Cascade Failures Analyses Improving Resilience on Transmission Expansion Planning

Luiz Eduardo de Oliveira
Dept. of Elect. and Compt. Engineering, FEUP
Porto, Portugal
luiz.eduardo@fe.up.pt

Phillipe Vilaça
Ayesa,
Sevilla, Spain
pvilaca@ayesa.com

João Tomé Saraiva
Dept. of Elect. and Compt. Engineering, FEUP
Porto, Portugal
jsaraiva@fe.up.pt

Julio A. D. Massignan
SIEMENS AG
Curitiba, Brazil
julio.massignan@siemens.com

***Abstract*—In every critical infrastructure system, unexpected events and outages have the potential to cause massive impacts, affecting people and the economy, such as in the power power grid blackouts. To avoid similar incidents in the future, extensive research is necessary to improve resilience and reliability of power grids. This work presents a Transmission Expansion Planning (TEP) model that confronts the largely adopted deterministic security criteria N-1 versus an AC-Cascade Failure Model (AC-CFM) analysis. The main goal is to highlight the importance of cascade failure analysis to increase power system resilience. Tests over the NREL-118 system verify the AC-CFM coupling in TEP models, demonstrating its benefits for assuming a risky proneness behavior for reaching long-term power grid resilience.**

***Index Terms*—AC-OPF, Cascade Failure Model, N-1 analyses, Transmission Expansion Planning.**

I. Introduction

In the last century, electricity became one of the most important needs of modern civilization. Therefore, power outages have the potential to cause catastrophic consequences in electrified communities [1]. In the summer of 2003, a line brushed against some overgrown trees in Ohio (U.S.), shutting it down. The protection system failed, forcing other power lines to backup an extra burden, tripping a cascade of failures throughout southeastern Canada and northeastern U.S. [1], [2]. In 2021, a devastating snowstorm swept through Texas, leading to a critical shortage of supplies and life-altering consequences [3]. Unforeseeable events are bound to happen, but if planning authorities had taken measures to increase the network's resilience with a protective umbrella, the consequences of unexpected events could have been lessened, turning black swans into grey ones [4].

Redundancy is a common approach to improve reliability and availability of a system under unexpected events, thereby, avoiding cascade failures. In power systems, it is about ensuring that there will be no blackouts with large repercussions. Even during failures, maintenance, and low or high demand conditions, the system should overcome these grid topology variations and keep providing electricity to the end consumers with quality and continuity [5].

The main goal of Transmission Network Planning (TEP) studies is to plan the investment in the construction of the maximum number of technical assets with the lowest costs possible. TEP should also address (un)planned outages to increase resilience, considering the necessary monetary amount to reinforce or create new energy pathways and the associated costs with the damage from indiscriminate outages [6]. To promote secure power supply and establish backup power flow paths during failures, planners must not only alleviate congestion and improve reliability on new topologies but also consider uncertainties in TEP studies, thereby reducing costs related to unreliability, and operational and maintenance costs [5]–[9]. Thus, we propose a comparative study between $i)$ TEP disregarding resilience analysis, $ii)$ TEP considering N-1 contingency [9]–[12]; and $iii)$ TEP coupled with AC-Cascade Failure model analyses [13]–[20]. As contributions, this paper lists:

- a multi-stage long-term TEP considering cascade failures and their expected investment, operative, and unreliability costs over the years.
- a method to reduce computational burden in N-1 analyses.

Beyond this introductory section, the mathematical formulations of the multi-stage deterministic TEP used as the benchmark is provided in Section II. Following, Section III presents the methodology applied in this study. In Section IV the TEP model coupled with AC-CFM analysis is tested over the NREL-118 Bus [21] and compared with the N-1 approach.

II. Transmission Expansion Planning

A. Mathematical Formulation

Mathematically, TEP is characterized as a Mixed Integer Non-Linear Programming (MINLP) problem, which combines integer and continuous variables in an optimization process, requiring a huge computational effort.

