Joint Distribution Network and Renewable Energy Expansion Planning Considering Demand Response and Energy Storage—Part I: Stochastic Programming Model

Miguel Asensio, Pilar Meneses de Quevedo, Gregorio Muñoz-Delgado, *Student Member, IEEE*, and Javier Contreras, *Fellow, IEEE*

Abstract—The first part of this two-paper series describes the incorporation of demand response (DR) and energy storage systems (ESSs) in the joint distribution and generation expansion planning for isolated systems. The role of DR and ESS has recently attracted an increasing interest in power systems. However, previous models have not been completely adapted in order to treat DR and ESS on an equal footing. The model presented includes DR and ESS in the planning of insular distribution systems. Hence, this paper presents a novel model to decide the joint expansion planning of distributed generation and the distribution network considering the impact of ESS and price-dependent DR programs. The problem is formulated as a stochastic-programming-based model driven by the maximization of the net social benefit. The associated deterministic equivalent is formulated as a mixed-integer linear program suitable for commercially available software. The outcomes of the model are the location and size of new generation and storage units and the distribution assets to be installed, reinforced or replaced. In the second companion paper, an insular case study (La Graciosa, Canary Islands, Spain) is provided illustrating the effects of DR and ESS on social welfare.

Index Terms—DR, renewable energy sources (RES) expansion planning, distribution network expansion planning, ESS, distribution systems.

NOMENCLATURE

Indices and Sets

b	Index for substation load levels
B	Set of substation load levels for the calculation of the substation price

i, j	Indexes for nodes
k	Index for alternatives for feeders, and transformers
K^l	Set of available alternatives for feeders
K^{tr}	Set of available alternatives for transformers
l	Index for feeder types
L	Set of feeder types, $L = \{EFF, ERF, NRF, NAF\}$ where EFF, ERF, NRF and NAF denote existing fixed feeders, existing replaceable feeders, new replacement feeders, and newly added feeders
ll, lb	Index for load levels, split in quarter (q), working day/weekend (r), day/night (n) and load block (b)
LL, LB	Set of load levels split in quarter (Q), working day/weekend (R), day/night (N) and load block (B)
p	Index for generator types
P	Set of generator types, $P = \{W, \Theta\}$ where W and Θ denote wind and photovoltaic generators, respectively
t	Index for time stages
T	Set of time stages
tr	Index for transformer types
TR	Set of transformer types, $TR = \{ET, NT\}$ where ET and NT denote existing transformers and newly added transformers, respectively.
w	Index for scenarios
W	Set of scenarios, $W = \{WW, PW, DW\}$ where WW, PW and DW denote wind, photovoltaic and demand scenarios
Υ^l	Set of branches with feeders of type l
$\Omega^l, \Omega^{LN}, \Omega^N, \Omega^p, \Omega^{ss}, \Omega^{ST}$	Sets of nodes connected to node i by a feeder l, load nodes, system nodes, candidate nodes for DG, substation and candidate nodes for storage

Parameters

$C_i^{I,SS}$	Investment cost of expanding existing substations by adding a new transformer or building a new substation
C_b	Costs for substation load level b
$C_{i,j,k}^{I,l}$	Investment cost of alternative k of feeder l in branch i-j
$C_{i,j,k}^{M,l}$	O&M cost of alternative k of feeder l in branch i-j
$C_i^{M,ST}$	O&M cost of storage st at node i
$C_{i,k}^{I,NT}$	Investment cost of adding alternative k of a new transformer in substation node i
$C_i^{I,p}$	Investment cost of generator p at node i
$C_i^{I,ST}$	Investment cost of a storage unit at node i
$C_i^{M,p}$	O&M cost of alternative k of generator p at node i
$C_{i,k}^{M,tr}$	O&M cost of alternative k of transformer tr installed in substation node i
$C^{E,p}$	Generation costs of generator type p
$\overline{C_{t,ll,w}^{SS}}$	Average substation cost at stage t for load level ll in scenario w considering adjacent blocks
$C^{ST,prod}$	Production cost of storage unit
$C^{ST,store}$	Storage cost of storage unit
$D_{i,t,ll,w}$	Expected demand at node i at stage t for load level ll in scenario w
$\tilde{D}_{i,t}$	Fictitious nodal demand in substation node i at stage t
$\bar{F}_{i,j,k}^l$	Maximum capacity in branch i-j for alternative k
$\bar{G}_{ik}^{tr}$	Upper limit for energy supplied by alternative k of transformer type tr in substation node i
$\bar{G}^p$	Maximum capacity of generator type p
$\hat{G}_{i,t,ll,w}^p$	Maximum power availability of generator p
I	Annual investment rate
IB_t	Investment limit at stage t
$l_{i,j}$	Feeder length
L_b^{min}	Lower limit of substation load level b
L_b^{max}	Upper limit of substation load level b
n_{DG}, n_T	Number of candidate nodes for distributed generation and number of stages
pf	System power factor
$RR^l, RR^{NT}, RR^p,$ RR^{SS}, RR^{ST}	Capital recovery rates for investment in feeders, new transformers, generators, substations and storage units
$\underline{G}^{ST}$	Minimum capacity of storage
$\bar{G}^{ST}$	Maximum capacity of storage
$Z_{i,j,k}^l$	Unitary impedance magnitude of feeders
$\xi_{lb,ll}$	Own- and cross-price elasticities for DR
$\pi_{ll,w}$	Weight of scenario w
Δ_{ll}, Δ_{lb}	Duration in hours of each load level ll
$\eta_i^{ST,prod}$	Production efficiency rates for storage unit
$\eta_i^{ST,store}$	Storage efficiency rates for storage unit

ε	Penetration limit for distributed generation
$\nu^l, \nu^{NT}, \nu^p, \nu^{ss}, \nu^{ST}$	Lifetimes of feeders, new transformers, generators, substation assets other than transformers, and storage
$\mu_{ll,w}^D$	Average demand factor at load level ll and scenario w
$\mu_{ll,w}^P$	Vector of maximum levels of wind and photovoltaic power generation at load level ll and scenario w

Variables

c_t^I	Investment cost at stage t
c_t^E	Energy cost at stage t
c_t^M	Maintenance cost at stage t
c_t^U	Unserved energy cost at stage t
c_t^{ST}	Energy cost for storage units at stage t
$c_{t,ll,w}^{SS}$	Substation price at stage t for load level ll and scenario w
$d_{i,t,ll,w}$	Demand at node i at stage t for load level ll and scenario w when considering DR
$d_{i,t,ll,w}^U$	Unserved energy at node i at stage t for load level ll at scenario w
$dr_{i,t,ll,w}^+$	Auxiliary binary variable associated with positive DR at node i at stage t, load level ll and scenario w
$dr_{i,t,ll,w}^-$	Auxiliary binary variable associated with negative DR at node i at stage t, load level ll and scenario w
$f_{i,j,k,t,ll,w}^l$	Current flow through alternative k feeder type l installed in branch i-j at stage t, load level ll and scenario w, measured at node i, which is greater than 0 if node i is the supplier and 0, otherwise
$\tilde{f}_{i,j,k,t}^l$	Fictitious current flow through alternative k of feeder l installed in branch i-j at stage t measured at node i. Greater than 0 if node i is the supplier and 0, otherwise
$g_{i,t,ll,w}^p$	Energy supplied by generator p in node i at stage t for load level ll in scenario w
$g_{i,k,t,ll,w}^{tr}$	Energy supplied by alternative k of transformer tr installed in substation node i at stage t for load level ll in scenario w
$g_{i,t,ll,w}^{ST,prod}$	Power production for a storage unit at node i, stage t for load level ll in scenario w
$g_{i,t,ll,w}^{ST,store}$	Power stored for a storage unit at node i, stage t for load level ll in scenario w
$\tilde{g}_{i,t}^{SS}$	Energy supplied by a fictitious substation at node i at stage t
$p_{t,ll,w}$	Demand payment at stage t for load level ll in scenario w
$x_{i,k,t}^{NT}$	Binary variable for the installation of alternative k of new transformers in substation node i at stage t

$x_{i,t}^p$	Binary variable for the installation of generator type p at node i at stage t
$x_{i,t}^{SS}$	Binary variable for the expansion of existing substations by adding a new transformer in substation node i at stage t
$x_{i,t}^{ST}$	Binary variable associated with the installation of storage unit st installed at nodes i at stage t
$\hat{x}_{i,t,ll,w}^{ST}$	Storage level at bus i at stage t at load level ll and scenario w
$y_{i,j,k,t}^l$, $y_{i,t}^p$, $y_{i,k,t}^{tr}$, $y_{i,t}^{ST}$	Binary utilization variables for feeders, generators, transformers and storage units
$z_{t,b,ll,w}$	Binary variable associated with substation price at stage t for substation load level b, load level ll and scenario w
$z_{t,ll,w}^{DR}$	Binary variable associated with DR at stage t for load level ll and scenario w
$\theta_{t,b,ll,w}$	Variable associated with substation demand at stage t for substation load level b load level ll and scenario w
$\rho_{t,b,ll,w}$	Variable associated with substation demand at stage t for substation load level b at load level ll and scenario w
$\varphi_{t,b,ll,w}$	Variable associated with demand payment linearization at stage t for substation load level b at load level ll and scenario w
$u_{i,t,ll,w}^{ST,prod}$	Variables related to production at node i, stage t, for load level ll in scenario w
$u_{i,t,ll,w}^{ST,store}$	Variables related to storage at node i, stage t, for load level ll in scenario w
$v_{i,t,ll,w}$	Voltage at node i, stage t, load level ll in scenario w.

