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# Long-term electricity procurement portfolio optimization

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ABSTRACT

This paper addresses the long-term electricity procurement portfolio optimization problem faced by an electricity Retailer. Differentiated asset options are considered to fully cover the forecasted electricity consumption represented by the Retailer, such as investing in new RES plants, a new CCGT unit, new battery energy storage systems and procuring electricity directly from the wholesale electricity market. A novel optimization model that takes into account the inherent technical and operating characteristics and constraints of each asset option as well as various financial parameters was formulated for the quantification of the timing, capacity and overall cost of the optimal mix that covers the Retailer's forecasted load portfolio in the most efficient way on a yearly basis. Multiple scenarios were formulated to capture the effect that the anticipated day-ahead market prices, the expansion of the Retailer's customer base, the incorporation of budget constraints that reflect the desired long-term investment strategy of the Retailer as well as the selection of common economic valuation parameters may have on the optimal mix of asset options. A case study on the long-term strategy (2021-2030) of a growing Retailer that participates in the Greek electricity market is presented illustrating the applicability and effectiveness of the proposed optimization model.

## Introduction

Since early 1990s, both generation and retail sectors of the electricity industry have been progressively experiencing ground-breaking reforms worldwide. Monopolistic environments have been gradually replaced by competitive markets in both sectors, where restructured former state-owned utilities and new private entities compete each other in each sector to gain market shares and maximize profits [1]. An electricity retailer (henceforth, "Retailer") is an intermediary between electricity producers and consumers and often operates as an entity that is independent of any generation or distribution company. The core business of the Retailer is to purchase energy from various resources and resell it to end-consumers through differentiated retail contracts aiming at the maximization of its own profits. In this context, in conjunction with the indisputable need to formulate competitive retail tariffs that will enable the Retailer to expand its customer base and increase market shares [2-7], the Retailer also faces the fundamental problem of making optimal decisions regarding the formulation of its electricity procurement portfolio mix aiming at the minimization of its total electricity procurement cost in the long-term.

The problem of optimal electricity procurement has gained much attention in the research community so far, where various methods and tools have been proposed to tackle this problem and provide effective solutions. In the short-term, one of the first works that focused on the determination of the forward-contract purchase that minimizes the expected procurement cost of a local distribution company subject to a cost-exposure constraint is presented in [8]. The problem of electricity procurement for a large consumer, involving pool market, bilateral contracts and self-production is presented in [9], while a similar approach also incorporating uncertainty and risk is presented in [10]. An analytical method for optimal hedging portfolio, including only forward and option contracts, is proposed in [11], while in [12] it is demonstrated that physical hedging, supported to some degree by forward contracting and spot transactions is an efficient and sustainable approach to Retailer's risk management in decentralized electricity markets. The electricity procurement of a retailer is modeled as an investment problem in [13], where the retailer invests in both the wholesale electricity market and financial market. A methodology that enables the retailer to get the bilateral quantity and price range for which his payoff is risk-constrained is presented in [14], while a multistage stochastic optimization model for an electricity retailer who

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## Nomenclature

*Indices and Sets*

$i$ ($I$) Index (set) of asset technologies/options, $I = \{w, pv, conv, b, m\}$, where $i$=$w$: wind plants, $i$=$pv$: PV plants, $i$=$conv$: conventional CCGT plant, $i$=$b$: battery energy storage systems (BESS) ($i$=$b,ch$: BESS while charging, $i$=$b,disch$: BESS while discharging), $i$=$m$: wholesale electricity market

$t$ ($T^y$) Index (set) of hours of year $y$ of the planning horizon

$y$ ($Y$) Index (set) of years of the planning horizon

*Parameters*

$\alpha$ Capital recovery factor

$n_b^{ch/disch}$ BESS charging/discharging efficiency

$\lambda_{t,y}$ Forecasted wholesale market price during hour $t$ of year $y$ of the planning horizon, in €/MWh

$B_y^{max}$ Maximum available budget for investment for year $y$ of the planning horizon, in €

$C_y^{i,inv,power}$ Specific investment cost of asset technology $i$ in year $y$ of the planning horizon, in €/MW

$C_y^{i,inv,energy}$ Specific investment cost of asset technology $i$ in year $y$ of the planning horizon, in €/MWh

$DR$ Nominal discount rate, in %

$C_{t,y}^i$ Total operating cost of asset technology $i$, including the fuel cost, $CO_2$ emissions cost and (fixed and variable) operation and maintenance (O&M) cost during hour $t$ of year $y$ of the planning horizon, in €/MWh

$C_y^{i,FOM}$ Fixed part of the operation and maintenance (O&M) cost of asset technology $i$ in year $y$ of the planning horizon, in €/MW-year

$C_y^{i,VOM}$ Variable part of the O&M cost of asset technology $i$ in year $y$ of the planning horizon, in €/MWh

$K_y^i$ Percentage of specific investment cost for the refurbishment of asset technology $i$, in %

$N$ Depreciation period, in years

$N_b$ Lifetime of batteries included in the BESS, in years

$P_{t,y}^{Load}$ Retailer's load during hour $t$ of year $y$ of the planning horizon, in MW

$P_{t,y}^{i,max}$ Energy injection profile of asset technology $i$ during hour $t$ of year $y$ of the planning horizon, in p.u. (energy injected in MWh / installed capacity in MW)

*Variables*

$Cost_y$ Total electricity procurement cost in year $y$ of the planning horizon, in €

$E_{t,y}^b$ Energy stored in BESS $b$ during hour $t$ of year $y$ of the planning horizon, in MWh

$IC_y^i$ Optimal investment cost of asset technology $i$ during year $y$ of the planning horizon, in €

$x_y^i$ Optimal level of capacity (expressed in power terms) of asset technology $i$ during year $y$ of the planning horizon, in MW

$z_y^b$ Optimal level of capacity (expressed in energy terms) of battery energy storage system $b$ during year $y$ of the planning horizon, in MWh

$p_{t,y}^i$ Power output of asset technology $i$ during hour $t$ of year $y$ of the planning horizon, in MWh/h

$sp_{t,y}^i$ Energy spillage of asset technology $i$ during hour $t$ of year $y$ of the planning horizon, in MWh/h

is contractually obliged to fulfill an uncertain demand by buying electricity from the spot market and by hedging spot price exposure with forward contracts for later delivery of electricity subject to various risk constraints is presented in [15]. The electricity procurement of a large consumer considering several alternatives (pool market, bilateral contracts and self-production) under a stochastic programming framework is addressed in [16-17]. A recent short-term decision model based on robust optimization for an electricity retailer in order to determine both the optimal electricity procurement strategy from multiple generation companies and spot market, and the electricity selling prices for customers (retail tariffs) is presented in [18]. Energy storage units in the form of electric vehicles are considered and scheduled in a two-stage two-level short-term procurement strategy optimization model of a smart grid retailer in [19]. A two-stage stochastic programming model for the solution of the short-term energy procurement problem of a large electricity consumer with multiple energy procurement sources, including renewable energy sources, self-generation by conventional thermal units, spot market, bilateral contracts, electrical energy storage and DR programs is presented in [20].

In the mid-term horizon, a power portfolio optimization model for minimizing the costs and managing the risks of a load serving entity is presented in [21], while a similar problem is solved using information gap decision theory and considering forward contracts, a limited self-generating facility, and the pool market as supply sources in [22]. A mixed-integer stochastic programming model that incorporates the conditional value-at-risk methodology and determines the optimal selling price of electricity to customers and the electricity procurement policy of a retailer considering spot market, forward contracts, call options and self-production for a monthly period is presented in [23]. A practical risk-constrained mathematical programming framework allowing an electricity retailer to determine the optimal selling prices to clients and manage the portfolio of forward contracts within a medium-term period while it can use the pool and forward contracts to procure their demand is shown in [24]. Finally, in [25] an optimal strategy composed of a mid-term planning model and a short-term planning model is presented. The mid-term planning is modeled as a stochastic optimization problem where the energy purchased from forward contracts and electricity retail price are determined. Given decisions determined in the mid-term model, the interruptible load contract and the amount of energy procured in the spot market are optimized in the short-term model. An extensive bibliographical survey of innovative decision-making methods for an electricity retailer has been recently presented in [26]. Table 1 provides the main features of each research work discussed herein.

All aforementioned works deal with the solution of the electricity retailer procurement portfolio problem either in the short-term horizon (e.g. day-ahead to week-ahead time periods) [8-20, 25] or the mid-term horizon (e.g. 1 month to 1 year ahead) [21-25], while most of them consider a limited set of available electricity procurement options (usually comprising only bilateral/forward contracts and spot market). In this context, RES generation facilities attaining grid parity (e.g. wind and PV plants) as well as battery energy storage systems are not explicitly modeled in almost any relevant work in the literature. Furthermore, the time horizon employed in all these models ranges from one day ahead to few months ahead, not providing adequate visibility to the Retailer to formulate his optimal electricity procurement strategy in the long-term (years ahead). Additionally, in case that self-generation facilities (comprising either conventional plants or renewable generation) are considered, only the short-term variable operating costs of the alternative procurement options are taken into account, fully ignoring any other related costs (e.g. investment costs, fixed O&M costs, BESS replacement costs) undertaken by a large consumer or Retailer. To the

**Table 1**
Main features of the research works reported in the literature and compared to the proposed work.

| Ref. | Horizon | Eligible resources | Investment decisions? | Costs considered |
|---|---|---|---|---|
| [8] | short-term | forward contracts, spot market | No | - |
| [9] | short-term | forward contracts, spot market, self-production | No | variable operating costs |
| [10] | short-term | forward contracts, spot market, self-production | No | variable operating costs |
| [11] | short-term | forward and option contracts | No | - |
| [12] | short-term | forward contracts, spot market, power plant | No | variable operating costs |
| [13] | short-term | forward contracts, spot market | No | - |
| [14] | short-term | forward contracts, spot market | No | - |
| [15] | short-term | forward contracts, spot market | No | - |
| [16] | short-term | forward contracts, spot market, self-production | No | variable operating costs |
| [17] | short-term | forward contracts, spot market, self-production | No | variable operating costs |
| [18] | short-term | conventional generating power plants, spot market | No | variable operating costs |
| [19] | short-term | electric vehicles, spot market | No | variable operating costs |
| [20] | short-term | forward (bilateral) contracts, spot market, RES, self-production, BESS, DR | No | variable operating costs |
| [21] | mid-term (1 month to 1 year ahead) | forward contracts, thermal, hydro and pumping units, spot market | No | variable operating costs and start-up costs |
| [22] | mid-term (months ahead) | forward contracts, spot market, self-production | No | variable operating costs |
| [23] | mid-term (1 month ahead) | forward contracts, spot market, call options, self-production | No | variable operating costs |
| [24] | mid-term (1 month ahead) | forward contracts, spot market | No | - |
| [25] | mid-term / short-term | Forward contracts, spot market, interruptible loads | No | - |
| This paper | long-term (multi-year) | spot market, RES (wind and PV), self-production CCGT, BESS | Yes | investment costs, fixed annual costs, variable operating costs, BESS replacement costs |

best of our knowledge, there is no reported work that addresses the long-term optimal electricity procurement problem faced by a Retailer, while considering differentiated alternative asset options and all associated costs to fully cover its forecasted electricity consumption, that is investing in new RES (wind and/or PV) plants, investing in a new CCGT unit, investing in new battery energy storage systems, and procuring electricity directly from the wholesale electricity market.