The initial phase of the model is dedicated to the multi-stage deterministic TEP problem. Therefore, a solution is considered feasible when the list of investments allows the system to operate properly, i.e. without Power Not Supplied ($PNS = 0$). The whole model searches to minimize investments ($C^{inv}_{\varpi,f,t}$), unreliability ($C^{unr}_{\varpi,f,t}$), and variable Operation and Maintenance $(o\&m)$ costs $(C^{o\&m}_{g,\tau,\varphi,t})$ involved along the planning horizon, but decision-makers are required to commit to their expansion plans in the present, here-and-now, when only maintenance is forecasted. Thus, the challenge is to solve the mathematical problem described by Equations (1) to (22) allowing enough network resilience to deal with failures by mitigating damages.

$$\min_{\substack{x\in X\\ g,\varpi,\tau}} Z = \sum_{\sigma\in\Omega_6}\sum_{t\in\Omega_1} C^{inv}_{\varpi,f,t} + A_{\sigma,t}\cdot\left[C^{o\&m}_{g,\tau,\varphi,t} + C^{unr}_{\varpi,f,t}\right] \quad (1)$$

The integer decision variables denoted as x in Equation (1) represent the investments planned for new transmission assets, which include overhead lines, cables, and transformers. The constructed and planned equipment are attached to the availability matrix (A) that models the N-1 safety criterium for all scenarios $(\sigma) \in \Omega_6$ and stage (t) of the planning $\in \Omega_1$, which directly impact in $C^{o\&m}_{g,\tau,\varphi,t}$ and $C^{unr}_{\varpi,f,t}$.

The TEP problem is formulated as a MINLP, which can be divided into two levels - an upper level and a lower level. The upper level, as described by equations (2) and (3), provides the values of $C^{inv}_{\varpi,f,t}$, while the lower level evaluates $C^{om}_{g,\tau,\varphi,t}$ and $C^{unr}_{\varpi,f,t}$. It should be mentioned that the second level of the problem is dependent on the equipment list generated by the upper level.

$$\min_{\{x\in X\}} C^{inv}_{\varpi,f,t} = \sum_{(i,j)\in\Omega_2} \frac{x_{(i,j),t}\cdot K_{(i,j)}}{(1+R)^t}, \forall t\in\Omega_1 \quad (2)$$

subject to:

$$0 \le \sum_{(i,j)\in\Omega_2} x_{(i,j),t} \le \overline{x}_{(i,j)} \quad (3)$$

In (2) and (3), K is the estimated initial cost of each project; R is the annual percentage rate; t represents each stage on the planning horizon; Ω_1 is the set of stages; Ω_2 encompasses all the connected bus pairs in the system, including the new projects, while the set Ω_3 represents all the buses in the network; respectively, Ω_4 is the set of all nonrenewable generators, while Ω_5 contain all renewable sources; The set Ω_6 denotes economic and operative N-1 scenarios.

The lower level subproblem evaluates the costs linked to the continuous decision variables, such as: generation (g); curtailment of primary sources (τ); overload (φ); and the artificial variables that can be interpreted as planned outages (ϖ), and allowed load-shedding from failures (f), which are obtained via an Interior Point Solver [22] applied in the problem described in Equations (4), (5) and (6), $\forall t \in \Omega_1, i \in \Omega_3 \vee i \in \Omega_5$, subject to constraints (7) to (22).

$$\sum_{\sigma\in\Omega_6}\sum_{t\in\Omega_1} A_{\sigma,t}\cdot\left[C^{o\&m}_{g,\tau,\varphi,t} + C^{unr}_{\varpi,f,t}\right] \quad (4)$$

The operation costs are modeled in Eq. (5), where $\mathcal{G}$ is the nominal operation cost of each generator per MWh; η is the curtailment penalty for each renewable MWh wasted; the costs associated with wind and solar energy are addressed in Eq. (5) by η = 3 USD/kWh [23], in order to minimize renewable curtailments. Furthermore, overload penalty is represented by ϕ, and it is set at 1 USD/kWh.

$$\min_{g,\tau,\varphi} C^{o\&m}_{g,\tau,\varphi,t} = \sum_{t\in\Omega_1}\left[\sum_{i\in\Omega_3} g_{i,t}\cdot\mathcal{G}_{i,t} + \eta\sum_{i\in\Omega_5}\tau_{i,t} + \phi\sum_{(i,j)\in\Omega_2}\varphi(i,j)\right] \quad (5)$$

In the model d and D are respectively the short- and the long-term demand; while F is is the energy lost during a short-term event of failure; γ is a penalization set at 10^{12} to avoid planning long-term PNS in the final solution; and, the Value of Lost Load $(VoLL)$ is set at 10 USD/kWh [23].

$$\min_{\varpi,f,t} C^{unr}_{\varpi,f,t} = \sum_{t\in\Omega_1}\left[\sum_{i\in\Omega_3}\gamma\cdot\varpi_{i,t}\cdot D_{i,t} + VOLL\cdot\sum_{\sigma\in\Omega_6} f_{i,t,\sigma}\cdot d_{i,t,\sigma}\right] \quad (6)$$

