e-HIGHWAY 2050

Modular Development Plan of the Pan-European Transmission System 2050

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WP 8	**Enhanced Pan-European Transmission Planning Methodology**		
D8.10	**High-level definition of a new methodology for long-term grid planning**		

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PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential, only for members of the consortium (including the Commission Services)	

Document information

General purpose

This document is the deliverable D8.10 of the e-Highway2050 project. It contains the high-level description of the new methodology for long-term grid planning that will be developed by Work Package 8.

Change status

Revision	Date	Changes description	Authors
V1.0	23.08.2013	Initial version	P. Panciatici M.S. Debry
V1.1	13.09.2013	Update based on corrections and comments from RSE, COMILLAS, SINTEF, TUB, ELIA	P. Panciatici M.S. Debry
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EXECUTIVE SUMMARY

Work Package 8 of e-Highway2050 project aims at developing a new methodology for long term grid planning and at specifying the associated new tools. This document, which consists of three parts, focuses on the high-level description of the methodology to develop.

The first part of the deliverable is the high-level problem statement. We want to find an optimal design of a very large grid including its modular development plan over a very long time horizon. This problem will be solved from a system operator perspective, with no control on generation planning. The objective function to minimize, the constraints to take into account and the possible controls are detailed in the document.

The second part is a review of the level of modelling used in transmission planning methodologies and in transmission planning tools.

In the third part, a high level description of the proposed methodology is given. This methodology can be divided into the six successive steps described below:

- In a first step, time series of controllable generation and consumption are calculated to ensure power adequacy between generation and consumption for each scenario and each time horizon considered. Grid constraints are not taken into account. Several patterns of uncertainties (e.g. load, wind...) are considered.
- In a second step, the initial pan European grid is reduced to get a simplified nodal grid of approximately 1 000 nodes. Generation and consumption are then located on that simplified grid for each scenario and each time horizon. Using DC approximation, overload problems are detected using a worst case approach and taking into account uncertainties and corrective actions. A clustering of the initial grid is carried out according to the critical branches, leading to a zonal initial grid of approximately 100 nodes.
- In the third step, for each scenario and each time horizon, the congestions' severities and associated costs are assessed.
- In the fourth step, the modular development plan is calculated at zonal level, by considering at the same time all time horizons and the whole set of scenarios. An optimization tool is used to choose the best combinations of new inter-zonal transmission capacities. As it is impossible to let the optimization tool choose among all technological alternatives, rules are defined and used to reduce ex-ante the number of technological alternatives. Three different possible architectures are considered, the first one giving priority to long distance connections, the second one to short distance connections and the last one should result in a hybrid architecture. The resulting modular development plans are ranked according to their total costs. The final choice between them is performed after assessing the robustness of the proposed architectures.
- In the fifth step, starting from the zonal modular development plans, grid expansion is performed for the two first time horizons at nodal level.
- In the sixth step, the robustness of the nodal grid architectures proposed for the two first time horizons is checked to ensure that these grids can be operated without major voltage or stability concerns.

The development of the methods associated to the 6 steps will be distributed as follows between the tasks of WP8:

- The work dedicated to adequacy simulations, which includes both calculations without grid constraints (step 1) and assessment of congestions' severities and associated costs (step 3) will be performed in *task 8.2: Definition of generation and demand scenarios*
- The work to detect overload problems (step 2) will be performed in *task 8.3.1: Detection of system overloads*

- The work aiming at determining the optimal grid expansion at zonal level (step 4) will be performed in *task 8.4: Enhanced modular development plan*
- The work dedicated to transmission planning at nodal level (step 5) will be performed in *task 8.3.2: Grid expansion at nodal level*
- The work dedicated to robustness estimation (step 6) will be performed in *task 8.5: Robustness of the proposed grid architectures*

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INTRODUCTION

The aim of this document is to mathematically formalize long term planning and to propose a new improved methodology with both scientific correctness and practical relevance. Advanced optimization and simulation methods are investigated to tackle this very complex problem, which includes highly combinatorial aspects and must cover the dynamic behaviour of the system. We propose to investigate the utilization of High Performance Computing facility (typically 1000 servers with 16 cores) to try to solve this very complex optimization problem.

The objective of the work package is to define a new methodology and specifications of new tools. The practical relevance will be checked in the task 8.6 “Enhanced long-term planning methodology” using realistic data but not necessarily actual data. We’ll take advantage of data collected in other work packages of the project, in particular on grid technologies (WP3).

In this document, we first give a high-level statement of the problem. We identify the challenges taking into account the state of the art. Then, we propose a high-level methodology. This methodology consists in splitting the whole problem into much more tractable sub problems and in defining the interactions between them.

1. High-level problem statement

The problem is to find an optimal design of a very large grid including its modular development plan over a very long time horizon. The initial conditions of the problem are the current conditions (architecture of the grid, generation mix, consumption pattern and behaviour, climate…).

We want to solve this problem as a system operator, without any control on the generation planning. The different possible generation mixes and their evolutions over the time horizon are defined through scenarios. Each scenario gives technological solutions for the generating units, their capacity, their costs and their location. In addition, the electrical consumption including its splitting in usages, its location and its temporal evolution is defined in the scenarios. These scenarios are based on the different possible energy policy choices.

In order to solve this problem, we have to define an objective function to minimize and the constraints to fulfil.

1.1. Objective function

The objective is to minimize the expected capital and operational expenditures (capex and opex) of the grid over the whole time horizon. We consider these expected values to tackle the uncertainties. Two levels of uncertainties appear in this problem: the very different possible futures (scenarios) and the stochastic behaviour of the system components (loads, primary energy, availability of devices and units …). The capital expenditures are identified with the amortization costs of grid investments. The operational expenditures for the grid operator are the costs of generation adjustments, losses, operation and maintenance.

The expansion planning N over the considered time horizon is the tree of the incremental grid developments to reach all possible optimal long-term grids starting from the actual one. The time to build grid assets is approximately 10 years, so we need to have a unique incremental grid development for the first 10 years.

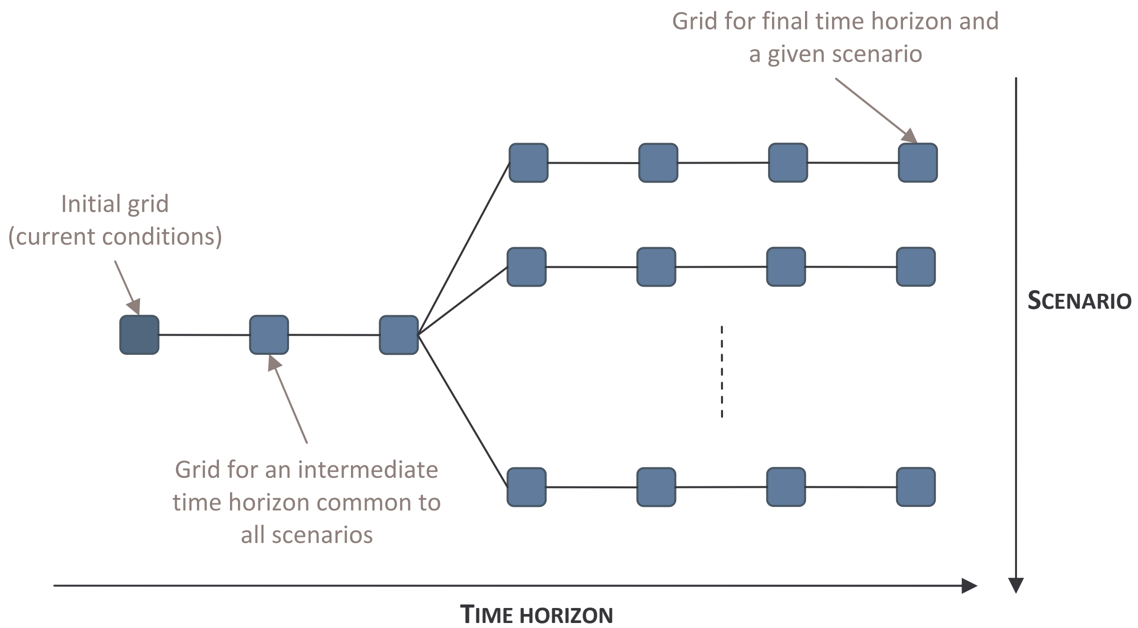


Figure 1: Expansion planning over the time period 2020 - 2050

$$\begin{cases} capex = f(N,S) \\ opex = g(N,S,U) \\ \min\limits_{N}\left\{\underset{S}{\mathrm{E}}(capex) + \underset{S,U}{\mathrm{E}}(opex)\right\} \end{cases}$$

Where:

- S is a scenario
- U is a pattern of uncertainties related to the stochastic behaviour of the system components

$$opex = C_G(N,S,U) - C_0(S,U)$$

Where:

- C_0 is the operational cost over the considered time horizon without any grid constraints (copper-plate approach).
- C_G is the operational cost over the considered time horizon considering the grid constraints after the expansion plan N.

A generation schedule is required to define generation adjustments. This generation schedule must be simulated by an "adequacy simulator". We propose to use a standard assumption which is a rational behaviour of the players minimizing their operational costs in a perfectly competitive market. This is not per say a "market simulator", indeed, strategic behaviour of the players are not simulated. The rationale is that the long term infrastructures should not be designed to try to cope with imperfect short term markets. This is the market design that must try to tend towards a perfect market.

The considered system will be the Pan European grid including UK and Nordic countries. The exchanges with neighbouring systems (mainly Africa, Russia, Middle East, ...) will be defined by scenarios.

The environmental impacts depend on scenarios; in the proposed optimization problem only the generation costs are considered. The assumption is that the costs of environmental impacts are included into them[1].

1.2. Constraints and controls

In this optimization problem, we have to take into account different constraints and also possible controls.

Different kinds of constraints and controls must be considered: the grid behaviour and the capacities of its components, the technical constraints on generation and consumption and the required level of reliability.

1.2.1. Grid behaviour and components capacities

For long-term grid planning, even if we want to enhance the methodology, we don't want to consider electromagnetic phenomena, unbalanced conditions (positive sequence only) and harmonics, which are too complex to be tackled at this planning stage. We believe that all these phenomena could be managed after the design of the grid.

Under these assumptions, the state of the positive sequence AC grid is defined by nodal complex voltage phasors $V_k\colon v_k(t) = V_k(t)e^{j2\pi f_{ref}t}$ where f_{ref} is the reference frequency of the grid. The behaviour of the grid is defined by a set of equations linking these voltage phasors with the complex currents phasors $I_k\colon i_k(t) = I_k(t)e^{j2\pi f_{ref}t}$ injected or withdrawn at electrical nodes (Kirchoff's laws, complex Ohm's law). Generally this leads to linear complex equations: $I = Y\,V$, where I is the vector of nodal current phasors I_k and V the vector of nodal voltage phasors V_k.

The capacity of the grid is constrained by limitations on components, which are translated into maximum current magnitudes in branches (transformers, lines, cables…) and into maximum voltage magnitudes on busbars. All these constraints can be expressed using the voltage phasors and summarized with an expression such as $G_{ac}(V) \le 0$.

To allow the grid users to make connection to the grid in a standardized way, contractual limits are defined, in particular on the minimum voltage magnitude. They can be included in the previous constraints.

The methodology must take into account the HVDC options, including multi-terminal configurations. Similar representations are used for the HVDC grids, including limitations on the AC/DC converters and on the HVDC cables: $I_{dc} = Y_{dc}\,V_{dc}$ and $G_{dc}(V_{dc}) \le 0$, where I_{dc} is the vector of HVDC currents and V_{dc} the vector of DC voltages. The AC and HVDC grids are connected through converters, leading to additional equations $\Lambda(V, V_{dc}) = 0$.

$$(1)\begin{cases} I = Y\,V \\ G_{ac}(V) \le 0 \\ I_{dc} = Y_{dc}\,V_{dc} \\ G_{dc}(V_{dc}) \le 0 \\ \Lambda(V, V_{dc}) = 0 \end{cases}$$

[1] If the costs of fossil fuels are low in a scenario, the market simulator will find a generation schedule producing a large amount of CO2.

Grid control:

Flows on the network can be controlled by several means: modifying grid topology, changing taps of phase shifters (PST) or modifying HVDC power set-points. The first one modifies network "impedances", the second one injects a phase angle difference whereas the latter only imposes a flow.

Similarly, several means are used to control voltages. Capacitor and reactor banks can be switched on and off to produce or consume reactive power. Dynamic reactive power compensation is also possible using FACTS such as SVC. Taps of on-load tap changers (OLTC) can be manually or automatically modified to control voltages on lower voltage levels.

Power system stabilizers (PSS) can be added to HVDC links and FACTS to improve the damping of some oscillation modes and consequently small signal stability of the system.

Grid protection:

Tripping is caused by external events (lightning, storms, excavators...) and the consecutive action of local protections. The behaviour of the protection system is not simulated. Only their global behaviour is taken into account by contingencies in reliability analysis.

Two kinds of protections can be installed on branches, aiming either at clearing short-circuits or at preventing current from exceeding maximum current thresholds (thermal limits).

Tripping may also be caused by internal fault of protections.

1.2.2. Modelling and technical constraints on generation

Generators are modelled as nodal current injectors (I in (1)).

Generators convert primary energy in electrical power. They have specific characteristics and costs depending on the primary energy and the conversion processes.

The primary energy can be:

- Storable (hydro, fuel, gas, nuclear power plants…)
- Stochastic (wind, solar, hydro…)

The generation could be dispatchable or non-dispatchable depending on the technology, for example: run-of-the river hydro power plants are nearly non dispatchable (no reservoir).

The modelling must take into account the size of the storages, the refuelling strategy and the probabilistic behaviour of stochastic energy sources.

The conversion processes have different dynamic behaviours and limitations. In any case, the generated active electrical power is limited at a maximum value. Some processes must generate a minimum active power, can have ramping constraints, minimal duration of generation and specific start-up/shut-down cycles.

Electrical interfaces manage the voltage and the reactive power. Generally there are limitations on the reactive power capabilities induced by technical constraints (maximum field and stator current…).

Table 1: Examples of conversion processes for the main primary energy sources

PRIMARY ENERGY	CONVERSION PROCESS		
Sun	-	PV panel	Converter
	Boiler	Turbine	Synchronous machine
Wind		Turbine	Synchronous machine / converter
		Turbine	Asynchronous machine + converter
Water inflows	River	Turbine	Synchronous machine
	Dam	Turbine	Synchronous machine
Ocean energy: waves, tides, marine currents…		Turbine	Synchronous machine
Gas, fuel, coal, biomass, geothermal	Boiler	Turbine	Synchronous machine
Nuclear fuel	Boiler	Turbine	Synchronous machine

The appropriate level of modelling has to be defined depending on each sub problem.

Generation control:

Ancillary services include primary controls and secondary controls.

A detailed modelling is required only for dynamic security assessment. When using DC approximation, a simplified ideal behaviour will be used. For dynamic security assessment, special attention will be paid to:

- AVR: automatic voltage regulator
  - Including excitation system and PSS power system stabilizer
- Speed governor: primary power and frequency control
- Wind and solar farms control
- AGC: Automatic Generation Control, Secondary power and frequency control
- Secondary voltage control

For DC approximation, the modelling is mainly adjustment of generation active power set-points. TSOs today perform these adjustments based on national regulatory frameworks, but a harmonized behaviour will be defined by scenario and considered in this project.

Generation protection:

Tripping of generation is induced by grid conditions, when voltage or frequency exceeds its normal operating range or when some synchronous machines lose synchronism.

Internal generation processes are not simulated. Tripping caused by these processes is defined by contingencies given in reliability analysis.

1.2.3. Modelling and technical constraints on consumption

Consumption can be controllable or uncontrollable. The share of controllable loads in consumption depends on scenarios. In case of a market-based framework, users adjust their consumption based on the prices of electricity. If they are included in ancillary services, controllable loads can be adjusted by system operators and can help relieve constraints on the system.

The power consumed by loads depends on meteorological conditions. Cloud covering impacts the use of lights. The consumption due to electrical heating or to air-conditioning is affected by temperature as well as by sunshine for the latter. Some weather dependent consumptions are spatially correlated with the generated power of generators whose production depends on the same meteorological variables.

The active and reactive power consumed by loads varies with frequency and voltage. The voltage dependence can be advantageous during large disturbances since the power consumed decreases with voltage, which relieves constraints on the system. Asynchronous motors are a particular case of voltage dependent loads with specific characteristics in case of severe voltage drops. In such conditions they are prone to stalling. The current they consume increases significantly, leading on the contrary to an increase of the reactive power consumed and consequently worsening the voltage drop. This must be considered when assessing voltage stability of grids with a large amount of asynchronous motors and in particular for scenarios with a high use of air-conditioning.

Consumption control:

Adjustment of controllable loads by TSOs (possibly via aggregators) today depends on national regulatory frameworks, but a harmonized behaviour by scenario will be defined and considered in this project.

In case of severe disturbances, the highest priority is to maintain the stability of the system. Emergency controls, whose impact on the consumption goes beyond contractual frameworks, are used. These include conservative voltage reduction (CVR), blocking of tap-changers and, in ultimate resort, load shedding. Emergency controls are considered explicitly only for robustness assessment, but as generally accepted in planning studies energy not supplied or loss of load are indexes to measure the relevance of the proposed expansion plan.

Consumption protection:

Some loads are equipped with protective devices. Tripping is caused by grid conditions, when voltage or frequency exceeds its normal operating range. This is particularly true for loads based on asynchronous motors, such as air-conditioning, and on power-electronics. The increasing share of power electronics based loads makes this phenomenon more and more important.

1.2.4. Required level of reliability

The definition of a required level of reliability is mandatory to perform a planning study.

ENTSO-E has defined some guidelines [1], which are summarized below.

Base Cases:

Base cases must be chosen to perform network analysis. For any relevant point in time, the expected state of the whole system, "with all network equipment available", is used.

Contingencies:

A contingency is the loss of one or several elements of the power transmission system. A differentiation is made between normal, rare and out-of-range contingencies. The wide range of climatic conditions and the size and strength of different networks within Europe mean that the frequency and consequences of contingencies vary among TSOs. As a result, the definitions of normal and rare contingencies can differ between TSOs. The standard allows for some variation in the categorization of contingencies, based on their likelihood.