In this framework, this paper proposes a novel optimization model that takes into account the inherent technical and operating characteristics and constraints of differentiated asset options as well as various financial parameters for the quantification of the timing, capacity and overall cost of the optimal sourcing mix that covers the Retailer's forecasted load portfolio in the most efficient way in the long-term. Multiple scenarios have been examined to capture the effect that the anticipated day-ahead market clearing prices, the future expansion of the Retailer's customer base, the incorporation of budget constraints that reflect the desired long-term investment strategy of the Retailer as well as the selection of common economic valuation parameters may have on the formulation of the optimal mix of asset options. Since RES plants already lie among the most favorable investment options for electricity procurement from the Retailer's viewpoint in real life, the proposed model provides the Retailers with a practical and easily replicable decision-making tool to assist them towards formulating their optimal long-term electricity procurement portfolio.

The main contributions of this paper are the following:

a) A novel modeling framework for the long-term optimal electricity procurement problem faced by an electricity Retailer is proposed, allowing for a concise, robust and efficient modeling of the inherent technical and operating characteristics and constraints of an extensive pool of candidate asset options, such as renewable energy sources, battery energy storage systems, conventional generation and wholesale electricity market.
b) A holistic approach regarding the detailed modeling of the associated operating costs of the various candidate asset options was adopted, allowing for the proper consideration of all relevant cost components (i.e. investment costs, fixed and variable operation and maintenance costs, fuel and $CO_2$ emissions costs, degradation costs) in the optimization model in contrast to all existing works where only the short-term variable operating costs of the alternative procurement options may be taken into account in the associated optimization models.
c) The application of the proposed modeling framework for a growing Retailer that participates in the Greek electricity market using real-life data for the next decade proves its effectiveness and computational efficiency.

The remainder of the paper is organized as follows: Section 2 provides the description of the problem addressed and the mathematical formulation of the proposed optimization model. Section 3 describes the case study along with the main simulation results, while valuable conclusions and policy implications are drawn in Section 4.

## Problem description and mathematical formulation

### *Problem description*

The goal of the long-term electricity procurement portfolio optimization problem faced by an electricity Retailer is to define and quantify the optimal mix of asset options that the Retailer should invest on in order to fully cover its forecasted electricity consumption in the most efficient (least-cost) way on a yearly basis for the forthcoming years. Various candidate options have been considered, as follows:

a) Not engaging in any investment: The Retailer is not engaged in any investment and, therefore, it covers its full short position by procuring electricity exclusively from the wholesale electricity market. Forecasted hourly wholesale Day-Ahead Market (DAM) clearing prices for the entire planning horizon are used to approximate[1] the expenses incurred by the Retailer.
b) Investing in a new CCGT: The Retailer decides to invest in the construction and operation of a new cost-efficient CCGT plant to cover (all or part of) the short position of its retail activities; in such case, investment and operating costs are concerned for the calculation of the expenses incurred by the Retailer.

[1] We use the word "approximate" since the wholesale market deals/purchases may include bilateral contracts, forward contracts, imports, DAM purchases, Intra-Day Market purchases, etc., which are priced/settled with a price very close to the DAM price. For this reason, there is no actual differentiation between these categories (as separate sources) to cover the Retailer's portfolio and therefore, all these sources have been collectively called "wholesale market" in this study.

c) Investing in new RES plants: The Retailer decides to invest in the construction and operation of RES plants to cover (all or part of) the short position of its retail activities. In this case, mainly investment costs are concerned (some operating costs for the operation of the RES plants and the balancing costs may also be considered) for the calculation of the expenses incurred by the Retailer. Since wind and PV plants are the most promising and cost-efficient technologies among all RES types, in this study only wind and PV plants are considered as available options to contribute to the formulation of the optimal energy procurement mix of the Retailer.
d) Investing in battery energy storage systems: This option concerns the installation and operation of utility-scale Battery Energy Storage Systems (BESS) to form part of the optimal electricity procurement mix of the Retailer. In this case, investment and operating costs are concerned for the calculation of the expenses incurred by the Retailer.

It should be mentioned that Power Purchase Agreements (PPAs) between the Retailer and third parties (either RES producers or gas-fired plants owners/operators) shall probably be concluded in contract prices that are very close (e.g. plus or minus 1-2 €/MWh) to the expected average DAM price during the duration of contract, due to the fact that the counterparty (before signing the contract) retains the option to sell its production to the DAM. For this reason, including another option to the herein described exercise would lead to the following obvious result:

a) In case the contract price was lower than the assumed DAM price, then the contract quantities would be chosen instead of the wholesale market;
b) In case the contract price was higher than the assumed DAM price, there would be no difference in the attained results.

For this reason and for the sake of simplicity, such options have been eliminated from the pool of available options for covering the forecasted electricity consumption to be represented by the Retailer in the future years.

In order to define the optimal mix of resources to cover the Retailer's future electricity portfolio with the lowest possible cost, taking into account the inherent technical, operating and financial characteristics and constraints of each option (e.g. efficiencies, production profiles, capital and fixed & variable operating costs, etc.), a suitable optimization problem has been formulated and solved. The outcome of this model comprises the: a) timing (year), b) capacity (in MW) and/or energy (in MWh) and c) overall cost (incl. investment and operating costs) of the optimal mix of assets/options that covers the Retailer's forecasted electricity portfolio at the lowest total cost on a yearly basis. The mathematical formulation of the proposed optimization model is presented and analyzed in the following paragraph.

*Mathematical formulation*

The objective function of the optimization problem to be minimized is as follows:

$$Min\,\mathrm{Cost}_y = \left\{ \begin{array}{l} a\cdot\left[IC_y^b + C_y^{w,inv}\cdot x_y^w + C_y^{pv,inv}\cdot x_y^{pv} + C_y^{conv,inv}\cdot x_y^{conv} + \dfrac{K_y^b\cdot C_y^b\cdot x_y^b}{(1+DR)^{N_b}}\right] \\ +C_y^{w,FOM}\cdot x_y^w + C_y^{pv,FOM}\cdot x_y^{pv} + C_y^{b,FOM}\cdot x_y^b \\ +C_y^{w,VOM}\cdot\sum_{t\in T^y}\left(p_{t,y}^w + sp_{t,y}^w\right) + C_y^{pv,VOM}\cdot\sum_{t\in T^y}\left(p_{t,y}^{pv} + sp_{t,y}^{pv}\right) + C_y^{b,VOM}\cdot\sum_{t\in T^y}p_{t,y}^{b,disch} \\ +C_y^{conv}\cdot\sum_{t\in T^y}p_{t,y}^{conv} \\ +\sum_{t\in T^y}\lambda_{t,y}\cdot p_{t,y}^m \end{array} \right\} \quad \forall y \varepsilon Y \tag{1}$$

The objective function (1) aims at the minimization of the total electricity procurement cost on a yearly basis comprising: (a) the total yearly investment cost in new capacity of all asset technologies/options, also incorporating the yearly cost accounting for the refurbishment of the BESS (mainly referring to battery replacement) (first line), (b) the total yearly fixed operation and maintenance (O&M) cost of wind plants, PV plants, and BESS (second line), (c) the total yearly variable O&M cost of wind plants, PV plants, and BESS (third line), (d) the total yearly operating cost of the conventional CCGT unit (fourth line), (e) the total yearly procurement cost related to electricity purchases directly from the wholesale market (fifth line). It is noted that all investment costs (first line) all multiplied by the coefficient α that stands for the capital recovery factor (CRF), so that only the annuities of the corresponding investment costs are considered in each year's optimization subproblems. The associated mathematical formula defining α is described by (2).

$$a = CRF = \frac{DR\cdot(1+DR)^N}{(1+DR)^N - 1} \tag{2}$$

$$P_{t,y}^{Load} + p_{t,y}^{b,ch} = p_{t,y}^w + p_{t,y}^{pv} + p_{t,y}^{conv} + p_{t,y}^{b,disch} + p_{t,y}^m \quad \forall t\in T^y, y\in Y \tag{3}$$

$$p_{t,y}^w + sp_{t,y}^w = x_y^w\cdot P_{t,y}^{w,max} \quad \forall t\in T^y, y\in Y \tag{4}$$

$$p_{t,y}^{pv} + sp_{t,y}^{pv} = x_y^{pv}\cdot P_{t,y}^{pv,max} \quad \forall t\in T^y, y\in Y \tag{5}$$

$$E_{t,y}^b = E_{t-1,y}^b + n_b^{ch}\cdot p_{t,y}^{b,ch} - \frac{p_{t,y}^{b,disch}}{n_b^{disch}} \quad \forall t\in T^y, y\in Y \tag{6}$$

$$p_{t,y}^{conv} \le x_y^{conv} \quad \forall t\in T^y, y\in Y \tag{7}$$

$$p_{t,y}^{b,ch} \le x_y^b \quad \forall t\in T^y, y\in Y \tag{8}$$

$$p_{t,y}^{b,disch} \le x_y^b \quad \forall t\in T^y, y\in Y \tag{9}$$

$$E_{t,y}^b \le z_y^b \quad \forall t\in T^y, y\in Y \tag{10}$$

$$IC_y^b \ge C_y^{b,inv,power}\cdot x_y^b \quad \forall y\in Y \tag{11}$$

$$IC_y^b \ge C_y^{b,inv,energy}\cdot z_y^b \quad \forall y\in Y \tag{12}$$

$$C_y^{w,inv} \cdot x_y^w + C_y^{pv,inv} \cdot x_y^{pv} + C_y^{conv,inv} \cdot x_y^{conv} + C_y^{b,inv,power} \cdot x_{t,y}^b + \frac{K_y^b \cdot C_y^{b,inv,power} \cdot x_{t,y}^b}{(1+DR)^{N_b}} \leq B_y^{max} \quad \forall y \in Y \tag{13}$$

