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Simultaneous Expansion of the Generation Park and the Transmission System through Mixed-Integer Nonlinear Programming Under Dynamic Load Scenarios

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Abstract: This article presents a hybrid mathematical model to address the interaction between transmission and energy generation expansion in response to dynamically increasing energy demand. By employing linear programming for optimal power flows, the proposed co-optimization model simultaneously solves the expansion of both the generation facilities and the transmission system in a single stage. Consequently, it enables the minimization of investment and operating costs for both new and existing generators, the investment costs of new components added to the transmission network, and the cost of unsupplied energy. The formulated optimization model is applied to a standard IEEE 14-bus power system under dynamic load scenarios with growth rates corresponding to expansion periods of two and five years.

Keywords: Power system planning; Generation expansion; Transmission network expansion; Simultaneous expansion planning; Mixed-Integer Nonlinear Programming (MINLP); Dynamic load scenarios; Optimal Power Flow (OPF).

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1. Introduction

Electricity consumption is steadily increasing, driven by the degree of technological innovation across various commercial and industrial processes. Consequently, electricity generation sources must be sufficient and reliable to ensure sustainable and productive economic progress. While a large part of the world has access to electric power services, it cannot be guaranteed that this energy is delivered with high quality standards, due to energy crises experienced in different regions. This situation, at least partially, stems from inadequate expansion of power systems to meet future demand requirements [1].

In power systems (PS), both the integration of various electricity generation technologies and the implementation of networks that enhance supply reliability can provide solutions to several challenges faced by modern electrical systems. These challenges include power quality issues, voltage instability, electrical losses, and environmental pollution. Such problems arise because power networks were not originally designed to accommodate the technological innovations that have emerged over time in the generation and transmission stages. Therefore, it is essential to focus on planning the expansion of generation facilities and transmission networks to enable effective adaptation of the resources available in the electrical grid [2].

Expansion problems are typically addressed in two interrelated but independent stages aimed at meeting demand and its growth over a given time horizon [3]. The first stage corresponds to Generation Expansion Planning (GEP), which determines generation requirements, and the second to Transmission Expansion Planning (TEP), which specifies network requirements or reinforcements

[4], [5]. Each stage considers distinct technical and economic conditions and can be formulated as an optimization problem with the objective of minimizing or maximizing a function based on a mathematical approach [6]. As energy needs become increasingly demanding, additional tools and expertise are required to resolve the challenges involved in managing the PS as a whole. This has led to the evolution of power system planning models and tools that integrate generation expansion and transmission growth to act in coordination. This integrated approach helps mitigate network issues arising from the high penetration of generation in response to dynamically growing demand [4], [7].

Integrated or simultaneous generation and transmission expansion planning (IGTEP) aims to identify the most cost-effective plan for determining the power capacity to be added, the type of generation and transmission required, the timing of investments, and the optimal locations for generation plants and transmission lines. This planning ensures that projected demand is met while complying with system constraints and required reliability levels [8].

In an effort to develop IGTEP models that reflect the real conditions of power systems, several studies have proposed approaches focused on maximizing social welfare, as seen in [9]. Other works, such as [10], have considered security constraints. In [11], both investment and operating costs were minimized, while [12] analyzed the effects of uncertainty in primary energy sources and their prices. In contrast, [13] addressed renewable energy penetration, and [12] explored losses and reactive power using AC and DC network models. These and other studies have emphasized the benefits of combining generation and transmission planning into unified objective functions under appropriately defined constraints.

Current research on IGTEP explores various methods grouped into two main categories, each with its own set of programming tools, whose application depends on computational limitations. The first category is based on mathematical optimization. For instance, some studies have formulated the IGTEP problem using Mixed-Integer Linear Programming (MILP) [14], linear programming [15], and MILP-based co-optimization approaches [16]. The second category involves metaheuristic algorithms. Notable examples include combined expansion planning with Monte Carlo simulation models [17], the use of Benders decomposition [18], stochastic algorithms [19], genetic algorithms [20], and hybrid methods integrating genetic algorithms with gradient-based techniques for IGTEP [21]. These studies present a variety of methodologies capable of solving simultaneous expansion planning problems. Such methodologies foster a large number of studies because IGTEP results tend to be satisfactory, ensuring both the overall minimization of costs and the fulfillment of projected demand within the defined planning horizon.

This research proposes a novel method for the simultaneous expansion of the generation stage and the transmission network using AC power flow models. The expansion is formulated as an optimization problem through Mixed-Integer Nonlinear Programming (MINLP). The innovation of the proposed model lies in the continuous and intensive interaction involved in solving n nonlinear programming problems for the modeled system. These problems, governed by the electrical laws of AC power flows, determine the inclusion of new generation units and possible new links in the network. The AC power flows, which include both active and reactive power, as well as voltage levels, are treated as variables that must remain within technical limits to guarantee reliability, continuity, and quality in steady-state operation of the system over the medium and long term. The objective of this work is to minimize the investment costs of new generators and newly added transmission elements, the operating costs of both existing and new generation units, and the CENS. The formulated model considers multiple dynamic load scenarios to evaluate the technical and economic aspects associated with the simultaneous expansion of the generation park and the transmission system in a test network. Therefore, the proposed model provides optimal investment strategies for sizing, siting, and scheduling new investments in generation units and interconnection networks to meet the forecasted demand.

This article is organized as follows: Section 2 analyzes the criteria for integrated expansion planning, along with the model and solution methods used for IGTEP. Section 3 formulates the objective function and constraints of the proposed IGTEP methodology. Section 4 presents the case studies. Section 5 discusses the results, and finally, Section 6 provides the conclusions of this research.

2. Integrated Planning for Power System Expansion

Expansion planning in power systems is a complex study aimed at determining the optimal way to expand generation, distribution, and transmission in order to meet consumers' energy needs at the lowest possible cost over a defined time horizon [22]. While the primary objective is to meet demand, the delivery of electricity must also be reliable, secure, and economical, considering the technical, economic, and political aspects involved in the power grid [23]. Traditionally, expansion planning has focused on generation due to the high investment costs it entails compared to transmission network expansion. It is worth noting that distribution also requires considerable investment, but in large part, this is the responsibility of entities other than those involved in production and transmission [24], [25].

The relationship between producer and consumer needs results in combined variables that highlight the necessity for tools that integrate the apparent separation between generation and transmission planning [26]. However, in practice, generation is typically planned and scheduled based on demand growth, thereby providing guidelines for the transmission network's expansion plan. Generation planning is based on assumptions about load growth at the distribution stage, which means that each planning process is treated separately due to the fragmented decisions made by investors and operators—ultimately leading to disorder in system expansion and reduced overall economic benefits [27].

