems in terms of the single-stage TEP problem. Within LP relaxations, the binary expansion decision variables are modelled as continuous ones. The heuristic framework is shown in Fig. 2.

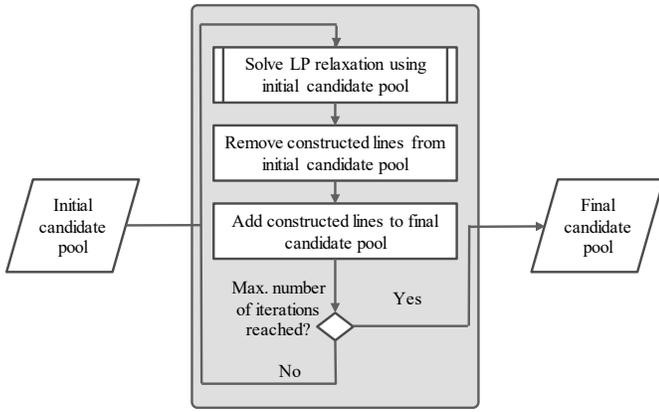


Figure 2. Heuristic framework for solving TEP problem using selection of expansion candidates.

The process starts with generating an initial candidate pool. Therefore, all point-to-point connections between two buses of the same voltage level are considered. To investigate only feasible candidates within the TEP optimization, the initial candidate pool is directly reduced by all candidates exceeding a maximum circuit length. In the next step, the initial candidate pool is reduced by solving the LP relaxation of the expansion problem described in Section II.A multiple times. The LP relaxation is obtained by neglecting (9) and assuming the decision variables indicating the construction status of expansion candidates to be continuous. Consequently, the LP relaxation allows a fractional construction of lines. Furthermore, the power flows on the expansion candidates do not depend on Ohm’s law and are determined freely by the solver. Those candidates that are constructed fractionally or completely by solving the LP relaxation are identified as suitable candidates and are added to a final candidate pool. Simultaneously, these candidates are removed from the initial candidate pool for the next LP solution. The LP relaxation is solved multiple times for increasing the quality of the final expansion candidate pool and consequently the quality of the final expansion plan. In each iteration, only the reduced initial candidate pool is considered. Thus, in each iteration, those candidates being constructed in any iteration before are excluded from the expansion portfolio. The number of iterations represents an input parameter of the heuristic framework. Nevertheless, each additional iteration increases the final candidate pool and hence the computational effort for solving the MILP problem. Identified expansion candidates are also used as potential locations for the serial placement of PSTs.

III. EXEMPLARY RESULTS

The suitability of the proposed TEP approach is shown by the application to a synthetic network model containing 120 buses. At first, the scenario framework and the technology portfolio are presented. Afterwards, exemplary results and

sensitivity analyses concerning expansion portfolio, operational flexibilities and the coupling between different planning stages are shown.

A. Scenario definition

This paper uses the scenario framework provided by a synthetic network model developed at the RWTH Aachen University [19]. The network model contains 120 buses on the 220 kV and 380 kV voltage level and includes load and generation patterns defined in hourly resolution for multiple scenarios. The scenarios differentiate with respect to the share of each generation technology. Consequently, each scenario provides scenario-specific power flows and thus overloads requiring a multitude of different expansion measures for each of them. The proposed approach is exemplarily applied to three scenarios used as coupled stages within the planning horizon. The period between two stages is assumed to five years. To limit the computational effort, three grid snapshots are investigated per stage which are chosen to capture the key bottlenecks within the network and are selected on the basis of congestions at the second stage. The grid snapshots are determined by clustering the grid snapshots of the whole year into three groups. The clustering approach follows the idea proposed in [20] and uses the location and dimension of bottlenecks per grid snapshot as cluster criterion. In a next step, a representative grid snapshot per cluster is calculated. The maximum line utilization across the analyzed grid snapshots per stage is shown in Fig. 3. As the figure shows, the overloads increase significantly between the different stages.

The system security is modeled by the 70 % criterion as a simplified method for estimating overloads in terms of N-1 contingencies [21]. The 70 % criterion classifies all lines and transformers with a loading higher than 70 % in the pre-contingency situation as overloaded. The overload energy per grid snapshot is calculated as the sum of overloads of all lines and transformers on the basis of the 70 % criterion. The overload energy of each representative grid snapshot as well as the grid snapshot-specific weighting factors $w_{CM,u}$ are shown in Table I. The grid snapshot-specific weighting factors are chosen to represent the overload energy of the whole scenario. This means that multiplying the overload energy per analyzed representative grid snapshot with the grid snapshot-specific weighting factor results in the same overload energy as the summation of the overload energy of all grid snapshots of the scenario.