Constraints (3)-(13) constitute the optimization problem constraints: Constraints (3) enforce the Retailer's power balance in each hour of the planning horizon. In other words, the Retailer's load (total consumers' electricity load) plus the charging load of the BESS must be equal to the total power output of all available electricity resources (i.e. wind plants, PV plants, CCGT, BESS in discharging mode, wholesale market) in each hour of the planning horizon. That way, it is ensured that the Retailer fully covers its short position in each hour of the year. Constraints (4) ensure that, in each hour of the planning horizon, the sum of the total power output of wind plants used for covering (all or part of) the Retailer's end-consumers portfolio plus the respective energy spillage[2] must be equal to the optimal level of capacity (in MW) times the hourly wind energy injection profile (in p.u. or, equivalently, in MWh injected/ installed MW). Similarly to constraints (4), constraints (5) are applicable to PV plants. Constraints (6) represent the BESS energy balance between two consecutive hours, considering both charging and discharging operation modes. Constraints (7) ensure that the maximum power output of CCGT plant in each hour cannot exceed the optimal level of capacity in each year of the planning horizon. Similarly, constraints (8) and (9) ensure that the charging / discharging power of BESS in each hour cannot exceed the optimal level of capacity in each year of the planning horizon, while constraints (10) ensure that the electricity stored in the BESS in each hour cannot exceed the optimal level of BESS (expressed in energy terms, MWh). Constraints (11)-(12) require that the optimal yearly BESS investment cost should be higher than the maximum between the yearly investment cost calculated in power terms and the yearly investment cost calculated in energy terms. Finally, constraints (13) enforce that the total investment cost incurred by the Retailer in each year of the planning horizon cannot exceed the maximum available yearly budget, which is usually pre-set by the Retailer in accordance with its overall desired market strategy.

It is noted that in the proposed model it is considered that each Retailer acts as a price-taker regarding the DAM price forecasts, i.e. each Retailer's optimal investment decision does not affect the resulting DAM prices, which are considered known based on prior long-term market simulation. In this context, the effect of differentiated investment intensity in new RES (PV and/or wind) generation should be taken into account a priori, when formulating the respective DAM prices scenarios. The proposed optimization model will then indicate the level of involvement of the Retailer in any of the available investment options taking into account all required input data (including the level of RES injections), since other critical factors can also affect the optimal decision (e.g. time synchronization of PV generation with the Retailer's own load demand profile).

The proposed model can be used as a starting point to determine the optimal timing and quantify the optimal capacity and overall cost for each candidate asset option that lead to the minimization of the Retailer's total cost in the long-term. The most appropriate location for the installation of the optimal RES, conventional unit or BESS capacities (which lie among the main outcomes of the proposed model) should be decided at a later stage by the Retailer. The proposed model can be regarded as a decentralized model that does not interrelate directly with the power system's operation (which is considered only in the TSO's modeling framework); this is the reason why network constraints have not been included in the proposed model formulation.

The aforementioned optimization problem has been formulated as a linear programming (LP) mathematical optimization model and tested in a real-life case study, further described in the following Section.

## Case study

The proposed optimization model has been tested for the determination of the optimal long-term electricity procurement portfolio of a hypothetical growing Retailer that participates in the Greek electricity market. The planning horizon spans the forthcoming decade (years 2021-2030).

Eighteen (18) scenarios have been simulated, which are formulated as the cartesian product of:

a) Three (3) wholesale DAM price scenarios (Low, Intermediate, High): These scenarios are the main output of detailed Greek wholesale electricity market simulations that were executed prior to conducting this study using a commercially available integrated software called "Long-Term Scheduling extended" (LTSx). LTSx has been developed by the Power Systems Lab, Aristotle University of Thessaloniki, Greece, for the solution of the mid-/long-term scheduling problem of the Greek wholesale electricity market, following the newly established market regulatory framework and in accordance with the provisions of the new Day-Ahead Market and Intra-Day Market Trading Rulebook [27] and the Balancing Market Rulebook [28].
b) Three (3) scenarios (Low, Base, High) of Retailer's future load to capture the probable expansion of its customer base.
c) Two (2) scenarios, regarding the activation of the maximum available yearly budget for investment (enforced by constraints (13) above). The first set of scenarios where no investment budget constraint is imposed (i.e. constraints (13) are not included in the optimization model) is denoted as "Group A" (Scenarios 1A-9A), while the second set of scenarios where the investment budget constraint (12) is activated is designated as "Group B" (Scenarios 1B-9B). The maximum available budget for investment per year (in €) for all scenarios of Group B has been set equal to 30% of the optimal yearly investment cost obtained in the first set of scenarios (Group "A" scenarios). Table 2 presents the list of the simulation scenarios.

### *Input data*

In this section, the input data used in the optimization model are analytically described. It is noted that for most of these data, especially for those concerning cost figures (e.g. investment costs, fixed and variable operating costs, etc.) updated available data published by well-known institutions worldwide were used, to take into account as much as possible the latest technological advances that have already led to significant (investment and operating) cost reduction and are expected to lead to further cost improvements, especially regarding the cost figures related to RES plants and BESS.

*Retailer load forecast*

Three (3) different scenarios regarding the evolution of the electricity consumption that the hypothetical Retailer will represent in the Greek interconnected power system during the next decade (2021-2030) have been formulated. Table 3 presents the forecasted electricity load (in MWh) on a yearly basis for the three scenarios, along with the respective increase rate per year. The aggregated yearly values are converted to hourly loads to be used in the simulation runs according to the hourly profile of the actual load of the Greek interconnected power system of year 2018 [29].

[2] In case that the available renewable generation (corresponding to the optimal renewable plants capacity) exceeds the total electricity load portfolio represented by the Retailer in any hour of the planning horizon, it is considered that the resulting energy spillage is sold to the wholesale electricity market, thus further improving the annual financial results of the Retailer.

**Table 2**
Scenarios configuration.

| Scenario | DAM Price Scenario | Retailer Load Scenario | Activation of maximum yearly budget for investment |
|---|---|---|---|
| S1A (S1B) | Low | Low | NO (YES) |
| S2A (S2B) | Low | Base | NO (YES) |
| S3A (S3B) | Low | High | NO (YES) |
| S4A (S4B) | Intermediate | Low | NO (YES) |
| S5A (S5B) | Intermediate | Base | NO (YES) |
| S6A (S6B) | Intermediate | High | NO (YES) |
| S7A (S7B) | High | Low | NO (YES) |
| S8A (S8B) | High | Base | NO (YES) |
| S9A (S9B) | High | High | NO (YES) |

*Financial and technical data*

Since the investment and operating cost figures of the various assets/options considered in this study are the key drivers for the formulation of the optimal mix that will lead to the least-cost long-term electricity procurement strategy for the Retailer, a bibliographical survey has been performed to derive solid estimates on the evolution of the investment and operating costs for wind plants, PV plants and BESS. Table 4 presents the relevant cost figures for wind plants, PV plants and a typical CCGT plant, while Table 5 presents the corresponding investment and operating costs as well as main technical data for BESS.

Regarding wind plants, it is clarified that onshore wind plants are only considered as available investment option. The investment and fixed O&M costs for 2020 were based on a recent technical report [30]. It is assumed that the investment cost decreases with a yearly rate equal to 0.85%, while fixed O&M cost decreases with a yearly rate of 0.65% for the period 2021-2030, based on the thorough analysis presented in [31]. It is considered that the variable O&M costs of wind plants are negligible and, therefore, for the purposes of this study, are considered equal to zero. These cost data are also fully aligned with similar long-term estimations that are included in recent technical reports prepared by well-known and credible institutions, such as IRENA [32], IEA [33], and the UK Department of Business, Energy and Industrial Strategy [34]. Therefore, they are deemed sufficient to model in a realistic way the evolution of the wind plants' investment and generating costs in the future.

Besides the anticipated decrease of the wind investment cost data, another critical factor that is expected to contribute further towards reducing the wind plants LCOE (and, therefore, increase their competitiveness as compared to other available energy resources) is the anticipated continuous increase of their capacity factor in the future, mainly due to the deployment of larger rotor diameters and taller towers, as explained in [30] and [32]. This should be taken into account in the formulation of the future wind energy injection profiles, which lie among the most important input data of the proposed optimization model. However, in the case study presented in this paper, we decided to use the historical capacity factors as derived by the actual hourly energy injection profiles (in MWh injected/MW installed) of the aggregated production of the Greek power system of the years 2016-2018 for each RES technology on the basis of publicly available data provided by the Greek Independent Power Transmission Operator and the Greek RES Operator (see also paragraph 3.1.3). These hourly data have been repeated consecutively to cover the study period 2021-2030 to account for the yearly stochasticity of RES generation. In this way we did not take into account any future improvement on the wind plants capacity factor. The explanation for not doing so lies in that, in the Greek interconnected power system, the most favorable terrains in terms of wind speed have already been occupied by the existing wind farms and the forthcoming wind parks are expected to be constructed in areas with notably lower wind potential. Therefore, it was considered that the positive effect of the increasing wind plants capacity factor due to technological advancement is expected to be fully counterbalanced by the less efficient terrains to be selected in terms of wind potential.