I. INTRODUCTION

PLANNING models have been used for many years to optimize generation investments in electric power systems. However, these models have not been completely adapted in order to treat price-dependent resources, such as DR or ESS, on an equal footing. The main advantage of ESS is the release of additional capacity to the grid when it is valuable, which might be critical in small or islanded systems. ESS represent the critical link between the energy supply and demand chains, standing as a key element for the increasing grid integration of renewable energies. ESS may contribute to increase the integration of the power generated by RES and also to reduce generation costs and improve the quality of power supply.

The present document stresses the importance of integrating DR to time-varying prices in those investment models. What is often underappreciated about real-time pricing mechanisms is that the impacts of these programs can be very consistent and predictable due to the fact that they are based on the collective response of a large number of participants. In medium- and long-term power system models, it is common practice the use load levels to represent the demand curve. The advantage

of the traditional approach lies in the fact that the computational burden is much lower, making the problem tractable. However, the main disadvantage of the considered representation is that, by doing so, information of the sequentiality of individual hours is lost. Furthermore, in power systems with high renewable penetration, the considered modelling procedure to incorporate uncertainty in wind and solar irradiation may not be sufficiently accurate, creating significant distortions in the model's results. Alternative approaches have been applied in literature, such as the net demand approach. This procedure does not eliminate the problem, since hours with high demand and high renewable generation and hours with low demand and low renewable penetration would fit the same net demand block. One key issue related to investment decisions for electric power systems with a high penetration of stochastic generation resources and price-dependent resources is the modelling of variability and uncertainty that influence the results of the investment problem. The integration of price-dependent resources, such as DR and ESS, calls for a review in the proposed methodology increasing the number of load blocks. A detailed representation of demand, wind and irradiation curves is required to allocate the effects of DR.

II. LITERATURE REVIEW AND CONTRIBUTIONS

A great variety of models has been proposed in literature for distribution and generation system planning. In [1], distribution network expansion through mixed-integer linear programming is addressed. In [2], they solve the same problem through mixed-integer quadratic programming. In [3], distribution network expansion planning is analyzed by a multistage model formulated through mixed-integer nonlinear programming. In [4], a heuristic method is proposed for investment planning in conventional distributed generation considering two different approaches, electricity market and bilateral contracts. In [5], a distribution system planning model is proposed using a mixed-integer nonlinear programming approach. In [6], the problem presented in [4] is solved through ant colony optimization. In [7] and [8], a multistage distribution network planning problem is proposed. In [9], a probabilistic approach to distribution system planning is shown. In [10], the distribution network expansion problem is analyzed through a heuristic algorithm. In [11], a multi-objective model, which takes into account investment and operating costs of candidate generators, the cost of the purchased energy and the cost of emissions is presented. The problem uses the particle swarm optimization method. In [12], a distribution system planning model immersed in an electricity market is proposed. Reference [13] shows the planning problem of primary distribution networks formulated as a multi-objective mixed-integer nonlinear problem considering the system's reliability costs in the contingency events. In [14], radiality constraints in distribution systems with DG are analyzed and a planning problem is solved. In [15] the work of [5] is extended through the implementation of a dynamic planning model considering growing demand and load levels. In [16], a multi-objective optimization model is presented for distribution system planning considering different types of DG. In [17], the multistage

TABLE I

COMPARISON OF MULTISTAGE CO-OPTIMIZED EXPANSION PLANNING MODELS CONSIDERING DEMAND RESPONSE AND STORAGE

Approach	Topological changes	Renewable generation	Correlation	Demand Response	Energy Storage	NSB Maximization
[1]- [6]	✗	✓	✗	✗	✗	✗
[7]- [13], [15]-[17]	✓	✓	✗	✗	✗	✗
[19]	✓	✓	✓	✓	✗	✗
[20]	✓	✓	✗	✓	✗	✗
[21]	✗	✓	✗	✓	✗	✗
[23] ,[25], [26]	✗	✓	✓	✗	✗	✗
[24]	✓	✓	✓	✗	✗	✗
Proposed approach	✓	✓	✓	✓	✓	✓

expansion planning problem of a distribution system where investments in the distribution network and in distributed generation are jointly considered is presented. In [18], an analytical framework to incorporate DR in long-term resource planning is presented. This paper defines a set of approaches that regulators and key industry stakeholders should consider when evaluating DR in future resource plans. In [19], the effects of integrating short-term DR into long-term generation investment planning are investigated. An hourly model is proposed, stressing the importance of integrating short-term DR to time-varying prices into long term investment models. Authors in [19] incorporate DR in a 4-week economic dispatch approach and extrapolate the results to one year. In [20], a network investment planning model for a high penetration of wind energy under a DR program is presented. In [21], the effects of DR on generation expansion planning in restructured power systems are modeled. [22] provides an alternative approach to model load levels in electric power systems with high renewable penetration. The approach introduces the concept of system states as opposed to load levels, allowing for a better incorporation of chronological information in power system models. Authors in [23], [25], and [26] provide a solution for the multistage expansion planning problem considering renewable generation and correlation. Authors in [24] enhance the previous approach including topological changes.

A symmetric treatment of load and generation creates the strongest possible incentive for final consumers to actively participate in the wholesale electricity market. The considered approach translates this argument to medium- and long-term distribution and generation expansion planning procedures. Additionally, the proposed approach creates incentive for investment in storage technologies, whose value for a central planner is the ability to turn low-priced electricity into high-price electricity.

Several references have been proposed in the literature targeting the aforementioned problems. However, in our opinion, none of the existing works sufficiently stresses the relevance of demand response and energy storage. Table I summarizes all these references whose formulation has been stated as MILP.

According to the presented state of the art, the following contributions can be listed:

- A novel model is proposed to accurately include DR and ESS in the joint distribution network and generation expansion planning. The approaches presented in [18]–[21] partially integrate DR in resource planning,

however, to our knowledge, the effect of DR in both distribution network and generation expansion planning has not yet been considered. Additionally, the impact of ESS on both resource plans and its combination with DR has not yet been investigated. Timing, location, and sizing of storage units, DG units and distribution assets are modeled. The model proposes social welfare maximization to adequately incorporate price-dependent resources.

- The present model stresses the importance of integrating DR to time-varying prices (real-time prices) into those investment models. Own-price and cross-price elasticities are included in order to incorporate consumers' willingness to adjust the demand profile in response to price changes. In contrast to [18]–[21], a novel approach to model load levels in electric power systems with high wind and PV penetration has been considered.

- Threats experienced by isolated systems as a consequence of increasing DG penetration are even higher than those experienced by interconnected systems since they cannot depend on the smoothing effect of a large balancing area. The novelty of the proposed approach is to stress the relevance of time-dependent resources in isolated systems.

- A scenario-based stochastic programming framework is proposed to model the correlated uncertainty characterizing demand and renewable-based power generation. The associated deterministic equivalent is formulated as a mixed-integer linear program suitable for commercially available software.

- A set of metrics to account for the effect of DR and ESS in the welfare for all relevant stakeholders are included.

The rest of this paper is organized as follows. Section IV describes the proposed formulation, including DR, ESS, substation price calculation and demand payment. Finally, some relevant conclusions are drawn in Section V. An Appendix is included describing the model linearization.

III. UNCERTAINTY MODELING

The increasing penetration of stochastic resources in electrical networks calls for a review on uncertainty modelling. In medium- and long-term power system models, it is generally accepted to approximate the demand curve by

load levels. However, in power systems with high renewable penetration, the traditional modelling procedure may not be sufficiently accurate, creating significant distortions in the model results. Additionally, the integration of price-dependent resources, such as DR or ESS, calls for a review in the proposed methodology increasing the number of load blocks.