- *A normal contingency is the (not unusual) loss of one of the following elements:*
  - *generator,*
  - *transmission circuit (overhead, underground or mixed),*
  - *a single transmission transformer or two transformers connected to the same bay,*
  - *shunt device (i. e. capacitors, reactors …),*
  - *single DC circuit,*
  - *network equipment for load flow control (phase shifter, FACTS …) or*
  - *a line with two or more circuits on the same towers if a TSO considers this appropriate and includes this contingency in its normal system planning*
- *A rare contingency is the (unusual) loss of one of the following elements:*
  - *A line with two or more circuits on the same towers if a TSO considers this appropriate and does not include this contingency in its normal system planning,*
  - *a single busbar,*
  - *a common mode failure with the loss of more than one generating unit or plant or*
  - *a common mode failure with the loss of more than one DC link.*
- *An out-of-range contingency includes the (very unusual) loss of one of the following:*
  - *Two lines independently and simultaneously,*
  - *a total substation with more than one busbar or*
  - *loss of more than one generation unit independently.*

N-1 criterion for grid planning:

The N-1 security criterion is satisfied if the network is within acceptable limits for expected transmission and supply situations as defined by the planning cases, following a temporary (or permanent) outage of one of the elements of the normal[2] contingency list.

A single contingency must not result in any cascade tripping that may lead to a serious interruption of supply within a wide-spread area (e. g. further tripping due to system protection schemes after the tripping of the primarily failed element).

Rare contingencies are assessed in order to prevent serious interruption of supply within a wide-spread area. This kind of assessment is done for specific cases based on the probability of occurrence and / or based on the severity of the consequences.

Out-of-range contingencies are very rarely assessed. Their consequences are minimized through Defence Plans.

Definition of limits:

- *Maximum permissible thermal load:*

[2] as defined in the previous paragraph

The base case and the post-fault steady states must not exhibit an excess of the permitted rating of the network equipment. Taking into account duration, short-term overload capability can be considered, assuming that the overloads can be eliminated by operational countermeasures within the defined time interval (corrective actions).

- *Minimum voltage levels:*

  The base case and the post-fault steady states must not exhibit a voltage collapse, nor in a permanent shortfall of the minimum voltage level of the transmission grid, which are needed in particular to ensure acceptable voltage levels in the sub-transmission grid.

- *Maximum voltage levels:*

  The base case and the post-fault steady states must not exhibit an excess of the maximum admissible voltage level of the transmission grids defined by equipment ratings taking into account duration.

Dynamic phenomena:

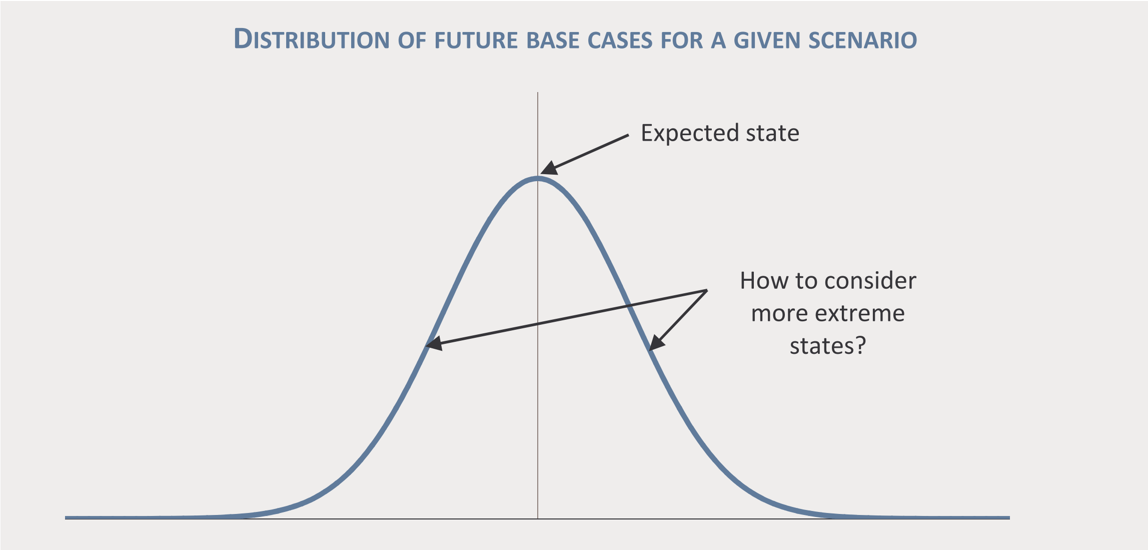
- ***Short circuit:*** *Maximum and minimum symmetrical and single-phase short-circuit currents are evaluated according to the IEC 60 909, in every bus of the transmission network. Moreover, m*inimum short-circuit currents must be assessed in particular in busbars where a HVDC installation is connected in order to check that it works properly.
- ***Stability:*** *Transient simulations and other detailed analysis oriented to identifying possible instability shall be performed only in cases where problems with stability can be expected, based on TSO knowledge. Taking into account the definitions and classifications of stability phenomena*[3]*, the objective of stability analysis is the rotor angle stability, frequency stability and voltage stability in case of normal contingencies, i. e. incidents which are specifically foreseen in the planning and operation of the system. For the assessment of normal contingencies a successful fault clearing by the primary protection system is implied.*
  - *Transient stability: Any 3-phase short circuits successfully cleared by the primary protection system in service (or forecasted) shall not result in a loss of synchronism and the disconnection of generation units.*
  - *Small Disturbance Angle Stability: Possible phase swinging and power oscillations (e. g. triggered by the loss of a big generating unit) in the transmission grid shall not result in poorly damped or even unstable power oscillations.*
  - *Voltage security: Normal contingencies (including loss of reactive power infeed) must not lead to violation of the admissible voltage range that is specified by the respective TSO (generally 0.95 p.u. – 1.05 p.u.). Moreover, voltage collapse analysis with a further demand increase by a certain percentage above the peak demand value is undertaken. The resulting voltage profile, reactive power reserves, and transformer tap positions are calculated."*

These guidelines need some clarifications and a feasibility check of their implementation.

[3] Definition and Classification of Power System Stability, IEEE / CIGRE Joint Task Force, June 2003

Base Cases:

The methodology to choose base cases must be defined. For a given scenario, the probabilistic behaviour of consumption and uncontrollable generation must be taken into account. Base cases based only on expected values could not be representative enough to define a robust expansion planning.



The assumption of availability of all equipments is obviously an approximation. Maintenance works and outages of equipments are mandatory in reality. The outage management is a complex process performed in year-ahead, month-ahead and week-ahead operational activities. It seems nearly impossible to simulate this process in the expansion planning problem. Generally, in this problem, margins are kept to ensure the required level of reliability in case of outages. The definitions of these margins are part of the know-how of the experts of the expansion planning problem. We will try to investigate some possible assessments of these margins as a part of the robustness analysis of expansion planning.

N-1 criterion:

The acceptable level of risk for N-k (k>1) is not defined. Is it acceptable to have a complete European black-out in case of an N-2 contingency? Time to restore a new secure state is not defined either ((N-1)-1). The ENTSO-E guidelines seem to allow corrective actions. This is an extension of the traditional pure preventive N-1 criterion. From a reliability point of view, we formally need to take into account the possible failure of corrective actions.

The feasibility of a full risk-based approach seems questionable. We propose to stick to N-1 criteria for the optimal expansion planning problem and to perform robustness analysis to try to answer the previous issues.

An optimal expansion planning could not economically tackle very low probability events (storms/floods impacting large areas...). The impact of these events must be mitigated by defence plans and restoration plans (including management of necessary means: spare parts...). Ideally one would like to have a co-design of the grid and of these defence/restoration plans. This is considered out of the scope for this project.

Taking into account the dynamic behaviour in all stages of the very complex optimization problem of expansion planning is not realistic. In this optimization problem we propose to use a grid modelling based on DC approximation. Only overload limits will be considered. A robustness analysis will be performed to check all other limits (voltage, stability).

2. State of the art and challenges

2.1. State of the art

2.1.1. Planning methodologies

Papers listed in annex 2 were reviewed to assess the level of modelling used in planning methodologies. The list consists of the articles published in IEEE journals and magazines (IEEE Transactions on Power Systems and IEEE Transactions on Power Delivery) from 2003 to 2013 and which title includes “transmission planning”, “expansion planning” or “transmission expansion”. We focused on papers dealing mainly with modelling issues in planning methodologies. We didn’t analyse papers presenting low level applied mathematics methods to solve transmission expansion problems without giving details about the modelling.

The table shown on the following pages describes the modelling used in the different articles. When information is missing in one article (no information about grid modelling – DC or AC load flow – for instance), a question mark is included in the corresponding box. A dash means that the feature is not considered in the article (for example wind power for articles in which a generic model only including costs is used for generating units).

ARTICLE	PLANNING	SIZE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
						THERMAL	HYDRO	WIND	PV		
	GT: generation and transmission planning **T:** transmission planning	**S:** small (< 100 nodes) **M:** medium (< 1000 nodes) **L:** large (> 1000 nodes)	Number of years	Time-steps: **H:** Hourly **W:** Weekly **M:** Monthly **Lc:** load duration curve	**F:** flows **PTDF** **OPF** **DC:** DC approximation **AC:** AC **Capex** **Opex** **A:** Amortization **AB:** annual budget constraints	**Pm:** Pmin **R:** Ramping **MD:** Minimal duration Availability: **Ar:** Random variables **As:** per scenario **C:** Start-up costs **Or:** Operational reserve **G:** Generic model (generation cost only) **Gs:** per scenario	Inflows: **Ir:** random variables **Is:** per scenario	Wind modelling: **Wr:** random variables **Ws:** per scenario **Cc:** Curtailment costs	Solar radiations and clouds modelling: **Sr:** random variables **Ss:** per scenario	Load modelling: **Lr:** random variables **Ls:** per scenario DSM modelling: **DSMe:** conservation of energy **DSMp:** peak shifting **DSM$:** price sensitive	**N-1p:** Preventive N-1 **N-kp:** Preventive N-k (k>1) **N-1c:** Preventive / corrective N-1 **Other:** other criteria **P:** Probabilistic **No:** no reliability criteria
[2]	GT	S	1	Lc	PTDF Capex	G	Is	Ws	–	Ls	no
[3]	T	M	1	Lc	DC / AC Capex	?	?	?	?	Ls	no
[4]	T	M	15	Lc	DC Capex, Opex, A	G, Ar	–	–	–	Ls	N-1c, P
[5],[6]	T	S	1	H	OPF Capex, Opex	G (except wind power)	–	Wr	–	Lr	?
[7]	GT	S	20	Lc	DC Capex	Pm, As/Ar (post-processing), Or	Is	Ws	Ss	DSM$, Ls	no
[8]	T	M	10		DC incl. losses Capex, A, AB	Pm, R, C	–	–	–	Ls	N-1p
[9]	T	S	15	H	DC Capex, Opex, A	G	–	–	–	Ls	no
[10]	T	S	4	Lc	DC Capex, A	Gs	–	–	–	Ls	no
[11]	T	S	1	Lc	DC Capex, Opex	?	?	Ws, Cc	?	Ls	no
[12]	GT	S/M/L	10/10/3	Lc	DC Capex, A	As, G	–	–	–	Ls	N-1c

ARTICLE	PLANNING	SIZE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
						THERMAL	HYDRO	WIND	PV		
	GT: generation and transmission planning T: transmission planning	S: small (< 100 nodes) M: medium (< 1000 nodes) L: large (> 1000 nodes)	Number of years	Time-steps: H: Hourly W: Weekly M: Monthly Lc: load duration curve	F: flows PTDF OPF DC: DC approximation AC: AC Capex Opex A: Amortization AB: annual budget constraints	Pm: Pmin R: Ramping MD: Minimal duration Availability: Ar: Random variables As: per scenario C: Start-up costs Or: Operational reserve G: Generic model (generation cost only) Gs: per scenario	Inflows: Ir: random variables Is: per scenario	Wind modelling: Wr: random variables Ws: per scenario Cc: Curtailment costs	Solar radiations and clouds modelling: Sr: random variables Ss: per scenario	Load modelling: Lr: random variables Ls: per scenario DSM modelling: DSMe: conservation of energy DSMp: peak shifting DSM$: price sensitive	N-1p: Preventive N-1 N-kp: Preventive N-k (k>1) N-1c: Preventive / corrective N-1 Other: other criteria P: Probabilistic No: no reliability criteria
[13]	T	S	1	Lc	DC Capex, Opex, AB	G?	–	–	–	Ls	N-kp*
[14]	T	?	1	?	?	?	Is	?	?	Ls	N-1p
[15]	T	S	5	Lc	DC Capex, Opex, A, AB	G	–	–	–	Ls	no
[16]	GT	S	10	Lc	DC Capex, Opex, A	Ar, G	–	–	–	Lr	no
[17]	T	S	1	Lc	AC Capex, Opex	G	–	–	–	Ls	other*
[18]	T	S	10	Lc	DC Capex, Opex	?	?	?	?	Ls	N-1p
[19]	GT	S	2	Lc	DC Capex, Opex	Pm, G	–	–	–	Ls	N-1p
[20]	T	S	1	Lc	DC Capex, AB	G	–	–	–	Ls	N-1p
[21]	T	S	1	Lc	DC	G?	–	Wr	–	Lr	no

* The considered N-k are deliberate outages.

* The reliability criteria used is related to the eigenvalues of the system Jacobian matrix and to reactive power reserve.

ARTICLE	PLANNING	SIZE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
						THERMAL	HYDRO	WIND	PV		
	GT: generation and transmission planning T: transmission planning	S: small (< 100 nodes) M: medium (< 1000 nodes) L: large (> 1000 nodes)	Number of years	Time-steps: H: Hourly W: Weekly M: Monthly Lc: load duration curve	F: flows PTDF OPF DC: DC approximation AC: AC Capex Opex A: Amortization AB: annual budget constraints	Pm: Pmin R: Ramping MD: Minimal duration Availability: Ar: Random variables As: per scenario C: Start-up costs Or: Operational reserve G: Generic model (generation cost only) Gs: per scenario	Inflows: Ir: random variables Is: per scenario	Wind modelling: Wr: random variables Ws: per scenario Cc: Curtailment costs	Solar radiations and clouds modelling: Sr: random variables Ss: per scenario	Load modelling: Lr: random variables Ls: per scenario DSM modelling: DSMe: conservation of energy DSMp: peak shifting DSM$: price sensitive	N-1p: Preventive N-1 N-kp: Preventive N-k (k>1) N-1c: Preventive / corrective N-1 Other: other criteria P: Probabilistic No: no reliability criteria
					Capex, Opex						
[22]	T	S	10	Lc	DC Capex, Opex	Pm, G	–	–	–	Ls	N-1p
[23]	T	L	6	Lc	AC Capex	G?	–	–	–	Ls	N-1p
[24]	T	S	1	n/a	DC Capex, Opex	?	?	?	?	+	no
[25]	T	S	1	Lc	AC Capex, A	G	–	–	–	Ls, DSM$	no
[26]	T	S	1	H	DC Capex, A	G	–	–	–	Ls, DSM$	no
[27]	T	S	1	Lc	F Capex	Or, G	–	–	–	Ls	N-kp
[28]	T	S	1	Lc	DC Capex, Opex	Gs	Is	–	–	Ls	N-1p
[29]	T	S	1	Lc	DC Capex, Opex, AB	?	?	?	?	Ls	N-kp*

+ Load uncertainty is expressed using intervals.

* The considered N-k are deliberate outages.

ARTICLE	PLANNING	SIZE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
						THERMAL	HYDRO	WIND	PV		
	GT: generation and transmission planning T: transmission planning	S: small (< 100 nodes) M: medium (< 1000 nodes) L: large (> 1000 nodes)	Number of years	Time-steps: H: Hourly W: Weekly M: Monthly Lc: load duration curve	F: flows PTDF OPF DC: DC approximation AC: AC Capex Opex A: Amortization AB: annual budget constraints	Pm: Pmin R: Ramping MD: Minimal duration Availability: Ar: Random variables As: per scenario C: Start-up costs Or: Operational reserve G: Generic model (generation cost only) Gs: per scenario	Inflows: Ir: random variables Is: per scenario	Wind modelling: Wr: random variables Ws: per scenario Cc: Curtailment costs	Solar radiations and clouds modelling: Sr: random variables Ss: per scenario	Load modelling: Lr: random variables Ls: per scenario DSM modelling: DSMe: conservation of energy DSMp: peak shifting DSM$: price sensitive	N-1p: Preventive N-1 N-kp: Preventive N-k (k>1) N-1c: Preventive / corrective N-1 Other: other criteria P: Probabilistic No: no reliability criteria
[30]	GT	S	1	Lc	DC Capex, A, AB	G, C	–	–	–	Ls	no
[31]	T	S	5	Lc	DC Capex, Opex, A	G, C	–	–	–	Ls	N-1p
[32]	T	S	1	**	DC Capex, Opex	?	?	?	?	**	no
[33]	T	M	1	H	DC Capex	Ar	Ir	Wr	–	Lr	N-1p
[34]	T	S	4	Lc	? Capex, Opex	?	?	?	?	Ls	?
[35]	T	S	1	Lc	F Capex	Ar, G?	–	–	–	Ls	no
[36]	T	S	1	Lc	DC + losses, Capex	G	–	–	–	Ls	no
[37]	T	M	6	Lc	PTDF Capex, Opex, A, AB	G	–	–	–	Ls	no
[38]	T	S	8	Lc	F Capex, A	G	–	–	–	Ls	no
[39]	T	S	8	?	OPF	Ar, G	–	–	–	Lr	no

** Demand is included in the objective function and maximized.

ARTICLE	PLANNING	SIZE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
						THERMAL	HYDRO	WIND	PV		
	GT: generation and transmission planning T: transmission planning	S: small (< 100 nodes) M: medium (< 1000 nodes) L: large (> 1000 nodes)	Number of years	Time-steps: H: Hourly W: Weekly M: Monthly Lc: load duration curve	F: flows PTDF OPF DC: DC approximation AC: AC Capex Opex A: Amortization AB: annual budget constraints	Pm: Pmin R: Ramping MD: Minimal duration Availability: Ar: Random variables As: per scenario C: Start-up costs Or: Operational reserve G: Generic model (generation cost only) Gs: per scenario	Inflows: Ir: random variables Is: per scenario	Wind modelling: Wr: random variables Ws: per scenario Cc: Curtailment costs	Solar radiations and clouds modelling: Sr: random variables Ss: per scenario	Load modelling: Lr: random variables Ls: per scenario DSM modelling: DSMe: conservation of energy DSMp: peak shifting DSM$: price sensitive	N-1p: Preventive N-1 N-kp: Preventive N-k (k>1) N-1c: Preventive / corrective N-1 Other: other criteria P: Probabilistic No: no reliability criteria
					Capex, Opex						
[40]	T	S	1	Lc	DC Capex, Opex	G	–	–	–	Ls	no
[41]	T	S	1	Lc	DC Capex	G	–	–	–	Ls	No

Spatial complexity:

In most of the articles, the developed methodology is applied on small networks with less than 100 nodes (31)[4]. Few methodologies are tested on networks with more than 1000 nodes (2), or with a number of nodes comprised between 100 and 1000 (5).