Regarding PV plants, both the investment and fixed O&M costs are expected to decrease significantly during the following years. For a utility-scale PV plant (e.g. $>$ 1 MW), investment cost is expected to decrease from 430,000€/MW in 2020 to 280,000€/MW in 2030, while the fixed O&M costs are expected to follow a similar trend, according to the relevant data presented in [35]. Similarly to wind plants, variable O&M costs are also considered equal to zero for PV plants.

Regarding the CCGT plant in this study, the investment cost is considered equal to 365,000 €/MW for the entire study period, based on recent publicly available information regarding the on-going construction of a new 826-MW CCGT plant by an EPC and energy production company in Greece [36, 37]. The unitary operating costs of CCGT (which comprise the fuel cost, $CO_2$ emissions cost and the (fixed and variable) O&M cost) are considered equal to the projected minimum variable cost (MVC, in €/MWh) of this CCGT unit operating in the Greek power system during the planning period. The MVC is calculated by LTSx software on the basis of the aforementioned individual operating cost components and the average monthly value of the period 2021-2030 ranges from 40.9 €/MWh for the Low DAM prices scenarios (S1-S3) to 49.8 €/MWh for the Intermediate DAM prices scenarios (S4-S6) and rises to 53.5 €/MWh for the High DAM prices scenarios (S7-S9).

Regarding BESS, the associated costs have changed rapidly over the recent years. This rapid cost decline has recently given BESS increasing attention in the long-term planning of the power sector and, therefore, are expected to play a key role in the energy transition worldwide. In this study, a 4-hour utility-scale Li-Ion BESS is considered as the best candidate option to cover (part of) the forecasted load demand. It is noted that not all components of the BESS cost scale directly with the energy storage capacity (i.e. MWh) of the system. For instance, the inverter costs scale according to the power capacity (i.e. MW) of the system, and some cost components such as the developer costs can scale with both power and energy storage. By expressing BESS costs in €/kWh, there is a deviation from other power generation technologies such as combustion turbines, PV plants or wind plants, where investment (capital) costs are usually expressed as €/MW (e.g. see Table 4).

However, in Table 5 the investment cost is primarily illustrated in €/MWh because that is the most common way that BESS costs have been expressed in publicly available documents to date [38]. The €/kWh costs can be easily converted to €/kW costs simply by multiplying by the duration (e.g., a €300/kWh, 4-hour battery would have an equivalent power capacity cost of €1,200/kW). Based on the extensive survey presented in [38], the total overnight capital cost for a 4-hour Li-Ion battery storage system is expected to decrease from 285,000 €/MWh in 2020 to almost 150,000€/MWh[3] in 2030. The evolution of the fixed and variable O&M costs for the entire study period has been calculated

[3] The average value between the low and average cost evolution scenario presented in [38] has been used, since it is our belief that the technological progress will be very fast and relevant investment costs will decrease sooner than currently expected. Since total overnight costs are presented in $/MWh in [38], an €/$ exchange rate of 1.1 for the entire planning period is used in order to convert them in €/MWh.

**Table 3**
Retailer forecasted electricity load scenarios.

| Year | Low Scenario | | Base Scenario | | High Scenario | |
|---|---|---|---|---|---|---|
| | Total Load [MWh] | YoY increase rate [%] | Total Load [MWh] | YoY increase rate [%] | Total Load [MWh] | YoY increase rate [%] |
| 2020 | 2,000,000 | - | 2,000,000 | - | 2,000,000 | - |
| 2021 | 2,200,000 | 10.0% | 2,280,000 | 14.0% | 2,360,000 | 18.0% |
| 2022 | 2,410,000 | 9.5% | 2,580,000 | 13.0% | 2,760,000 | 17.0% |
| 2023 | 2,630,000 | 9.0% | 2,890,000 | 12.0% | 3,200,000 | 16.0% |
| 2024 | 2,850,000 | 8.5% | 3,200,000 | 11.0% | 3,650,000 | 14.0% |
| 2025 | 3,080,000 | 8.0% | 3,520,000 | 10.0% | 4,090,000 | 12.0% |
| 2026 | 3,310,000 | 7.5% | 3,840,000 | 9.0% | 4,500,000 | 10.0% |
| 2027 | 3,540,000 | 7.0% | 4,150,000 | 8.0% | 4,900,000 | 9.0% |
| 2028 | 3,770,000 | 6.5% | 4,440,000 | 7.0% | 5,300,000 | 8.0% |
| 2029 | 4,000,000 | 6.0% | 4,730,000 | 6.5% | 5,670,000 | 7.0% |
| 2030 | 4,200,000 | 5.0% | 5,010,000 | 6.0% | 6,030,000 | 6.5% |

**Table 4**
Investment and operating costs for RES plants and CCGT.

| Year | Wind Plants | | | PV Plants | | | CCGT Plant Investment Cost [€/MW] |
|---|---|---|---|---|---|---|---|
| | Investment Cost [€/MW] | Fixed O&M Cost [€/MW-y] | Variable O&M Cost [€/MWh] | Investment Cost [€/MW] | Fixed O&M Cost [€/MW-y] | Variable O&M Cost [€/MWh] | |
| 2020 | 1,150,000 | 23,000 | - | 430,000 | 8,500 | - | 365,000 |
| 2021 | 1,139,650 | 22,846 | - | 415,000 | 8,330 | - | 365,000 |
| 2022 | 1,129,393 | 22,693 | - | 400,000 | 8,160 | - | 365,000 |
| 2023 | 1,119,229 | 22,541 | - | 385,000 | 7,990 | - | 365,000 |
| 2024 | 1,109,156 | 22,390 | - | 370,000 | 7,820 | - | 365,000 |
| 2025 | 1,099,173 | 22,240 | - | 355,000 | 7,650 | - | 365,000 |
| 2026 | 1,089,281 | 22,091 | - | 340,000 | 7,480 | - | 365,000 |
| 2027 | 1,079,477 | 21,943 | - | 325,000 | 7,310 | - | 365,000 |
| 2028 | 1,069,762 | 21,796 | - | 310,000 | 7,140 | - | 365,000 |
| 2029 | 1,060,134 | 21,650 | - | 295,000 | 6,970 | - | 365,000 |
| 2030 | 1,050,593 | 21,505 | - | 280,000 | 6,800 | - | 365,000 |

**Table 5**
Investment and operating costs and technical data for BESS.

| Year | Investment Cost [€/MW] | Investment Cost [€/MWh] | Fixed O&M Cost [€/MW-y] | Variable O&M Cost [€/MWh] | Battery Replacement Cost [%] | Battery Round-Trip Efficiency [%] |
|---|---|---|---|---|---|---|
| 2020 | 1,140,000 | 285,000 | 8,571 | 0.273 | 25% | 86% |
| 2021 | 1,069,091 | 267,273 | 8,311 | 0.273 | 25% | 86% |
| 2022 | 998,182 | 249,545 | 8,051 | 0.273 | 25% | 86% |
| 2023 | 925,455 | 231,364 | 7,791 | 0.273 | 25% | 86% |
| 2024 | 856,364 | 214,091 | 7,531 | 0.273 | 25% | 86% |
| 2025 | 785,455 | 196,364 | 7,273 | 0.273 | 25% | 86% |
| 2026 | 749,091 | 187,273 | 7,014 | 0.273 | 25% | 86% |
| 2027 | 712,727 | 178,182 | 6,756 | 0.273 | 25% | 86% |
| 2028 | 676,364 | 169,091 | 6,498 | 0.273 | 25% | 86% |
| 2029 | 638,182 | 159,545 | 6,240 | 0.273 | 25% | 86% |
| 2030 | 601,818 | 150,455 | 5,982 | 0.273 | 25% | 86% |

using interpolation based on indicative values shown in [39]. It is also known that according to the latest technological status, BESS will certainly require a battery replacement in the mid-term. Given that no detailed information on the timing and the relevant cost is currently available, we estimate that the battery replacement will take place $N_b = 10$ years after the installation year and the relevant cost is equal to $K_y^b = 25\%$ of the total investment cost. Finally, the BESS round-trip efficiency is considered equal to 86% (i.e. $n_b^{ch} = n_b^{disch} = 92.7\%$) [39].

Regarding the common economic valuation indices that are necessary for the respective calculations, the nominal discount rate per year (DR) has been considered equal to the Weighted Average Cost of Capital (WACC) of the Retailer (DR=WACC=7.0%), while the depreciation period of all possible investment options (assets) is equal to N = 20 years.

*RES plants production*

Regarding wind and PV plants production, normalized hourly energy injection profiles of the aggregated production of the Greek power system of the years 2016-2018 for each RES technology have been calculated (expressed in p.u or, equivalently, in injected MWh/installed MW) based on publicly available data provided by the Greek Independent Power Transmission Operator [29] and the Greek RES Operator [40]. This way, instead of using typical (e.g. average) monthly/annual RES generation profile timeseries that would be kept intact for each month/year of the entire study period, we used the rolling three-year RES generation timeseries on an hourly basis for the entire study period 2021-2030 to partially account for the yearly stochasticity of RES generation (i.e. similarly to the climatic years, as used in the ENTSO-E Mid-Term Adequacy Forecast Study (MAF) [41]).