In order to adequately accommodate the increasing amount of renewable generation in the proposed expansion model, a novel approach to model load levels with high wind and PV penetration has been considered dividing the traditional load duration curve in a tractable amount of blocks (48). The considered criteria to split the load, wind and solar irradiation curves are: quarter, working/non-working day and day/night. While quarter and working/non-working day criteria are fixed criteria, day/night criterion has been considered based on solar irradiation. Therefore, an hour where solar irradiation is higher than zero is considered as day in the model, while an hour without solar irradiation is assigned to the corresponding night period. Doing so, the best possible integration of PV technologies within the burdens of the proposed methodology is guaranteed. Historical data of wind and PV power capacity factors (or wind speed and solar irradiation) are used throughout the same period considered for the demand. For all the hours allocated to each demand block, we consider the corresponding wind and photovoltaic power capacity factors. Using the obtained data, wind and PV duration curves for each block are built, arranging the data from higher to lower values in order to be jointly represented with the demand. An example with the discretization of demand, wind speed and irradiation for a particular load curve is depicted in Fig. 1. With the aim of reducing the loss of information on the sequence of individual hours when composing the load duration curve, wind and irradiation curves have been split into 16 different load curves, based on quarters (q), working-day/weekend (r) and day/night criteria (n), containing each curve three blocks (b) for a total of 48 blocks. The uncertainties in the demand, wind speed, and solar irradiation within each demand block are represented by considering different demand factor levels. To do so, we build the cumulative distribution function (cdf) of the demand, wind and PV factors within each demand block. Then, this cdf is divided into a selected number of segments (three in the proposed paper), each one with an associated probability. In order to simplify the formulation of the problem, each stage is considered to be defined by 3 years. This procedure is repeated for each considered period, given a total number of 27 operating conditions for each of the 48 considered blocks (16 load curves x 3 blocks). The weight of each of these blocks is computed as the number of hours times the probability of each operating condition within the demand block. The annual pattern is repeated for every block considered in the formulation, being therefore the probability of each scenario in every stage constant. The approach proposed in the present formulation enhances [23] and [24] in order to adequately integrate time-dependent resources in the expansion planning.

The modelling of uncertainty in a distribution system for each single load block is based on the load, wind and solar
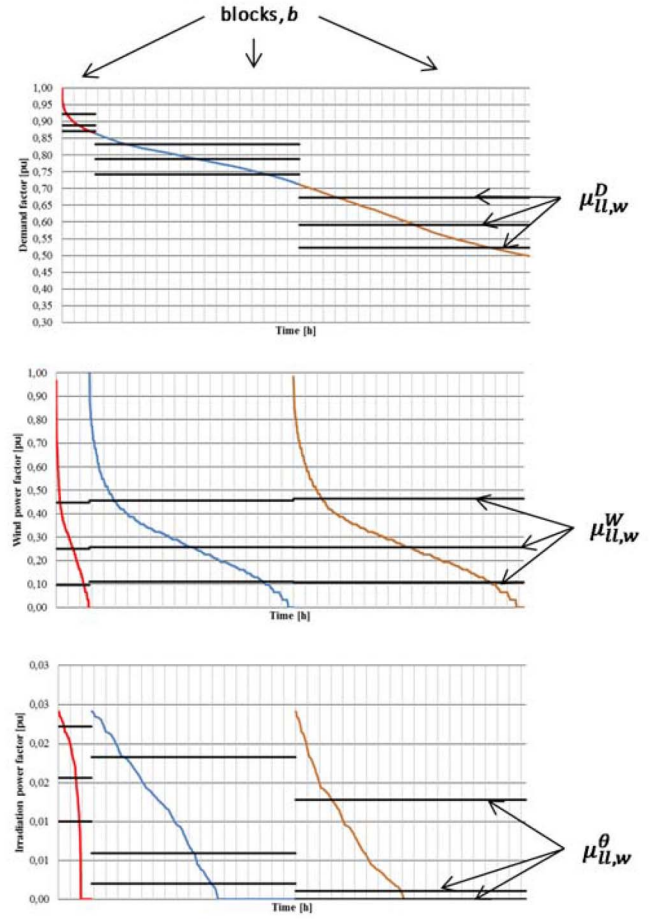

Fig. 1.   Load, wind, and irradiation curves.

irradiation curves. Hourly historical demand data is arranged from higher to lower values keeping the correlation between the different hourly data of wind and PV productions. The load duration curve is approximated using demand blocks. In order to accurately include peak demand in the model, the length of the demand blocks varies along the load duration curve. For each demand block, wind and PV productions are arranged from higher to lower values in order to be jointly represented with demand. For each demand block, all combinations of demand, wind power factor and PV power factor levels are considered. Each combination is assigned a probability within the demand block equal to the probability of the demand factor level times the probability of the wind power factor and the PV power factor levels. For the present paper, 48 demand blocks, 3 factor levels for demand, 3 factor levels for wind power and 3 levels for PV power have been considered.

For each load level ll, each scenario w comprises an average demand factor $\mu_{ll,w}^{D}$, a maximum level of wind power generation $\mu_{ll,w}^{W}$, and a maximum level of PV power generation $\mu_{ll,w}^{\theta}$. Nodal demands in each scenario are equal to the product of the forecasted values and the demand factor $\mu_{ll,w}^{D}$) throughout the planning horizon. Moreover, for each scenario w, based on the information provided by the manufacturer, average factors $\mu_{ll,w}^{W}$ and $\mu_{ll,w}^{\theta}$ are converted to maximum levels of wind and
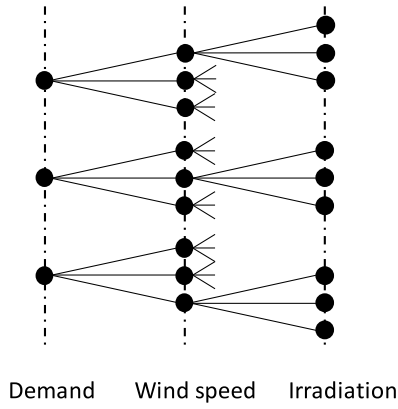
Fig. 2.　Considered scenario tree for demand, wind speed and irradiation.

Fig. 3.　ESS and DR effect on a particular load duration curve.

photovoltaic power generation, $\hat{G}^W_{i,t,ll,w}$ and $\hat{G}^\theta_{i,t,ll,w}$, respectively. This assumption is deemed adequate considered the size and orography of the island. For the sake of simplicity, we consider that $\mu^W_{ll,w}$ and $\mu^\theta_{ll,w}$ are identical for all candidate nodes and all considered time stages. It is worth mentioning that the methodology proposed in this paper is related to a central planning context, where distribution assets are both owned and operated by Distribution Companies (DISCOs). Therefore, ESS are managed to increase the economic benefit of the generation and distribution company. On the contrary, DR reflects the behaviour of consumers, aimed at reducing the total payment over the considered time horizon. The impact of both technologies will be analyzed in the proposed case study, outlining the above-mentioned effect.

Energy shifting linked to DR and ESS has been considered in the proposed formulation to be limited to blocks within the same quarter and weekend/working day load duration curve. DR has been introduced in the model considering elastic demand functions calibrated by load levels. The values considered for the elasticity of demand are positively defined only for the n and b levels, being 0 in other cases. In the same way, the transition function for the storage system has been formulated to be accomplished at the n, b levels. Fig. 3 represents a possible interaction at the n, b levels considered for DR and the transition function of the ESS. In this particular situation, energy consumption is shifted from higher to lower prices, represented by blue and red bars, respectively. For each quarter (q) and working day/weekend (r), the energy can be exchanged between: blocks of the same day; blocks of the same night; blocks from day to night; blocks from night to day.

IV. PROBLEM FORMULATION

The problem is formulated as a stochastic-programming-based model driven by the maximization of the net social benefit. The associated scenario-based deterministic equivalent is formulated as a mixed-integer linear program for which finite convergence to optimality is guaranteed and efficient off-the-shelf software is available. Based on [25], the stochastic programming model can be mathematically formulated 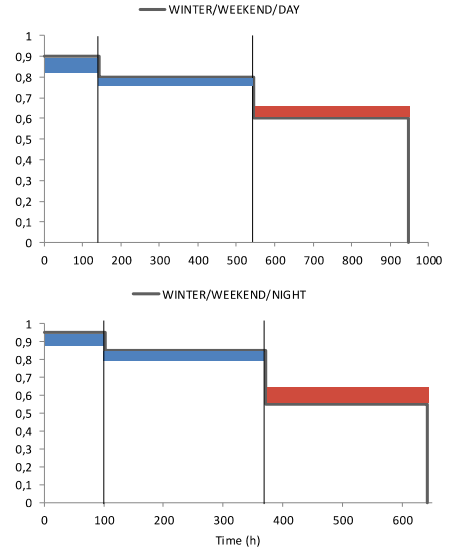as a scenario-based deterministic equivalent, as described next. The probability tree represents the dynamics of the random parameters and the non anticipativity of the decisions. The probability tree associated to every single considered variable (wind speed, irradiation and demand) is represented by Fig. 2. In this model, a scenario-based stochastic programming framework is used to minimize the present value of the expected investment and operational costs under the correlated uncertainty of renewable-based generation and demand.