Since the main goal of this paper is to verify the benefits of incorporating the AC-CFM analyses in TEP, the short- and long-term uncertainties related to solar irradiation, wind speed, and inflow variations are disregarded. In the following Equations, the curtailment refers to a wind or solar power production that was not absorbed by the system. According to (7), the total generation (g) on each bus is defined by the sum of nonrenewable sources (N), plus renewable feed-in, namely hydro (H), wind (W) and solar generation (Φ), minus curtailment of primary sources (τ).

$$g_{(i,t)} = \sum_{n\in\Omega_4} N_{(i,n,t)} + \sum_{n\in\Omega_5}\left[\Phi_{(i,n,t)} + W_{(i,n,t)} + H_{(i,n,t)} - \tau_{(i,n,t)}\right] \quad (7)$$

The lower level constraints reflect the AC-OPF model from (8) to (22), $\forall t \in \Omega_1, (i,j) \in \Omega_2 \vee i \in \Omega_3, \forall\sigma \in \Omega_6$. In this formulation, l is the annual load growth in percentage; voltages (V) and their phase angles (θ) are subject to the active and reactive long-term power balance referred by Eqs. (10) and (11). The short-term AC power balance is described in (13) and (14). The apparent power transmitted from node (S_i) to node (S_j) considering the availability (A) expected for the initial system topology (X_0) and new transmission assets to be installed (X) is subjected to (21).

$$g_{(i,t)} = D_{(i,t)} + S_{(i,j),t} \quad (8)$$

$$S^2_{(i,j),t} = P^2_{(i,j),t} + Q^2_{(i,j),t} \quad (9)$$

$$P(V,\theta)_{(i,j),t} + \cos(\theta)\cdot(\tau_{i,t} + \varpi_{i,t}\cdot D_{i,t} - g_{i,t}) \quad (10)$$

$$Q(V,\theta)_{(i,j),t} + \sin(\theta)\cdot(\tau_{i,t} + \varpi_{i,t}\cdot D_{i,t} - g_{i,t}) \quad (11)$$

$$0 \le \varpi_{i,t} \le 1 \quad (12)$$

$$P(V,\theta)_{(i,j),t} + \cos(\theta)\cdot(\tau_{i,t} + f_{i,t}\cdot d_{i,t} - g_{i,t}) \quad (13)$$

$$Q(V,\theta)_{(i,j),t} + \sin(\theta)\cdot(\tau_{i,t} + f_{i,t}\cdot d_{i,t} - g_{i,t}) \quad (14)$$

$$0 \le f_{i,t} \le 1 \quad (15)$$

$$P(V,\theta)_{(i,j),t} = V_{i,t}\cdot\sum_{(i,j)\in\Omega_2} V_{j,t}\cdot\left[G_{(i,j),t}\cdot\cos\theta_{(i,j),t} + B_{(i,j),t}\cdot\sin\theta_{(i,j),t}\right] \quad (16)$$

$$Q(V,\theta)_{(i,j),t} = V_{i,t}\cdot\sum_{(i,j)\in\Omega_2} V_{j,t}\cdot\left[G_{(i,j),t}\cdot\sin\theta_{(i,j),t} - B_{(i,j),t}\cdot\cos\theta_{(i,j),t}\right] \quad (17)$$

$$|P_{(i,j),t}| \leq \overline{P}_{(i,j),t} \tag{18}$$

$$|Q_{(i,j),t}| \leq \overline{Q}_{(i,j),t} \tag{19}$$

$$\underline{V}_{i,t} \leq V_{i,t} \leq \overline{V}_{i,t} \tag{20}$$

$$A_{\sigma,t} \cdot (X + X_0) \cdot S_{(i,j)} \leq (X + X_0) \cdot \overline{S}_{(i,j)} \tag{21}$$

$$D_{(i,t+1)} = D_{(i,t)} \cdot (1 + l)^t \tag{22}$$

B. N-1 contingencies safety criteria

Accurately assessing the power supply capability of power systems is critical from a social and economic perspective [9], [11]. In the event of a fault or a planned outage, power systems should be able to redirect power flows with the minimum service interruption satisfying users' electricity consumption under the N-1 reliability guideline [9], [12].