TABLE I. CHARACTERISTICS OF GRID SNAPSHOTS

Grid snapshot	Overload energy [GWh]			$w_{CM,u}$
	Stage 1	Stage 2	Stage 3	
I	0.06	1.13	1.97	555
II	0.05	2.14	3.54	261
III	0.00	0.68	1.51	34

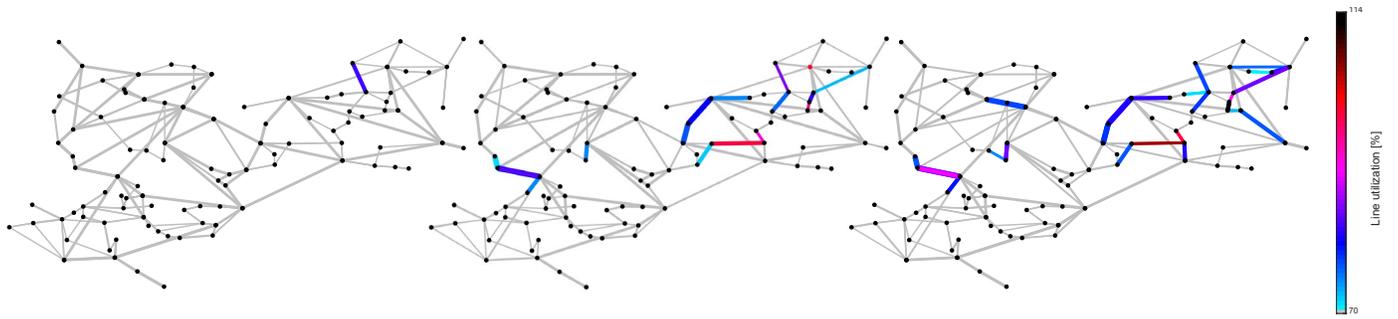


Figure 3. Maximum line utilization across analyzed grid snapshots at the first (left), second (center) and third stage (right).

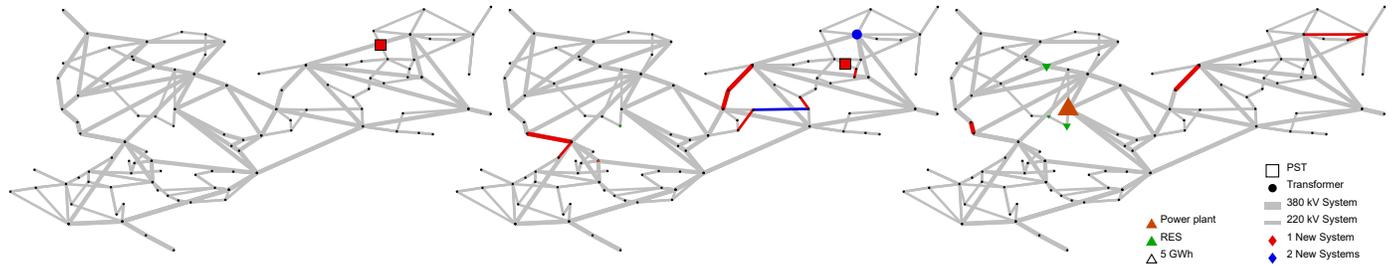


Figure 4. Network expansion measures and congestion management interventions at the first (left), second (center) and third stage (right). Shown congestion management interventions do not include volumes for interventions during the periods between stages.

The analyzed expansion options specified by voltage level and investment costs are shown in Table II. Expansion costs are chosen on the basis of [22] and [23]. Depending on the number of already installed circuits within one transmission corridor the construction of new AC circuits requires the construction of new poles. This means that developing a new transmission corridor causes higher expansion costs than adding a new circuit in an existing one. In general, it is differentiated between poles designed for two or four circuits. A detailed description of costs for poles and circuits is presented in [11]. Furthermore, constructing new AC circuits or transformers as well as placing new PSTs requires the installation of additional switching bays.