The proposed formulation is based on the work in [17]. However, when DR is integrated in the expansion planning model, the minimization of costs partially disregard the benefits consumers receive from the modification of their electricity consumption [24]. The objective function (1) has been modified to maximize the net social welfare or benefit (NSB) of the system and represents the present value of the total payment of the consumers minus the present value of the total cost, which consists of five terms: (2) investment, (3) maintenance, (4) production, (5) unserved energy and (6) storage.

A. Objective Function

$$
\begin{aligned}
NSB = \max \Bigg\{ & \sum_{t,ll,w} \Bigg((1+I)^{-(t-1)} \\
& + \frac{(1+I)^{-(n_T-1)}}{I} \Bigg) \big[\pi_{ll,w} p_{t,ll,w} \big] \\
& - \sum_t \frac{(1+I)^{-(t-1)}}{I} c^I_t \\
& - \sum_t \Big[(1+I)^{-(t-1)} \big(c^M_t + c^E_t + c^{ST}_t + c^U_t \big) \Big] \\
& - \frac{(1+I)^{-(n_T-1)}}{I} \Big(c^M_{n_T} + c^E_{n_T} + c^{ST}_{n_T} + c^U_{n_T} \Big) \Bigg\}
\end{aligned}
$$

(1)

where:

$$c_t^I = \sum_{l \in \{NRF, NAF\}} RR^l \sum_{k \in K^l} \sum_{(i,j) \in \Upsilon^l} C_{i,j,k}^{I,l} \ell_{i,j} x_{i,j,k,t}^l$$
$$+ RR^{SS} \sum_{i \in \Omega^{SS}} C_i^{I,SS} x_{i,t}^{SS} + RR^{NT} \sum_{k \in K^{NT}} \sum_{i \in \Omega^{SS}} C_{i,k}^{I,NT} x_{i,k,t}^{NT}$$
$$+ \sum_{p \in P} RR^p \sum_{i \in \Omega^p} C_i^{I,p} pf \bar{G}^p x_{i,t}^p$$
$$+ RR^{ST} \sum_{i \in \Omega^p} C_i^{I,ST} pf \bar{G}^{ST} x_{i,t}^{ST}; \quad \forall t \in T \quad (2)$$

$$c_t^M = \sum_{l \in L} \sum_{k \in K^l} \sum_{(i,j) \in \Upsilon^l} C_{i,j,k}^{M,l} \left(y_{i,j,k,t}^l + y_{j,i,k,t}^l \right)$$
$$+ \sum_{tr \in TR} \sum_{k \in K^{tr}} \sum_{i \in \Omega^{SS}} C_{i,k}^{M,tr} y_{i,k,t}^{tr} + \sum_{p \in P} \sum_{i \in \Omega^p} C_i^{M,p} y_{i,t}^p$$
$$+ \sum_{p \in P} \sum_{i \in \Omega^{ST}} C_i^{M,ST} y_{i,t}^{ST}; \quad \forall t \in T \quad (3)$$

$$c_t^E = \sum_{w \in \Pi} \pi_{ll,w} pf \sum_{ll \in LL} \Delta_{ll} \left(\sum_{tr \in TR} \sum_{k \in K^{tr}} \sum_{i \in \Omega^{SS}} c_{t,ll,w}^{SS} g_{i,k,t,ll,w}^{tr} \right.$$
$$\left. + \sum_{p \in P} \sum_{i \in \Omega^p} pf C^{E,p} g_{i,t,ll,w}^p \right); \quad \forall t \in T$$
$$(4)$$

$$c_t^U = \sum_{w \in \Pi} \pi_{ll,w} pf \sum_{ll \in LL} \sum_{i \in \Omega_t^{LN}} \Delta_{ll} C^U d_{i,t,ll,w}^U; \quad \forall t \in T \quad (5)$$

$$c_t^{ST} = \sum_{w \in \Pi} \pi_{ll,w} pf \sum_{ll \in LL} \Delta_{ll} \left(\sum_{i \in \Omega^{ST}} C^{ST,prod} g_{i,t,ll,w}^{ST,prod} \right.$$
$$\left. + C^{ST,store} g_{i,t,ll,w}^{ST,store} \right); \quad \forall t \in T$$
$$(6)$$

where:

$$RR^l = \frac{I(1+I)^{v^l}}{(1+I)^{v^l} - 1}, \quad \forall l \in \{NRF, NAF\};$$

$$RR^{NT} = \frac{I(1+I)^{v^{NT}}}{(1+I)^{v^{NT}} - 1};$$

$$RR^p = \frac{I(1+I)^{\eta^p}}{(1+I)^{\eta^p} - 1}, \quad \forall p \in P;$$

$$RR^{ss} = \frac{I(1+I)^{v^{SS}}}{(1+I)^{v^{SS}} - 1},; \text{ and}$$

$$RR^{st} = \frac{I(1+I)^{v^{ST}}}{(1+I)^{v^{ST}} - 1}$$

Note that capital recovery rates for investment in feeders, new transformers, generators, substations and storage units are dependent on each lifecycle. It is worth mentioning that for each time stage, a single binary variable per feeder in branch *i-j* is used to model the corresponding investment decision, namely $x_{i,j,k,t}^l$. In contrast, two binary variables, $y_{i,j,k,t}^l$ and $y_{j,i,k,t}^l$, are associated with each feeder in order to model its utilization in both directions.

B. Generation, Network and Investment Constraints

Constraints (7) represent the nodal current balance equations, i.e., Kirchhoff's current law.

$$\sum_{l \in L} \sum_{k \in K^l} \sum_{j \in \Omega_i^l} \left(f_{i,j,k,t,ll,w}^l - f_{j,i,k,t,ll,w}^l \right)$$
$$= \sum_{tr \in TR} \sum_{k \in K^{tr}} g_{i,k,t,ll,w}^{tr} + \sum_{p \in P} g_{i,t,ll,w}^p + g_{i,t,ll,w}^{ST,prod}$$
$$- g_{i,t,ll,w}^{ST,store} - d_{i,t,ll,w} - d_{i,t,ll,w}^U; \forall i \in \Omega^N, \quad \forall t \in T,$$
$$\forall ll \in LL, \forall w \in \Pi \quad (7)$$

The enforcement of Kirchhoff's voltage law (8) for all feeders in use leads to the following expressions. The nodal voltage modules are limited by upper and lower limits (9). The nonlinear constraint reformulation is presented in Appendix A.

$$y_{i,j,k,t}^l \left[Z_{i,j,k}^l \ell_{i,j} f_{i,j,k,t,ll,w}^l - \left(v_{i,t,ll,w} - v_{j,t,ll,w} \right) \right] = 0; \quad \forall l \in L,$$
$$\forall i \in \Omega_j^l, \forall j \in \Omega^N, \forall k \in K^l, \forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (8)$$

$$\underline{V} \le v_{i,t,ll,w} \le \bar{V}; \quad \forall i \in \Omega^N, \forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (9)$$

The current flow is restricted by the maximum capacity of the feeders (10). This is formulated as follows:

$$0 \le f_{i,j,k,t,ll,w}^l \le y_{i,j,k,t}^l \bar{F}_{i,j,k}^l; \quad \forall l \in L, \forall i \in \Omega_j^l, \forall j \in \Omega^N,$$
$$\forall k \in K^l, \forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (10)$$

If a feeder is not used, then the current flow is 0. The current supply by substations depends on the number of transformers, which have a maximum current value that can be supplied. Constraint (11) sets the upper bounds for current that can be supplied by the transformers in use. The current supplied by renewable generators is limited by the maximum power availability depending on the meteorology. Wind generators' upper limits depend on wind speed and PV generators' upper limits depend on solar irradiation (12). The variable associated with unserved energy, d_{itb}^U, is limited by the corresponding load demand (13). Constraint (14) limits the level of penetration of DG as a fraction ε of the demand.