Therefore, considering the interdependence between generation and transmission expansion—and the significant investments both require—it is essential to adopt an integrated planning approach that justifies the new infrastructure from both a technical and economic standpoint, since such developments have a direct impact on all users of the system. This issue has been the subject of limited research and is known as Integrated Generation and Transmission Expansion Planning [28]. IGTEP is a process that employs various methodologies and models to coordinate expansion plans simultaneously, with the goal of determining the location, quantity, and type of generation and transmission units to be added to the power system at the appropriate time, ensuring that projected demand is met at minimum cost and under reliable conditions [29].

2.1. Criteria for Integrated Expansion Planning

The formulation of the IGTEP problem involves several criteria distributed across different stages, enabling effective system integration for electricity supply. Moreover, these criteria impact the complexity of the modeling process due to the number of variables and data involved, which can lead to challenges in data processing and computation. Therefore, robust computational tools are required to handle this type of analysis. The following section presents these criteria in a general manner.

2.1.1. Demand Growth

Electric power systems evolve in efficiency and structure according to demand behavior. Their adaptation depends on energy consumption, which is complex to measure due to its high level of uncertainty [30]. For this reason, over time, various methods have been developed and refined to forecast the dynamic behavior of demand and to establish corresponding growth rates. These forecasts serve as the foundation for power system studies within their respective time frames. Therefore, demand contributes to expansion planning by incorporating load growth rates, particularly exponential growth rates applicable at the continental (American) level [31].

2.1.2. Generation Expansion Planning

GEP generally determines the entry, size, and optimal location of new power generation units while minimizing total cost over a medium- or long-term planning horizon. Generation expansion typically adopts an energy-focused approach and disregards transmission network constraints [32]. Therefore, to address the IGTEP problem, it is essential to consider the active and reactive power contributions of the generators, plant capacity factors, investment and operational costs of generation facilities, and the location and capacity of the units involved in the expansion plan.

2.1.3. Transmission Expansion Planning

TEP refers to the installation of new transmission lines or the expansion of the capacity of existing lines within a power system [10]. Transmission expansion planning identifies the network reinforcements required to ensure energy delivery to system users at minimum cost, while also pinpointing the supply points established by GEP. The criteria that TEP must consider for integrated planning focus on link-related characteristics, such as line investment and operating costs, network topology, line loading capacity, operating voltage levels, and active and reactive power flow.

2.1.4. Unsupplied Energy

This criterion is incorporated when the generation resources or transmission infrastructure are unable to meet the demand during the period in which the expansion is evaluated.

2.2. Model and Solution Method for IGTEP

To perform a combined expansion study, it is necessary to define a mathematical model capable of incorporating the previously mentioned criteria. For this study, the model considers the expansion of both the generation and transmission stages, while also applying AC power flow equations. Solving these equations enables a highly accurate approximation of the real operation of power systems, despite the mathematical complexity introduced by the nonlinearities of the load flow equations [33]. These equations are characterized by voltage, angle, active power, and reactive power variables, which determine the flows in the transmission network based on generation and demand levels [28], [34].

The power flow model in this work is based on the following assumptions: the technical and economic characteristics of generators and transmission lines are known; new transmission lines have the same characteristics as existing ones; growing demand—which drives the need for system expansion—is represented through dynamic load scenarios based on growth rates; and Energy Not Supplied (ENS) is assigned a value when generation resources or transmission infrastructure are insufficient to meet demand over a given period.

For the formulation of load flow studies within the integrated expansion plan, it is essential to define a methodology that satisfies the objective function of minimizing costs (investment, operating, and ENS) by optimally deploying new generation and reinforcing the transmission network according to demand growth. A variety of solution methods exist, ranging from metaheuristic algorithms to classical mathematical optimization methods, each with its own advantages and limitations [35]. Considering the challenges posed by generation and transmission expansion planning, this work uses a mathematical co-optimization algorithm based on MINLP. This approach is suitable due to the nonlinear nature of the equations, the non-convexity arising from decision variables inherent to electrical laws, and the large scale of the problem. The selected algebraic modeling approach enables the simultaneous identification of the best expansion alternatives for generation units and the transmission network to meet future demand, using a minimum-cost criterion for both operation and investment.

3. Methodology for the Simultaneous Expansion of Generation and Transmission

The simultaneous expansion of the generation and transmission stages of the power system is obtained by solving a MINLP model, which involves binary decision variables and mixed-type variables. Their interaction enables the determination of the new infrastructure required in the aforementioned segments of the power sector.

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3.1. Objective Function

The objective function is divided into three components: the first corresponds to the costs associated with the generation park, the second relates to the costs of the new transmission system infrastructure, and the third evaluates the ENS.

3.1.1. Generation Park Costs

For generators, operational costs are modeled in (1), and the annualized investment costs of new generators incorporated in the medium term are represented in (2) and (3).

$$COG = Tt\left(\sum_{G_o} P_{G_o} \cdot CO_{G_o} + \sum_{G_n} P_{G_n} \cdot CO_{G_n}\right) \tag{1}$$

$$CAIG = \sum_{G_n} C_{G_n} \cdot fcr_{G_n} \cdot CI_{G_n} \tag{2}$$

$$fcr_{G_n} = \frac{td_{G_n}(1 + td_{G_n})^{Vu_{G_n}}}{(1 + td_{G_n})^{Vu_{G_n}} - 1} \tag{3}$$

3.1.2. Transmission Infrastructure Costs

The new transmission infrastructure implemented through system expansion results in annualized investment costs, as modeled in (4) and (5).

$$CAIT = \frac{1}{2}\sum_{N}\sum_{M}\sum_{k} CI_{n,m} \cdot fcr_{n,m} \cdot \alpha_{n,m,k} \tag{4}$$

$$fcr_{n,m} = \frac{td_{n,m}(1 + td_{n,m})^{Vu_{n,m}}}{(1 + td_{n,m})^{Vu_{n,m}} - 1} \tag{5}$$

3.1.3. Costs of Energy Not Supplied

ENS occurs when the generation system is unable to meet demand. This shortage results in a significant cost to consumers and is modeled in (6).

$$CENS = Tt \cdot CE \cdot \sum_{n} Pens_n \tag{6}$$

3.2. Constraints

The constraints in the model correspond to the technical aspects of the power system, including the modeling of AC power flows, operational characteristics of generators, interconnection link capacity limits, and their implications for the associated variables.