*DAM prices forecasts*

As already mentioned, wholesale electricity market consists one of the main options of the Retailer to cover (all or part of) its short position. For this purpose, three distinct DAM prices scenarios (Low, Intermediate, High) have been generated, as the main outcome of detailed Greek electricity market simulations that were executed using hourly time

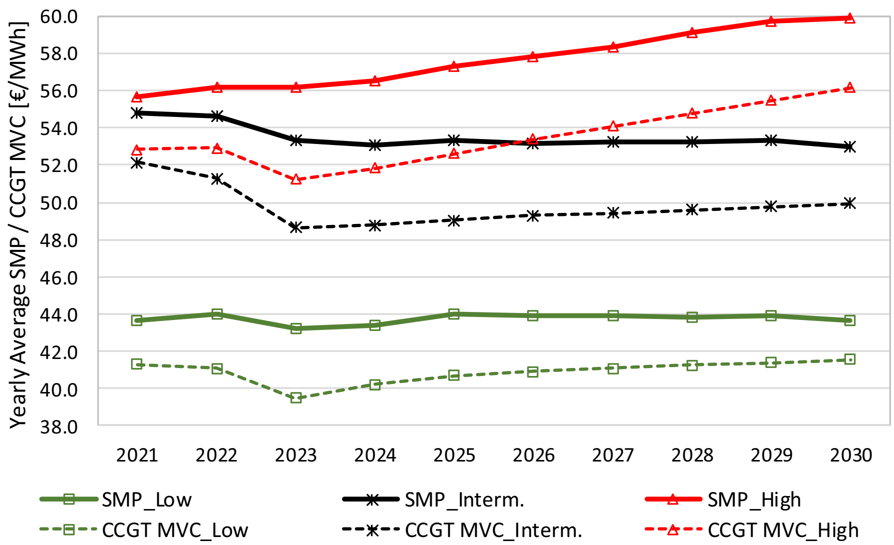


**Fig. 1.** DAM prices and CCGT plant minimum variable cost scenarios.

resolution prior to the development of the proposed optimization model. Different core assumptions regarding the main system parameters (i.e. system load, gas prices and $CO_2$ prices, unit availability) were adopted in the three scenarios, whereas the RES penetration plan is in accordance with the ambitious mid-term energy and climate goals included in the approved National Energy and Climate Plan (NECP) that was officially submitted by the Greek State to the European Commission [42]. These parameters are the key driving factors that lead to different trajectories regarding the evolution of the resulting DAM prices. For each wholesale market prices scenario the corresponding CCGT operating cost has been calculated, since the CCGT's variable cost is directly dependent on the evolution of the main system parameters (i.e. gas prices, $CO_2$ prices) that greatly affect the market outcome. Figure 1 illustrates the yearly average DAM prices along with the candidate CCGT yearly average MVC for all three scenarios.

*Test results*

In this Section, the simulation results as well as additional calculations regarding the impact that the optimal investment strategy would have on the annual electricity procurement costs of the Retailer in the forthcoming decade (2021-2030) are presented and discussed.

*Group "A" simulations*

Simulation results primarily show that for all scenarios of Group A (S1A-S9A, where no investment budget constraint is applicable) the optimal electricity procurement portfolio for the next decade should rely heavily on PV plants complemented by significant amounts of electricity procured directly from the wholesale market, while investing in cost-efficient CCGT capacity appears as a marginally viable option.

Figures 2-4 illustrate the optimal energy procurement mix in terms of volume (installed capacity in MW for PV and CCGT, MWh for energy procured from the wholesale market) per year and scenario. It is shown that PV installed capacity shall optimally increase from ~500 MW in 2021 to ~930-1600 MW in 2030, given the very low and gradually decreasing total cost of PV production (see Table 4), independent of the prevailing market conditions (e.g. DAM prices, etc.). Wholesale market appears as the main alternative option, especially for time periods with reduced or zero PV production (e.g. night hours).

Regarding the potential investment in a CCGT plant, although the candidate CCGT plant is considered to present the lowest operating cost among all available CCGTs in the Greek power system and could consist an acceptable (in terms of total cost) investment option, Fig. 4 indicates that for all scenarios assuming low DAM prices (S1A-S3A) and for most years in the scenarios assuming intermediate DAM prices (i.e. 2021-2022, 2026-2030 in S4A-S6A), the CCGT's annual total production cost (annualized investment cost + total operating cost, expressed in €/MWh) slightly exceeds the forecasted DAM clearing prices and, therefore, it is preferable for the Retailer to resort to the wholesale market to fully cover its energy procurement needs instead of investing in new CCGT capacity. However, in the scenarios assuming high DAM prices (S7A-S9A) and for the years 2023-2030, CCGT plant's total annualized cost (in €/MWh) is lower than the assumed DAM prices, thus rendering CCGT a viable investment option, yet with relatively limited capacity. It should be noted that the attained optimal CCGT capacity does not correspond to a real power plant due to the low optimal capacity resulted in the model execution results. Therefore, a post-process is necessary in this case to either (a) zeroize the plant capacity for all years, or (b) increase the plant capacity to a level that could become feasible for construction based on the current models of the gas turbine providers. Option (a) is implicitly considered in this study.

On the other hand, wind plants and BESS[4] do not offer realistic and cost-efficient alternative investment options in any scenario and, therefore, should not initially participate in the Retailer's electricity procurement portfolio for the forthcoming years.

The developed optimization model also foresees that in case that the optimal hourly PV (or wind) generation exceeds the hourly electricity load represented by the Retailer, the resulting PV (or wind) surplus generation is sold to the wholesale market at the respective hourly market clearing prices (DAM prices). In this context, Fig. 5 illustrates the PV surplus generation per year and scenario, which presents a clearly increasing trend over the years, ranging from 3.9% to 16.9% of the total PV generation[5]. This alternative contributes significantly to optimizing the electricity procurement strategy aiming at the lowest possible overall cost.

Figure 6 presents the coverage of the Retailer's total electricity load indicatively for Scenario S5A (intermediate DAM prices, Base electricity

[4] It is considered that no additional revenues are provided to storage facilities through a long-term capacity market or a capacity / flexibility remuneration mechanism.

[5] Analytical calculations show that the percentage of PV curtailment is higher for scenarios representing higher SMPs (e.g. 7.7-16.9% for S7A-S9A as compared to 3.9-9.4% for S1A-S3A), since it is more profitable for the Retailer to optimize its portfolio mix by investing in higher PV capacity and, consequently, selling higher surplus PV generation at higher prices to DAM.