$$0 \le g_{i,k,t,ll,w}^{tr} \le y_{i,k,t}^{tr} \bar{G}_{i,k}^{tr}; \quad \forall tr \in TR, \forall i \in \Omega^{SS}, \forall k \in K^{tr},$$
$$\forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (11)$$

$$0 \le g_{i,t,ll,w}^p \le y_{i,t}^p \hat{G}_{i,t,ll,w}^p; \quad \forall p \in P, \forall i \in \Omega^p, \forall t \in T,$$
$$\forall ll \in LL, \forall w \in \Pi \quad (12)$$

$$0 \le d_{i,t,ll,w}^U \le d_{i,t,ll,w}; \quad \forall i \in \Omega_j^l, \forall t \in T, \forall ll \in LL, \forall w \in \Pi$$
$$(13)$$

$$\sum_{p \in P} \sum_{i \in \Omega^p} g_{i,t,ll,w}^p + \sum_{i \in \Omega^{ST}} \left(g_{i,t,ll,w}^{ST,prod} - g_{i,t,ll,w}^{ST,store} \right)$$
$$\le \varepsilon \sum_{i \in \Omega_t^{LN}} d_{i,t,ll,w}; \quad \forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (14)$$

The power supplied or stored by storage units is limited by the minimum between their capacities and the maximum capacity (15)–(16). Finally, in (17), binary variables

$u_{i,t,ll,w}^{ST,prod}$ and $u_{i,t,ll,w}^{ST,store}$ are defined to avoid producing and storing energy simultaneously.

$$\underline{G}^{ST} u_{i,t,ll,w}^{ST,prod} \leq g_{i,t,ll,w}^{ST,prod} \leq \bar{G}^{ST} u_{i,t,ll,w}^{ST,prod};$$
$$\forall i \in \Omega^{ST}, \forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (15)$$

$$\underline{G}^{ST} u_{i,t,ll,w}^{ST,store} \leq g_{i,t,ll,w}^{ST,store} \leq \bar{G}^{ST} u_{i,t,ll,w}^{ST,store};$$
$$\forall i \in \Omega^{ST}, \forall t \in T, \forall ll \in LL, \forall w \in \Pi \quad (16)$$

$$u_{i,t,ll,w}^{ST,prod} + u_{i,t,ll,w}^{ST,store} \leq y_{i,t}^{ST} \quad (17)$$

Along the planning horizon, it is only possible to invest in one of the candidate alternatives for each component (18)–(22). Constraints (23) guarantee that new transformers can only be added in substations that have been previously expanded or built. Candidate assets for reinforcement, replacement or installation can only be used once the investment is made. Under the assumption that the existing network is radial, (24)–(26) model the utilization of both existing and newly installed feeders explicitly characterizing the direction of current flows in order to keep radiality. However, for the interested reader, if radiality operation is considered and meshed topologies are allowed, equal symbols at equations (24)–(26) need to be modified relaxing these equations. The utilization of new transformers is formulated in (27) and the utilization of installed generators and generic storage units is modelled in (28) and (29). The total investment cost at each stage t has an upper limit that cannot be exceeded. Constraints (30) impose this budget limit for investment at each stage.

$$\sum_{t \in T} \sum_{k \in K^l} x_{i,j,k,t}^l \leq 1; \forall l \in \{NRF, NAF\}, \quad \forall (i,j) \in \Upsilon^l \quad (18)$$

$$\sum_{t \in T} x_{i,t}^{SS} \leq 1; \quad \forall i \in \Omega^{SS} \quad (19)$$

$$\sum_{t \in T} \sum_{k \in K^{NT}} x_{i,k,t}^{NT} \leq 1; \quad \forall i \in \Omega^{SS} \quad (20)$$

$$\sum_{t \in T} x_{i,t}^p \leq 1; \quad \forall i \in \Omega^p \quad (21)$$

$$\sum_{t \in T} x_{i,t}^{ST} \leq 1; \quad \forall i \in \Omega^{ST} \quad (22)$$

$$x_{i,k,t}^{NT} \leq \sum_{\tau=1}^t x_{i,\tau}^{SS}; \quad \forall i \in \Omega^{SS}, \forall k \in K^{NT}, \forall t \in T \quad (23)$$

$$y_{i,j,k,t}^{EFF} + y_{j,i,k,t}^{EFF} = 1; \quad \forall (i,j) \in \Upsilon^{EFF}, \forall k \in K^{EFF}, \forall t \in T \quad (24)$$

$$y_{i,j,k,t}^l + y_{j,i,k,t}^l = \sum_{\tau=1}^t x_{i,j,k,\tau}^l; \quad \forall l \in \{NRF, NAF\},$$
$$\forall (i,j) \in \Upsilon^l, \forall k \in K^l, \forall t \in T \quad (25)$$

$$y_{i,j,k,t}^{ERF} + y_{j,i,k,t}^{ERF} = 1 - \sum_{\tau=1}^t \sum_{\kappa \in K^{NRF}} x_{i,j,\kappa,\tau}^{NRF}; \quad \forall (i,j) \in \Upsilon^{ERF},$$
$$\forall k \in K^{ERF}, \forall t \in T \quad (26)$$

$$y_{i,k,t}^{NT} \leq \sum_{\tau=1}^t x_{i,k,\tau}^{NT}; \quad \forall i \in \Omega^{SS}, \forall k \in K^{NT}, \forall t \in T \quad (27)$$

$$y_{i,t}^p \leq \sum_{\tau=1}^t x_{i,\tau}^p; \quad \forall i \in \Omega^p, \forall t \in T \quad (28)$$

$$y_{i,t}^{ST} \leq \sum_{\tau=1}^t x_{i,\tau}^{ST}; \quad \forall i \in \Omega^{ST}, \forall t \in T \quad (29)$$

$$\sum_{l \in \{NRF, NAF\}} \sum_{k \in K^l} \sum_{(i,j) \in \Upsilon^l} C_{ijk}^{I,l} \ell_{ij} x_{i,j,k,t}^l + \sum_{i \in \Omega^{SS}} C_i^{I,SS} x_{it}^{SS}$$
$$+ \sum_{k \in K^{NT}} \sum_{i \in \Omega^{SS}} C_{ik}^{I,NT} x_{i,k,t}^{NT} + \sum_{p \in P} \sum_{i \in \Omega^p} C_{ik}^{I,p} pf \bar{G}_k^p x_{i,t}^p$$
$$+ \sum_{p \in P} \sum_{i \in \Omega^{ST}} C_i^{I,ST} pf \bar{G}^{ST} x_{i,t}^{ST} \leq IB_t; \quad \forall t \in T \quad (30)$$

Generally, distribution networks are radially operated regardless of their topologies. Note that constraints (31) impose load nodes to have a single input flow while expression (32) sets a maximum of one input flow for the remaining nodes. As shown in [14], traditional radiality constraints (31)–(32) may fail to guarantee a radial operation of the distribution system when DG is considered, due to issues with transfer nodes and isolated generators. This difficulty is overcome by adding the set of radiality constraints (33)–(39). The existence of isolated generators is disabled in (33)–(39), which model a fictitious system with fictitious demands. The fictitious demand at load nodes that are candidate locations for DG installation is equal to 1 p.u., whereas at the remaining nodes it is set to 0 (40).

$$\sum_{l \in L} \sum_{i \in \Omega_j^l} \sum_{k \in K^l} y_{i,j,k,t}^l = 1; \quad \forall j \in \Omega_t^{LN}, \forall t \in T \quad (31)$$

$$\sum_{l \in L} \sum_{i \in \Omega_j^l} \sum_{k \in K^l} y_{i,j,k,t}^l \leq 1; \quad \forall j \notin \Omega_t^{LN}, \forall t \in T \quad (32)$$

$$\sum_{l \in L} \sum_{k \in K^l} \sum_{j \in \Omega_i^l} \left(\tilde{f}_{i,j,k,t}^l - \tilde{f}_{j,i,k,t}^l \right) = \tilde{g}_{i,t}^{SS} - \tilde{D}_{i,t}; \quad \forall i \in \Omega^N, \forall t \in T \quad (33)$$

$$0 \leq \tilde{f}_{i,j,k,t}^{EFF} \leq n_{DG}; \quad \forall i \in \Omega_j^{EFF}, \forall j \in \Omega^N, \forall k \in K^{EFF}, \forall t \in T \quad (34)$$

$$0 \leq \tilde{f}_{i,j,k,t}^{ERF} \leq \left(1 - \sum_{\tau=1}^t \sum_{\kappa \in K^{NRF}} x_{ij\kappa\tau}^{NRF} \right) n_{DG}; \quad \forall (i,j) \in \Upsilon^{ERF},$$
$$\forall k \in K^{ERF}, \forall t \in T \quad (35)$$