In other words, the planned solution $(X + X_0)$ that results from solving a TEP optimization should have enough redundancy to deal with outages. In this deterministic analysis, $\forall t \in \Omega_1 \wedge (i,j) \in \Omega_2$, the availability (a) of each substation and transmission equipment in the network is represented by the Availability matrix (A), which is detailed in Equation (23):

$$A = \begin{pmatrix} a_{1,1} & a_{1,2} & \cdots & a_{1,j} \\ a_{2,1} & a_{2,2} & \cdots & a_{2,j} \\ \vdots & \vdots & \ddots & \vdots \\ a_{i,1} & a_{i,2} & \cdots & a_{i,j} \end{pmatrix} = \begin{pmatrix} 0 & 1 & \cdots & 1 \\ 1 & 0 & \cdots & 1 \\ \vdots & \vdots & \ddots & \vdots \\ 1 & 1 & \cdots & 0 \end{pmatrix} \tag{23}$$

Since TEP is an NP-hard optimization problem, the planner should be aware of the computational burden required for such type of problem. Furthermore, the N-1 analysis increases the static resilience of the network by looking not only at the most overloaded branches but also in all single pathways responsible for connecting far generators, or loads, to the whole system. However, it becomes a time-consuming analysis. Aiming to allow efficiency on N-1 analyses, some authors use DC-OPF to reduce the computational burden [11], while others use AC-OPF end-to-end [9].

III. Methodology

This work introduces an AC-Cascade Failure model analysis presented in [13] into TEP models. Originally, AC-CFM algorithm is implemented[1] in MATLAB and uses the PF solvers of the MATPOWER toolkit [22].

N-1 criteria increase the network resilience but do not ensure safety against unpredictable faults and cascading events, which the AC-CFM algorithm intends to encompass. Fig. 1 illustrates the flowchart of the entire methodology. In Figure 1, the deterministic TEP is presented in blue, while N-1 analyses and/or AC-CFM as an assistant in the decision-making process, when the TEP algorithm reaches the stopping criteria, it returns a set of candidate expansion plans to the planner.

Trying to avoid premature convergence to local minima solutions and mismatching information from gradient-based algorithms, we decided to implement a self-adaptive process inspired by the Evolutionary Particle Swarm Optimization (EPSO) method in this work. In short, its input parameters are the maximum number of iterations allowed, i.e., the stopping criteria; the number of particles and replications of the population. Additional information about the EPSO algorithm can be found in [24].

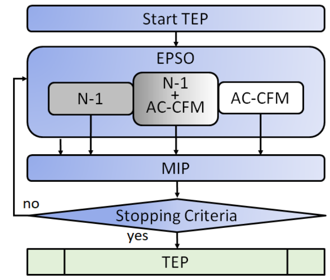

Fig. 1. Flowchart of the proposed methodology.

[1]Source files are at https://github.com/mnoebels/AC-CFM

A. AC-Cascade Failure Model

In power systems, TSOs should properly control voltage level, frequency, and rotor angle of synchronous generating units to maintain the power system stability [13]–[17]. Abnormal operative conditions can trigger cascading events which might lead to a blackout if not solved in proper time [13], [18]–[20]. The implementation of protection schemes in power systems, such as Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS) techniques, serves as the last line of defense against cascading events [20]. These techniques are implemented to preserve the system's voltage and frequency during large disturbances [13].

A cascading failure can dismantle the network into several islands. From the initial decline of voltage / frequency, until their nominal threshold are surpassed, the time frame for implementing all necessary restorative measures to mitigate the danger of total system failure is a short brief period [25].

The approach used by AC-CFM to tackle cascades in each island is recursive, and it continues until they are fully in a stationary state. The succession of Protection Mechanisms (PMs) is applied on every island as soon as the fault occurs. If any PM has changed the topology of a given island, such as loads, generators, or operating lines, the recursion is applied to the new island from the beginning. Else, if the specified tolerances of PMs are not exceeded, or the conditions remain the same, the cascade within the island is considered stable, and the model advances to the next island. The AC-CFM block shown in Fig. 1 is detailed in Fig. 2.

B. Application of Protection Mechanisms

Following [13], the different stages of PMs should be enabled in sequence: *1)* maintenance of frequency stability; *2)* control of over- and underexcitation; and, then, *3)* handle undervoltages; while *4)* Lines which exceeds their nominal load rating should be tripped by overload protection (OLP).