3.2.1. Flows in Transmission Network Links

This constraint associates the variable $\alpha_{n,m,k}$ with the AC power flow equations. In this case, both active and reactive power must be modeled. For this purpose, the Big M method is used [36], [37], which is based on associating constraints with large negative constants that would not be part of any optimal solution. When applying the Big M method in constraints, it ensures that variable enforcement occurs only when a defined binary variable takes on a specific value, while leaving the variables "open" if the binary variable takes the opposite value.

$$P_{n,m,k} - \left[\sum_{m=1}^{M} |V_n||V_m|(g_{nm}cos\theta_{nm} + b_{nm}sen\theta_{nm})\right] \le M \cdot (1 - \alpha_{n,m,k}) \tag{7}$$

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$$P_{n,m,k} - \left[\sum_{m=1}^{M} |V_n||V_m|(g_{nm} cos\theta_{nm} + b_{nm} sen\theta_{nm}) \right] \geq -M \cdot (1 - \alpha_{n,m,k}) \tag{8}$$

$$Q_{n,m,k} - \left[\sum_{m=1}^{M} |V_n||V_m|(g_{nm} sin\theta_{nm} - b_{nm} cos\theta_{nm}) \right] \leq M \cdot (1 - \alpha_{n,m,k}) \tag{9}$$

$$Q_{n,m,k} - \left[\sum_{m=1}^{M} |V_n||V_m|(g_{nm} sin\theta_{nm} - b_{nm} cos\theta_{nm}) \right] \geq -M \cdot (1 - \alpha_{n,m,k}) \tag{10}$$

3.2.2. Power Transfer Limits of the Links

The transfer limits on the links are related to the maximum or minimum amount of active or reactive power that can be transferred through a given link, whether it is an existing or a new one. The transferred power must not exceed the thermal or loading limit of the link.

$$P_{n,m,k} \leq LTP_{n,m} \cdot \alpha_{n,m,k} \tag{11}$$

$$P_{n,m,k} \geq -LTP_{n,m} \cdot \alpha_{n,m,k} \tag{12}$$

$$Q_{n,m,k} \leq LTQ_{n,m} \cdot \alpha_{n,m,k} \tag{13}$$

$$Q_{n,m,k} \geq -LTQ_{n,m} \cdot \alpha_{n,m,k} \tag{14}$$

3.2.3. Bidirectionality of Decision Variables for the New Link

This constraint ensures that the decision to incorporate a new link between two nodes is not duplicated and does not have an additional impact on the investment cost of the new transmission infrastructure.

$$\alpha_{n,m,k} = \alpha_{m,n,k} \tag{15}$$

3.2.4. Nodal Balance

The formulation of the nodal balance is applicable to the active and reactive power at each node of the power system and must comply with the concept established by Kirchhoff's First Law.

$$Pens_n + \sum_{G_o \in n} P_{G_o} + \sum_{G_n \in n} P_{G_n} - \left(P_{Ln} \cdot f_{Lg}\right) = \sum_m \sum_k P_{n,m,k} \tag{16}$$

$$\sum_{G_o \in n} Q_{G_o} + \sum_{G_n \in n} Q_{G_n} - \left(Q_{Ln} \cdot f_{Lg}\right) = \sum_m \sum_k Q_{n,m,k} \tag{17}$$

3.2.5. Capacity of New Generators

This constraint allows the incorporation of a generation plant based on demand requirements and its growth through the use of a binary decision variable.

$$Cap_{G_n} \leq Cmax_{G_n} \cdot \beta_{G_n} \tag{18}$$

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3.2.6. Generation Output Limits

This constraint ensures that the active and reactive power dispatched by any generator does not exceed the limits defined by the generator capability curve.

$$Pmin_{G_o} \leq P_{G_o} \leq Cmax_{G_o} \tag{19}$$

$$Pmin_{G_n} \leq P_{G_n} \leq Cmax_{G_n} \tag{20}$$

$$Q_{G_o} \leq Cmax_{G_o} \cdot tan\left[cos^{-1}\left(f_{PLG_o}\right)\right] \tag{21}$$

$$Q_{G_n} \leq Cmax_{G_n} \cdot tan\left[cos^{-1}\left(f_{PLG_n}\right)\right] \tag{22}$$

$$Q_{G_o} \geq -Cmax_{G_o} \cdot tan\left[cos^{-1}\left(f_{PLG_o}\right)\right] \tag{23}$$

$$Q_{G_n} \geq -Cmax_{G_n} \cdot tan\left[cos^{-1}\left(f_{PLG_n}\right)\right] \tag{24}$$

3.2.7. Nodal Voltage Limits

This constraint ensures that the nodal voltages in per unit remain within the defined range to guarantee voltage stability in the system.

$$Vmin_n \leq V_n \leq Vmax_n \tag{25}$$

3.2.8. Nodal Angle Limits

This constraint ensures that the voltage angles at the nodes remain within the specified range, thereby maintaining angular stability in the system.

$$\theta min_n \leq \theta_n \leq \theta max_n \tag{26}$$

$$\theta_{slack} = 0 \tag{27}$$

3.2.9. Optimization Model Pseudocode

By solving the proposed mixed-integer nonlinear optimization model, the expansion of new links in the transmission system can be determined, and simultaneously, the new generation plants to be incorporated into the system are obtained, all while minimizing the costs associated with the generation and transmission stages.

The decision to expand the generation and transmission stages not only considers minimizing associated costs but also takes into account relevant aspects, such as network constraints — the application of power flow equations and their implications for link loading. It also incorporates the application of the Big M method, which facilitates the decision to include new links, directly impacting the need to incorporate new generations. The decision to incorporate is provided by binary variables, which resolve the inclusion of generation and transmission elements, ensuring the supply of demand and consequently the fulfillment of link loading constraints and voltage level requirements.

Representation 1 presents the pseudocode of the proposed heuristic.

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Representation 1. Pseudocode of the optimization model.

Simultaneous expansion of the generation park and the transmission system through mixed-integer nonlinear programming	
Step 1	Acquisition of the power system data.
Step 2	Determination of the factors associated with the expansion of the generation and transmission stages: - Potential generators to be incorporated - Discount rate - Useful life - Demand growth rate - Cost of energy not supplied - Analysis period.
Step 3	Definition of variables Continuous: $P_{G_o}, Q_{G_o}, P_{G_n}, Q_{G_n}, Cap_{G_n}, V_n, \theta_n, Pens_n, P_{n,m,k}, Q_{n,m,k}$ Binary: $\alpha_{n,m,k}, \beta_{n,m,k}$
Step 4	Optimization model *Objective function* Minimization of generation and transmission stage costs, including the cost of energy not supplied *Constraints* - Decision to implement new links - Power transfer limits of the links - Bidirectionality of decision variables for the new link - Nodal balance - Capacity of new generators - Generation output limits - Nodal voltage limits - Nodal angle limits.
Step 5	Application of the model to the case studies.
Step 6	Analysis of results.
Step 7	End.