$$0 \leq \tilde{f}_{j,i,k,t}^{ERF} \leq \left(1 - \sum_{\tau=1}^t \sum_{\kappa \in K^{NRF}} x_{ij\kappa\tau}^{NRF} \right) n_{DG}; \quad \forall (i,j) \in \Upsilon^{ERF},$$
$$\forall k \in K^{ERF}, \forall t \in T \quad (36)$$

$$0 \leq \tilde{f}_{i,j,k,t}^l \leq \left(\sum_{\tau=1}^t x_{i,j,k,\tau}^l \right) n_{DG}; \quad \forall l \in \{NRF, NAF\},$$
$$\forall (i,j) \in \Upsilon^l, \forall k \in K^l, \forall t \in T \quad (37)$$

$$0 \leq \tilde{f}_{j,i,k,t}^l \leq \left(\sum_{\tau=1}^t x_{i,j,k,\tau}^l \right) n_{DG}; \quad \forall l \in \{NRF, NAF\},$$
$$\forall (i,j) \in \Upsilon^l, \forall k \in K^l, \forall t \in T \quad (38)$$

$$0 \leq \tilde{g}_{i,t}^{SS} \leq n_{DG}; \quad \forall i \in \Omega^{SS}, \forall t \in T \quad (39)$$

$$\tilde{D}_{i,t} = \begin{cases} 1; & \forall i \in \Omega_t^{LN}, \forall t \in T \\ 0; & \forall i \notin \Omega_t^{LN}, \forall t \in T \end{cases} \quad (40)$$

Such fictitious nodal demands can only be supplied by fictitious substations located at the original substation nodes, which inject fictitious power through the actual feeders. Constraints in (33) represent the fictitious current nodal balance equations. Constraints (34)–(38) limit the fictitious flows through the feeders. Constraints (39)–(40) set the limits for the fictitious currents injected by fictitious substations.

C. Demand Response Constraints

The inclusion of DR in the problem formulation requires an adequate treatment of uncertainties in the system and load levels. In an attempt to accommodate the increasing amount of RES in existing power systems and to provide an adequate framework for the DR impact in existing power system models, load period approach and a clustering approach have recently been applied to accurately represent load curve. DR has been introduced in the model considering elastic demand functions calibrated by load levels. Positive and negative demand shifting is limited by the maximum amount of shiftable load, expressed as a function of the substation prices and the demanded energy (41)–(42). The slope of the demand function is determined by the elasticity considerations already discussed. At least some of the customers are considered to participate in real-time pricing, where consumers face risks associated to spot pricing. The considered elasticities represent the participation of consumers in such a tariff modelling, where smaller elasticities correspond to lower participation levels. Final demand levels for each considered block are defined in (43). Constraint (44) guarantees that the overall positive and negative demand responses are equivalent. Constraint (45) defines the average price for the considered load level. It is calculated based on the substation prices at stage t for load level ll and scenario w obtained from the solution of the model without DR.

$$dr^+_{i,t,ll,w} \leq \max\left\{0, \sum_{lb}\xi_{lb,ll}\frac{(D_{i,t,ll,w}\Delta_{ll}+D_{i,t,lb,w}\Delta_{lb})}{\Delta_{lb}+\Delta_{ll}}\right.$$
$$\left.\frac{\left(c^{SS}_{t,lb,w}-\overline{C^{SS}_{t,ll,w}}\right)}{\overline{C^{SS}_{t,ll,w}}}\right\} \quad \forall i \in \Omega^i, \forall t \in T,$$
$$\forall ll \in LL, \forall w \in \Pi \qquad (41)$$

$$dr^-_{i,t,ll,w} \leq \max\left\{0, \sum_{lb}\xi_{lb,ll}\frac{(D_{i,t,ll,w}\Delta_{ll}+D_{i,t,lb,w}\Delta_{lb})}{\Delta_{lb}+\Delta_{ll}}\right.$$
$$\left.\frac{\left(c^{SS}_{t,ll,w}-\overline{C^{SS}_{t,ll,w}}\right)}{\overline{C^{SS}_{t,ll,w}}}\right\} \quad \forall i \in \Omega^i, \forall t \in T,$$
$$\forall ll \in LL, \forall w \in \Pi \qquad (42)$$

$$d_{i,t,ll,w} = D_{i,t,ll,w} + dr^+_{i,t,ll,w} - dr^-_{i,t,ll,w} \qquad (43)$$

$$\sum_{ll}dr^+_{i,t,ll,w} = \sum_{ll}dr^-_{i,t,ll,w} \quad \forall i \in \Omega^i, \forall t \in T,$$
$$\forall ll \in LL, \forall w \in \Pi \qquad (44)$$

$$\overline{C^{SS}_{t,ll,w}} = \frac{\sum_{lb}C^{SS}_{t,lb,w}\Delta_{lb}}{\sum_{lb}\Delta_{lb}} \quad \forall \xi_{lb,ll} > 0 \; \forall i \in \Omega^i, \forall t \in T,$$
$$\forall ll \in LL, \forall w \in \Pi \qquad (45)$$

The reference price-quantity pair composed of the weighted average price and the fixed demand level $\overline{C^{SS}_{t,ll,w}}$ is considered to be the base point of the linear demand function for each load level. The price elasticity assumptions determine the slope of the demand function with own-price elasticities $(\xi_{ll,ll})$ and cross-price elasticities $(\xi_{lb,ll})$ being exogenously provided, based upon values from the literature. Own-price elasticity refers to how energy consumers react to every single load level, considering the average price of the incumbent load levels. Cross-price elasticity (also known as elasticity of substitution) refers to the consumer's reaction to the prices in other load levels. The addition of price elasticities results in DR function $d_{i,t,ll,w}$, which expresses the quantity demanded $(d_{i,t,ll,w})$ as function of the relative deviations of load level prices from the reference level. In [27], a clear analysis on the demand response sensitivities to participation rates and elasticities is presented. Based on [27], the present paper assumes a cross-price elasticity of 2% between day and night periods and 4% between the levels corresponding to the same load block. Different methodologies have been defined in literature [27]–[29] to adequately account for DR in both, network and generation expansion planning modelling. The nonlinear constraint reformulation is presented in Appendix B.

D. Energy Storage Constraints

In modern power systems, storage devices have grown rapidly. Energy storage units are integrated to Energy Distribution Systems (EDS) to meet several purposes such as real time power demand, smoothing output power of Renewable Energy Resources (RES), improving power system reliability and being economically efficient. Consequently, a generic storage system is modelled and mathematically represented through (46):

$$\sum_{n,b}\left[\Delta_{ll}\left(\eta^{ST,store}_i g^{ST,store}_{i,t,ll,w} - \left(\frac{1}{\eta^{ST,prod}_i}\right)g^{ST,prod}_{i,t,ll,w}\right)\right]$$
$$= 0 \quad \forall q \in \Omega^Q, \forall r \in \Omega^R, \forall i \in \Omega^{ST}, \forall t \in T, \forall w \in \Pi \quad (46)$$

In medium- and long-term power system models, it is a common approach to approximate the demand curve by load levels in order to make the models computationally tractable. However, in such an approach, the chronological information between individual hours is lost (and therefore also the transition's function of the ESS). The proposed approach considering different demand blocks following the above-described criteria allows to better integrate chronological information in power system models, thereby resulting in a more accurate representation of system outcomes such as electricity prices and total cost. In order to adequately represent the ESS transition, (46) is formulated to be accomplished at the n, b level (day/night, load block).

E. Substation Prices

To adequately integrate price-dependent resources, the substation price has been defined as a function of the injected power in the distribution network. Equations (1), (4), (41), (42) and (51) are affected by these variable substation costs.
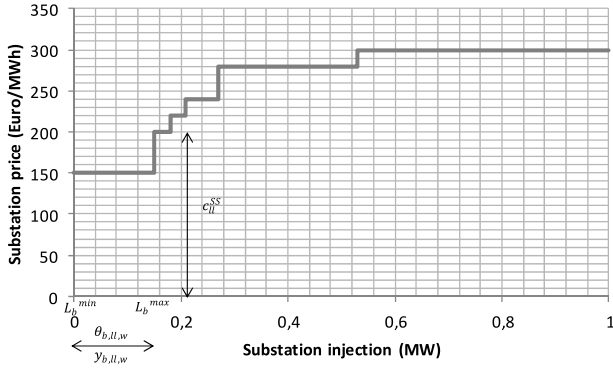
Fig. 4. Substation prices.