1) Under- and Overfrequency: Sudden mismatches between electrical and mechanical power change rotor frequency

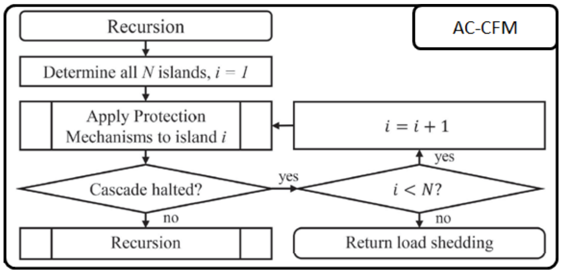

Fig. 2. Flowchart illustrating the recursive approach of AC-CFM [13].

of synchronous generators, Δg. The use of protective strategies, such as under-frequency load shedding (UFLS) or over-frequency generator shedding (OFGS), can reinstate the power equilibrium and and maintain the frequency at an acceptable operating level.

The AC-CFM incorporates Algorithms 1 and 2 to execute UFLS and OFGS mechanisms. To ensure that the frequency remains within set limits, the maximum generation imbalance (δG_{max}) considers the limited ability of generators ($g_{i,t}$) to adapt to changes in load in a short period. Additionally, $\delta G_{overhead}$ addresses network losses. The model applies UFLS and OFGS repeatedly until δG_{max} is no longer surpassed, and balance is restored.

Algorithm 1 UFLS (based on [13]).

if $\Delta g < \delta G_{max}$ **and** Δg less than available capacity. **then**
  Distribute slack generation proportionally.
else
  Reduce loads to $(1 - \delta G_{overhead})$, but not exceeding the available capacity.

Algorithm 2 OFGS (based on [13]).

if $\Delta g < \delta G_{max}$ **then**
  Distribute slack generation proportionally.
else
  Trip generators, from the smallest to the largest, ensuring $\sum g - \sum d \leq \delta G_{max}$

2) Over- and Underexcitation: In response to changes in reactive power demanded from a generator unit, the excitation system of synchronous machines adjusts its excitation voltage to maintain the terminal voltage stability. Timewise, the excitation system can alter the magnetic field to accommodate different reactive power outputs. Over- and under-excitation beyond their limiters (OXL and UXL, respectively) lead to overheating and eventually damage to the generator and needs to be prevented. OXL and UXL constrain the field current, and as a result, the terminal voltage is readjusted [13]. The implementation of OXLs and UXLs in AC-CFM is shown in Algorithm 3.

3) Undervoltage: To avoid voltage drops at the receiving end of a line due to reactive power flow, UVLS can be implemented to gradually decrease demand at the bus avoiding

Algorithm 3 OXL/UXL (based on [13])

for $n \in \Omega_4 \vee \Omega_5$, exceeding their reactive power limits **do**
  Convert bus i who place generator n into PQ bus.
  Set reactive power output equal to its reactive power limit.

voltage collapse until the voltage is again within acceptable levels. For instance, UVLS schemes are required by the North American Electric Reliability Corporation (NERC) to handle mismatches up to 25% in connected loads [26]. AC-CFM incorporates UVLS through Algorithm 4, which sets the load shedding block size δP_{ls} preventing cascade voltage drops below the lower voltage limit on other blocks, and the maximum block-wise load shedding amount ($\delta P_{ls,max}$) before shedding all loads at the bus.

Algorithm 4 UVLS (based on [13]).

Shed δP_{ls} of load at buses falling below the UVLS trigger voltage
if applied load shedding at a bus exceeds $\delta P_{ls,max}$ **then**
  Trip all loads at this bus

4) Overload: The overload protection trips all branches that exceed their operational rating. In this work, the overload capacity in each line was set at 15% during a failure contingency.

IV. Simulations and Results

A. Outline of the tests

This section is focused on assessing the impact of the AC-CFM analysis on network resilience when solving the Transmission Expansion Planning. To achieve this goal, three simulations are conducted on the NREL-118 system.

- Simulation 1 - Deterministic TEP.
- Simulation 2 - TEP + N-1.
- Simulation 3 - TEP + N-1 + AC-CFM.

With a reconfigured generation representation based on three regions of the US Western Interconnection from the Western Electricity Coordination Council (WECC), the NREL-118 system is a publicly accessible version of the IEEE 118-bus test system [21]. In this way, its topology consists of 91 loads and 117 branches, of which 12 are inter-ties, as well as nine transformers and 327 generators utilizing various generation technologies with distinct heat rate functions. Moreover, GHG emission rates and hourly time-series data for a full year of load, wind, and solar generation are accessible to set up the baseline case.