Temporal complexity:

Less than half of the articles deal with multi-year planning methodologies (17). The longest time horizon considered is 20 years.

A non-sequential approach with a load duration curve is used in most of the articles (30). Only a few of them use a sequential approach with an hourly time-step (4).

Grid modelling:

In most cases, DC approximation is used (26). Flows (3), PTDF (2), OPF (2) and AC load flow (4) are also used. Dynamic simulations are never used.

Capital expenditures are always considered. In half of the articles operational expenditures are also minimized (21). The considered opex are the cost of load curtailment (13), the congestion costs (7) and the cost of losses (3).

Less than half of the methodologies take into account amortization of investments (13), even less of them consider annual budget constraints (7).

Generation modelling:

Most of the time a generic model which only includes generation costs is used (26). Operating constraints, such as minimum power (4), ramping (1), start-up costs (3) and operational reserve (2) are sometimes modelled. Minimal duration is never modelled. In a few methodologies, availability of generating units is considered, either using scenarios (2) or random variables (6).

Hydro power is sometimes specifically modelled. Hydro inflows are then either input scenarios of the methodology (4) or modelled with random variables (1). Reservoir hydro units are modelled in one article.

Wind power is also sometimes considered, either with input scenarios (3) or random variables (3). Related curtailment costs are rarely taken into account (1). Correlation between wind farms generation is never explicitly mentioned but may be considered when random variables are used.

PV is specifically modelled in only one article, using scenarios as input data of the methodology. Related curtailment costs are not considered.

Load modelling:

In most cases, load scenarios are input data of the methodology (32). A few methodologies allow to model load using random variables (5). Demand-side management is rarely considered (3) and is always price sensitive. Correlation is never explicitly mentioned but may be taken into account when random variables are used. Load is never modelled by sectors. The proposed methodologies never include a method to dispatch zonal load forecasts on nodes. When zonal forecasts are used, either load distribution factors are used to get nodal forecasts before applying the methodology, or no information about the method to dispatch forecasts on nodes is given.

[4] The figures between brackets correspond to the number of articles that include the mentioned characteristic.

<u>Reliability criteria</u>:

Half of the methodologies include a reliability criterion (16). In most case curative actions are not considered (18). The reliability criterion is most of the time the N-1 criterion (12). An N-k criterion is sometimes considered (3), in particular when dealing with deliberate outages (2).

These results might suggest that modelling is more detailed in single-year planning methodologies than in multi-year planning methodologies. That is however not the case. This is shown by the following charts, which compare the percentages of articles presenting one of the features mentioned above considering on the one hand all articles and on the other hand only the ones dealing with multi-year planning methodologies. Results obtained for multi-year planning methodologies are quite similar to the one obtained for all articles. It is worth noting that all articles considering ramping or minimum power of generating units, as well as one article out of 2 considering reserve and 2 articles out of 3 considering start-up costs are about multi-year planning methodologies.

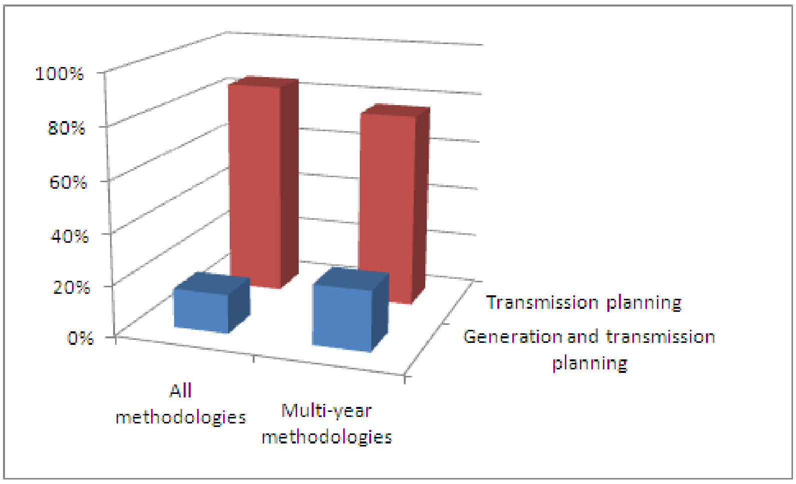


Figure 2: Types of planning methodologies

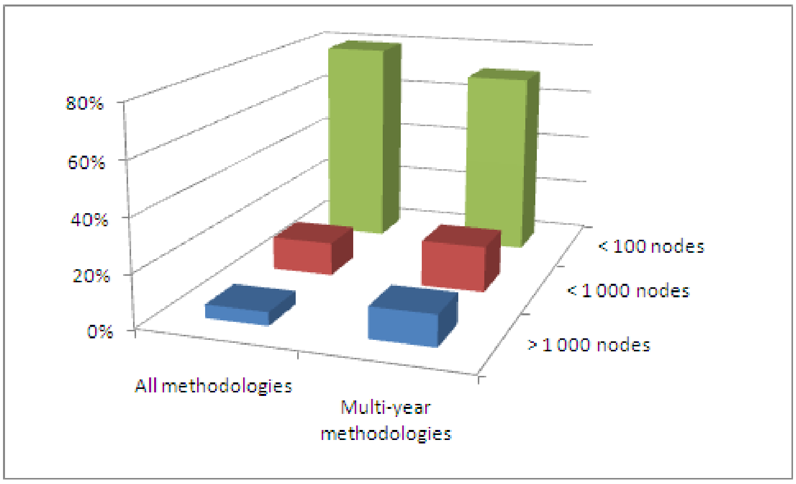


Figure 3: Size of the grid

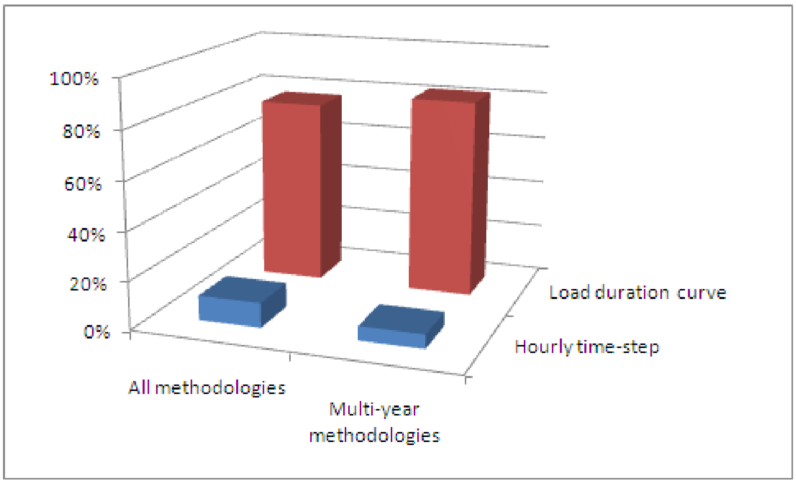


Figure 4: Time-steps

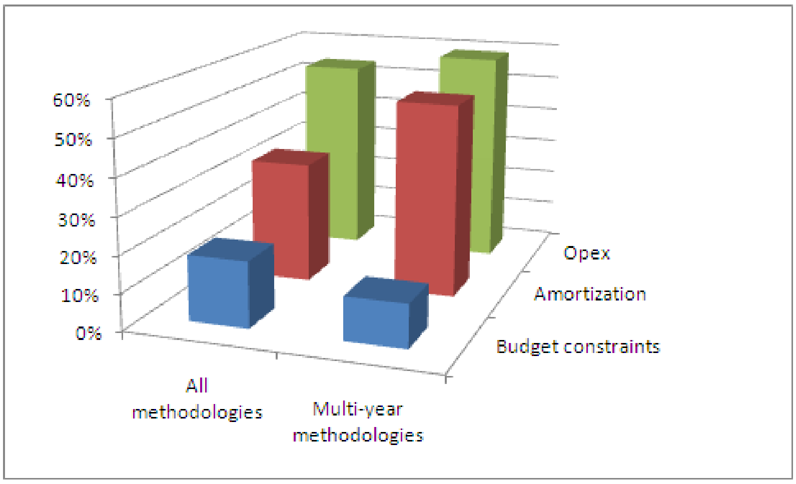


Figure 5: Opex, amortization and budget constraints

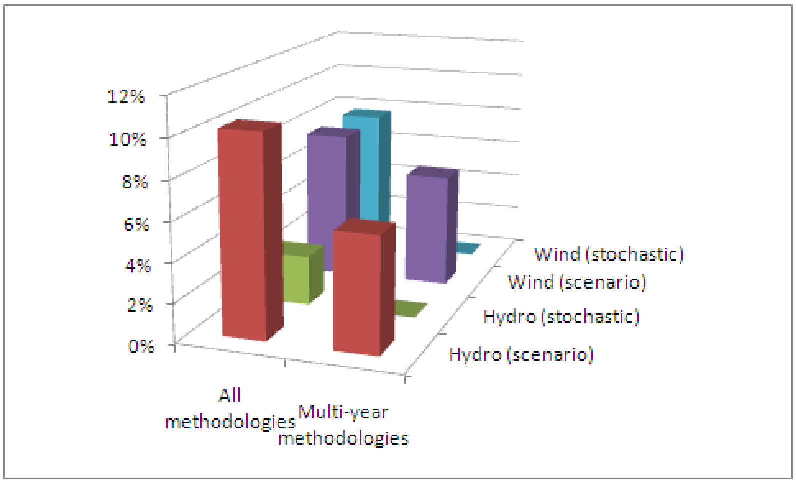


Figure 6:Wind and hydro power generation

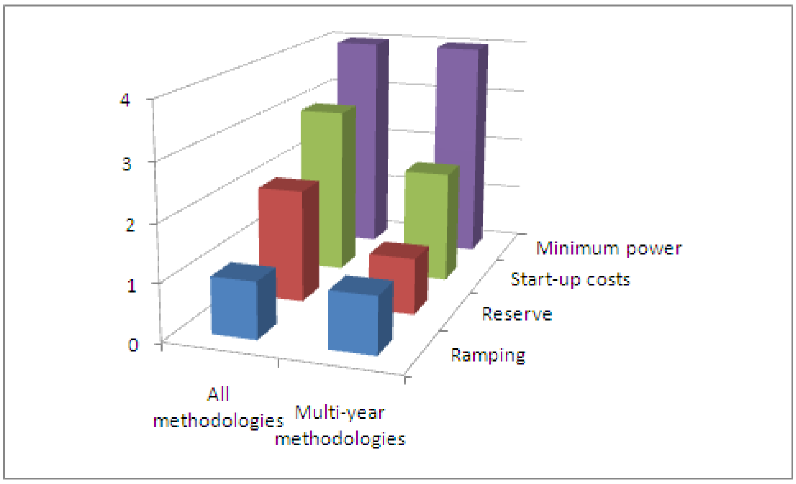


Figure 7: Characteristics of generating units

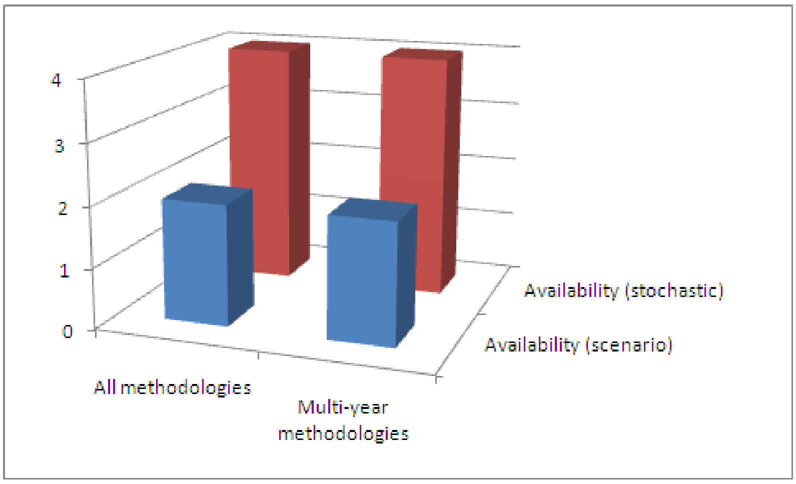


Figure 8: Availability of generating units

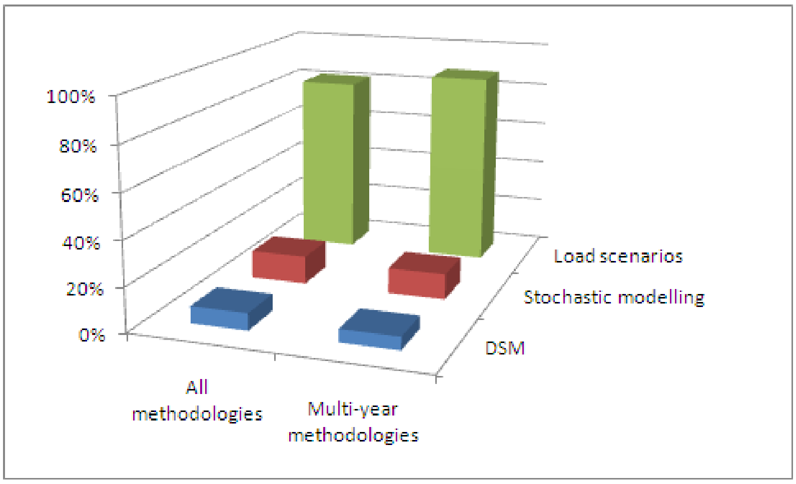


Figure 9: Load modelling

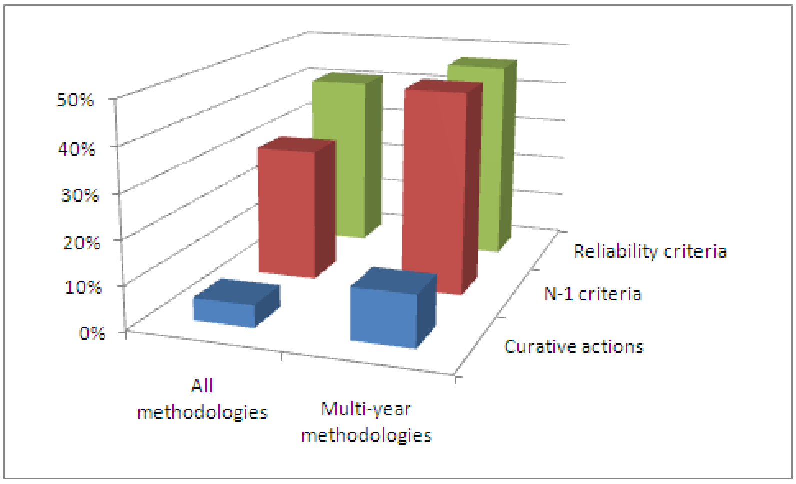


Figure 10: Reliability criteria

2.1.2. Existing planning tools

3 types of tools can be used for planning.

Reliability assessment tools are used to evaluate the level of reliability of a given set of investments. They can be deterministic or probabilistic. The former are for example load flow and stability programs and are not specific to transmission planning. The latter compute indices such as loss of load probability, loss of load expectation or expected unserved energy.

Production cost tools perform a chronological (most of the time an hourly) optimization of the system operation. As reliability assessment tools, they are evaluation models since they do not optimize infrastructure investments. They often include reliability assessment methods.

Expansion planning tools are used to determine minimum cost sets of infrastructure investments subject to constraints related to load, reserve, reliability or sometimes environmental impact. Most of them only optimize generation investments, very few optimize transmission investments. Expansion planning tools often include a production cost evaluation, and consequently also reliability assessment methods.

The table below summarizes characteristics of tools belonging to the 3 categories. As most of them are proprietary tools, documents describing in detail all the features included in the table is rarely available. It might happen that the description below is incomplete for some tools. Deterministic reliability assessment tools are not included since they are not specific to system planning.