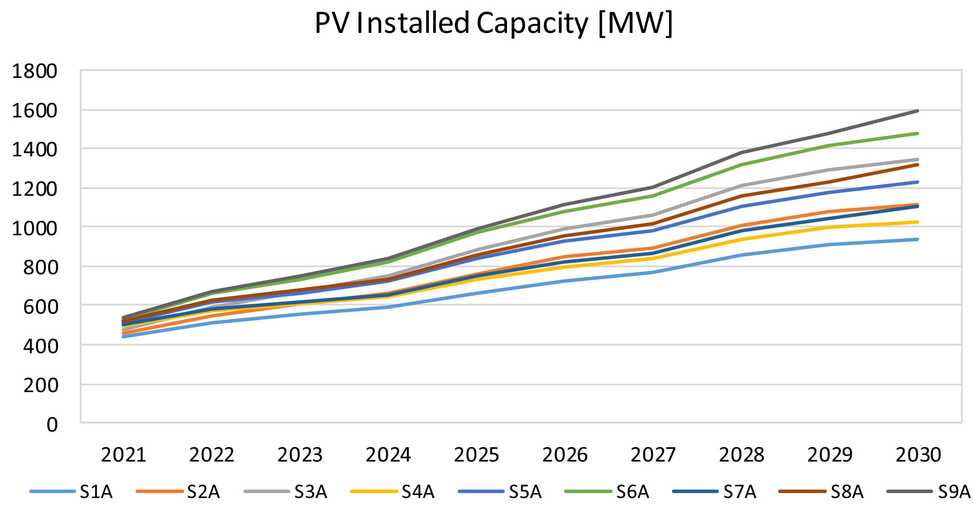


**Fig. 2.** Optimal PV installed capacity for investment.

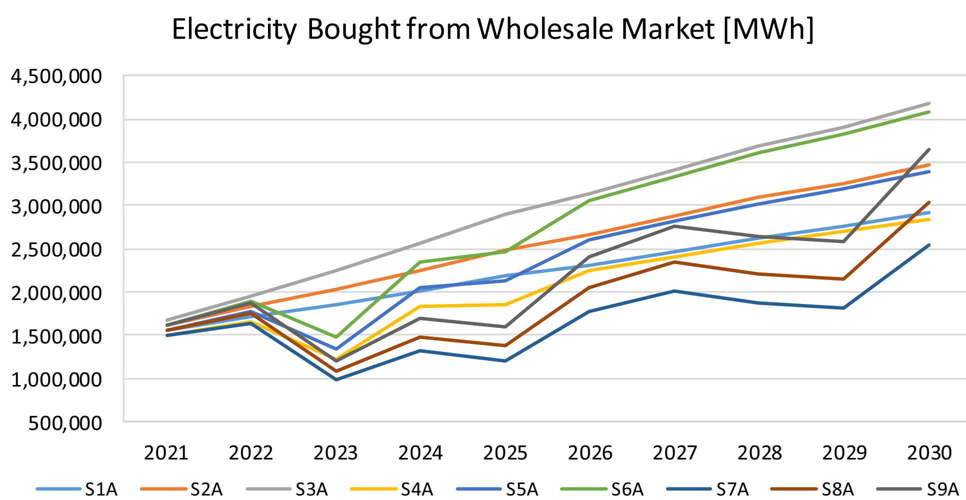


**Fig. 3.** Optimal energy quantities to be purchased directly from the wholesale market.

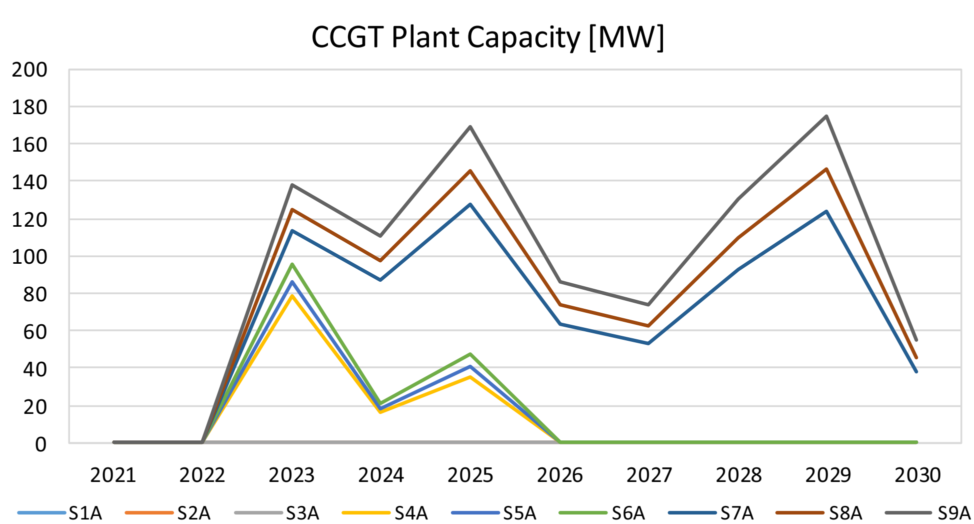


**Fig. 4.** Optimal CCGT plant capacity for investment.

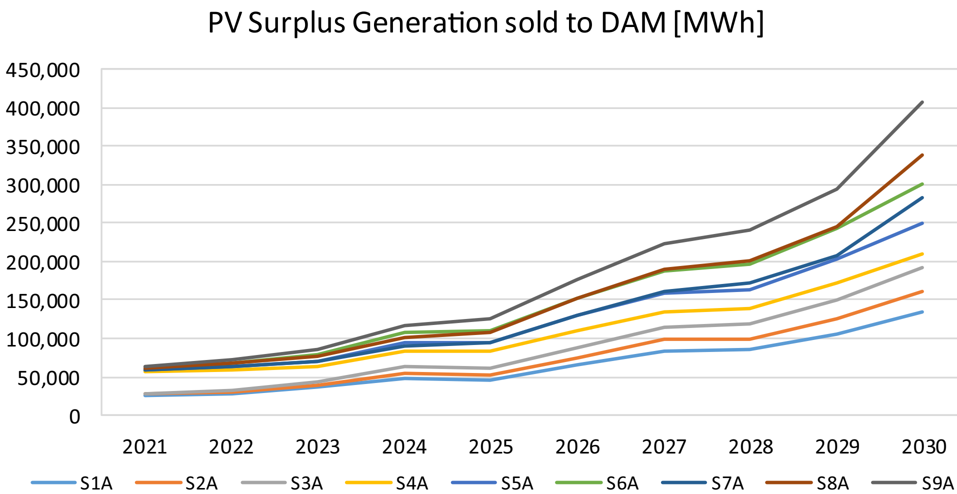


**Fig. 5.** PV surplus generation sold to the wholesale market (DAM).

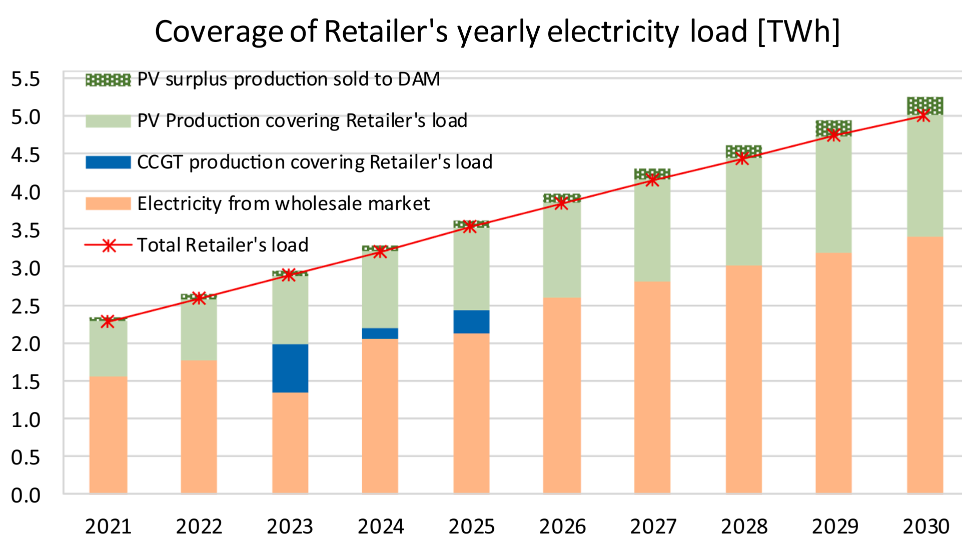


**Fig. 6.** Coverage of Retailer's yearly electricity load.

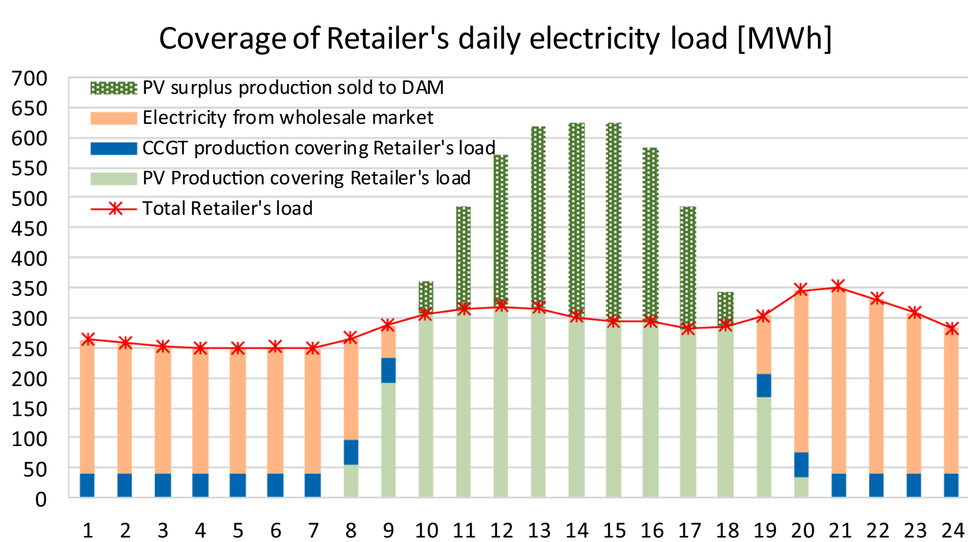


**Fig. 7.** Coverage of Retailer's daily electricity load (typical spring day of 2025).

load, no investment budget constraint) from the various assets/resources (PV, CCGT, wholesale market) on a yearly basis, while Figure 7 illustrates the resulting optimal electricity procurement mix for a typical spring (April) day of year 2025 again for Scenario S5A.

Given all above, it is concluded that PV technology is the most favorable investment option, since its unitary total cost decreases from ~31€/MWh in 2021 to ~22€/MWh in 2030 in all scenarios, whereas the unitary cost of purchasing electricity directly from the wholesale market is significantly higher and lies in the range of ~44–61 €/MWh during the study period, depending on the DAM price scenario examined. Slightly higher cost figures than DAM prices are observed (on average) for the CCGT plant, thus limiting its presence in the Retailer's portfolio for most scenarios and years. However, the limited and volatile energy production capability of PV plants calls for additional electricity resources (i.e. mostly electricity procurement from the wholesale market as well as limited contribution from the CCGT plant) to fully cover the daily profile of the total Retailer load (especially during hours with zero PV generation, i.e. night hours, see also Fig. 7).

Aggregated cost figures per year and scenario regarding the implementation of the respective optimal electricity procurement strategy are illustrated in Fig. 8-11. Specifically, Fig. 8 shows the annual payable total cost (defined as the sum of the total yearly investment and operating costs of all options minus the revenues acquired from selling the surplus PV and wind generation to DAM). As expected, the continuous increase of the Retailer's load over the years that shall optimally be covered by continuously increasing investments in PV capacity as well as by electricity procurement from the wholesale market (and by investing in limited CCGT plant capacity) leads to monotonically increasing annual payable total costs for the Retailer, notwithstanding the increasing revenues obtained by the increasing PV surplus generation that is sold to the DAM (see Fig. 5).

Figure 9 shows the annual total cost reduction that can be obtained by the implementation of the said optimal electricity procurement strategy with respect to the Business-As-Usual (BAU) case[6]. The annual cost savings for the Retailer increase from ~8.1 M€ for S1A in 2021 to ~85 M€ in 2030 for S9A, where the prevailing market conditions (high Retailer load and high DAM prices) render the optimal electricity procurement strategy (PV capacity + CCGT capacity + electricity purchased from the wholesale market) much more valuable for the Retailer as compared to the BAU case. It is also underlined that the annual cost reduction for scenarios S1A-S3A is significantly lower as compared to scenarios S4A-S9A, since in the low DAM prices scenarios the alternative option of purchasing the total Retailer's load exclusively from the wholesale market results in relatively low cost (due to the very low SMPs observed), which, in turn, weakens considerably the need for investing in PV capacity.

Finally, Fig. 10 illustrates the total investment cost for each year and scenario. It is clarified that the total investment costs are calculated as total overnight costs (no amortization and depreciation is considered in these calculations). It is shown that, although the PV investment cost (in €/MW) decreases rapidly over the years, the total investment costs are, in general, stable or they follow a slightly increasing trend over the years, mainly due to monotonically increase of the optimal PV capacity in all scenarios. It is also noted that the contribution of CCGT investment costs in the total investment costs is marginal, given the limited (or zero) optimal CCGT plant capacity in the simulation scenarios.

*Group "B" simulations*

Group B scenarios have been simulated considering that, for each year, the maximum investment cost should not exceed the 30% of the average total investment cost required in all scenarios of Group A, as shown in Table 6.

Given the incorporation of the aforementioned maximum available budget constraint in the optimization model, simulation runs indicate that the Retailer should focus on investing exclusively in PV capacity, while all other resource technologies (CCGT, wind plants and BESS) do not consist competitive options.

Table 7 shows the optimal electricity procurement portfolio per year that is identical for all scenarios of Group B. The only parameter that is differentiated among all scenarios is the electricity quantities (in MWh) bought from the wholesale market, so that the total Retailer's load is fully covered in each year. It is also noted that since the optimal PV capacity per year in these scenarios is significantly reduced (around 30% of the optimal PV capacity of Group A simulation results on average), no PV surplus generation is observed in Group B scenarios, denoting that the optimal PV capacity in these scenarios cannot fully cover the respective hourly load of the Retailer during any hour of the study horizon. This, in turn, increases significantly the quantities of electricity purchased from the wholesale market. Obviously, the solution obtained in these scenarios is suboptimal with respect to the corresponding Group A scenarios results in terms of total payable cost, leading to significantly reduced annual cost reduction (in €) with respect to the BAU case, as illustrated in Fig. 11. Indicatively, the difference in annual cost reduction observed between the corresponding Group A and Group B scenarios lies in the range of 64.4-71.3% for scenarios S2, S5 and S8, while similar figures can be derived for all respective scenarios of Group A and Group B.