4. Case Studies

The proposed mixed-integer nonlinear programming mathematical model was applied to the IEEE 14-bus system, as illustrated in Figure 1. To evaluate the mathematical model, the following case studies are considered:

- Case 1: Expansion of the model power system in the generation and transmission stages for a period of 2 years.
- Case 2: Expansion of the model power system in the generation and transmission stages for a period of 5 years.

Each case uses dynamic load scenarios, increasing demand exponentially at annual rates of 5%, 7%, and 9%. Accordingly, three analyses will be conducted for each case described. Table 1 presents the characteristics of the power system network used as a model [38].

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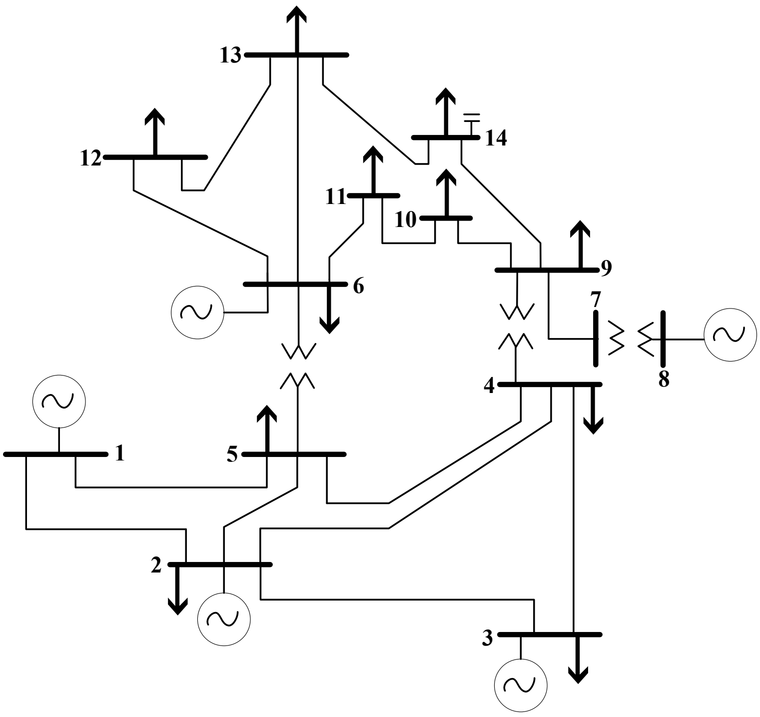

Figure 1. Single-line diagram of the IEEE 14-bus system.

Table 1. Parameters of the 14-bus network.

N_i	N_j	R [pu]	X [pu]	Bl [pu]	Limit [MVA]	Cost [MMUSD]
1	2	0.01938	0.05917	0.0528	120	66.63
1	5	0.05403	0.22304	0.0492	65	36.12
2	3	0.04699	0.19797	0.0438	36	20.00
2	4	0.05811	0.17632	0.0374	65	36.18
2	5	0.05695	0.17388	0.0340	50	27.76
3	4	0.06701	0.17103	0.0346	65	36.12
4	5	0.01335	0.04211	0.0128	45	25.01
4	7	0	0.55618	0	32	12.00
4	9	0	0.25202	0	45	14.00
5	6	0.09498	0.19890	0	18	26.99
6	11	0.12291	0.25581	0	32	47.96
6	12	0.06615	0.13027	0	32	48.10
6	13	0	0.17615	0	32	8.00
7	8	0.09711	0.11038	0	32	44.12
7	9	0.03181	0.08450	0	32	48.00
9	10	0.12711	0.27038	0	32	48.07
9	14	0.08205	0.19207	0	12	18.01
10	11	0.22092	0.19988	0	12	17.99
13	14	0.17093	0.34802	0	12	18.00

The data associated with each of the buses are presented in Table 2, while the parameters characterizing the generators located in the electrical system are listed in Table 3.

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Table 2. Bus data in the 14-bus network.

Bus	Pd [MW]	Qd [Mvar]	Area	Voltage [kV]
1	0	0	1	138.0
2	21.7	12.7	1	138.0
3	94.2	19.0	1	138.0
4	47.8	-3.9	1	138.0
5	7.6	1.6	1	138.0
6	11.2	7.5	1	138.0
7	0	0	2	69.0
8	0	0	3	13.8
9	29.5	16.6	2	69.0
10	9.0	5.8	2	69.0
11	3.5	1.8	2	69.0
12	6.1	1.6	2	69.0
13	13.5	5.8	2	69.0
14	14.9	5.0	2	69.0

Table 3. Data of the generators in the 14-bus system.

Bus	P_{max} [MW]	P_{min} [MW]	Cost [USD/MWh]	Q_{max} [Mvar]	Q_{min} [Mvar]
1	160	10	20	100	-100
2	80	20	20	50	-42
3	50	20	40	40	0
6	30	0	40	24	-24
8	30	0	40	24	-24

Table 4 presents the technical parameters of the potential generators to be incorporated into the reference power system, while Table 5 shows the economic parameters of these generators.

Table 4. Technical data of the potential generators.

	Bus	C_{max} [MW]	P_{min} [MW]	Q_{max} [Mvar]	Q_{min} [Mvar]
Gn_1	2	150	0	70	-70
Gn_2	6	100	0	60	-60
Gn_3	14	200	0	80	-85
Gn_4	3	100	0	60	-60
Gn_5	4	100	0	60	-60

Table 5. Economic data of the potential generators.

	Bus	Investment [USD/kW]	Operating cost [USD/MWh]	Lifetime Years	pf
Gn_1	2	1200	20	50	0.80
Gn_2	6	600	50	20	0.94
Gn_3	13	1000	30	50	0.82
Gn_4	3	500	80	25	0.93
Gn_5	4	350	120	25	0.96

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5. Results Analysis

Given the described cases and the dynamic load scenarios applied to each one, the results are evaluated from both technical and economic perspectives.

5.1. Case 1

By applying the mathematical model over a 2-year analysis period for each dynamic load scenario, the results of the electrical and economic variables are obtained. Generation and demand are evaluated, as presented in Table 6. Figure 2 illustrates the results of active generation and supplied demand, including the corresponding losses.

Table 6. Active power results by load scenario, Case 1.