TOOL	OBJECTIVE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
		NB OF YEARS	TIME-STEPS		THERMAL	HYDRO	WIND	PV		
	RA: reliability assessement PC: production cost (G)TEP: (generation and) transmission expansion planning	N: multi-year 1: single-year	S: sequential (time-step) NS: non sequential	Areas: multi-area Detailed: detailed network F: flows PTDF / DC / AC OPF Capex / Opex A: Amortization AB: annual budget constraints	Pm: Pmin R: Ramping MD: Minimal duration Availability: Ar: Random variables As: per scenario C: Start-up costs Or: operating reserves	V: Valley modelling Inflows: Ir: random variables Is: per scenario	Wind modelling: Wr: random variables Ws: per scenario Co: Correlation between wind farms generation	Solar radiations and clouds modelling: Sr: random variables Ss: per scenario Co: correlation between PV generation	Load modelling: Lr: random variables Ls: per scenario DSM: DSM modelling Co: Correlation between nodes or zones	Contingency selection: Enum: enumeration MC: Monte-Carlo CA: corrective actions No: no reliability criteria
PSS/TPLAN [42]	RA	1	NS	Detailed, AC						MC, CA
TRELSS [43]	RA	1	NS	Detailed, DC / AC	As, C	Is			Ls	Enum, CA
MECORE [44] [45]	RA	1	NS	Detailed, DC	Ar				Ls, Co	MC
ProMod [46]	PC	1	S (hourly)	Detailed, F / DC	Pm, R, MD, As or Ar, C, Or				Ls	Enum
GridView [47] [48]	PC	N	S (hourly)	Detailed, OPF AB	Or Ar				Ls, DSM	MC, CA
MTSim	PC	1	S (hourly)	Areas, PTDF, Opex	Pm, R, MD, As	Is	Ws	Ss	Ls, DSM	No
ANTARES	PC	1	S (hourly)	Areas, F / DC / PTDF Opex	Pmin, MD, Ar	Ir	Wr, Co	Sr, Co	Lr	MC
PLEXOS [49] [50]	GTEP	N	S (?)	Detailed, OPF	R, As or Ar, Or	V, Ir	Wr	Sr		N-1p, P?
ReEDS [51]	GTEP	N	NS	Areas, F / PTDF Capex, A	Pmin, Or		Wr, Co	Sr, Co	DSM	No
TEPES [52]	TEP	N		F, DC Capex, Opex?	Pmin, C, Ar	Ir	Wr	Sr	Lr	Enum?
ESPAUT	TEP	N	NS	Areas, Detailed, DCOPF, Capex, Opex	Pm, As	Fixed gen.	Ws	Ss	Ls, DSM	Enum
REMARK+	RA	1	S	Areas, Detailed, DCOPF, Opex	Ar	V, Ir	Wr	Sr	Ls	MC
EMPS with investment	GTEP	N	S / NS	Areas Capex, Opex, A	Pm, Ar / As, C, Or	V, Ir / Is	Wr / Ws, Co	Sr / Ss, Co	Ls, DSM	No

TOOL	OBJECTIVE	TIME		GRID MODELLING	GENERATION MODELLING				LOAD MODELLING	RELIABILITY CRITERIA
		NB OF YEARS	TIME-STEPS		THERMAL	HYDRO	WIND	PV		
	RA: reliability assessement PC: production cost (G)TEP: (generation and) transmission expansion planning	N: multi-year 1: single-year	S: sequential (time-step) NS: non sequential	Areas: multi-area Detailed: detailed network F: flows PTDF / DC / AC OPF Capex / Opex A: Amortization AB: annual budget constraints	Pm: Pmin R: Ramping MD: Minimal duration Availability: Ar: Random variables As: per scenario C: Start-up costs Or: operating reserves	V: Valley modelling Inflows: Ir: random variables Is: per scenario	Wind modelling: Wr: random variables Ws: per scenario Co: Correlation between wind farms generation	Solar radiations and clouds modelling: Sr: random variables Ss: per scenario Co: correlation between PV generation	Load modelling: Lr: random variables Ls: per scenario DSM: DSM modelling Co: Correlation between nodes or zones	Contingency selection: Enum: enumeration MC: Monte-Carlo CA: corrective actions No: no reliability criteria
algorithm [53]										
Samnett [54]	GTEP	N	S / NS	Areas/Detailed, PTDF	Pm, Ar / As, C, Or	V, Ir / Is	Wr / Ws, Co	Sr / Ss, Co	Ls, DSM	No

2.2. Challenges

Long-term transmission planning raises many challenges.

Transmission planning is usually performed for time horizons comprised between 10 and 20 years. 20 years is indeed the largest one considered by the articles reviewed in chapter 2.1.1. Long-term transmission planning up to the year 2050 implies to go a step further and broadens the range of energy scenarios that may happen. Taking into account very different scenarios to elaborate a development plan with a unique path for the ten first years is challenging.

The complexity of the problem comes from 3 different dimensions:

- Defining electricity highways able to transmit electricity produced by renewable energy sources throughout Europe requires an adapted working scale. It would be too complex – and, considering the time horizon, not pertinent – to consider the whole European transmission network (10 000 nodes). A sufficient level of detail must however be kept when modelling the grid to take into account distributed phenomena that might be significant in some scenarios. Distributed generation such as wind or solar parks of a few MW, or demand-side management are examples of such phenomena. This leads to **spatial complexity**.
- Time constants range from milliseconds to several years, leading to **temporal complexity**. In case network expansion leads to commissioning of a significant number of power electronics based devices, such as HVDC converter stations and FACTS, the stability of the grid may be affected by their very short time constants (tens or hundreds of milliseconds). An hourly time step is generally considered for unit commitments. Generating units are subject to technical and physical constraints (starting process, ramp up, energy balance...) leading to complex temporal coupling. Transmission investments take several years to be implemented and the permitting process could take more than ten years.
- **Stochastic complexity** must also be taken into account. Besides uncontrollable load, the growing part of renewable energy sources implies to model variations of wind, solar radiation and water inflows. Failures of generating units are also stochastic inputs and must be considered.

Considering spatial, temporal and stochastic complexity together is out of reach. Trade-offs must be made to take into account at most two of them in details at the same time and using an aggressive approximation for third one. For instance, checking adequacy between generation and consumption requires considering temporal and stochastic complexity, but could be done with a simplified grid model. A more detailed model is needed to assess system stability but such studies are done for only a few snapshots. Reducing the complexity of the problem is however challenging. Methods to reduce the size of the grid or to choose a few relevant snapshots among the 8760 hours of a year have to be developed.

Another challenge is to take into account the possible flexibility in the operation of system. There is a trade-off between flexibility and capacity of the grid. Building infrastructure that will not be used during a significant number of hours per year seems suboptimal. To cope with low duration congestions, solutions based on controllable devices (FACTS – flexible alternating current transmission system, controllable generating units or demand side management) could be preferred. Moreover, the reliability could be ensured by corrective actions (post-fault actions) using these controllable devices. We propose to investigate how to take into account this flexibility in the planning methodology. FACTS will be described in the grid modelling and their actions will be simulated using an optimal DC power flow (namely: PST and HVDC links embedded in AC grid). The adjustments of controllable generations and consumptions will be based on their location, cost and capacity as defined by scenario.

3. Proposed high-level methodology

3.1. Decomposition in sub problems and links between them

The following notations are used in the remainder of the document:

- $\mathcal{H}$ is the set of time horizons to be considered to build the modular development plan. Assuming that we want to solve the long-term planning problem with 2050 as the final time horizon, a time-step of 5 years and the 2020 grid as initial conditions, then $\mathcal{H} = [2025; 2030; \dots; 2050]$.
- $\mathcal{S}$ is the set of scenarios describing the different possible evolutions of generation capacities and mixes and of electrical consumption. $\mathcal{S}$ is given as an input.

The aim is to solve the problem of long term planning in six successive steps described below.

In a first step, for each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$, controllable generation and consumption are calculated with an hourly time-step to ensure power adequacy between generation and consumption. Grid constraints are not taken into account in this first step ("copper plate" approach). Several patterns of uncertainties related to the stochastic behaviour of system components (loads, primary energy, and availability of generating units...) are considered, leading to simulate several Monte-Carlo years for each scenario and each time horizon.

In the second step, for each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$, generation and consumption are located on the initial grid (i.e. the grid corresponding to initial conditions). As performing network expansion with a time horizon of 40 or 50 years on a detailed European network of approximately 10 000 nodes is unrealistic and computationally impossible, the initial grid is first reduced to get a simplified nodal initial grid of approximately 1 000 nodes. Generation and consumption are located on that simplified grid. Using DC approximation, overload problems are detected using a worst case approach and taking into account uncertainties and corrective actions. A clustering of the initial grid is then carried out according to the critical branches, leading to a zonal initial grid (approximately 100 nodes).

In the third step, for each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$, a post-processing based on a DCOPF of adequacy results obtained in the first step is performed using the zonal initial grid to assess the congestions' severities and associated costs.

In the fourth step, the modular development plan is calculated at zonal level, by considering at the same time all time horizons and the whole set of scenarios. An optimization tool is used to choose the best combinations of new inter-zonal transmission capacities. As it is impossible to let the optimization tool choose among all technological alternatives, rules are defined and used to reduce ex-ante the number of technological alternatives. Moreover, only a limited number of snapshots can be used by the optimization tool for each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$. A set of relevant snapshots is determined ex-ante. We want to consider three different possible architectures, the first one giving priority to long distance connections, the second one to short distance connections and the last one should result in a hybrid architecture. The resulting modular development plans are ranked according to their total costs (capital and operational expenditures). The final choice is performed after assessing the robustness of the proposed architectures (see below).

In the fifth step, starting from the zonal modular development plans, grid expansion is performed for the two first time horizons at nodal level, using the simplified grid elaborated in the second step. As for the previous step, a list of candidates for nodal expansion is determined ex-ante.

In the sixth step, the robustness of the nodal grid architectures proposed for the two first time horizons is checked to ensure that these grids can be operated without major voltage or stability concerns.

The sequence of these steps and the links between them are illustrated on the next figure.

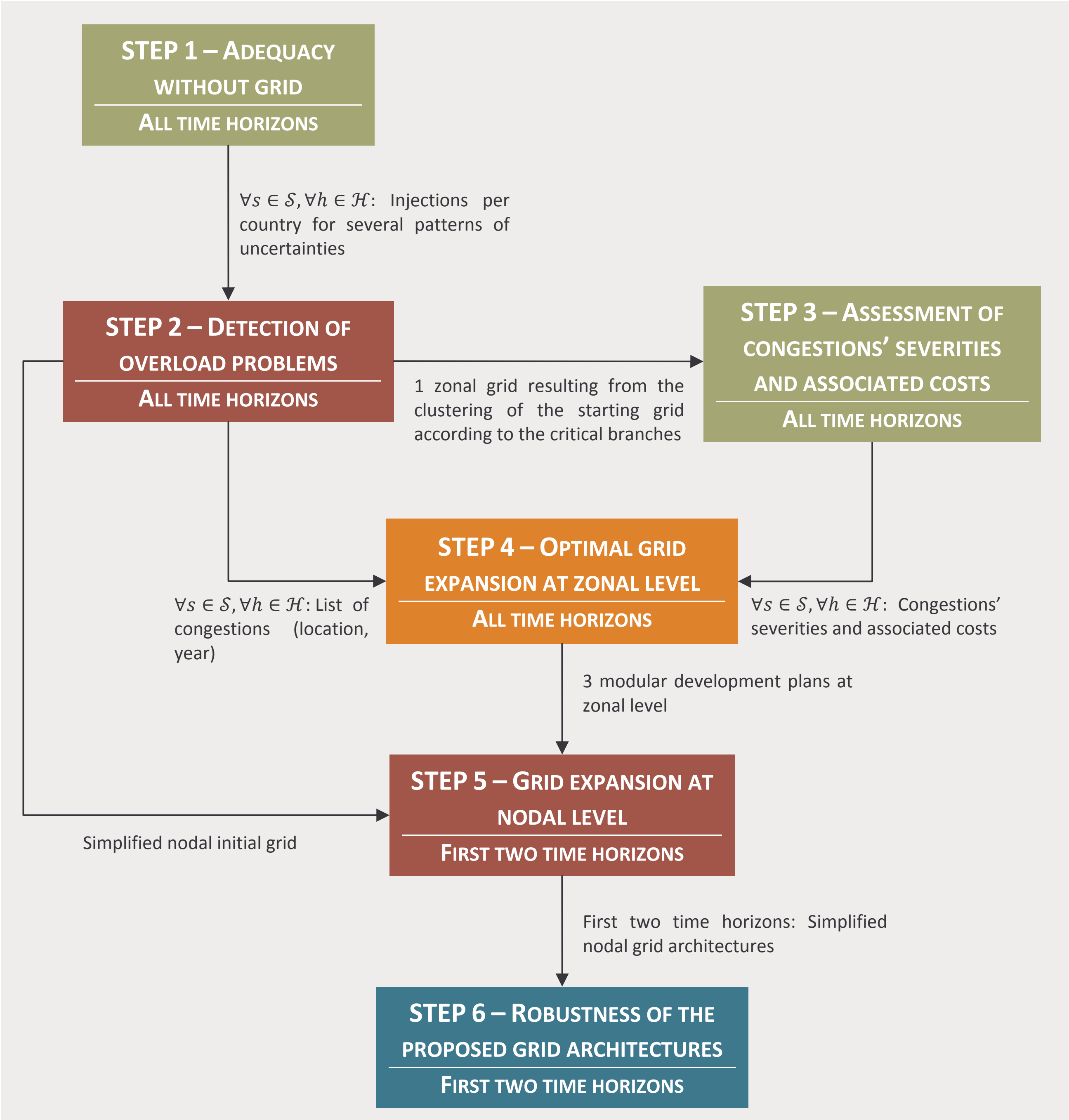


Figure 11: Sequence of steps and interfaces between the steps

The development of the methods associated to the 6 steps will be distributed as follows between the tasks of WP8:

- The work dedicated to adequacy simulations, which includes both calculations without grid constraints (step 1) and assessment of congestions' severities and associated costs (step 3) will be performed in *task 8.2: Definition of generation and demand scenarios*
- The work to detect of overload problems (step 2) will be performed in *task 8.3.1: Detection of system overloads*

- The work aiming at determining the optimal grid expansion at zonal level (step 4) will be performed in *task 8.4: Enhanced modular development plan*
- The work dedicated to transmission planning at nodal level (step 5) will be performed in *task 8.3.2: Grid expansion at nodal level*
- The work dedicated to robustness estimation (step 6) will be performed in *task 8.5: Robustness of the proposed grid architectures*

The different steps are explained in more details within the following chapters.

3.2. Computation of generation and demand time series (Adequacy without grid)

3.2.1. Problem statement

For a scenario $s \in \mathcal{S}$ and a time horizon $h \in \mathcal{H}$, the problem is to compute the hourly dispatch of controllable generation and consumption, and thus to calculate time series of power injection in each location of the system.

Such time series depend on a number of uncertainties, namely the evolution throughout the year of uncontrollable load, wind, solar radiations and hydro inflows, and the availability of generating units.

For a given pattern of uncertainties, controllable generation and consumption are the result of an optimization problem, whose objective function is the minimization of the operational expenditures of the system over the whole year. The operational expenditures considered here are the generation costs and possibly the costs of load shedding and of generation curtailment. As explained in chapter 1, we want to solve the overall problem of grid planning as a system operator and therefore grid expansion will be defined by minimizing the expected *grid* capital and operational expenditures. The problem considered here is different. The aim is to build generation schedules to meet load evolution. Such generation schedules are defined by producers, who try to minimize their own operational expenditures. This is why operational expenditures *related to generation* are considered here.

In this optimization problem, one of the constraints to take into account is power adequacy, which must be ensured for each time step:

$$\forall t, \sum_{g} P_{g,t} = \sum_{c} P_{c,t}$$

$P_{g,t}$ is the power produced by the generating unit g at time step t and $P_{c,t}$ the power consumed by load c at time step t. This general formulation does not preclude taking into account pumping and storage which can be considered either as generating units or as loads. The maintenance and refuelling strategies will be simulated but not the unforeseen outages. In order to cope with such possible contingencies, we propose to keep margins and to reduce the maximum technical capacities of generators.

Grid constraints can also be taken into account. However, for grid planning, they should not be taken into account in a first phase. The exchanges between geographical areas should not be bound by existing grid constraints. The new exchange capacities that would be needed at the considered time horizons must on the contrary be calculated.

The other constraints that can be considered are related to the behaviour of generating units (e.g. minimum and maximal power, ramp constraints), to the behaviour of consumption (e.g. demand side management) or to the operation of the grid (e.g. reserves). One key point is to model the system elements with a homogeneous level of details. For instance, a precise modelling of demand side management may be useless for a system with many hydro valleys if hydro modelling is simplistic. The error caused by such simplifications could be greater than gains brought by the modelling of demand side management.

This optimization problem allows calculating controllable generation and consumption for a given pattern of uncertainties. It must be repeated to take into account a large number of such patterns, which are generated via Monte-Carlo simulations. This requires a modelling of uncertainties by stochastic processes. Uncertainties are uncontrollable load, wind, solar radiations, hydro inflows and availability of generating units. The stochastic processes must represent seasonal and daily variations, temporal and spatial correlation of each of the stochastic inputs as well as temporal and spatial correlation between the stochastic inputs. For instance, electrical consumption due to air-conditioning is obviously correlated to solar generation. Ignoring this correlation could lead to consider for adequacy calculations some cases with much air-conditioning but with few PV generation in the same geographical area. Grid reinforcements could then be oversized to cope with such unrealistic situations.

3.2.2. Proposed methodology

As the first step of the methodology, we propose to calculate hourly time series of power injections for each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$. Those time-series are obtained via an adequacy simulator which performs the hourly dispatch of controllable generation and consumption. The impact of uncertainties is considered thanks to Monte-Carlo simulations.

This first step is necessary to ensure the consistency of scenarios in terms of generation adequacy. The generation fleet must be sufficient to meet the consumption and must not be oversized. Grid constraints, which are not necessary for such adequacy calculations, are not considered in this first phase. As a result, the time series contain information about the grid capacities needed to accommodate the considered load and generation fleet. This information is used later on in the methodology (see chapter 3.3).

This first step comprises two stages performed for each scenario and each time horizon. They are described below.

Generation of correlated time series of stochastic inputs

Using the information contained in the considered scenario, uncontrollable load, wind, solar radiations, hydro inflows and availability of generating units are modelled with stochastic processes capturing seasonal and daily variations as well as temporal and spatial correlations. Monte-Carlo simulations are then performed to generate correlated time series of these variables covering the considered time horizon with an hourly time step.

The challenge and field of research associated with this part of the methodology is the modelling of temporal and spatial correlation between stochastic inputs. Contrary to seasonal and daily variations and to temporal and spatial correlation of a given stochastic input, they are rarely considered today when performing power adequacy simulations.

Power adequacy simulations without grid constraints

For each of the Monte-Carlo years previously generated, a deterministic power adequacy simulation is performed. Its outputs are hourly time series of controllable generation and consumption over the considered time horizon.

In order to ensure a homogeneous modelling of system elements, we propose to start with a simulator which only includes the essential elements for adequacy simulations (called ***Reference Adequacy Model*** in the remainder of this document) and to assess the impact of possible additional features one by one.