TABLE II. TECHNICAL OPTIONS FOR NETWORK EXPANSION

Expansion measure	Voltage level	Inv. costs
AC circuit conductor	220 kV	0.15 M€/km
AC circuit conductor	380 kV	0.20 M€/km
Poles for two AC circuits	220 kV, 380 kV	1.10 M€/km
Poles for four AC circuits	220 kV, 380 kV	1.40 M€/km
Transformer	220/380 kV	8.5 M€
PST	220 kV, 380 kV	0.03 M€/MW
Switching bay	220 kV, 380 kV	4 M€

The rating of a PST is assumed to be equal to the transmission capacity of the serially connected transmission circuit. The angle of PSTs representing the operational flexibility is limited to $\pm 30^\circ$ [24]. The cost term for operational costs of installed assets is set to 0.8 % of the investment costs [25] and the discount rate is set to 4 % per year [12]. The technology-specific cost coefficient for curtailment of renewable energies used within the objective function is

assumed to five times the average marginal costs of conventional power plants. To keep the TEP optimization problem still tractable, two LP relaxation-iterations are solved within the heuristic framework described in Section II.D. For calculating the initial candidate pool, a maximum circuit length of 100 km is taken into account while the maximum distance between two stations amounts to 600 km. It is assumed that further voltage levels cannot be added to a station. To reduce the computational complexity, the installation of PSTs is limited to the placement in series to existing circuits.

B. Results assessment

The initial candidate pool contains 823 AC candidates of 4136 potential point-to-point connections and 271 PSTs resulting from the number of lines within the initial topology (166 PST locations in the case of neglecting the number of parallel PSTs). The initial candidate pool is reduced by the proposed selection approach to 54 AC systems and 49 PSTs (31 PST locations in the case of neglecting the number of parallel PSTs) defining the final candidate pool. It is assumed that per AC expansion candidate up to two parallel circuits can be constructed. Fig. 4 shows the network expansion measures determined for each stage within the planning horizon. Furthermore, congestion management interventions identified at the corresponding stage are shown. Triangles directed downwards indicate a net power curtailment and triangles directed upwards represent a net increase of generation.

The network structure is reinforced by 13 AC systems on a circuit length of 599.1 km and two transformers as well as two PSTs are placed within the planning horizon. As new circuits in parallel to existing circuits cause lower expansion costs than new circuits within new transmission corridors, only existing transmission corridors are reinforced. At the last two stages

congestion management interventions are used besides expanding the grid structure for resolving overloads. The present value of all investment costs and operational costs concerning installed assets amount to 313.6 M€. The present value of the operational costs concerning congestion management costs amount to 20.1 M€. The overloads in the western region of the grid structure are resolved by new AC circuits. The overloads located in the central part of the grid structure are alleviated by congestion management measures. New AC circuits and transformers as well as PSTs resolve the bottlenecks in the eastern regions.

For quantifying the benefit provided by the proposed co-optimization formulation (data set P in Fig. 5), the results presented in Fig. 4 are compared to the optimal expansion plan determined by the base case formulation (only AC expansion, data set B in Fig. 5). Furthermore, the benefit of PSTs and congestion management interventions is investigated via sensitivity analyses. Therefore, the expansion of AC systems in combination with congestion management interventions (data set E1 in Fig. 5) as well as the combined expansion of AC systems and PSTs (data set E2 in Fig. 5) are analyzed.

The proposed co-optimization formulation reduces the present value of overall costs by 16.5 % compared to those costs generated by the base case formulation. The combination of AC systems with the sole investigation of congestion management interventions or placement of PSTs enables a reduction of overall costs by 8.3 % and 10.5 % compared to the costs determined by the base case formulation.

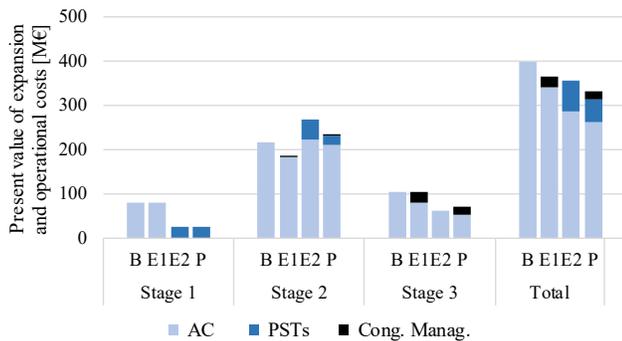


Figure 5. Present value of expansion and operational costs depending on available expansion portfolio and operational flexibilities.

C. Sensitivity analysis concerning the multi-stage character of the TEP formulation

To evidence the benefit of the proposed multi-stage TEP approach investigating all stages simultaneously, the results shown in Section III.B are compared to the results of a pseudo-dynamic one. The pseudo-dynamic approach contains a sequential static planning for all stages analyzing separately the expansion requirements for each stage. The topology identified for one stage forms the starting topology for the following stage. Table III presents the results for the base case model explained in Section II.A using the pseudo-dynamic and the multi-stage simulation as well as the results for the proposed model using both simulation approaches.