Parameter [MW]	Load scenarios 5%	7%	9%
Active power from existing generation	293.84	304.95	316.26
New generation power	-	-	-
Load	285.55	296.53	307.72
Losses	8.29	8.43	8.54

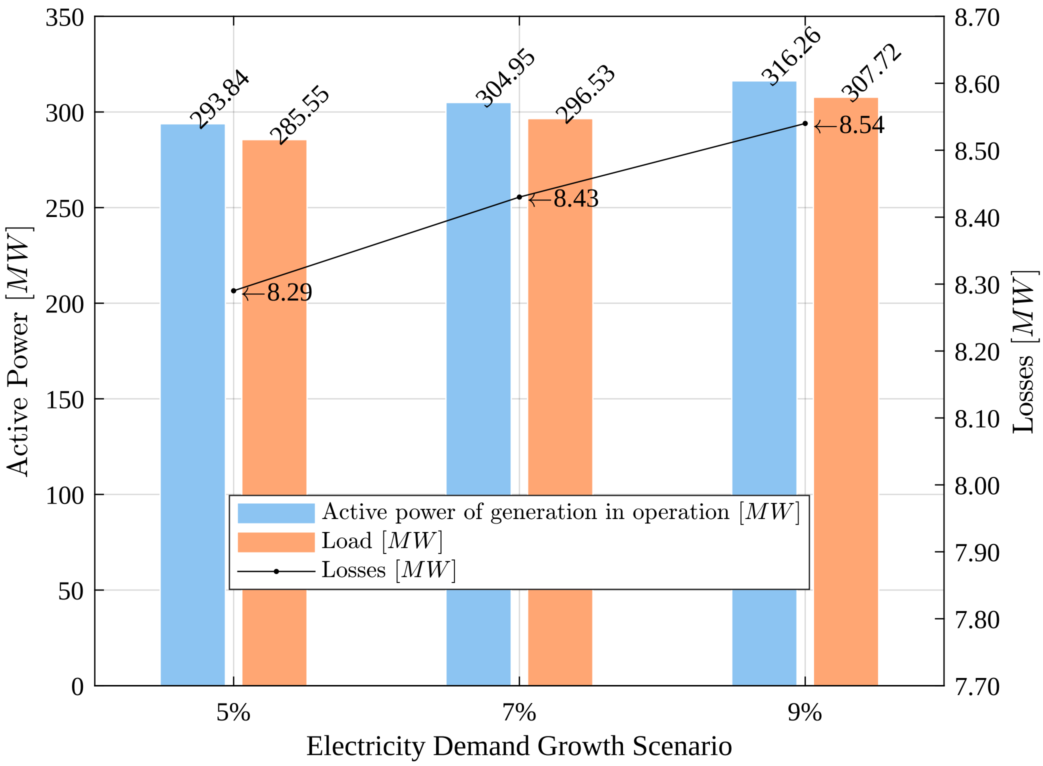

Figure 2. Generation output and active demand for each dynamic load scenario, Case 1.

The results show that, for each analyzed load scenario, the operating generation fleet—with a nominal capacity of 350 MW—is sufficiently robust to supply the demand and meet the network's operational requirements. Therefore, the model indicates that no generation expansion is required.

On the other hand, when evaluating active power losses in relation to the supplied demand for each load scenario, it is concluded that the average percentage of losses amounts to 2.84%.

Table 7 presents the results for reactive power. The analysis reveals that the total reactive power capacity produced by the generators is 238 Mvar, which supplies the increased load and compensates for network losses without the need to increase generation. The results are illustrated in Figure 3.

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Table 7. Reactive power results by load scenario, Case 1.

Parameter [Mvar]	Load scenarios 5%	7%	9%
Reactive power from existing generation	85.700	90.394	93.046
Reactive power from new generation	-	-	-
Load	81.034	84.150	87.325
Losses	4.667	6.243	5.721

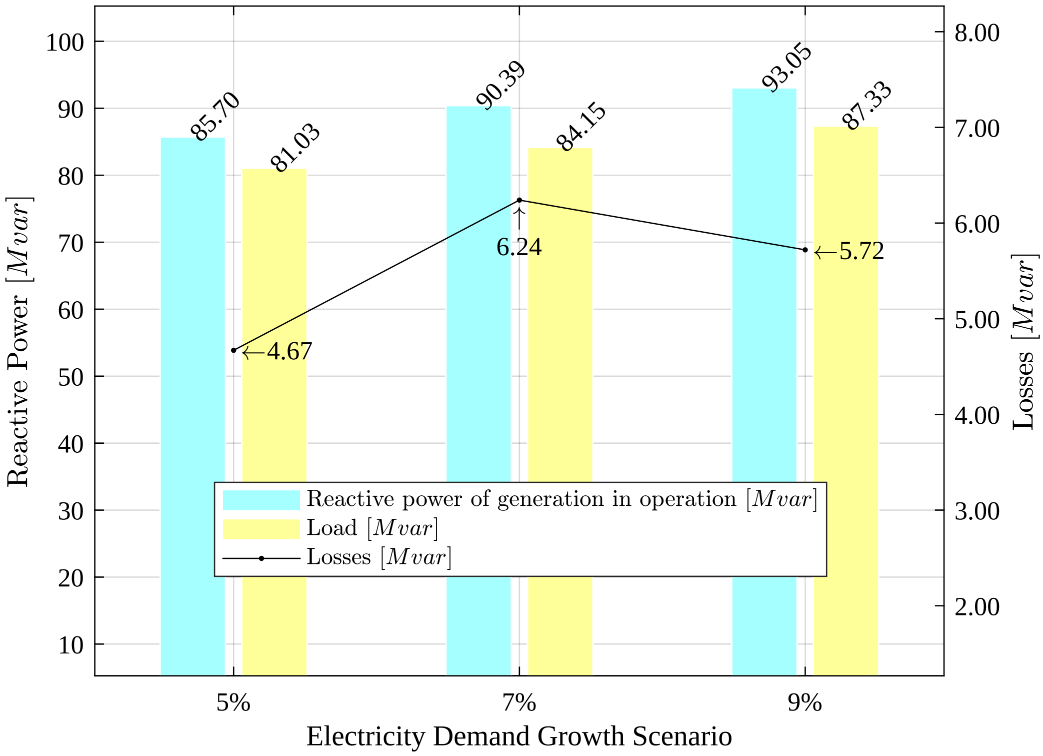

Figure 3. Reactive generation output and demand for each dynamic load scenario, Case 1.

An evaluation of reactive power losses relative to the supplied demand in each load scenario shows that the average loss percentage amounts to 6.59%. Given that reactive power production is directly related to voltage levels, voltage profiles at the end of the analysis period are verified for each dynamic load scenario, as illustrated in Figure 4.