3.2.3. Risks and mitigation plan

The table below summarizes the risks associated to the definition of generation and demand time series and the corresponding mitigation measures.

	Potential risk or failure mode	Effect of failure	Severity	Probability	Mitigation plan
1	No critical review of existing solutions	No assessment of new needs	High	Low	We base our methodology on the review of at least 2 existing tools (Antares and MTSim), which are rather different. We want to decide which are the relevant features for pan European long term planning.
2	Too many additional features to study for the Reference Adequacy Model (common part between Antares and MTSim) to be evaluated on a large system	Difficult to decide on the relevance of these features for large systems	Medium	Medium	Ranking of the possible additional features approved by all WP8 partners at the beginning of the task, so as to consider first those likely to have the greatest impact

3.3. Detection of overload problems and assessment of congestions' severities and their associated costs

3.3.1. Problem statement

When performing network planning, congestions are detected using DC approximation, in order to separate overload problems from voltage and stability issues. The latter will be tackled later on in the methodology, when the former are solved.

Detecting overload problems on a large grid is challenging since time complexity is added to spatial complexity due to the size of the network. Indeed, generation and consumption are defined with hourly time-steps for a large number of Monte-Carlo years, leading to several thousands of injection patterns. One of the challenges is to detect which of these patterns will lead to congestions. We want to solve this problem without selecting ex-ante some “representative” time-steps (such as peak or off-peak), which does not ensure an exhaustive detection of overload problems. This is all the more true as the increasing level of uncertainties can lead to much contrasted injection patterns.

Regarding spatial complexity, long-term planning requires an adapted scale. Using the whole European network, which includes about 10 000 nodes, is unrealistic. The European grid must be reduced. Existing network reduction techniques mainly aim at keeping branches currently likely to be overloaded and at reducing the other parts of the network. They are not relevant for long-term planning since deep changes in generation and consumption patterns can completely change the list of such critical branches. We want to define a method for network reduction based on a criterion unlikely to change by the considered time horizons.

The increased level of grid flexibility can allow alleviating congestions without resorting to generation adjustments, which are generally more expensive. Corrective actions such as phase shifter actions or modification of HVDC links set-points must be taken into account to detect only the constraints that cannot be solved with such “costless” actions.

The assessment of congestions’ severities and their associated costs are important factors when it comes to deciding on network reinforcements. We want to calculate the probabilistic severities and costs of the detected overload problems so as not to propose network expansion for congestions likely to occur very rarely (a few hours per year for instance). The underlying assumption is that corrective actions able to solve such congestions will be available when they occur and that, even if they happen to have a cost, they will be far less expensive than the network reinforcements required solving the congestion.

3.3.2. Proposed methodology

Reduction of the initial network

The European network includes approximately 10 000 nodes. As explained above, detecting the congestions that would occur if the injections foreseen for a scenario $s \in \mathcal{S}$ and a time horizon $h \in \mathcal{H}$ were applied on the complete existing European grid is unrealistic. A method for network reduction based on a criterion unlikely to change by the considered time horizons is needed.

We propose to use electrical distance as a criterion and to aggregate the nodes that are electrically close to each other. Assuming that this criterion will not change by the considered time horizons means that the electrical distance between nodes will not increase. In other words, existing grid infrastructure will not be removed.

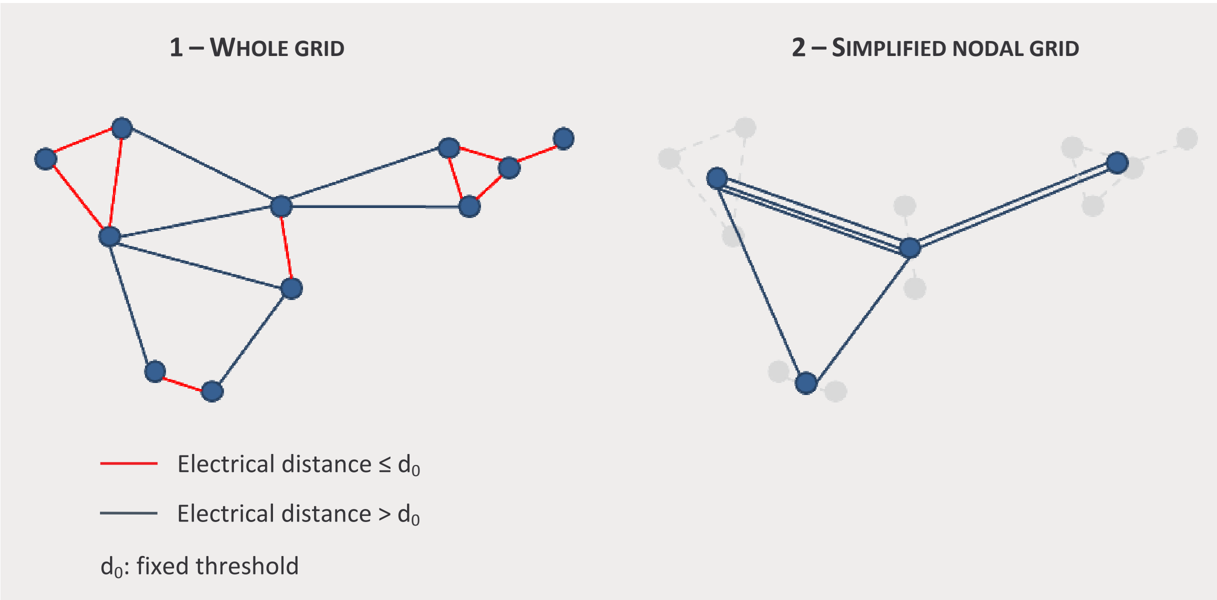


Figure 12: Method for grid reduction based on electrical distance

Aggregating nodes electrically close to each other also implies that very local congestions cannot be detected, which is an acceptable assumption for a continent wide planning methodology. Local reinforcements, if they are necessary, shall be planned in a second stage.

We aim at reducing the size of the European network of a factor 10, leading to a simplified nodal grid of approximately 1 000 nodes. In the remainder, the terms ***simplified nodal grid*** or more simply ***nodal grid*** will be used to refer to the output of grid reduction, whether before or after grid expansion.

Automatic mapping of generation and consumption on nodes

In a second step, generation and consumption must be located on the nodal initial grid. We want to define an automatic method based on maps showing for instance location of sources of primary energy (wind, sun, hydraulic...) and population density.

Detection of overload problems

To take into account the stochastic behaviour of system components (loads, primary energy, availability of devices and units...), generation and consumption are defined with an hourly time-step for a large number of Monte-Carlo years, leading to thousands of injection patterns. We want to detect congestions without selecting ex-ante some “representative” patterns with a worst case approach and using information included in Monte-Carlo simulations.

Upper and lower bounds of each injection can be deduced from Monte-Carlo simulations, leading to:

$$I_{min} \leq I \leq I_{max}$$

where I is the vector of nodal injections and I_{min} and I_{max} the vectors of minimum and maximum nodal injections. Adding this information is possible using principal component analysis:

$$I = I^0 + A.J$$

with J the vector of principal components. The size of I being N and as we know that injections on the European grid are correlated, the size of J is M, with $M \ll N$. Lower and upper bounds can be calculated for vector J:

$$J_{min} \leq J \leq J_{max}$$

The worst case for a branch is the set of nodal injections that leads to the maximum flow in this branch in the presence of the best possible controls (phase shifter angle, HVDC active power set-points...). We will consider the base state only (no contingency), since mixing a worst case approach and contingencies would lead to design the grid for very extreme (and rare) cases.

For a given set of uncertain nodal injections J (J), finding the best possible costless controls can be done by solving the following optimization problem that minimizes the total relative violation of line thermal limits:

$$\min_{\theta,\delta_0,u_0} \delta_0$$
$$s.t.$$
$$\begin{cases} I = I^0 + A.J \\ I_{min} \leq I \leq I_{max} \\ \sum I_k = 0 \\ g(\theta, u_0, I) = 0 \\ h_i(\theta, u_0, I) \leq \delta_0.L_i \\ u_0^{min} \leq u_0 \leq u_0^{max} \\ \delta_0 \geq 0 \end{cases}$$

δ_0 is the violation (when > 1) of thermal limit (L_i) of branch i in N state. x_0 is the vector of state variables (voltage angles) and u_0 the vector of controls. Function g denotes the DC power flow equations and function h_i the thermal limits constraints of branch i (linear equations). The constraint $\sum I_k = 0$ is added to ensure the balance.

Let us call δ_0^* the solution of the problem. δ_0^* is the minimum overload that can occur on branch i in N state given the injection pattern J. $\delta_0^* < 1$ means that branch i is not overloaded. The worst case for branch i can be found by maximizing this value considering all the possible injection patterns, yielding:

$$\max_{J,\delta} \delta$$
$$s.t.$$
$$J_{min} \leq J \leq J_{max}$$
$$\delta \leq \delta_0^*$$
$$\delta_0^* = \underset{\theta,\delta_0,u_0}{\operatorname{argmin}} \delta_0$$
$$s.t.$$
$$\begin{cases} I = I^0 + A.J \\ I_{min} \leq I \leq I_{max} \\ \sum I_k = 0 \\ g(\theta, u_0, I) = 0 \\ h_i(\theta, u_0, I) \leq \delta_0.\mathrm{L_i} \\ \delta_0 \geq 0 \end{cases}$$

δ^* is the maximal overload that can happen on branch i in N state.

Branches for which this value is greater than one are ***critical branches*** that can be overloaded.

Areas with new load centres or generation plants (for example offshore wind farms) at a time horizon $h > 2020$ and electrically not connected at the initial time horizon ($h = 2020$) must be considered in the detection of critical branches. To perform balanced DC power flows, fictitious lines with infinite capacities will be added for the detection. Obviously new lines will be required to connect these areas to the pan European grid. These areas will be kept as zones in the reduction of the grid presented below.

Reduction of the nodal initial grid according to critical branches

For each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$, we propose to carry out a clustering of the grid according to the critical branches detected in the previous step, leading to a ***zonal initial grid*** for scenario s and time horizon h.

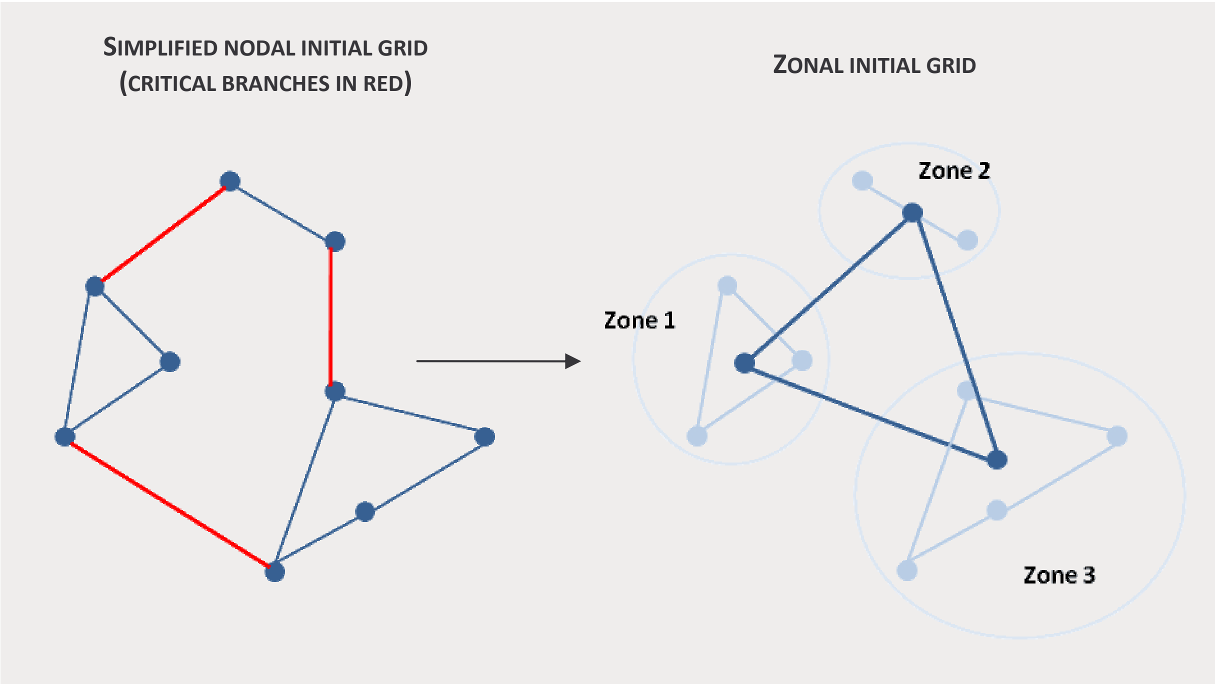


Figure 13: Clustering of the simplified nodal grid according to the critical branches

We then want to merge the obtained zonal initial grids (one per scenario and per time horizon), so as to get one unique zonal grid that can be used to elaborate a modular development plan. The simplest way would be to keep all critical branches and reduce the other parts of the network. Such a method would probably lead to significantly increase the size of the resulting network. Yet, this size cannot be too large, otherwise optimizing grid expansion over some decades, for several scenarios and taking into account the stochastic behaviour of system components – at least partly – will not be possible (see chapter 3.4 for more details). We want to use smarter methods to reduce as much as possible the size of the merged network, so as it includes a reasonable number of nodes (about 100). Different approaches could be considered, at least two:

First approach:

1.) detect critical branches for every scenario and every year,
2.) classify nodes into zones for every scenario and every year,
3.) merge all the "zonal" grids into one that is valid for all scenarios and all years

Second one:

1.) detect critical branches for every scenario and every year,
2.) merge all critical branches in single aggregated set,
3.) classify nodes into zones based on the aggregated set of critical branches

The precise method will be defined during the research activity using realistic data.

Assessment of congestions' severities and their associated costs

The congestions' severities on critical branches and their associated costs can be estimated by post-processing the results of adequacy simulations (see chapter 3.2). Injections can be located on the zonal initial network with a method similar to the one used to perform this mapping on the nodal initial grid, yielding hourly zonal injections for every Monte-Carlo year, every time horizon and every scenario.

The ideal solution would be to run again the "adequacy simulator" with grid constraints. By limiting the number of zones to around 100 and using a HPC facility, the problem is perhaps solvable. The feasibility of the problem must however be assessed as we also want to use the possibilities offered by existing flexible grid devices (PSTs, HVDCs) in 2020.

As an alternative solution, if the ideal previous one is intractable, we could compute the flows between the zones on critical branches using a DCOPF to take into account the possible controls (PSTs, HVDCs).

For a given set of nodal injections I (I), finding the minimal adjustments' costs of controllable generation and load using best possible costless controls (HVDC, PST) can be done by solving an optimization problem. The idea is to solve a large number of independent problems trying to minimize the impact on the optimal generation/load patterns computed by the adequacy simulator without grid. Below, we propose a simplified formulation of this problem (in particular the objective function) which will be more precisely defined during our research activity.

$$\min_{\theta,u_c,u_0} \sum_{\mathrm{g} \in \mathrm{S_c}} \mathrm{c_g} \left| u_{c,g} - u_{c,g}^0 \right|$$

$$s.t.$$

$$\begin{cases} g(\theta, u_p, u_0, I) = 0 \\ h(\theta, u_p, u_0, I) \leq L \\ u_p^{min} \leq u_p \leq u_p^{max} \\ u_0^{min} \leq u_0 \leq u_0^{max} \end{cases}$$

Where $\mathrm{S_c}$ is the set of controllable injections (generations or loads), $\mathrm{c_g}$ is the adjustment's cost of the injection g, u_c is the vector of active power of the controllable injections, u_c^0 is the vector of active power injections computed previously by adequacy simulation without grid. u_0 is the vector of costless actions (PST, HVDC).

This is a huge number of independent DCOPFs. Let's try to find a rough estimate of the needed computation power and its cost.

Number of hours per year = 8760

Number of Monte Carlo simulations per time horizon and per scenario = 2000

Number of time horizons = 6 (2025, 2030, 2035, 2040, 2045, 2050)

Number of scenarios = 7

That is mean 735 840 000 DCOPFs.

Each DCOPF (not very large LP, only 100 zones) does not require a large computation time.

For a computation time of 1 second, if we use a HPC Cloud with 16000 cores (1000 servers with 16 cores), we need around 13 hours of computation to solve all these DCOPFs. The cost for such a run using the current HPC Cloud offers is less than 25 k€. This is not an incredible amount of money, considering that in an operational use, we'll do this at most once every year for a joint planning study at European Level. Moreover, the cost to access HPC Cloud is decreasing rapidly.

After this previous computation whatever the chosen option, the congestions' severity and their associated costs are compared to reduce the list of congestions to tackle in the global optimization process: multi time horizons and multi scenarios. Constraints whose severities and costs are lower than thresholds to be defined are no longer considered. We assume that they will be solved using other preventive or corrective actions whose cost will be lower than the one of corresponding reinforcements. The severities and the associated costs will be precisely defined during our research activity. For example, for costs associated to binding constraints, we can think obviously to use Lagrange multipliers.

3.3.3. Risks and mitigation plan

The table below summarizes the risks associated to the detection of system overloads and the corresponding mitigation measures.

	Potential risk or failure mode	Effect of failure	Severity	Probability	Mitigation plan
1	Difficult automatic mapping of generation and consumption defined by control blocks on nodes	No automatic method, manual process required: time consuming and/or more man power	Low	Medium	A partial automatic method will be proposed. Specification of light dedicated tools to help planners.
2	Too many zones	Too much computational power required	Medium	Medium	The maximum number of zones will be a tuneable parameter in the methodology.
3	Not enough zones	Results not fully realistic	Medium	High	We propose a formulation of the definition of the zones, which tries to maximize the realism under the computational power constraints.