Since the optimization process is conducted by a meta-heuristic, the Capital, operating, and unreliability costs are expected to differ between these simulations. Nevertheless, this study uses the same operating conditions for all simulations. As far as the parameters of the evolutionary calculation algorithm (upper-level decision-making) are concerned, the initial population has 20 particles, and the replication operator, which allows copies of the population in every iteration, is set to 3. All tested simulations were terminated immediately after running 20 consecutive iterations with no observed change in the best results obtained so far to avoid early stopping at local minima and long simulation times. Also, the maximum number of iterations allowed is 150.

The simulations were conducted with a 10-year planning horizon accounting for emergencies, i.e., allowing a 15% overload with a penalty of USD 1/kWh. The yearly demand factor was set at 2%, meaning that the initial demand grows, preserving its power factor from 4000 MW and 1517.1 MVAR to 4907.1 MVA at the end of the planning horizon.

B. Hardware and software features

The tests were conducted on a computer equipped with an 11th Generation Intel® Core(TM) i7-11800H @ 2.30 GHz processor, 16 GB of RAM, and running Windows 10 Pro (64-bit) with MatLab 9.8 Release R2020a. To reduce computation time and exploit the most of the available hardware, the code was designed using parallelization techniques.

C. Simulation 1 - Deterministic TEP

The deterministic TEP is the benchmark of this study, where PNS is avoided, but no safety criteria are applied. In this way, the TEP solution has a low investment cost but may not be prepared for a maintenance period or an unexpected outage. Considering the best-found solution, the algorithm took an average of 96 seconds to perform 60 iterations to reach its present-worth global cost of $65.376 MUSD. This amount is forecasted to be spent in the next ten years. Thus, it comprises $22.760 MUSD for investments, $29.459 MUSD for operations and maintenance, and $13.157 MUSD for curtailment penalties. This simulation disregards the unreliability cost since PNS is avoided and failures are not addressed.

The initial activities on the investment plan are dated to the second year, in which one inter-regional link (branch 54, connecting bus 30 to 38) and a substation (connecting bus 64 to 61) can transform 1870 MVA, 138/345kV. In the third year, an overhead line (branch, connecting bus 27 to 115) is required to finish the investment rounds.

D. Simulation 2 - TEP considering N-1 analysis

While deterministic criteria may fastly result in cheaper network investments, they cannot guarantee satisfactory reliability indices for the entire network since it does not consider the probabilistic nature of equipment outage events. Moreover, applying this criterion to all possible operation scenarios can result in extensive computation time. According to Gomes et al. [9], these limitations highlight the need for a probabilistic approach to obtain more reliable and efficient results.

In this way, we performed a TEP considering N-1 analysis. In Simulation 2, the algorithm ran for 97 hours and 42 minutes to achieve 56 iterations. The number of investments grew from Simulation 1 to Simulation 2. According to Table I, only in the first year the investment plan requires 12 new projects, justifying the high investment over the planning horizon, $217.133 MUSD. The global cost of this expansion plan is planned to be about $255.619 MUSD. Costs related to maintenance and curtailment are, respectively, $28,699 MUSD and $9.787 MUSD.

TABLE I
RESULTS FROM TEP CONSIDERING N-1 ANALYSIS

Year	New Connections
1	8-5, 30-38, 38-65, 65-66, 68-69, 24-72, 70-74, 17-113, 21-22, 27-28, 28-29, 37-39
3	63-59
5	30-17

E. Simulation 3 - TEP considering N-1 analysis and AC-CFM

While reliability improvements can lower the likelihood of cascading failures, they cannot completely eliminate them. Therefore, it is crucial to incorporate stress factors into electricity system planning to minimize the occurrence of outages during stressed conditions. Although avoiding cascading failure is still a priority, planning for stressed systems should take into account wider stress impacts and a longer timescale than any individual cascading failure event.

In this work, we used the N-1 method to avoid PNS coupled to the AC-CFM algorithm, which relies on the network response under failure. This approach ran for 118 hours and 46 minutes while did perform 44 iterations, confirming its time-consuming characteristic. The global costs achieved are $340,385 MUSD, in which new assets represent $306,018 MUSD. The other provisioned costs are about 34,367 MUSD, being $26.459 MUSD from the operations side. Compared to the other simulations, the high connectivity of this resultant network justifies the curtailment penalties reduction to $0,408 MUSD. Even with the high number of connections failures can still occur, resulting in $1,520 MUSD from overloading costs and $5,978 MUSD from load sheddings. Table II details this expansion plan timeline.