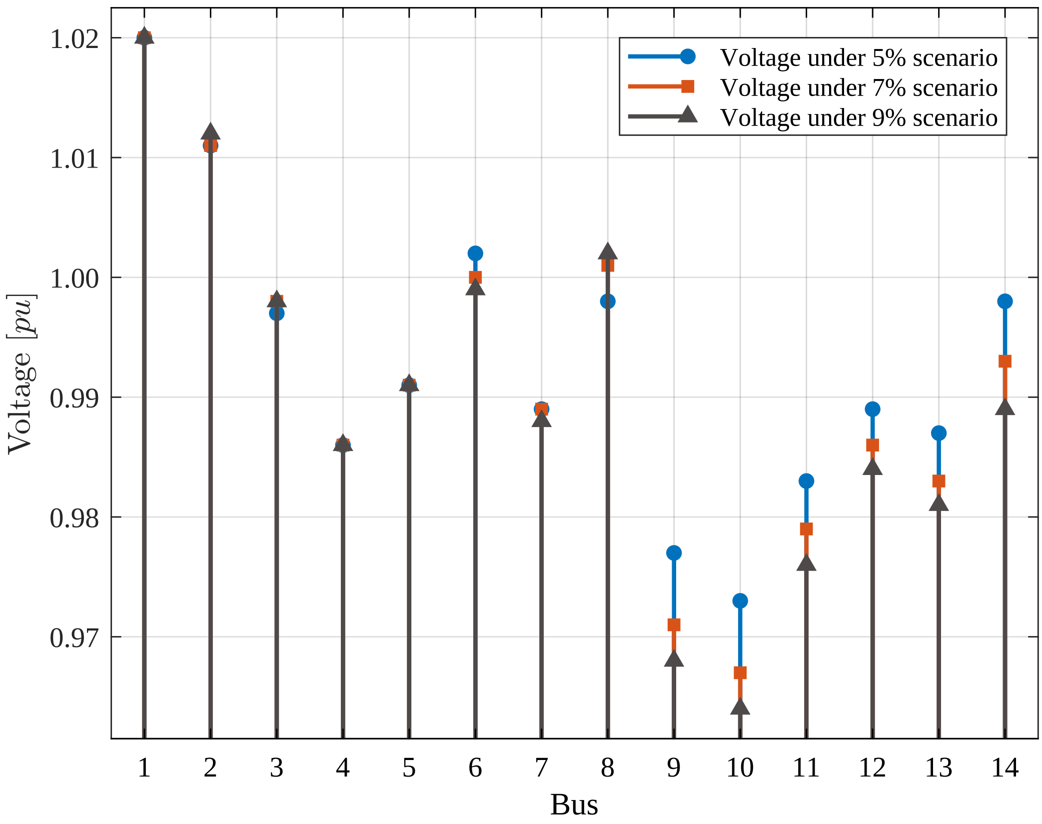

Figure 4. Voltage profiles for each dynamic load scenario, Case 1.

Figure 4 shows that for all demand growth scenarios, voltage levels remain within the operational band, ensuring voltage stability across the system. To complement the technical analysis, the transmission network expansion is also examined. The results of this verification are presented in Table 8.

Table 8. Activated transmission links by load scenario, Case 1.

	Load scenarios		
Link	5%	7%	9%
Link $N_4 - N_9$	✓	✓	✓
Link $N_2 - N_3$	✓	✓	✓

Based on Table 8, it is concluded that although no expansion of the generation system is required—since the installed capacity is sufficient to supply the demand—the model indicates the need to reinforce the transmission system. For this case, regardless of the load scenario, the link connecting node 4 to node 9 is activated, corresponding to the expansion of a substation, and a new transmission line is added between nodes 2 and 3. Figure 5 shows the single-line diagram of the expanded electrical system for all load scenarios.

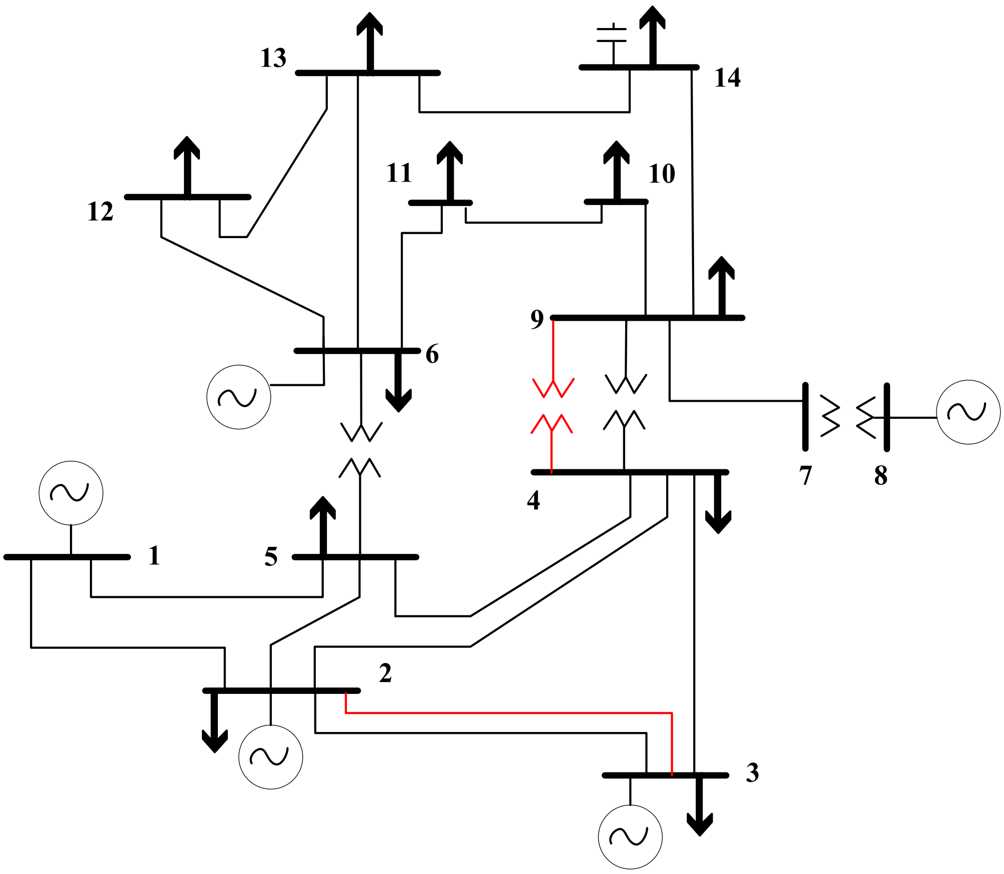

Figure 5. Single-line diagram, Case 1: 5%, 7%, and 9%.