3.4. Optimal grid expansion at zonal level

3.4.1. Problem statement

Given a zonal initial network and, for each scenario $s \in \mathcal{S}$ and each time horizon $h \in \mathcal{H}$, a list of congestions, the problem is to find a modular development plan which minimizes the expected grid capital and operational expenditures over the whole considered time period and meets the following constraints:

- congestions are alleviated by the proposed reinforcements
- the incremental grid development is unique for the first 10 years

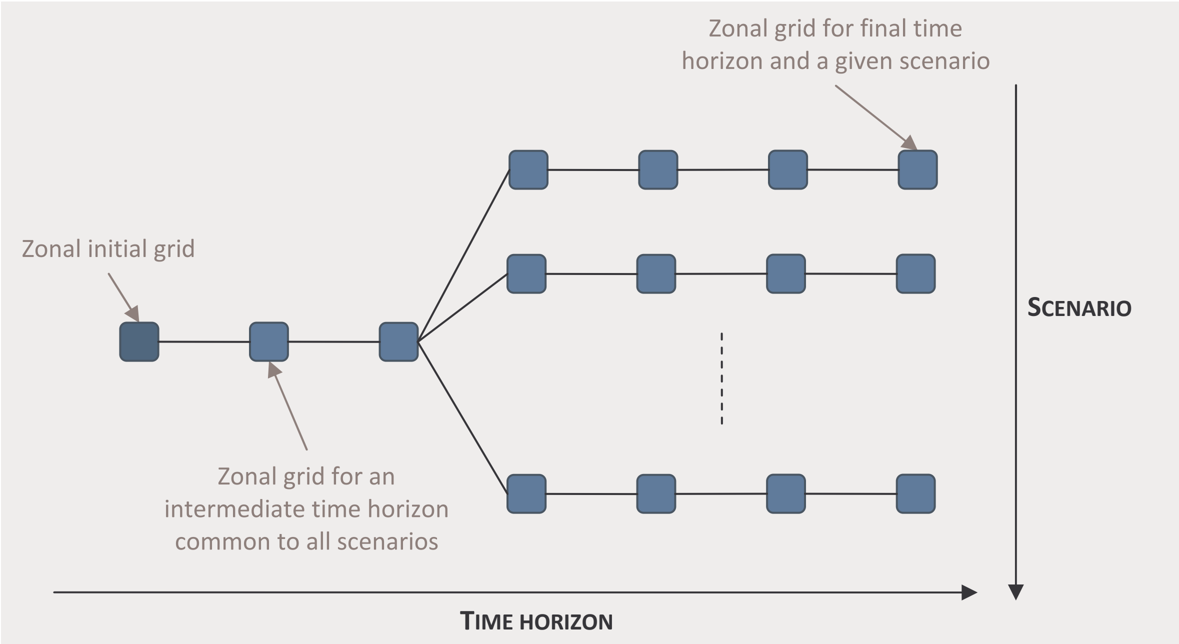


Figure 14: Modular development plan at zonal level

As the grid considered here is the zonal one, only the base state is assessed in this step, since it may not be reasonable to perform a contingency analysis on such a reduced network. Contingencies are evaluated later on in the methodology (see chapter 3.6).

3.4.2. Proposed methodology

The proposed methodology consists in 3 steps that are described below.

Selection of representative snapshots

Considering every snapshot (i.e. every hour of every Monte-Carlo year for all considered time horizons and all scenarios) to solve this optimization problem is not realistic[5]. Criteria must be defined to select a limited number of representative snapshots per scenario and per time horizon.

Elaboration of a list of possible new transmission capacities

Another challenge is to define, for each of the considered time horizons, where new infrastructures can be connected to the zonal initial grid. It is impossible to let a cost-based optimization tool choose among all technological alternatives because it would lead to unrealistic options (AC lines of a few thousands of kilometres). Conversely, capacities decided ex-ante by experts and validated afterwards through simulations may be suboptimal. We propose to use an optimization tool to find the grid expansion but to reduce ex-ante the number of technological alternatives using rules. These rules will allow choosing a specific technology for each new inter-zonal transmission capacity taking into account distance, acceptability of overhead lines...

Optimal grid expansion at zonal level

Once representative snapshots as well as technological options for each new inter-zonal transmission capacity are identified, the optimization problem can be solved. The output is a modular development plan at zonal level (approximately 100 nodes) minimizing the expected grid capex and opex for all the time horizons.

The reliability and robustness issues could not be included very easily in this optimization phase. We propose to define three main alternatives and the "robustness assessment" task will then select among them. These alternatives will also allow comparing long distance connections to local expansions (upgrades of existing corridors...). We propose to consider the following alternatives:

1. choice of transmission capacities based only on costs
2. choice based on costs and penalization of long distance connections
3. choice based on costs and penalization of short distance connections

Option 3 will give a priority to long distance connections, option 2 to short distance connections and option 1 should result in a hybrid architecture.

The result will be three different modular development plans (3 times Figure 14) ranked accordingly to their total costs.

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[5] The following assumptions:

- grid planning from 2020 to 2050 with a time step of 5 years
- 5 scenarios
- 1 000 Monte-Carlo years per scenario and per time horizon

lead to more than 200 million snapshots.

3.4.3. Risks and mitigation plan

The table below shows the risk associated to the grid expansion at zonal level and the corresponding mitigation measures.

	Potential risk or failure mode	Effect of failure	Severity	Probability	Mitigation plan
1	The ambition has been set too high to reach satisfactory results within the three year project	Downgraded outputs when compared to expectations at project start	Medium	High	Expectations have been set intentionally high in order to push as far as possible methodology and tools. Other R&D project will be needed in the future to take advantage of new high performance computing facilities.

3.5. Grid expansion at nodal level

3.5.1. Problem statement

The objective is to define precise nodal grid expansions for the two first considered time horizons (2025, 2030) and for the three possible zonal architectures (long distance connections, short distance connections, hybrid) defined by the "optimal grid expansion at zonal level" described in 3.4.

The result will be three different nodal grid expansions for the two first considered time horizons ranked accordingly to their total costs. They will be compliant with the grid capacities defined in the zonal approach. These designs will ensure system reliability (N-1) taking into account all the possible flexible devices (existing and new ones).

3.5.2. Proposed methodology

The nodal description will be precise enough with 1 000 buses for the whole pan European grid. The initial grid will be the one defined by using the method proposed in 3.2.2 "Reduction of the initial network".

The technology to provide the inter-zonal capacities will be selected in "optimal grid expansion at zonal level". The implementation at nodal level will only split the inter-zonal capacities in several actual transmission links, keeping the selected technology (AC, DC VSC, DC LCC...).

The same snapshots as the ones selected in "optimal grid expansion at zonal level" will be used. The building of the nodal snapshots starting from the zonal ones will be done using the same method as the one defined in 3.2.2 "Automatic mapping of generation and consumption on nodes".

The consistency between the 2 time horizons will be ensured.

For each new inter-zonal capacity, we will define a reasonable number of candidates for nodal expansion between the 2 considered zones using heuristics (sensitivity analysis...).

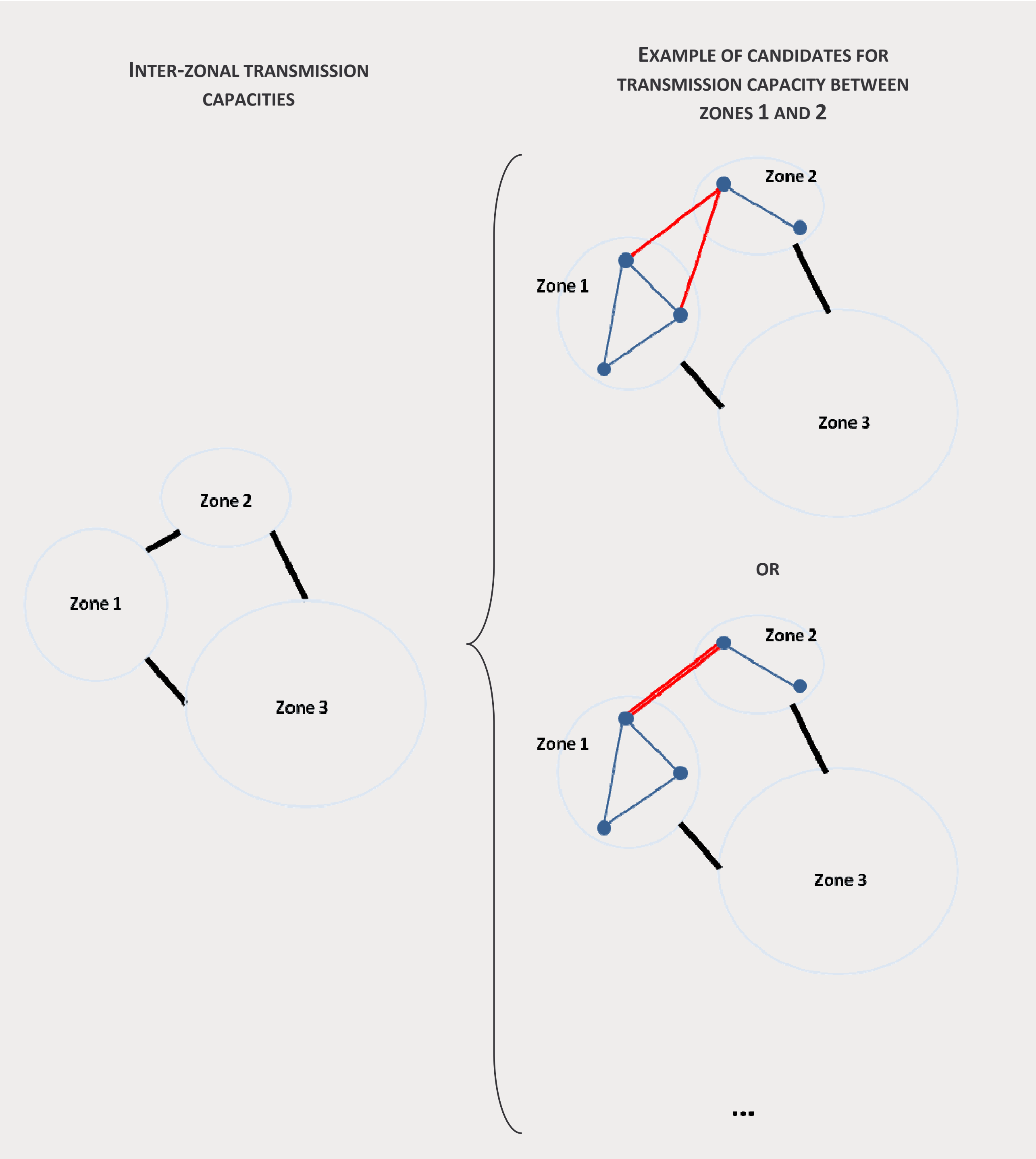

Figure 15: Set of candidates given to the optimizer for transmission capacity between zones 1 and 2

An optimizer will choose the best configuration mixing all the candidates for all the inter-zonal capacities, ensuring reliability (N-1) and fulfilling the given inter-zonal capacities. The flexibility brought by special devices (PST, HVDC links...) will be used to minimize the costs.

The optimizer will choose the need and the capacity of the 3 red links keeping the capacity between zones 1 and 2 while ensuring the N-1 criterion. In this illustration, we just show the candidates between zones 1 and 2, but the optimizer will solve a global problem, taking into account all candidates between all zones.

3.5.3. Risks and mitigation plan

The table below summarizes the risks associated to the grid expansion at nodal level and the corresponding mitigation measures.

	Potential risk or failure mode	Effect of failure	Severity	Probability	Mitigation plan
1	Too many candidates for nodal links	Too much computational power required	Medium	Medium	The maximum number of candidates will be a tuneable parameter in the methodology.
2	Too few candidates for nodal links	Results not fully realistic	Medium	High	Planning experts will be asked to review the proposed heuristics to define the candidates.

3.6. Robustness of the grid architecture proposed

3.6.1. Problem statement

The objective is to check that a grid architecture could be operated without major voltage and stability concerns. All the previous stages of the methodology are based on DC approximation and do not guarantee the absence of voltage and dynamic problems. This analysis will allow eliminating problematic grid architectures.

The robustness of the nodal grid architectures proposed for the two first time horizons will be assessed on selected snapshots.

3.6.2. Proposed methodology

A method will be proposed to select snapshots subject to possible voltage and stability problems among the ones selected in 3.4.2 “optimal grid expansion at zonal level”. The selection could be driven by specific phenomena: one selection for voltage problems, one selection for transient stability problems, one selection for small signal stability problems...

Realistic base cases will be built to ensure the convergence of AC power flows, adding possible reactors and capacitors. The associated costs will be estimated.

The modelling of the dynamic behaviour including control and protection will be done using standard ideal models.

For each phenomenon, we will define a method to select possible problematic contingencies. Then possible problems will be checked for each phenomenon, each associated snapshot and contingencies. This analysis could be based on time domain simulations or relevant approximations reducing the required computation time.

These assessments are done first for the nodal grid architectures corresponding to the modular development plan of minimum cost. If they prove to be unacceptable or if the cost (mainly MVar investments ensuring a good voltage profile) is greater than the cost of the next possible architectures (in increasing order of cost) then we will assess the robustness of the next possible architecture and so on.

For low probability events, the feasibility of designing defence plans to cap the impact of such events will be examined. Since the number of low probability events is very high, an exhaustive enumerative approach to check the efficiency of an ideal defence plan is out of reach. Rather, a criterion based on the speed of the spatial expansion of collapse will be envisaged, together with innovative approaches recently reviewed for instance within the Task Force: Understanding, Prediction, Mitigation and Restoration of Cascading Failures, IEEE PES Computer and Analytical Methods Subcommittee (CAMS).

3.6.3. Risks and mitigation plan

The table below shows the risk associated to the robustness analysis and the corresponding mitigation measure.

	Potential risk or failure mode	Effect of failure	Severity	Probability	Mitigation plan
1	The ambition has been set too high to reach satisfactory results within the three year project	Downgraded outputs when compared to expectations at project start	Medium	High	Expectations have been set intentionally high in order to push as far as possible methodology and tools. Other R&D project will be needed in the future to take advantage of new advanced control theories (Homogeneous Polynomial Lyapunov Functions (HPLFs), flat pseudospectral method…).

ANNEX 1 – Glossary

Scenario	Input of the methodology describing one possible evolution of generation capacities and of electrical consumption
(Simplified) nodal grid	Grid resulting from the reduction of the complete pan European grid (including UK and Nordic countries) whose nodes electrically close to each other were aggregated
Critical branch	Branch of the nodal initial grid which is likely to be overloaded for some scenarios and time horizons
Zonal grid	Grid resulting from the clustering of the simplified nodal grid according to critical branches
Reference Adequacy Model	Simulator prototype which includes only the elements essentials to perform adequacy simulations and will be developed based on the review of existing tools
Inter-zonal transmission capacity	For a given scenario and a given time horizon, transmission capacity needed between two zones of the zonal grid to accommodate generation and consumption defined in the scenario

ANNEX 2 – References

General references

[1] 10-Year Network Development Plan 2012, ENTSO-E, 5 July 2012

Transmission expansion planning methodologies

[2] A Three-Level Static MILP Model for Generation and Transmission Expansion Planning

Pozo, D. ; Sauma, E.E. ; Contreras, J. Power Systems, IEEE Transactions on

Volume: 28 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2012.2204073

Publication Year: 2013 , Page(s): 202 - 210

We present a three-level equilibrium model for the expansion of an electric network. The lower-level model represents the equilibrium of a pool-based market; the intermediate level represents the Nash equilibrium in generation capacity expansion, taking into account the outcomes on the spot market; and the upper-level model represents the anticipation of transmission expansion planning to the investment in generation capacity and the pool-based market equilibrium. The demand has been considered as exogenous and locational marginal prices are obtained as endogenous variables of the model. The three-level model is formulated as a mixed integer linear programming (MILP) problem. The model is applied to a realistic power system in Chile to illustrate the methodology and proper conclusions are reached.

[3] Transmission Network Expansion Planning With Complex Power Flow Models

Bent, R. ; Toole, G.L. ; Berscheid, A. Power Systems, IEEE Transactions on

Volume: 27 , Issue: 2

Digital Object Identifier: 10.1109/TPWRS.2011.2169994

Publication Year: 2012 , Page(s): 904 - 912

In recent years, the transmission network expansion planning (TNEP) problem has become increasingly complex. As this problem is a nonlinear and nonconvex optimization problem, researchers have traditionally focused on approximate models of power flows to solve the TNEP problem. Until recently, these approximations have produced results that are straightforward to adapt to the more complex problem. However, the power grid is evolving towards a state where the adaptations are no longer as easy (e.g., large amounts of limited control, renewable generation), necessitating new approaches. In this paper, we propose a discrepancy-bounded local search (DBLS) that encapsulates the complexity of power flow modeling in a black box that may be queried for information about the quality of a proposed expansion. This allows the development of an optimization algorithm that is decoupled from the details of the underlying power model. Case studies are presented to demonstrate cost differences in plans developed under different power flow models.

[4] Hybrid AC/DC Transmission Expansion Planning

Lotfjou, A. ; Yong Fu ; Shahidehpour, M. Power Delivery, IEEE Transactions on

Volume: 27 , Issue: 3

Digital Object Identifier: 10.1109/TPWRD.2012.2194515

Publication Year: 2012 , Page(s): 1620 - 1628

This paper proposes a hybrid algorithm for the ac/dc transmission expansion planning (TEP). The stochastic simulation method would consider random outages of generating units and ac/dc transmission lines as well as load forecast errors. The mixed-integer linear programming problem is decomposed into a master planning problem with integer investment decision variables and subproblems which examine the feasibility of master planning solution and calculate the optimal operation schedule over the planning horizon. The independent system operator would utilize the proposed method to select the optimal set of ac/dc transmission lines for satisfying TEP criteria: supplying load forecasts, minimizing investment costs, and optimizing market operations. The proposed set of dc transmission system may use either current source converters or voltage source converters. Numerical examples illustrate the effectiveness of the proposed TEP model.