The aforementioned expression (4) models all production costs including substation production costs, which are dependent on the substation price for the considered load level and generation of the individual units. To do this, a binary expansion approach [25] has been used. The discrete substation price $c_{t,ll,w}^{SS}$ has been defined by b steps (or blocks) between L_b^{min} and L_b^{max} by adding binary variable $z_{t,b,ll,w}$ (47). Variable $\theta_{t,b,ll,w}$ represents the level of substation power injection for each considered step b (Fig. 4). The value of $\theta_{t,b,ll,w}$ is limited by the upper and lower limits of the considered step (48). The sequentiality of the active step b introduced in the formulation of the substation price is guaranteed in (49). Equation (50) guarantees the equivalence between the sum of the energy supplied by the different transformers and the considered substation power injection. The nonlinear constraint reformulation is presented in Appendix C.

$$c_{t,ll,w}^{SS} = \sum_b C_b z_{t,b,ll,w} \tag{47}$$

$$z_{t,b,ll,w} L_b^{min} \leq \theta_{t,b,ll,w} \leq z_{t,b,ll,w} L_b^{max} \tag{48}$$

$$z_{t,b,ll,w} \geq z_{t,b+1,ll,w} \tag{49}$$

$$\sum_{i \in \Omega^{SS}} g_{i,t,ll,w}^{tr} = \sum_{b \in \Omega^B} z_{t,b,ll,w} \theta_{t,b,ll,w}. \tag{50}$$

F. Demand Payment

Electricity customers in isolated electric power systems expect reasonable and non-discriminatory prices. Substation prices have been considered in the proposed methodology as an adequate non-discriminatory price signal for consumers. Constraint (51) models the demand payment for each load level as a function of the substation price and the total volume of demand (Fig. 1). The nonlinear constraint reformulation is presented in Appendix D.

$$p_{t,ll,w} = \sum_{i \in \Omega^N} c_{t,ll,w}^{SS} pfd_{i,t,ll,w}. \tag{51}$$

V. CONCLUSION

DR and ESS are considered a promising subject in operation and planning of electrical power systems. However, the impact of both technologies in joint distributed generation and distribution network expansion planning has not been fully analyzed yet. The first of this two-paper series formulates the effect of these two technologies in distribution systems expansion planning. A responsive demand has the potential to play an important role in more flexible and smarter power systems. Its relevance in the short-term operation of electric power systems has been extensively investigated, where symmetric treatment of demand and generation creates the strongest incentive for final consumers to participate actively in the wholesale electricity market. When considering medium- and long-term planning, demand responsiveness has an impact on reduction or deferment in the required expansion planning. DR can even substitute generation and distribution network expansion, as shown in the companion paper, where generation and network investments have been deferred. DR can contribute to adequately accommodate renewable generation in a joint distribution and generation expansion planning problem, increasing the volume of RES optimal allocated in the system. Additionally, the present study investigates the costs and benefits of ESS deployment and the reduction of network investment cost by deploying ESS. Therefore, an adequate expansion planning requires the integration of DR and ESS in the planning process, since some overinvestments may be averted.

Further work will address the issues brought up by incorporating Demand Response and ESS, solving the problem using bi-level programming techniques. Research will also be conducted comparing the proposed approach with enhanced planning methodologies such as k-means and system states.

APPENDIX

MODEL LINEARIZATION

The optimization model for the joint generation and distribution network expansion planning presented includes nonlinearities which make the optimal solution hard to obtain. Instead of directly addressing the original problem of mixed-integer nonlinear programming, a mixed-integer linear formulation is proposed. The nonlinearities are related to the bilinear terms involving the products of continuous and binary decision variables. These nonlinearities are recast as linear expressions by using a piecewise linear approximation for energy losses and integer algebra results for the bilinear terms.

A. Kirchhoff's Law Linearization

Constraints in (8) model Kirchhoff's voltage law for all feeders in use considering existing fixed feeders, existing replaceable feeders, new replacement feeders, and newly added feeders. These constraints are only active when the corresponding line is used. The equivalent integer linear reformulation (also known as Fortuny-Amat and McCarl reformulation) is defined in (A1), where M is a large enough positive constant and its influence is similar to constraint (8). This non-linearity is modeled through binary variables and the expression associated with Kirchhoff's voltage law. The linear formulation of these constraints is presented below:

$$-M\left(1 - y_{i,j,k,t}^l\right) \leq Z_{i,j,k}^l f_{i,j,k,ll,w}^l - \left(v_{i,t,ll,w} - v_{j,t,ll,w}\right)$$
$$\leq M\left(1 - y_{i,j,k,t}^l\right); \tag{A1}$$

B. Demand Response Linearization

Constraints (42) and (43) represent positive and negative demand shifting, respectively. The equivalent integer linear reformulation is defined in (B1)–(B2).

$$-M\left(1 - z_{t,ll,w}^{DR}\right) \leq dr_{t,i,ll,w}^{+}$$

$$-\sum_{lb} \xi_{lb,ll} \frac{\left(D_{i,t,ll,w}\Delta_{ll} + D_{i,t,lb,w}\Delta_{lb}\right)}{\Delta_{lb} + \Delta_{ll}} \frac{\left(c_{t,lb,w}^{SS} - \overline{C_{t,ll,w}^{SS}}\right)}{\overline{C_{t,ll,w}^{SS}}}$$

$$\leq M\left(1 - z_{t,ll,w}^{DR}\right) \tag{B1}$$

$$-M\left(1 - z_{t,ll,w}^{DR}\right) \leq dr_{t,i,ll,w}^{-}$$

$$-\sum_{lb} \xi_{lb,ll} \frac{\left(D_{i,t,ll,w}\Delta_{ll} + D_{i,t,lb,w}\Delta_{lb}\right)}{\Delta_{lb} + \Delta_{ll}} \frac{\left(c_{t,lb,w}^{SS} - \overline{C_{t,ll,w}^{SS}}\right)}{\overline{C_{t,ll,w}^{SS}}}$$

$$\leq M\left(1 - z_{t,ll,w}^{DR}\right). \tag{B2}$$

C. Substation Energy Price Linearization

Non-linear terms associated with the product of binary and continuous variables (52) are discretized to:

$$\theta_{t,b,ll,w} = z_{t,b,ll,w} \sum_{i \in \Omega^{SS}} g_{i,k,t,ll,w}^{tr} \tag{C1}$$

The non-linear product of binary and continuous variables can be equivalently reformulated as an integer equation (also known as Big-M reformulation) (C2). In constraint (C2) M is a large-enough positive constant.

$$- \left(1 - z_{t,b,ll,w}\right)M \leq \theta_{t,b,ll,w} - \sum_{i \in \Omega^{SS}} \sum_{k \in K^{tr}} g_{i,k,t,ll,w}^{tr}$$

$$\leq \left(1 - z_{t,b,ll,w}\right)M \tag{C2}$$

The formulation of the objective function as a maximization problem requires additional constraints to guarantee the correctness of the substation price linearization (C3)–(C4).

$$\rho_{t,b,ll,w} = z_{t,b+1,ll,w}L_{b}^{max} \tag{C3}$$

$$-\left(1 - z_{t,b,ll,w}\right)M \leq \rho_{t,b,ll,w} - \theta_{t,b,ll,w} \leq \left(1 - z_{t,b,ll,w}\right)M. \tag{C4}$$

D. Demand Payment Linearization

According to (47)–(50), substation prices have been defined by b steps (or blocks) between L_{b}^{min} and L_{b}^{max} by adding binary variable $z_{t,b,ll,w}$. Then, the equivalent integer linear reformulation of (51) is defined in (D1)–(D2).

$$\varphi_{t,b,ll,w} = z_{t,b,ll,w} \sum_{i \in \Omega^{N}} d_{t,i,ll,w} \tag{D1}$$

The non-linear product of binary and continuous variables can be equivalently reformulated as an integer linear set of equations (also known as Big-M reformulation) (D2).

$$- \left(1 - z_{t,b,ll,w}\right)M \leq \varphi_{t,b,ll,w} - \sum_{N \in \Omega^{N}} d_{i,t,ll,w}$$

$$\leq \left(1 - z_{t,b,ll,w}\right)M. \tag{D2}$$

REFERENCES

[1] T. Gönen and B. L. Foote, "Distribution-system planning using mixed-integer programming," *IEEE Proc. C Gener. Transm. Distrib.*, vol. 128, no. 2, pp. 70–79, Mar. 1981.

[2] N. Ponnavaikko, K. S. Prakasa Rao, and S. S. Venkata, "Distribution system planning through a quadratic mixed integer programming approach," *IEEE Trans. Power Del.*, vol. 2, no. 4, pp. 1157–1163, Oct. 1987.