The resulting voltages for each load scenario are listed in Table 9, while power flows through each link of the simulated network for every load scenario are presented in Appendix A.

Table 9. Voltages by load scenario, Case 1.

Node	5%		7%		9%	
	Voltage [pu]	Angle [deg]	Voltage [pu]	Angle [deg]	Voltage [pu]	Angle [deg]
1	1.020	0	1.020	0	1.020	0
2	1.011	-3.53	1.011	-3.53	1.012	-3.54
3	0.997	-5.32	0.998	-7.54	0.998	-7.56
4	0.986	-5.68	0.986	-5.69	0.986	-5.66
5	0.991	-7.21	0.991	-7.23	0.991	-7.18
6	1.002	-13.05	1.000	-13.66	0.999	-13.23
7	0.989	-13.20	0.989	-14.46	0.988	-14.23
8	0.998	-12.58	1.001	-13.42	1.002	-13.04
9	0.977	-13.29	0.971	-14.72	0.968	-14.57
10	0.973	-13.61	0.967	-14.91	0.964	-14.73
11	0.983	-13.49	0.979	-14.45	0.976	-14.15
12	0.989	-14.18	0.986	-14.89	0.984	-14.52
13	0.987	-14.43	0.983	-15.20	0.981	-14.85
14	0.998	-16.08	0.993	-17.29	0.989	-17.12

Based on the results of the electrical variables, the operating costs of energy production from the operating generation, as well as the annualized investment costs of the incorporated links, are determined. The costs for each load scenario in Case 1 are presented in Table 10.

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Table 10. Costs by load scenario, Case 1.

Scenario	Costs in million USD [MUSD] Network	Operation of G_o	Total
5%	3.22	120.16	123.38
7%	2.10	138.10	140.19
9%	2.58	141.17	143.75

5.2. Case 2

For a 5-year analysis period under each dynamic load scenario, the results of the electrical and economic variables are obtained. Analogous to Case 1, production and demand are evaluated, and the results are presented in Table 11. Figure 6 illustrates the results of active power generation and supplied demand, including the corresponding losses.

Table 11. Active power results by load scenario, Case 2.

Parameter [MW]	Load Scenarios 5%	7%	9%
Active power from operating generation	249.13	290.00	296.32
Active power from new generation	89.89	82.80	112.71
Load	330.56	363.26	398.50
Losses	8.46	9.53	10.54

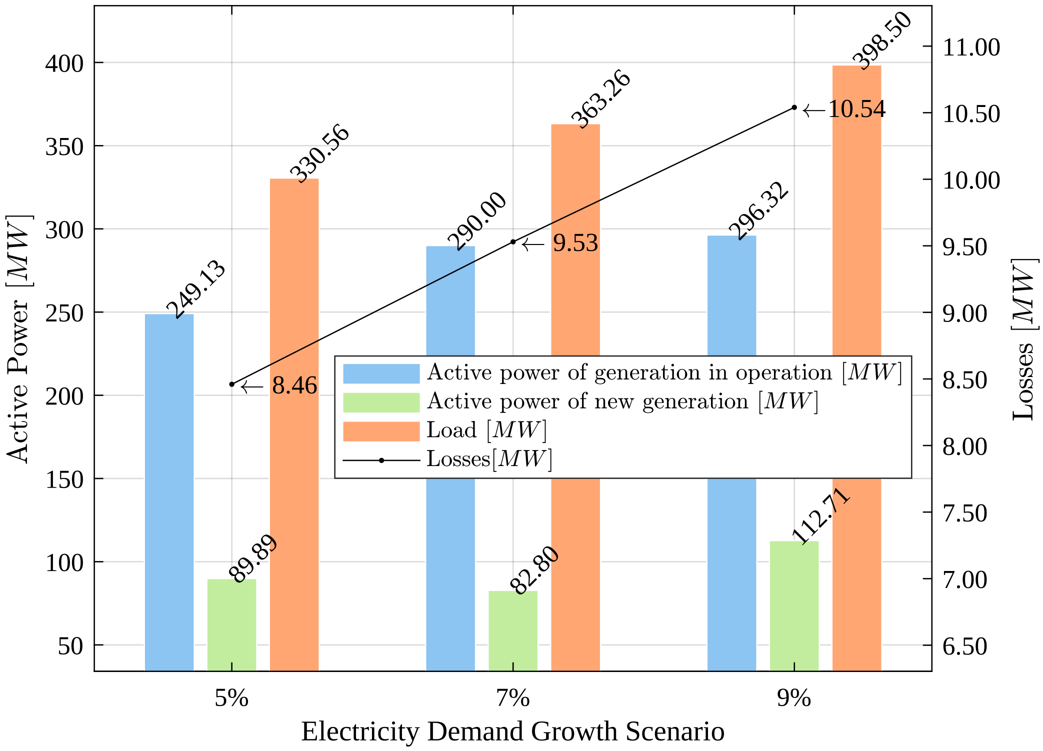

Figure 6. Generation and active demand supplied for each dynamic load scenario, Case 2.

From the results for each analyzed load scenario, it can be concluded that the existing generation fleet must be expanded in order to meet the demand and fulfill the network's operational requirements. Therefore, the results of the generation expansion are presented in Table 12.

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Table 12. Active power from new generation by load scenario, Case 2.

	Active Power [MW]		
	Load Scenarios		
Location	5%	7%	9%
Node 2	-	8.073	18.25
Node 3	35.081	17.000	32.41
Node 14	54.804	57.723	62.05

Considering the analysis period and the associated increase in load, it can be stated that the new generation along with the existing generation enables the system to meet the demand and compensate for active power losses. In this context, the average percentage of active power losses with respect to the supplied demand across the load scenarios reaches a value of 2.61%.

Similarly, a reactive power analysis is carried out. The results are shown in Table 13, from which it can be observed that the model performs an allocation of reactive power between the new and existing generators. This allocation not only supplies the increased load but also compensates for losses occurring in the network. The results are illustrated in Figure 7.

Table 13. Reactive power results by load scenario – Case 2.