[5] Incorporating Large-Scale Distant Wind Farms in Probabilistic Transmission Expansion Planning—Part II: Case Studies

Moeini-Aghtaie, M. ; Abbaspour, A. ; Fotuhi-Firuzabad, M. Power Systems, IEEE Transactions on

Volume: 27 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2011.2182364

Publication Year: 2012 , Page(s): 1594 - 1601

This paper is the second part of a two-paper set which comprehensively sets forth an innovative approach in transmission grid reinforcement studies in the presence of wind energy. Part I thoroughly defined the theory and algorithms. Here, to trace the feasibility of the proposed algorithm, three different case studies are implemented on the 24-Bus IEEE Reliability Test System (IEEE-RTS). The optimal solutions in Pareto fronts of different cases are reached, analyzed, and the final solution (optimal plan) of each case is obtained using the fuzzy decision making method. Moreover, in order to analyze the effects of variations in the large-scale wind farm generation on the transmission expansion planning (TEP) studies, the methodology is applied to the Iran 400-kV transmission grid. Two different generation expansion strategies are considered to investigate the impacts of various renewable energy policies on the TEP results. The wind energy-imposed costs of these two strategies are addressed, discussed, and compared to introduce some recommendations for wind integration policies.

[6] Incorporating Large-Scale Distant Wind Farms in Probabilistic Transmission Expansion Planning—Part I: Theory and Algorithm

Moeini-Aghtaie, M. ; Abbaspour, A. ; Fotuhi-Firuzabad, M. Power Systems, IEEE Transactions on

Volume: 27 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2011.2182363

Publication Year: 2012 , Page(s): 1585 - 1593

With increment in the penetration of wind energy in power systems, the necessity of considering its impacts on transmission expansion planning (TEP) studies, especially for large scale wind farms, is inevitable. A new multi-objective (MO) optimization transmission expansion planning algorithm considering wind farm generation is presented in this two-paper set. Part I is mainly devoted to derivation of the theory and algorithm. The objective functions used in the TEP studies take into account investment cost, risk cost and congestion cost. The combination of Monte Carlo simulation (MCS) and Point Estimation Method (PEM) is implemented to investigate the effects of network uncertainties. Due to its comparative assessment potential and good handling of the non-convex problems and non-commensurable objective functions, the Non-Dominated Sorting Genetic Algorithm II (NSGA II) is widely used for evaluating the MO optimization problem. Eventually, for selecting the final optimal solution, a Fuzzy decision making approach is applied based on decision maker preferences.

[7] Coordination of Short-Term Operation Constraints in Multi-Area Expansion Planning

Khodaei, A. ; Shahidehpour, M. ; Lei Wu ; Zuyi Li Power Systems, IEEE Transactions on

Volume: 27 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2012.2192507

Publication Year: 2012 , Page(s): 2242 - 2250

This paper presents a comprehensive expansion planning algorithm of generation and transmission components in multi-area power systems. The objective is to minimize the total system cost in the planning horizon, comprising investment and operation costs and salvage values subject to long-term system reliability and short-term operation constraints. The multi-area expansion planning problem is decomposed into a planning problem and annual reliability subproblems. The planning decisions calculated in the planning problem would also satisfy the short-term operation constraints. A detailed model of thermal and hydro units is considered using the mixed-integer programming (MIP) formulation. In addition, a multi-state representation for the expansion planning of renewable energy units is explored. The proposed approach considers customers' demand response as an option for reducing the short-term operation costs. The planning problem solution is applied to the annual reliability subproblems which examine system reliability indices as a post-processor. If the reliability limit is not satisfied, additional reliability constraints will be introduced which are based on the sensitivity of system reliability index to investment decisions. The new reliability constraints are added to the next iterations of the planning problem to govern the revised plan for the optimal expansion. Numerical simulations indicate the effectiveness of the proposed approach for solving the operation-constrained multi-area expansion planning problem of practical power systems.

[8] A Mixed-Integer Linear Programming Approach for Multi-Stage Security-Constrained Transmission Expansion Planning

Hui Zhang ; Vittal, V. ; Heydt, G.T. ; Quintero, J. Power Systems, IEEE Transactions on

Volume: 27 , Issue: 2

Digital Object Identifier: 10.1109/TPWRS.2011.2178000

Publication Year: 2012 , Page(s): 1125 - 1133

The transmission expansion planning (TEP) problem in modern power systems is a large-scale, mixed-integer, non-linear and non-convex problem. Although remarkable advances have been made in optimization techniques, finding an optimal solution to a problem of this nature can still be extremely challenging. Based on the linearized power flow model, this paper presents a mixed-integer linear programming (MILP) approach that considers losses, generator costs and the N - 1 security constraints for the multi-stage TEP problem. The losses and generator cost are modeled as piecewise linear functions of the line flows and the generator outputs, respectively. The IEEE 24-bus system is used to compare the lossy and the lossless model. The results show that the lossy model provides savings in total cost in the long run. The selection of the best number of piecewise linear sections L is also shown. Then a complete planning framework is presented and a multi-stage TEP is performed on the IEEE 118-bus test system. Simulation results show that the proposed approach is accurate and efficient, and has the potential to be applied to large-scale power system planning problems.

[9] A Scenario-Based Multi-Objective Model for Multi-Stage Transmission Expansion Planning

Maghouli, P. ; Hosseini, S.H. ; Buygi, M.O. ; Shahidehpour, M. Power Systems, IEEE Transactions on

Volume: 26 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2010.2048930

Publication Year: 2011 , Page(s): 470 - 478

The unbundling of the electricity industry introduced new uncertainties and escalated the existing ones in transmission expansion planning. In this paper, a multi-stage transmission expansion methodology is presented using a multi-objective optimization framework with internal scenario analysis. Total social cost (TSC), maximum regret (robustness criterion), and maximum adjustment cost (flexibility criterion) are considered as three optimization objectives. Uncertainties are considered by defining a number of scenarios. To overcome the difficulties in solving the nonconvex and mixed integer optimization problem, the genetic-based Non-dominated Sorting Genetic Algorithm (NSGA II) is used. Then, fuzzy decision making is applied to obtain the optimal solution. The planning methodology is applied to the Iranian 400-kV transmission grid to show feasibility of the proposed algorithm.

[10] A Strategy to Solve the Multistage Transmission Expansion Planning Problem

Vinasco, G. ; Rider, M.J. ; Romero, R. Power Systems, IEEE Transactions on

Volume: 26 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2011.2126291

05744145.pdf

Publication Year: 2011 , Page(s): 2574 - 2576

In this letter, a heuristic to reduce the combinatorial search space (CSS) of the multistage transmission expansion planning (MTEP) problem is presented. The aim is to solve the MTEP modeled like a mixed binary linear programming (MBLP) problem using a commercial solver with a low computational time. The heuristic uses the solution of several static transmission expansion planning problems to obtain the reduced CSS. Results using some test and real systems show that the use of the reduced CSS solves the MTEP problem with better solutions compared to other strategies in the literature.

[11] Robust Transmission Network Expansion Planning Method With Taguchi's Orthogonal Array Testing

Han Yu ; Chung, C.Y. ; Wong, K.P. Power Systems, IEEE Transactions on

Volume: 26 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2010.2082576

Publication Year: 2011 , Page(s): 1573 - 1580

This paper proposes a robust transmission network expansion planning (RTNEP) method with Taguchi's orthogonal array testing (TOAT) which considers generation dispatch and operating uncertainties caused by load demand and renewable energy output. TOAT is a method which has been proven to be optimal to select representative scenarios for testing from all the possible combinations. This paper employs TOAT to determine testing scenarios in transmission network expansion planning (TNEP). A new RTNEP formulation is then proposed based on the multiple testing scenarios. The simulation results have demonstrated the effectiveness of the proposed RTNEP.

[12] Transmission Switching in Expansion Planning

Khodaei, A. ; Shahidehpour, M. ; Kamalinia, S. Power Systems, IEEE Transactions on

Volume: 25 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2009.2039946

Publication Year: 2010 , Page(s): 1722 - 1733

Transmission switching (TS) is introduced to add flexibility to the transmission and generation capacity expansion planning problem. TS could improve the performance of the capacity expansion planning model and reduce the total planning cost. The capacity expansion planning problem is decomposed into a master problem and two subproblems. The master problem utilizes the candidate set for additional generating unit and transmission capacity investments to find the optimal plan throughout the planning horizon. The subproblems use the optimal plan, apply transmission switching to relieve any transmission flow violations, and calculate the optimal dispatch of generating units. The transmission network contingencies are also considered in the subproblems. The case studies exhibit the effectiveness of the proposed expansion planning approach.

[13] A Risk-Based Approach for Transmission Network Expansion Planning Under Deliberate Outages

Arroyo, J.M. ; Alguacil, N. ; Carrión, M. Power Systems, IEEE Transactions on

Volume: 25 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2010.2042310

Publication Year: 2010 , Page(s): 1759 - 1766

This paper presents a risk-based approach for the transmission network expansion problem under deliberate outages. Malicious attacks expose network planners to a new challenge: how to expand and reinforce the transmission network so that the vulnerability against intentional attacks is mitigated while meeting budgetary limits. Within this framework network planners face the nonrandom uncertainty of deliberate outages. Unlike in previous approaches, the risk associated with this uncertainty is explicitly addressed in the proposed model. Risk characterization is implemented through the minimax weighted regret paradigm. The resulting mixed-integer nonlinear programming formulation is transformed into an equivalent mixed-integer linear programming problem for which efficient commercial solvers are available. Numerical results illustrate the performance of the proposed methodology. The risk-based expansion plans are compared with those achieved by a previously reported risk-neutral model. An out-of-sample assessment is carried out to show the advantages of the risk-based model over the risk-neutral approach. In addition, the tradeoff between risk mitigation and cost minimization is analyzed.

[14] Transmission Planning Criteria and Their Application Under Uncertainty

Cámac, D. ; Bastidas, R. ; Nadira, R. ; Dortolina, C. ; Merrill, H.M. Power Systems, IEEE Transactions on

Volume: 25 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2010.2049035

Publication Year: 2010 , Page(s): 1996 - 2003

Planning criteria are the basis of transmission planning. These criteria implicitly embody resolve conflicting objectives (e.g., cost vs. reliability). Quantitative methods are used to set criteria by resolving conflicting objectives. Once criteria are set, they must be applied under uncertainty in future demand, generation, etc. Transmission plans are evaluated for hundreds of possible futures. Risk analysis measures robustness, exposure, and regret. Non-financial hedges can reduce risk. These risk concepts have a rich history but are rarely applied in transmission planning. Developing criteria, and applying them under uncertainty, are illustrated by a recent planning study for Peru.

[15] A Transmission Planning Framework Considering Future Generation Expansions in Electricity Markets

Motamedi, A. ; Zareipour, H. ; Buygi, M.O. ; Rosehart, W.D. Power Systems, IEEE Transactions on

Volume: 25 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2010.2046684

Publication Year: 2010 , Page(s): 1987 - 1995

This paper proposes a transmission planning framework in a market environment in which only the generation sector is deregulated. The proposed framework is based on modeling generation companies' (GenCos') strategic behavior and anticipating their expansion patterns from the viewpoint of a transmission system planner. The transmission expansion planning problem in this paper is modeled as a four-level optimization problem. A solution method based on agent-based systems and search-based optimization techniques is proposed to determine the optimal transmission expansion plan.

[16] Market-Based Generation and Transmission Planning With Uncertainties

Jae Hyung Roh ; Shahidehpour, M. ; Lei Wu Power Systems, IEEE Transactions on

Volume: 24 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2009.2022982

Publication Year: 2009 , Page(s): 1587 - 1598

This paper presents a stochastic coordination of generation and transmission expansion planning model in a competitive electricity market. The Monte Carlo simulation method is applied to consider random outages of generating units and transmission lines as well as inaccuracies in the long-term load forecasting. The scenario reduction technique is introduced for reducing the computational burden of a large number of planning scenarios. The proposed model assumes a capacity payment mechanism and a joint energy and transmission market for investors' costs recovery. The proposed approach simulates the decision making behavior of individual market participants and the ISO. It is an iterative process for simulating the interactions among GENCOs, TRANSCOs and ISO. The iterative process might be terminated by the ISO based on a pre-specified stopping criterion. The case studies illustrate the applications of proposed stochastic method in a coordinated generation and transmission planning problem when considering uncertainties.

[17] Flexible Transmission Expansion Planning With Uncertainties in an Electricity Market

Jun Hua Zhao ; Zhao Yang Dong ; Lindsay, P. ; Kit Po Wong Power Systems, IEEE Transactions on

Volume: 24 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2008.2008681

Publication Year: 2009 , Page(s): 479 - 488

Deregulation of the electric power industry has introduced new uncertainties for market participants and made planning of transmission expansion more difficult. More flexible transmission expansion plans are needed, to cope with the increased risks. In this paper, a novel planning approach is proposed to meet the above challenge. In our approach, the planning process is modeled as a mixed integer nonlinear programming (MINLP) problem, so that conflicting objectives can be optimized simultaneously. To minimize planning risks, our method identifies several scenarios based on statistics and expert knowledge; the most flexible expansion plan is selected as the plan that has least adaptation cost. The proposed method is tested with the IEEE 14-bus system. Promising results are obtained to demonstrate the effectiveness of our method.

[18] A Multi-Objective Framework for Transmission Expansion Planning in Deregulated Environments

Maghouli, P. ; Hosseini, S.H. ; Buygi, M.O. ; Shahidehpour, M. Power Systems, IEEE Transactions on

Volume: 24 , Issue: 2

Digital Object Identifier: 10.1109/TPWRS.2009.2016499

Publication Year: 2009 , Page(s): 1051 - 1061

Deregulation of power system has introduced new objectives and requirements for transmission expansion problem. In this paper, a static transmission expansion methodology is presented using a multi-objective optimization framework. Investment cost, reliability (both adequacy and security), and congestion cost are considered in the optimization as three objectives. To overcome the difficulties in solving the nonconvex and mixed integer nature of the optimization problems, the genetic based NSGA II algorithm is used followed by a fuzzy decision making analysis to obtain the final optimal solution. The planning methodology has been demonstrated on the IEEE 24-bus test system to show the feasibility and capabilities of the proposed algorithm. Also, in order to compare the historical expansion plan and the expansion plan developed by the proposed methodology, it was applied to the real life system of northeastern part of Iranian national 400-kV transmission grid.

[19] A Multiyear Security Constrained Hybrid Generation-Transmission Expansion Planning Algorithm Including Fuel Supply Costs

Sepasian, M.S. ; Seifi, H. ; Foroud, A.A. ; Hatami, A.R. Power Systems, IEEE Transactions on

Volume: 24 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2009.2021218

Publication Year: 2009 , Page(s): 1609 - 1618

This paper addresses the problem of a multiyear security constrained hybrid generation-transmission expansion planning. It is assumed that the overall generation requirements of a network are known along the planning horizon, but their allocations are unknown. Moreover the fuel cost throughout the network is not uniform. By allocating the overall generation capacity among the grid nodes, and determining the new transmission element additions along the planning horizon, the overall cost of the system is minimized. The problem is formulated as a mixed integer nonlinear programming problem, which for a large-scale system is

very difficult to solve. In this paper a new constructive heuristic approach is proposed, so that the problem can be readily solved. To assess the capabilities of the proposed approach, two networks are studied: the Garver test grid as a small grid and the Iranian power grid as a large-scale grid.

[20] A Bilevel Approach to Transmission Expansion Planning Within a Market Environment

Garcés, L.P. ; Conejo, A.J. ; Garcia-Bertrand, R. ; Romero, R. Power Systems, IEEE Transactions on

Volume: 24 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2009.2021230

Publication Year: 2009 , Page(s): 1513 - 1522

We present a bilevel model for transmission expansion planning within a market environment, where producers and consumers trade freely electric energy through a pool. The target of the transmission planner, modeled through the upper-level problem, is to minimize network investment cost while facilitating energy trading. This upper-level problem is constrained by a collection of lower-level market clearing problems representing pool trading, and whose individual objective functions correspond to social welfare. Using the duality theory the proposed bilevel model is recast as a mixed-integer linear programming problem, which is solvable using branch-and-cut solvers. Detailed results from an illustrative example and a case study are presented and discussed. Finally, some relevant conclusions are drawn.

[21] A Chance Constrained Transmission Network Expansion Planning Method With Consideration of Load and Wind Farm Uncertainties

Yu, H. ; Chung, C.Y. ; Wong, K.P. ; Zhang, J.H. Power Systems, IEEE Transactions on

Volume: 24 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2009.2021202

Publication Year: 2009 , Page(s): 1568 - 1576

This paper proposes a chance constrained formulation to tackle the uncertainties of load and wind turbine generator in transmission network expansion planning. A combined Monte Carlo simulation/analytical probabilistic power flow analysis method is first presented to obtain the probability density function of wind turbine generator output. The paper then shows the development of the chance constrained formulation with the inclusion of the wind turbine generator probability density function and probabilistic power flow in the formulation. The proposed formulation is more computationally efficient and can deal with uncertainties in transmission network expansion planning. The power of the new method is shown through the application of the formulation to two test systems.

[22] Congestion-Driven Transmission Planning Considering the Impact of Generator Expansion

Tor, O.B. ; Guven, A.N. ; Shahidehpour, M. Power Systems, IEEE Transactions on

Volume: 23 , Issue: 2

Digital Object Identifier: 10.1109/TPWRS.2008.919248

Publication Year: 2008 , Page(s): 781 - 789

This paper presents a multi-year transmission expansion planning (TEP) model which considers the transmission congestion and the impact of generation investment cost in the planning horizon. The Benders decomposition approach is utilized which decomposes TEP into a master problem and two subproblems representing security and optimal operation. The operation cost due to congestion (OCC) is considered in the proposed model given that the congestion level is a proper criterion for measuring the degree of competitiveness in an electricity market. The model evaluates sensitivity of the optimal TEP to congestion level, planning horizon, and financial constraints. Regulators can utilize the proposed results to provide long-term TEP to market players and to develop incentive mechanisms to trigger generation investments. The proposed approach is applied to a hypothetical system and Turkish power system.