[3] Y. Tang, "Power distribution system planning with reliability modeling and optimization," *IEEE Trans. Power Syst.*, vol. 11, no. 1, pp. 181–189, Feb. 1996.

[4] W. El-Khattam, K. Bhattacharya, Y. Hegazy, and M. M. A. Salama, "Optimal investment planning for distributed generation in a competitive electricity market," *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1674–1684, Aug. 2004.

[5] W. El-Khattam, Y. G. Hegazy, and M. M. A. Salama, "An integrated distributed generation optimization model for distribution system planning," *IEEE Trans. Power Syst.*, vol. 20, no. 2, pp. 1158–1165, May 2005.

[6] H. Falaghi and M.-R. Haghifam, "ACO based algorithm for distributed generation sources allocation and sizing in distribution systems," in *Proc. IEEE Power Tech*, Lausanne, Switzerland, Jul. 2007, pp. 555–560.

[7] S. Haffner, L. F. A. Pereira, L. A. Pereira, and L. S. Barreto, "Multistage model for distribution expansion planning with distributed generation—Part I: Problem formulation," *IEEE Trans. Power Del.*, vol. 23, no. 2, pp. 915–923, Apr. 2008.

[8] S. Haffner, L. F. A. Pereira, L. A. Pereira, and L. S. Barreto, "Multistage model for distribution expansion planning with distributed generation—Part II: Numerical results," *IEEE Trans. Power Del.*, vol. 23, no. 2, pp. 924–929, Apr. 2008.

[9] Y. M. Atwa, E. F. El-Saadany, M. M. A. Salama, and R. Seethapathy, "Optimal renewable resources mix for distribution system energy loss minimization," *IEEE Trans. Power Syst.*, vol. 25, no. 1, pp. 360–370, Feb. 2010.

[10] M. Lavorato, M. J. Rider, A. V. Garcia, and R. Romero, "A constructive heuristic algorithm for distribution system planning," *IEEE Trans. Power Syst.*, vol. 25, no. 3, pp. 1734–1742, Aug. 2010.

[11] K. Zou, A. P. Agalgaonkar, K. M. Muttaqi, and S. Perera, "Multi-objective optimisation for distribution system planning with renewable energy resources," in *Proc. IEEE Int. Energy Conf. Exhibit. (EnergyCon)*, Manama, Bahrain, Dec. 2010, pp. 670–675.

[12] V. V. Thang, D. Q. Thong, and B. Q. Khanh, "A new model applied to the planning of distribution systems for competitive electricity markets," in *Proc. Electr. Util. Deregul. Restruct. Power Technol. (DRPT)*, Weihai, China, Jul. 2011, pp. 631–638.

[13] A. M. Cossi, L. G. W. da Silva, R. A. R. Lázaro, and J. R. S. Mantovani, "Primary power distribution systems planning taking into account reliability, operation and expansion costs," *IET Gener. Transm. Distrib.*, vol. 6, no. 3, pp. 274–284, Mar. 2012.

[14] M. Lavorato, J. F. Franco, M. J. Rider, and R. Romero, "Imposing radiality constraints in distribution system optimization problems," *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 172–180, Feb. 2012.

[15] E. Naderi, H. Seifi, and M. S. Sepasian, "A dynamic approach for distribution system planning considering distributed generation," *IEEE Trans. Power Del.*, vol. 27, no. 3, pp. 1313–1322, Jul. 2012.

[16] X. Xiao, Z. Lin, F. Wen, and J. Huang, "Multiple-criteria decision-making of distribution system planning considering distributed generation," in *Proc. Int. Conf. Sustain. Power Gener. Supply (SUPERGEN)*, Hangzhou, China, Sep. 2012, pp. 1–6.

[17] G. Muñoz-Delgado, J. Contreras, and J. M. Arroyo, "Joint expansion planning of distributed generation and distribution networks," *IEEE Trans. Power Syst.*, vol. 30, no. 5, pp. 2579–2590, Sep. 2015.

[18] A. Satchwell and R. Hledik, "Analytical frameworks to incorporate demand response in long-term resource planning," Lawrence Berkeley Nat. Lab., Berkeley, CA, USA, Tech. Rep. DE-AC02-05CH11231, Sep. 2013.

[19] C. De Jonghe, B. F. Hobbs, and R. Belmans, "Optimal generation mix with short-term demand response and wind penetration," *IEEE Trans. Power Syst.*, vol. 27, no. 2, pp. 830–839, May 2012.

[20] A. K. Kazerooni and J. Mutale, "Network investment planning for high penetration of wind energy under demand response program," in *Proc. 11th Int. Conf. Probab. Methods Appl. Power Syst. (PMAPS)*, Singapore, Jun. 2010, pp. 238–243.

[21] M. Samadi, M. H. Javidi, and M. S. Ghazizadeh, "Modeling the effects of demand response on generation expansion planning in restructured power systems," *J. Zhejiang Univ. Sci. C*, vol. 14, no. 12, pp. 966–976, Dec. 2013.

[22] A. L. Motto, F. D. Galiana, A. J. Conejo, and J. M. Arroyo, "Network-constrained multiperiod auction for a pool-based electricity market," *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 172–180, Feb. 2012.

[23] S. Montoya-Bueno, J. I. Muñoz, and J. Contreras, "A stochastic investment model for renewable generation in distribution systems," *IEEE Trans. Sustain. Energy*, vol. 6, no. 4, pp. 1466–1474, Oct. 2015.

[24] G. Muñoz-Delgado, J. Contreras, and J. M. Arroyo, "Multistage generation and network expansion planning in distribution systems considering uncertainty and reliability," *IEEE Trans. Power Syst.*, to be published, doi: 10.1109/TPWRS.2015.2503604.

[25] B. F. Hobbs, H. B. Rouse, and D. T. Hoog, "Measuring the economic value of demand-side and supply resources in integrated resource planning models," *IEEE Trans. Power Syst.*, vol. 8, no. 3, pp. 979–987, Aug. 1993.

[26] Ö. Özdemir, F. D. Munoz, J. L. Ho, and B. F. Hobbs, "Economic analysis of transmission expansion planning with price-responsive demand and quadratic losses by successive LP," *IEEE Trans. Power Syst.*, vol. 31, no. 2, pp. 1096–1107, Mar. 2016.

[27] K. Dietrich, J. M. Latorre, L. Olmos, and A. Ramos, "Demand response and its sensitivity to participation rates and elasticities," in *Proc. 8th Int. Conf. Eur. Energy Market (EEM)*, Zagreb, Croatia, May 2011, pp. 716–717.

[28] A. K. Kazerooni and J. Mutale, "Transmission network planning under a pricebased demand response program," in *Proc. IEEE PES* Transm. Distrib. Conf. Expo., New Orleans, LA, USA, Apr. 2010, pp. 1–7.

[29] K. Dietrich, J. M. Latorre, L. Olmos, and A. Ramos, "Demand response in an isolated system with high wind integration," *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 20–29, Feb. 2012.

Pilar Meneses de Quevedo received the Ingeniero Industrial degree from the University of Cantabria, Spain, in 2005, and the M.Sc. degree from the Universidad Pontificia of Comillas, Madrid, Spain, in 2008. She is currently pursuing the Ph.D. degree with the University of Castilla-La Mancha.

Her research interests are in the fields of power systems operations, planning, and electricity markets.

Gregorio Muñoz-Delgado (S'14) received the Ingeniero Industrial degree and the M.Sc. degree from the Universidad de Castilla-La Mancha, Ciudad Real, Spain, in 2012 and 2013, respectively, where he is currently pursuing the Ph.D. degree.

His research interests are in the fields of power systems planning, operations, and economics.

Miguel Asensio received the M.Sc. degrees from the Polytechnic University of Madrid, Spain, in 2003, and Comillas University, Madrid, Spain, in 2013. He is currently pursuing the Ph.D. degree with the University of Castilla-La Mancha, Spain. He has been with the German, Italian, and Spanish Electrical Sector from 2003 to 2012. His research interests lie within the area of decision-making support systems in the energy sector, electricity market, and operational issues and transmission pricing.

Javier Contreras (SM'05–F'15) received the B.S. degree in electrical engineering from the University of Zaragoza, Zaragoza, Spain, in 1989, the M.Sc. degree from the University of Southern California, Los Angeles, in 1992, and the Ph.D. degree from the University of California, Berkeley, in 1997.

He is currently a Full Professor with the University of Castilla-La Mancha, Ciudad Real, Spain. His research interests include power systems planning, operations and economics, and electricity markets.