As shown in Table III, the solution of the multi-stage formulation results in a reduction of the present value of overall costs of 5.1 % compared to the costs generated by the pseudo-dynamic approach. Within the multi-stage approach, the costs at the first and second stage are larger than the costs within the pseudo-dynamic formulation. At the third stage, the multi-stage approach results in significantly lower costs. Fig. 6 visualizes the cost optimal measures identified by the pseudo-dynamic approach. Compared to the results presented in Fig. 4, the expansion measures differ, in particular, in the north-east region of the network. Due to the foresight across all stages, the expansion requirements of the third stage can be anticipated at the first two stages. Furthermore, the integration of intertemporal interdependencies into a multi-stage formulation shows a greater benefit in the case of co-optimizing expansion planning and grid operation than in the case of the sole optimization of the expansion planning.

TABLE III. PRESENT VALUE OF OVERALL SYSTEM COSTS FOR MULTI-STAGE AND PSEUDO-DYNAMIC FORMULATION

Simulation	Present value of overall system costs [M€] (comparison of multi-stage formulation to pseudo-dynamic one)			
	Stage 1	Stage 2	Stage 3	Total
Pseudo-dynamic, base case	19.0	277.8	116.0	412.8
Multi-stage, base case	79.5	215.8	104.4	399.7 (-3.2 %)
Pseudo-dynamic, proposed method	19.0	215.3	117.2	351.5
Multi-stage, proposed method	27.3	233.8	72.6	333.7 (-5.1 %)

IV. CONCLUSION AND OUTLOOK

This paper presents a novel multi-stage approach for the co-optimization of transmission expansion planning and grid operation. The co-optimization is formulated as a MILP problem using DC power flow equations. The investigated expansion portfolio contains AC systems and PSTs. Within the grid operation, operating points of the installed PSTs are optimized and congestion management interventions such as redispatch of conventional power plants or curtailment of renewable energies are calculated. The grid operation is endogenously determined within the optimization problem. To keep the TEP formulation still tractable, a heuristic framework based on LP relaxations for choosing suitable expansion candidates is applied. Exemplary results show the significant potential of the co-optimization of expansion planning and grid operation for reducing total expansion and operational costs. Within the test system, the present value of overall costs is reduced to 83.5 % compared to the present value of those costs generated by the base case formulation (no PST, no congestion management interventions). Using a multi-stage formulation as presented in this paper enables the identification of an expansion plan characterized by the present value of total costs being 5.1 % lower than the present value determined by a pseudo-dynamic one.

Future work will focus on the availability of expansion measures at different planning stages, as the availability of expansion projects is often characterized by different planning and approval processes. Furthermore, the integration of

additional security constraints will be analyzed to accommodate security constraints for the N-1 contingency analysis instead of a simplified modeling based on the 70 % criterion.

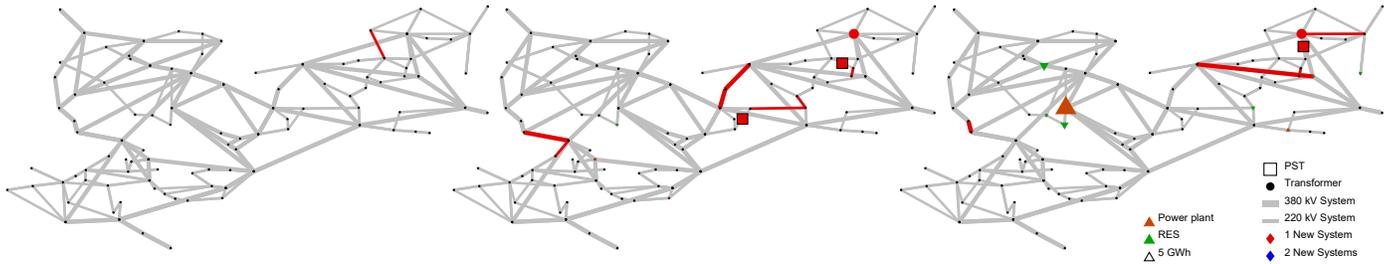


Figure 6. Network expansion measures and congestion management interventions at the first (left), second (center) and third stage (right) using a pseudo-dynamic formulation. Shown congestion management interventions do not include volumes for interventions during the periods between stages.

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