*Sensitivity analysis*

In this paragraph, the effect that the selection of WACC may have on the optimal electricity procurement strategy and respective costs is examined. For this purpose, a sensitivity analysis has been performed for S5A (intermediate DAM prices, base electricity load, no investment budget constraint applicable), with WACC equal to 4% and 10%, instead of 7% used in the Base scenario. Table 8 presents the main simulation results regarding the optimal electricity procurement mix (in MW of installed capacity or MWh bought per asset option) for covering the total electricity consumption needs of the Retailer per year for the three scenarios addressed in this sensitivity analysis.

Simulation results show the strong dependence of the diversification of the optimal electricity procurement portfolio on the selected WACC value. Specifically, for WACC=4% CCGT plant capacity and wind capacity become a viable investment option, however not throughout the entire study period. PV plants are also affected positively and increase their optimal capacity taking advantage of the lower cost of capital, while BESS seem not to be a viable investment option in any year even under these favorable financial conditions. However, in this case and in order to yield feasible results, a post-process analysis is required to formulate a long-term investment strategy that will lead to non-decreasing optimal yearly capacity per asset technology over the planning period. On the contrary, for increased WACC=10%, the CCGT plant, wind plants and BESS do not clearly consist viable investment options, whereas the presence of PV generation is slightly reduced in favor of increased electricity procurement directly from the wholesale market.

Regarding cost savings, for lower WACC values the annual cost reduction with respect to the BAU case is notably higher, as expected. Specifically, for WACC=4% the annual cost savings obtained are 24.1-37.9% higher as compared to WACC=7%, while for WACC=10% the annual cost savings are 21.9-35.8% lower as compared to the base scenario (see Fig. 12). However, in the case of WACC=4%, since the optimal solution requires increased investments mainly in CCGT plant and wind capacity, increased cash outflows requirements are implied to fully implement the proposed investment strategy.

In case of Group B scenarios, the variation of WACC taking into account the activation of the maximum available budget constraint does

[6] Business-As-Usual (BAU) refers to the case where no investment strategy is implemented, and the total electricity consumption is covered exclusively by electricity procurement from the wholesale market invoiced at the respective hourly DAM clearing prices (or close to these prices).

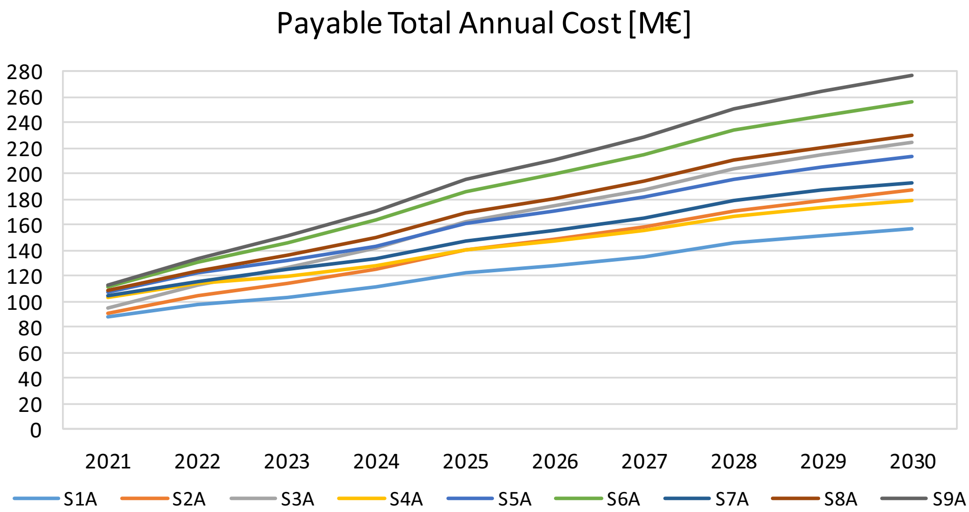


**Fig. 8.** Payable annual total cost.

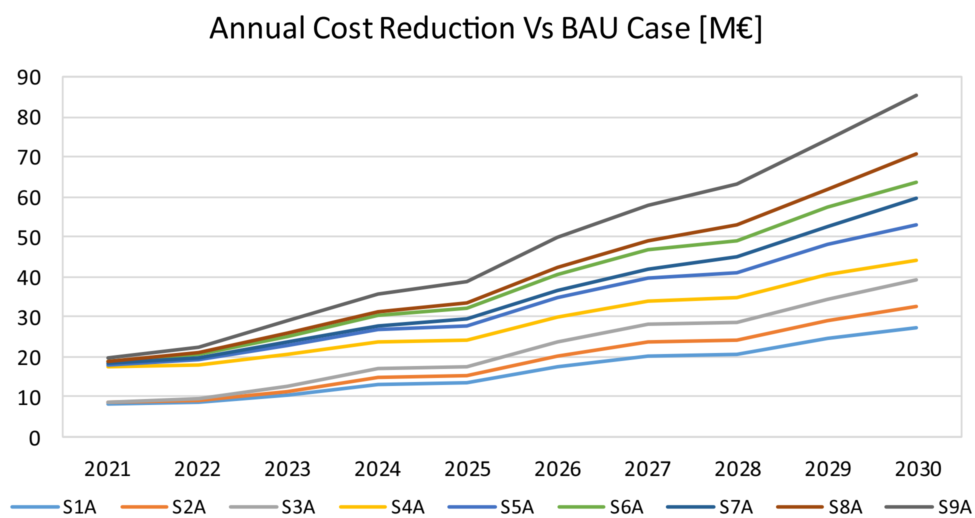


**Fig. 9.** Annual cost reduction vs Business-As-Usual case.

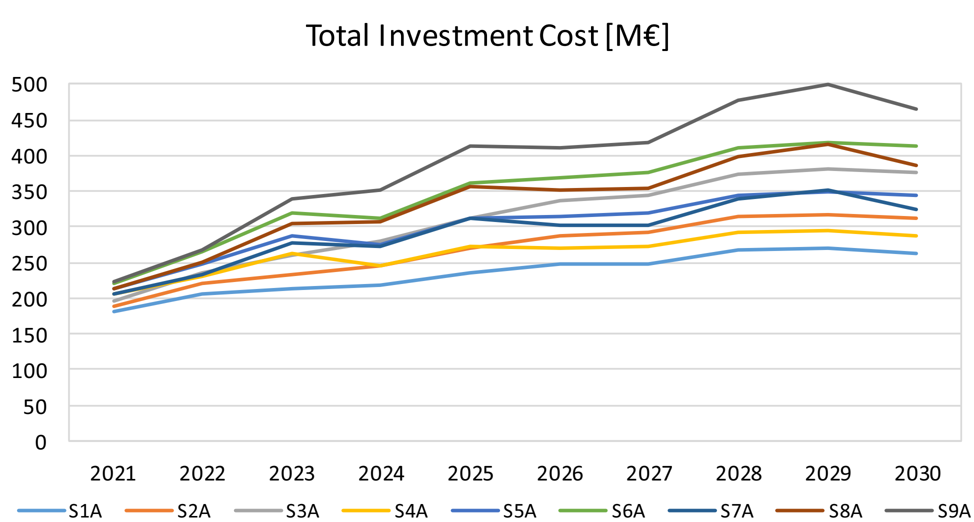


**Fig. 10.** Total investment cost.

**Table 6**
Maximum investment cost per year (Group B Scenarios).

| Year | Average Investment Cost of Group A Scenarios [€] | Maximum Investment Cost of Group B Scenarios [€] |
|---|---|---|
| 2021 | 205,188,656 | 61,556,597 |
| 2022 | 239,301,076 | 71,790,323 |
| 2023 | 277,425,994 | 83,227,798 |
| 2024 | 278,349,017 | 83,504,705 |
| 2025 | 316,306,667 | 94,892,000 |
| 2026 | 321,108,728 | 96,332,618 |
| 2027 | 324,821,940 | 97,446,582 |
| 2028 | 357,127,417 | 107,138,225 |
| 2029 | 366,178,109 | 109,853,433 |
| 2030 | 367,657,614 | 110,297,284 |

not allow for any differentiation in the optimal electricity procurement strategy as compared to the one analyzed in paragraph 3.2.2, which comprises exclusively moderate increasing PV capacity (from 148.3 MW in 2021 to 393.9 MW in 2030, see Table 7), independent of system and market conditions.

The resulting LP model includes 87,843 equations and 122,983 variables per year. The execution time for each yearly simulation run remained below 15 sec in all scenarios, proving that the proposed optimization model is robust and computationally efficient. All simulation runs were performed on a 3.7-GHz Intel Quad Core processor with 64 GB of RAM, running 64-bit Windows and using the CPLEX 12.0 solver under GAMS 24.2 [43].

## Conclusion and policy implications

In this paper the long-term electricity procurement portfolio optimization problem faced by an electricity Retailer was formulated and solved. The ultimate goal was to define and quantify the optimal mix of asset options that allows the Retailer to fully cover its forecasted electricity consumption at the lowest cost on a yearly basis for a future planning horizon. A novel LP optimization model incorporating the inherent technical and operating characteristics and constraints of various candidate investment options was developed and tested. Simulation results from 18 scenarios using real-life operational and cost data illustrated that the optimal electricity procurement portfolio for the next decade should rely heavily on PV plants complemented by significant amounts of electricity procured directly from the wholesale market, while investing in cost-efficient CCGT capacity currently appears as a marginally viable option. Wind plants and BESS do not still offer realistic and cost-efficient alternative investment options and, therefore, should not initially participate in the Retailer's electricity procurement portfolio for the forthcoming years. It has also been shown that the derived optimal electricity procurement portfolio leads to significant annual cost savings as compared to the business-as-usual case. However, the enforcement of maximum available yearly budget for investment in energy production assets although limiting the yearly cash outflows will naturally lead to suboptimal portfolio mix in terms of total annual costs incurred by the Retailer. Sensitivity analysis also highlighted that the selection of the WACC value in conjunction with the assumed financial data mainly regarding investment and operating costs for all available asset options are the key issues that should be carefully addressed in order to ensure that the proposed optimal electricity procurement strategy is realistic and the expected returns will allow for the long-term financial viability of the Retailer.