TABLE II
RESULTS FROM TEP CONSIDERING N-1 + AC-CFM

Year	New connections
1	13-15, 15-19, 22-23, 23-25, 25-27, 31-32, 19-34, 33-37, 30-38, 41- 42, 44-45, 24-70, 85-86, 82-96, 80-97, 109-110, 114-115, 76-118, 6-7, 21-22, 28-29, 31-32, 63-64, 65-68, 47-69, 69-70, 24-72
4	48-49
5	49-51

F. Discussion

In the first view, the investment cost strongly determines the global cost in all Simulations. Another aspect is that the more the network is meshed, the more costs related to overload, curtailment, power not supplied, and failures are reduced. From Simulation 1 to 3, these costs reduced from $42.616 MUSD to $34.367 MUSD, meaning almost 19.35% less.

Taking Simulation 3 as the most reliable TEP, when expansion plans from Simulations 1 and 2 are tested under contingency and failures, the difference between the forecasted Global Cost (GC) represents the Reliability Cost (C^{rel}_{sim}), see Eq. 24. On the other hand, the difference between Total Expected Cost (TEC) and the forecasted Global Cost (GC)

shows the Unreliability Cost (C^{unr}) for each simulation (sim). The C^{unr}_{sim} show how to uncover these TEPs when facing massive failures. In terms of Equation 6, C^{unr}_{sim} can be addressed as in Equation 25. Table III shows these values.

$$C^{rel}_{sim} = GC_3 - GC_{sim} \tag{24}$$

$$C^{unr}_{sim} = TEC_{sim} - GC_{sim} \tag{25}$$

TABLE III
UNRELIABILITY EVALUATION

	Costs (MUSD)		
Parameter	***Simulation 1***	***Simulation 2***	***Simulation 3***
GC_{sim}	65.376	255.619	340.385
TEC_{sim}	903.510	378.525	340.385
C^{rel}_{sim}	275.009	84.765	0
C^{unr}_{sim}	838.134	122.906	0

Simulations 1 and 2 suggests a very risky behavior towards faults compared to Simulation 3. In simulation 1, C^{rel}_1 represents 32.81% of C^{unr}_1. Thus, if the planner pays for reliability, they will buy an umbrella protection capable of handling two times the payment. Further, the transmission shield might be the difference between full or part blackouts in extreme unpredictable situations.

Besides, C^{rel}_2 is 68.96% of C^{unr}_2. These concepts are relative and depend on political, social, and economic needs. For instance, by adding climate changes and extreme weather events, Simulation 3 may suffer from these uncertainties, requiring a different Expansion Plan. Considering that TEP is a risky-proneness process, an uncovered expansion plan can increase the consequences of highly improbable events, dragging power systems down to ruin.

V. CONCLUSION

This work introduces the AC-CFM in TEP analyses to reduce unexpected unreliable costs from failures or planned outages. Simulations show that it is recommendable for the planner to assume a risky proneness behavior.

The computational burden is another aspect that should be highlighted. The brute force approach enabled with N-1 analysis results in exponential growth of the computational burden in TEP. Creating a new layer of analysis over each N-1 topology, AC-CFM, is also a time-consuming tool. Studies towards computational efficiency should be evaluated to deal with this bottleneck.

For future works, it is noteworthy the inclusion of Monte Carlo simulation to observe the different possible maintenance, fault, and asset degradation scenarios. Still, studies addressing network resilience could encompass climate changes and extreme weather conditions.

REFERENCES

[1] G. Maldonado, "The performance of north american nuclear power plants during the electric power blackout of august 14, 2003," in *IEEE Symp. Conf. Record Nuclear Science 2004.*, vol. 7, pp. 4603–4606, 2004.

[2] J. Minkel, "The 2003 northeast blackout–five years later," *Scientific American*, vol. 13, pp. 1–3, 2008.

[3] NERC, "2021 summer reliability assessment," *North American Electric, Reliability Corporation*.

[4] N. N. Taleb, *The Black Swan: The Impact of the Highly Improbable*. London: Random House, 1 ed., 2008.

[5] S. Lumbreras, H. Abdi, and A. Ramos, *Transmission Expansion Planning: The Network Challenges of the Energy Transition*. Springer International Publishing, 2020.

[6] A. Moreira, D. Pozo, A. Street, E. Sauma, and G. Strbac, "Climate-aware generation and transmission expansion planning: A three-stage robust optimization approach," *Euro. Jour. Oper. Research*, 2021.