[23] An Expert System Approach for Multi-Year Short-Term Transmission System Expansion Planning: An Indian Experience

Gajbhiye, R.K. ; Naik, D. ; Dambhare, S. ; Soman, S.A. Power Systems, IEEE Transactions on

Volume: 23 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2007.913687

Publication Year: 2008 , Page(s): 226 - 237

This paper proposes an expert system approach to short-term expansion planning (STEP). The rules which drive STEP can be classified into MW, MVAR, and ampacity management rules. MW and ampacity management rules are for alleviating transmission line congestion. Reactive power management is required for voltage control at load busses, conformity to the capacity curve of the generators, and containing the MW losses within acceptable limits. Embedding reactive power management in STEP is a challenging task since ac load flow may not converge in absence of proper reactive power planning and load modeling. Therefore, we also propose enhancements to the fast decoupled load flow algorithm for on-the-fly reactive power management. The enhanced algorithm not only can detect divergent load flow scenarios but also self-correct it by restarting the whole process with greater degree of freedom in reactive power controls. The proposed approach leads to development of an automated tool for STEP which has the capability to work, even with incomplete information. A simple method for evaluating location and requirement of shunt reactor is also proposed. By analysis and comparative evaluation, we show that the proposed system can arrive at a solution which is close to optimal. Results on the Western Regional Grid of India with an approximate load of 28 000 MW and 1200 nodes are presented to demonstrate effectiveness of the proposed approach.

[24] The Interval Minimum Load Cutting Problem in the Process of Transmission Network Expansion Planning Considering Uncertainty in Demand

Peng Wu ; Haozhong Cheng ; Jie Xing Power Systems, IEEE Transactions on

Volume: 23 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2008.922573

Publication Year: 2008 , Page(s): 1497 - 1506

This paper studies the minimum load cutting problem existing in the process of transmission network expansion planning when load is uncertain and expressed in interval number. The interval most minimum load cutting model is established and can be solved to get the maximum value of the minimum load cutting number when load is interval uncertain. The solution can be used to evaluate the safety of the planning schemes under interval uncertainty and guide the new plans' making under interval load. The load values in the optimal solution of this problem have been proved to be at their lower or upper limits. Two different algorithms are proposed to solve this model. One is better in being capable of getting global optimal solution, while the other is better in calculation speed. Both of them are compared with two traditional methods that are generally used to evaluate the system's safety under uncertainty in aspects of precision and speed. This evaluation method is applied to the greedy randomized adaptive search procedure algorithm to solve the transmission expansion planning problem under interval load. The case results show the rightness and validity of the model and algorithms proposed in this paper.

[25] Transmission Expansion Planning in Electricity Markets

de la Torre, S. ; Conejo, A.J. ; Contreras, J. Power Systems, IEEE Transactions on

Volume: 23 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2007.913717

Publication Year: 2008 , Page(s): 238 - 248

This paper presents a mixed-integer linear programming (LP) formulation for the long-term transmission expansion planning problem in a competitive pool-based electricity market. To achieve optimal expansion planning while modeling market functioning, we define a number of scenarios based on the future demand in the system and we simulate the maximization of the aggregate social welfare. Investment and operating costs, transmission losses and generator offers, and demand bids are considered. We propose to use a set of metrics to rate the effect of the expansion on the generators, demands, and the system as a whole. The proposed model is applied to the Garver six-bus system and to the IEEE 24-bus reliability test system. Simulation results can be interpreted in economic terms based on the values of the metrics obtained for different scenarios, parameters, and topologies.

[26] An Effective Transmission Network Expansion Cost Allocation Based on Game Theory

Ruiz, P.A. ; Contreras, J. Power Systems, IEEE Transactions on

Volume: 22 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2006.888987

Publication Year: 2007 , Page(s): 136 - 144

The expansion of transmission systems impacts many entities in the market environment. Each entity may fare better or worse as a result of congestion relief in the presence of new investments. Negatively affected firms exert their influence to prevent the expansion from taking place. The opposition of these firms and the lack of appropriate incentives results in insufficient investments in transmission assets. The network is being frequently used at its maximum limits, leading to economic inefficiencies and reduced reliability. Hence, there is a need for effective incentive schemes for network expansion. In this paper, we propose a game theory-based scheme for the allocation of transmission expansion costs among market entities. The allocation takes into account both the physical and economic impacts of the new transmission assets and the influence of each firm on the expansion decision. This is the first scheme designed to give all market participants explicit incentives to support the expansion. The application of the allocation solution to the Garver six-bus system is presented to illustrate the capabilities of the proposed method

[27] Transmission Expansion Planning Using Contingency Criteria

Jaeseok Choi ; Mount, T.D. ; Thomas, R.J. Power Systems, IEEE Transactions on

Volume: 22 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2007.908478

Publication Year: 2007 , Page(s): 2249 - 2261

This paper proposes a methodology for choosing the best transmission expansion plan considering various types of security (operating reliability) criteria. The proposed method minimizes the total cost that includes the investment cost of transmission as well as the operating cost and standby cost of generators. The purpose of the study is development of new methodology for solving transmission system expansion planning problem subject to contingency criteria which are essentially extensions of the (N-1) contingency criterion. The transmission expansion problem uses an integer programming framework, and the optimal strategy is determined using a branch and bound method that utilizes a network flow approach and the maximum flow-minimum cut set theorem. The characteristics of the proposed method are illustrated by applying it to a five-bus system and a 21-bus system. The results of these case studies demonstrate that the proposed method provides a practical way to find an optimal plan for power system expansion planning.

[28] Value-Based Transmission Expansion Planning of Hydrothermal Systems Under Uncertainty

Oliveira, G.C. ; Binato, S. ; Pereira, M.V.F. Power Systems, IEEE Transactions on

Volume: 22 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2007.907161

Publication Year: 2007 , Page(s): 1429 - 1435

Transmission planning studies in hydrothermal systems deal with complex issues. Two include 1) the need for a robust grid that can accommodate a large number of economic dispatch patterns caused by differing hydrological conditions in the river basins and 2) the high cost of grid reinforcements due to the large distance from hydro plants to load centers and the required N-l security criterion. It is thus necessary to consider the tradeoff between supply reliability and reinforcement cost. The resulting planning problem is formulated as a large-scale mixed integer nonlinear optimization model. The objective function is to minimize the sum of investment costs and expected load-shedding costs. The constraints include linearized power flow equations, limits on circuit flows for all combinations of economic dispatch points (which capture hydrological variation), and circuit contingencies (which capture supply reliability). This paper describes a new solution scheme for this problem that is based on two techniques: 1) the extension of a binary disjunctive technique, which transforms the integer nonlinear problem into a linear one and 2) screening strategies, which allow a judicious choice of contingencies and candidate circuits. Planning studies for Brazil and Bolivia are presented and discussed.

[29] Vulnerability-Constrained Transmission Expansion Planning: A Stochastic Programming Approach

Carrión, M. ; Arroyo, J.M. ; Alguacil, N. Power Systems, IEEE Transactions on

Volume: 22 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2007.907139

Publication Year: 2007 , Page(s): 1436 - 1445

This paper provides a stochastic programming approach to optimally reinforce and expand the transmission network so that the impact of deliberate attacks is mitigated. The network planner selects the new lines to be built accounting for the vulnerability of the transmission network against a set of credible intentional outages. The vulnerability of the transmission network is measured in terms of the expected load shed. An instance of the previously reported terrorist threat problem is solved to generate the set of credible deliberate attacks. The proposed model is formulated as a mixed-integer linear program for which efficient solvers are available. Results from a case study based on the IEEE Two Area Reliability Test System are provided and analyzed.

[30] Generation and Transmission Expansion Under Risk Using Stochastic Programming

Álvarez López, J. ; Ponnambalam, K. ; Quintana, V.H. Power Systems, IEEE Transactions on

Volume: 22 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2007.901741

Publication Year: 2007 , Page(s): 1369 - 1378

In this paper, a new model for generation and transmission expansion is presented. This new model considers as random events the demand, the equivalent availability of the generating plants, and the transmission capacity factor of the transmission lines. In order to incorporate these random events into an optimization model, stochastic programming and probabilistic constraints are used. A risk factor is introduced in the objective function by means of the mean-variance Markowitz theory. The solved optimization problem is a mixed integer nonlinear program. The expected value of perfect information is obtained in order to show the cost of ignoring uncertainty. The proposed model is illustrated by a six- and a 21-node network using a dc approximation.

[31] Multiyear Transmission Expansion Planning Using Ordinal Optimization

Min Xie ; Jin Zhong ; Wu, F.F. Power Systems, IEEE Transactions on

Volume: 22 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2007.907160

Publication Year: 2007 , Page(s): 1420 - 1428

The increasing complexity of the transmission expansion planning problem in the restructured industry makes simulation the only viable means to evaluate and compare the performances of different plans. Ordinal optimization is an approach suitable for solving the simulation-based multiyear transmission expansion planning problem. It uses crude models and rough estimates to derive a small set of plans for which simulations are necessary and worthwhile to find good enough solutions. In the end, reasonable solutions are obtained with drastically reduced computational burden.

[32] Transmission Network Expansion Planning Considering Uncertainty in Demand

Silva, Id.J. ; Rider, M.J. ; Romero, R. ; Murari, C.A.F. Power Systems, IEEE Transactions on

Volume: 21 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2006.881159

Publication Year: 2006 , Page(s): 1565 - 1573

This paper presents two mathematical models and one methodology to solve a transmission network expansion planning problem considering uncertainty in demand. The first model analyzed the uncertainty in the system as a whole; then, this model considers the uncertainty in the total demand of the power system. The second one analyzed the uncertainty in each load bus individually. The methodology used to solve the problem, finds the optimal transmission network expansion plan that allows the power system to operate adequately in an environment with uncertainty. The models presented are solved using a specialized genetic algorithm. The results obtained for several known systems from literature show that cheaper plans can be found satisfying the uncertainty in demand

[33] Probabilistic midterm transmission planning in a liberalized market

Sanchez-Martin, P. ; Ramos, A. ; Alonso, J.F. Power Systems, IEEE Transactions on

Volume: 20 , Issue: 4

Digital Object Identifier: 10.1109/TPWRS.2005.856984

Publication Year: 2005 , Page(s): 2135 - 2142

This paper shows a midterm transmission planning methodology for liberalized electricity markets. This methodology evaluates expansions and reinforcements using a transmission adequacy linear programming model. This type of modeling solves efficiently, taking into account power exchange deviations, n-1 network preventive adequacy level, and nonsupply demand. Statistical results are obtained sampling power exchange scenarios and computing transmission investment sensitivities. After each sample of generation and consumption bidding and generator and circuit failures, means, ranges, and confidence intervals of transmission investment sensitivities are updated. These sensitivities are computed using dual variables and reduced costs of the transmission adequacy model. This statistical sensitivity information and additional information are evaluated jointly using multicriteria decision theory. An extended Garver's six-bus and the Spanish system cases are analyzed.

[34] Reinforcement scheduling convergence in power systems transmission planning

Reis, F.S. ; Carvalho, P.M.S. ; Ferreira, L.A.F.M. Power Systems, IEEE Transactions on

Volume: 20 , Issue: 2

Digital Object Identifier: 10.1109/TPWRS.2005.846073

Publication Year: 2005 , Page(s): 1151 - 1157

The paper presents a new approach to the reinforcement scheduling problem in transmission power systems planning. This problem is typically formulated as a large scale multistage decision under uncertainty problem. We represent uncertainty by load/generation scenarios and propose the use of Gaussian search techniques to solve the scenario deterministic subproblems. The solution of each subproblem is a schedule of reinforcements. As information is different from scenario to scenario, scheduling conflicts may appear at optimal subproblem decisions. We solve these conflicts with a progressive hedging algorithm. Decision convergence on reinforcement scheduling is achieved for the first decision stage by progressively modifying the individual scenario subproblems. We present a rule for modifying scenario subproblems, discuss the algorithms presented, and illustrate their application with an example built over the IEEE 14-bus network.

[35] A Method for Transmission System Expansion Planning Considering Probabilistic Reliability Criteria

Jaeseok Choi ; TrungTinh Tran ; El-Keib, A.A. ; Thomas, R. ; HyungSeon Oh ; Billinton, R. Power Systems, IEEE Transactions on

Volume: 20 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2005.852142

Publication Year: 2005 , Page(s): 1606 - 1615

This paper proposes a method for choosing the best transmission system expansion plan considering a probabilistic reliability criterion$(_Rhbox LOLE)$. The method minimizes the investment budget for constructing new transmission lines subject to probabilistic reliability criteria, which consider the uncertainties of transmission system elements. Two probabilistic reliability criteria are used as constraints.

One is a transmission system reliability criterion$(_Rhbox LOLE_ TS)$constraint, and the other is a bus/nodal reliability criterion$(_Rhbox LOLE_ Bus)$constraint. The proposed method models the transmission system expansion problem as an integer programming problem. It solves for the optimal strategy using a probabilistic branch and bound method that utilizes a network flow approach and the maximum flow-minimum cut set theorem. Test results on an existing 21-bus system are included in the paper. They demonstrate the suitability of the proposed method for solving the transmission system expansion planning problem subject to practical future uncertainties.

[36] Transmission System Expansion Planning Using a Sigmoid Function to Handle Integer Investment Variables

de Oliveira, E.J. ; da Silva, I.C., Jr. ; Pereira, J.L.R. ; Carneiro, S., Jr. Power Systems, IEEE Transactions on

Volume: 20 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2005.852065

Publication Year: 2005 , Page(s): 1616 - 1621

This paper presents an optimum power flow (OPF) modeling algorithm that uses the primal–dual interior point technique to determine the best investment strategy in the transmission line expansion problem. In the proposed method, the expansion decision (0 or 1) is mitigated by using a sigmoid function, which is incorporated in the OPF problem through the modified dc power flow equations. The investment decision is taken using a new heuristic model based on good sensitivity produced by the OPF results. Additionally, the transmission power losses are considered in the network model. The proposed methodology has been compared with methods available in the literature, using both a test system and an equivalent of the southeastern Brazilian system.

[37] A Multiyear Dynamic Approach for Transmission Expansion Planning and Long-Term Marginal Costs Computation

Braga, A.S.D. ; Saraiva, J.T. Power Systems, IEEE Transactions on

Volume: 20 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2005.852121

Publication Year: 2005 , Page(s): 1631 - 1639

This paper presents a multicriteria formulation for multiyear dynamic transmission expansion planning problems. This formulation considers three criteria: investment costs, operation costs, and the expected energy not supplied. The solution algorithm adopts an interactive decision-making approach that starts at a nondominated solution of the problem. This solution is identified transforming two of the three criteria in constraints specifying aspiration levels and using afterwards simulated annealing to deal with the integer nature of investment decisions. After obtaining this first solution, the decision maker can alter the aspiration levels and run the application again to obtain a new solution. Once an expansion plan is accepted, the algorithm computes long-term marginal costs, reflecting both investment and operation costs. These costs are more stable than short-term ones and inherently address the revenue reconciliation problem well known in short-term approaches. The developed algorithm is tested using a case study based on the Portuguese 400/220/150-kV transmission network.

[38] Congestion-driven transmission expansion in competitive power markets

Shrestha, G.B. ; Fonseka, P.A.J. Power Systems, IEEE Transactions on

Volume: 19 , Issue: 3

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A framework for transmission planning in a deregulated power market environment is discussed. The level of congestion in the network is utilized as the driving signal for the need of network expansion. A compromise between the congestion cost and the investment cost is used to determine the optimal expansion scheme. The long-term network expansion problem is formed as the decoupled combination of: 1) the master problem (minimization of investment costs subject to investment constraints and the Benders cuts generated by the operational problem (power pool) and 2) the operational problem, whose solution provides congestion details and associated multipliers. A proper power-pool model is developed and solved for congestion cost, congestion revenue, and transmission shadow prices. Linear programming is utilized to solve the investment subproblem, while the quadratic programming technique has been used to solve the operational problem. The algorithm has been developed for the complete planning process, which provides the expansion schemes for the planning horizon. The technique has been applied to illustrate the network planning study for a modified IEEE 24-bus test system.

[39] Market-based transmission expansion planning

Buygi, M.O. ; Balzer, G. ; Shanechi, H.M. ; Shahidehpour, M. Power Systems, IEEE Transactions on

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Publication Year: 2004 , Page(s): 2060 - 2067

Restructuring and deregulation has exposed transmission planner to new objectives and uncertainties. Therefore, new criteria and approaches are needed for transmission planning in deregulated environments. A new market-based approach for transmission planning in deregulated environments is presented in this paper. The main contribution of this research is: i) introducing a new probabilistic tool, named probabilistic locational marginal prices, for computing the probability density functions of nodal prices; ii) defining new market-based criteria for transmission expansion planning in deregulated environments; and iii) presenting a new approach for transmission expansion planning in deregulated environments using the above tool and criteria. The advantages of this approach are: i) it encourages and facilitates competition among all participants; ii) it provides nondiscriminatory access to cheap generation for all consumers; iii) it considers all random and nonrandom power system uncertainties and selects the final plan after risk assessment of all solutions; and iv) it is value based and considers investment cost, operation cost, congestion cost, load curtailment cost, and cost caused by system unreliability. The presented approach is applied to IEEE 30-bus test system.

[40] A new strategy for transmission expansion in competitive electricity markets

Risheng Fang ; Hill, D.J. Power Systems, IEEE Transactions on

Volume: 18 , Issue: 1

Digital Object Identifier: 10.1109/TPWRS.2002.807083

Publication Year: 2003 , Page(s): 374 - 380

It will be important to develop a transmission network capable of handling future generation and load patterns in a deregulated, unbundled, and competitive electricity market. A new strategy for transmission expansion under a competitive market environment is therefore presented in this paper. In the proposed strategy, a new transmission planning model is developed to consider a variety of market-driven power-flow patterns while a decision analysis scheme is incorporated to minimize the risk of the selected plan. Numerical examples are given to illustrate the potential of the proposed strategy to make a significant contribution to transmission planning in competitive markets.

[41] Transmission expansion planning: a mixed-integer LP approach

Alguacil, N. ; Motto, A.L. ; Conejo, A.J. Power Systems, IEEE Transactions on

Volume: 18 , Issue: 3

Digital Object Identifier: 10.1109/TPWRS.2003.814891

Publication Year: 2003 , Page(s): 1070 - 1077

This paper presents a mixed-integer LP approach to the solution of the long-term transmission expansion planning problem. In general, this problem is large-scale, mixed-integer, nonlinear, and nonconvex. We derive a mixed-integer linear formulation that considers losses and guarantees convergence to optimality using existing optimization software. The proposed model is applied to Garver's 6-bus system, the IEEE Reliability Test System, and a realistic Brazilian system. Simulation results show the accuracy as well as the efficiency of the proposed solution technique.

Transmission expansion planning tools

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