The primary goal of this work is to provide a practical, effective and computationally efficient optimization model that can be easily

**Table 7**
Optimal electricity procurement portfolio (Group B Scenarios).

| Year | PV Capacity [MW] | Wind/ CCGT/ BESS Capacity [MW] | PV Production [MWh] | Electricity bought from wholesale market [MWh] | | |
|---|---|---|---|---|---|---|
| | | | | S1B, S4B, S7B | S2B, S5B, S8B | S3B, S6B, S9B |
| 2021 | 148.3 | 0.0 | 225,600 | 1,974,400 | 2,054,400 | 2,134,400 |
| 2022 | 179.5 | 0.0 | 255,251 | 2,154,749 | 2,324,749 | 2,504,749 |
| 2023 | 216.2 | 0.0 | 319,335 | 2,310,665 | 2,570,665 | 2,880,665 |
| 2024 | 225.7 | 0.0 | 343,523 | 2,506,477 | 2,856,477 | 3,306,477 |
| 2025 | 267.3 | 0.0 | 380,157 | 2,699,843 | 3,139,843 | 3,709,843 |
| 2026 | 283.3 | 0.0 | 418,537 | 2,891,463 | 3,421,463 | 4,081,463 |
| 2027 | 299.8 | 0.0 | 455,307 | 3,084,693 | 3,694,693 | 4,444,693 |
| 2028 | 345.6 | 0.0 | 492,764 | 3,277,236 | 3,947,236 | 4,807,236 |
| 2029 | 372.4 | 0.0 | 550,086 | 3,449,914 | 4,179,914 | 5,119,914 |
| 2030 | 393.9 | 0.0 | 598,174 | 3,601,826 | 4,411,826 | 5,431,826 |

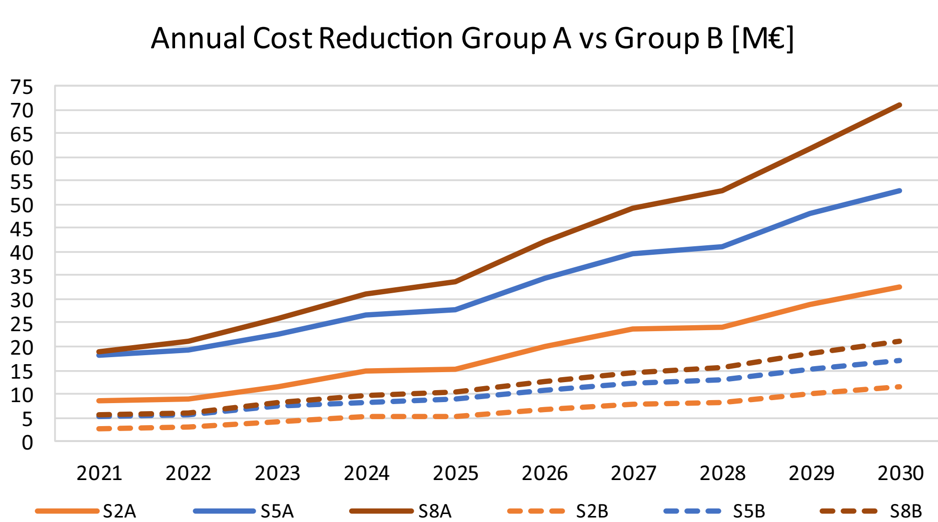


**Fig. 11.** Annual cost reduction with respect to BAU case – Group A vs Group B scenarios.

**Table 8**
Optimal electricity procurement portfolio (Scenario S5A – Sensitivity analysis).

| Year | WACC [%] | PV Capacity [MW] | Wind Capacity [MW] | CCGT Capacity [MW] | BESS Capacity [MW] | Electricity bought from wholesale market [MWh] |
|---|---|---|---|---|---|---|
| 2021 | 7% | 511.3 | 0.0 | 0.0 | 0.0 | 1,560,146 |
| 2022 | | 616.7 | 0.0 | 0.0 | 0.0 | 1,765,723 |
| 2023 | | 664.9 | 0.0 | 86.4 | 0.0 | 1,340,845 |
| 2024 | | 723.6 | 0.0 | 18.2 | 0.0 | 2,054,400 |
| 2025 | | 835.4 | 0.0 | 40.6 | 0.0 | 2,120,504 |
| 2026 | | 924.6 | 0.0 | 0.0 | 0.0 | 2,603,011 |
| 2027 | | 980.2 | 0.0 | 0.0 | 0.0 | 2,820,332 |
| 2028 | | 1,108.2 | 0.0 | 0.0 | 0.0 | 3,023,906 |
| 2029 | | 1,180.6 | 0.0 | 0.0 | 0.0 | 3,188,804 |
| 2030 | | 1,226.8 | 0.0 | 0.0 | 0.0 | 3,396,914 |
| 2021 | 4% | 561.4 | 0.0 | 0.0 | 0.0 | 1,520,868 |
| 2022 | | 663.0 | 0.0 | 0.0 | 0.0 | 1,690,461 |
| 2023 | | 712.2 | 20.3 | 235.2 | 0.0 | 393,279 |
| 2024 | | 770.4 | 0.0 | 248.6 | 0.0 | 505,335 |
| 2025 | | 895.4 | 0.0 | 287.0 | 0.0 | 492,982 |
| 2026 | | 990.5 | 0.0 | 248.5 | 0.0 | 908,696 |
| 2027 | | 1,049.9 | 0.0 | 289.7 | 0.0 | 865,289 |
| 2028 | | 1,138.9 | 0.0 | 275.2 | 0.0 | 1,002,821 |
| 2029 | | 1,210.6 | 95.0 | 336.0 | 0.0 | 836,364 |
| 2030 | | 1,318.5 | 101.6 | 297.6 | 0.0 | 1,346,431 |
| 2021 | 10% | 466.4 | 0.0 | 0.0 | 0.0 | 1,602,657 |
| 2022 | | 561.8 | 0.0 | 0.0 | 0.0 | 1,816,328 |
| 2023 | | 618.8 | 0.0 | 0.0 | 0.0 | 2,020,487 |
| 2024 | | 667.4 | 0.0 | 0.0 | 0.0 | 2,242,266 |
| 2025 | | 765.8 | 0.0 | 0.0 | 0.0 | 2,486,411 |
| 2026 | | 847.2 | 0.0 | 0.0 | 0.0 | 2,665,930 |
| 2027 | | 902.1 | 0.0 | 0.0 | 0.0 | 2,881,473 |
| 2028 | | 1,019.5 | 0.0 | 0.0 | 0.0 | 3,090,777 |
| 2029 | | 1,086.9 | 0.0 | 0.0 | 0.0 | 3,256,122 |
| 2030 | | 1,127.1 | 0.0 | 0.0 | 0.0 | 3,465,590 |

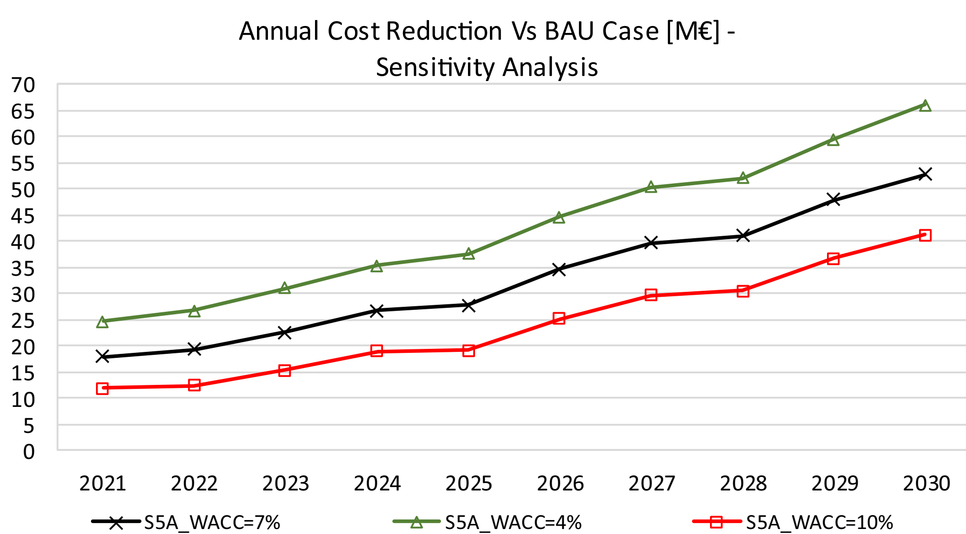


**Fig. 12.** Annual cost reduction vs BAU case – Sensitivity Analysis for S5A.

replicated and implemented directly by Retailers (especially the newcomers and growing entities) in order to assist them in formulating their optimal electricity procurement portfolio in the long-term. The extended set of simulation results under various scenarios reveals that any Retailer can use the main outcomes of the proposed optimization model as a starting point in order to further investigate the technical feasibility and economic viability of the optimal investment decisions in the long-term.

Finally, it is underlined that in the above modeling framework the various options for electricity procurement refer to possible investments to be conducted exclusively by the Retailer, excluding any other options that may yield similar results, such as concluding a PPA with a third party owing a cost-efficient CCGT or a PPA with a third-party RES (wind and/or PV plant) owner. For this purpose, the simulation analysis and all relevant calculations were performed on the basis of the Levelized Cost of Electricity (LCOE), expressed in €/MWh of each alternative option. In this context, the option of concluding a PPA with a third-party CCGT or RES plant does not provide any meaningful insight in the framework of this study, since it is highly probable that a third party would normally ask for a PPA at a price very close to the wholesale market price instead of its own project's LCOE. In other words, such cases constitute a simplified approach of the long-term electricity procurement portfolio optimization that is equivalent to the business-as-usual case, where no investment strategy is implemented and the total electricity consumption is covered exclusively by electricity purchases from the wholesale market invoiced at the respective hourly market clearing prices.

The authors' future research shall focus in incorporating in the model formulation the associated balancing cost of the RES plants stemming from their stochastic production, which leads to forecast errors. This balancing cost must be incorporated in the model in order to take into account more accurately all related cost components related to the eligible asset options available to the Retailer.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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