[7] L. E. Oliveira, J. T. Saraiva, J. A. D. Massignan, and P. V. Gomes, "Integration of business climate resilience on the transmission expansion planning over the low-carbon energy transition," in *2022 18th International Conf. on the European Energy Market (EEM)*, pp. 1–6, 2022.

[8] W. Li, *Probabilistic Transmission System Planning*. IEEE Press Series on Power and Energy Systems, Wiley, 2011.

[9] P. V. Gomes, J. T. Saraiva, L. Carvalho, B. Dias, and L. W. Oliveira, "Impact of decision-making models in transmission expansion planning considering large shares of renewable energy sources," *Electric Power Systems Research*, vol. 174, p. 105852, 2019.

[10] M. Majidi-Qadikolai and R. Baldick, "Integration of N-1 contingency analysis with systematic transmission capacity expansion planning: Ercot case study," *IEEE Trans. on Power Systems*, vol. 31, no. 3, 2016.

[11] M. Khanabadi, H. Ghasemi, and M. Doostizadeh, "Optimal transmission switching considering voltage security and n-1 contingency analysis," *IEEE Transactions on Power Systems*, vol. 28, no. 1, pp. 542–550, 2013.

[12] F. Luo, C. Wang, J. Xiao, and S. Ge, "Rapid evaluation method for power supply capability of urban distribution system based on n1 contingency analysis of main-transformers," *International Journal of Electrical Power Energy Systems*, vol. 32, no. 10, pp. 1063–1068, 2010.

[13] M. Noebels, R. Preece, and M. Panteli, "An AC cascading failure model for resilience analysis in power networks," *IEEE Systems Journal*, 2020.

[14] H. Haes Alhelou, M. E. Hamedani-Golshan, T. C. Njenda, and P. Siano, "A survey on power system blackout and cascading events: Research motivations and challenges," *Energies*, vol. 12, no. 4, 2019.

[15] J. Beyza and J. M. Yusta, "Integrated risk assessment for robustness evaluation and resilience optimisation of power systems after cascading failures," *Energies*, vol. 14, no. 7, 2021.

[16] I. Dobson, "Estimating the propagation and extent of cascading line outages from utility data with a branching process," *IEEE Transactions on Power Systems*, vol. 27, no. 4, pp. 2146–2155, 2012.

[17] J. Kim, K. R. Wierzbicki, I. Dobson, and R. C. Hardiman, "Estimating propagation and distribution of load shed in simulations of cascading blackouts," *IEEE Systems Journal*, vol. 6, no. 3, pp. 548–557, 2012.

[18] Y. Dai, R. Preece, and M. Panteli, "Risk assessment of cascading failures in power systems with increasing wind penetration," *Electric Power Systems Research*, vol. 211, p. 108392, 2022.

[19] C. Zhai, G. Xiao, M. Meng, H. Zhang, and B. Li, "Identification of catastrophic cascading failures in protected power grids using optimal control," *Journal of Energy Engineering*, vol. 147, no. 1.

[20] D. Ahmedt-Aristizabal, M. A. Armin, S. Denman, C. Fookes, and L. Petersson, "Graph-based deep learning for medical diagnosis and analysis: Past, present and future," *Sensors*, vol. 21, no. 14, 2021.

[21] I. Peña, C. B. Martinez-Anido, and B.-M. Hodge, "An extended ieee 118-bus test system with high renewable penetration," *IEEE Transactions on Power Systems*, vol. 33, no. 1, pp. 281–289, 2018.

[22] R. D. Zimmerman and C. E. Murillo-Sánchez, "Matpower," Oct. 2020.

[23] A. Khodaei and M. Shahidehpour, "Microgrid-based co-optimization of generation and transmission planning in power systems," *IEEE Transactions on Power Systems*, vol. 28, no. 2, pp. 1582–1590, 2013.

[24] V. Miranda, H. Keko, and A. Jaramillo, *EPSO: Evolutionary Particle Swarms*. Springer Berlin Heidelberg, 2007.

[25] M. Braun, C. Hachmann, and J. Haack, "Blackouts, restoration, and islanding: A system resilience perspective," *IEEE Power and Energy Magazine*, vol. 18, no. 4, pp. 54–63, 2020.

[26] NERC, "Automatic underfrequency load shedding," Tech. Rep. PRC-006-3, North American Electric Reliability Corporation, USA, 2017.