	Load Scenarios		
Parameter [Mvar]	5%	7%	9%
Reactive power from existing generation	109.254	105.155	110.678
Reactive power from new generation	-8.252	6.515	14.508
Load	93.807	103.088	113.089
Losses	7.195	8.582	12.097

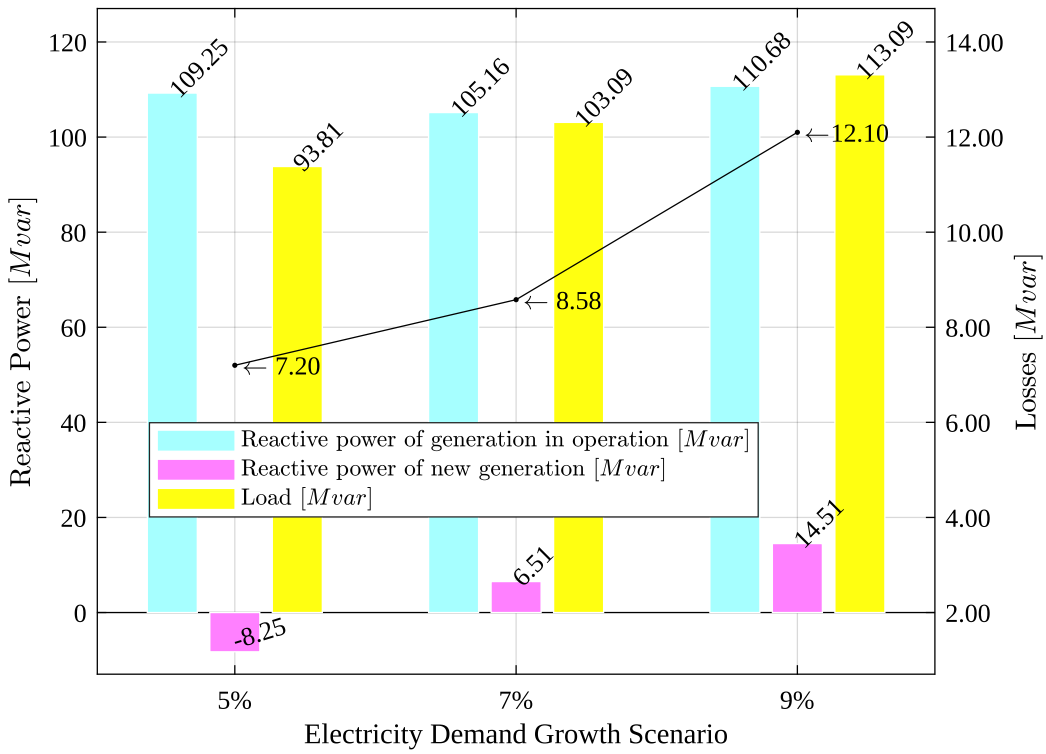

Figure 7. Reactive generation and demand for each dynamic load scenario, Case 2.

Based on the results obtained for each analyzed load scenario, as previously indicated, the existing generation fleet must be expanded to meet demand and satisfy the network's operational requirements. Accordingly, the results of the generation expansion are presented in Table 14.

Table 14. Reactive power from new generation by load scenario, Case 2.

Reactive Power [Mvar]			
	Load Scenarios		
Location	5%	7%	9%
Node 2	-	3.495	13.687
Node 3	-13.327	-6.719	-12.809
Node 4	5.076	9.738	13.630

As a complement, by evaluating the reactive power losses relative to the supplied demand for each load scenario, it is observed that the average percentage of losses amounts to 8.90%. In this regard, since reactive power production is directly related to voltage levels, voltage profiles are verified at the end of the analysis period for each load scenario, as illustrated in Figure 8.

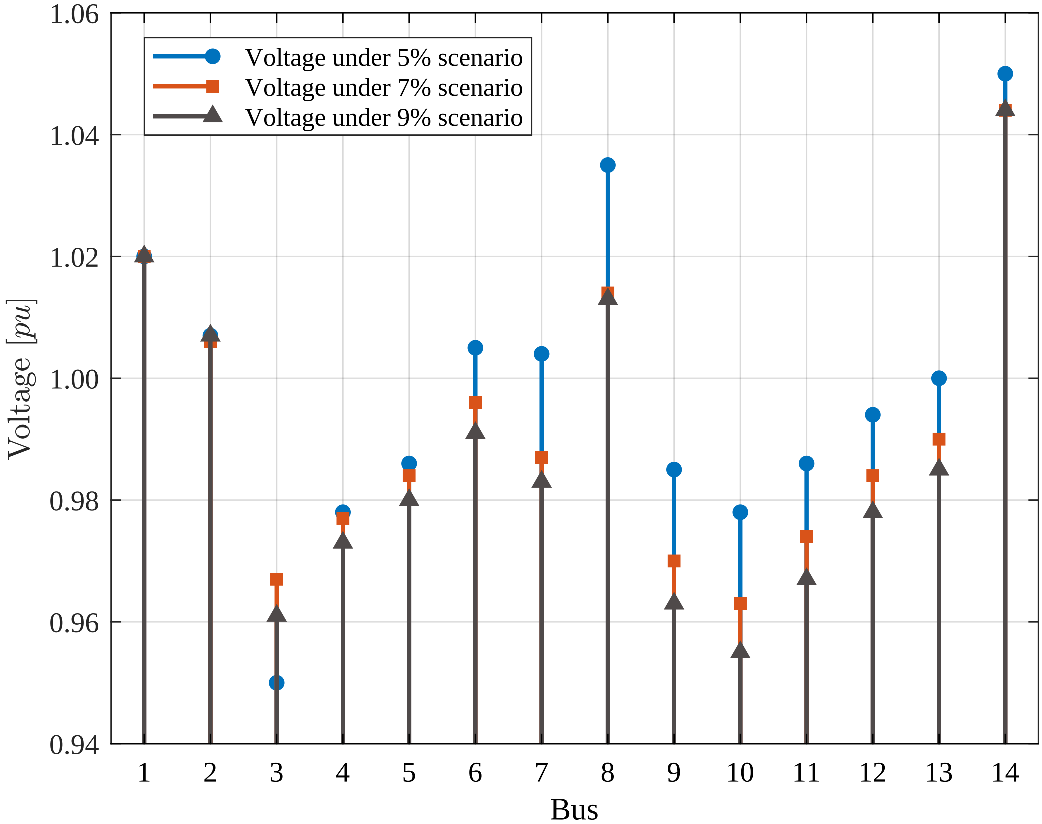

Figure 8. Voltage profiles for each dynamic load scenario, Case 2.

From Figure 8, it is evident that in all demand growth scenarios, the voltage levels remain within the operational band. This ensures that the system maintains its voltage stability. To complement the technical analysis, the network expansions are verified; the verification results are presented in Table 15.

Table 15. Network link activation by load scenario.

	Load Scenarios		
Link	5%	7%	9%
Link $N_2 - N_3$	-	✓	✓

From Table 15, it is concluded that, except for the 5% demand growth scenario, network expansions are implemented; even though generation expands in all demand scenarios. In this case, the

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model indicates the need to reinforce the transmission system, activating the new link connecting node 2 and node 3. Figures 9 and 10 show the one-line diagrams of the expanded power system.

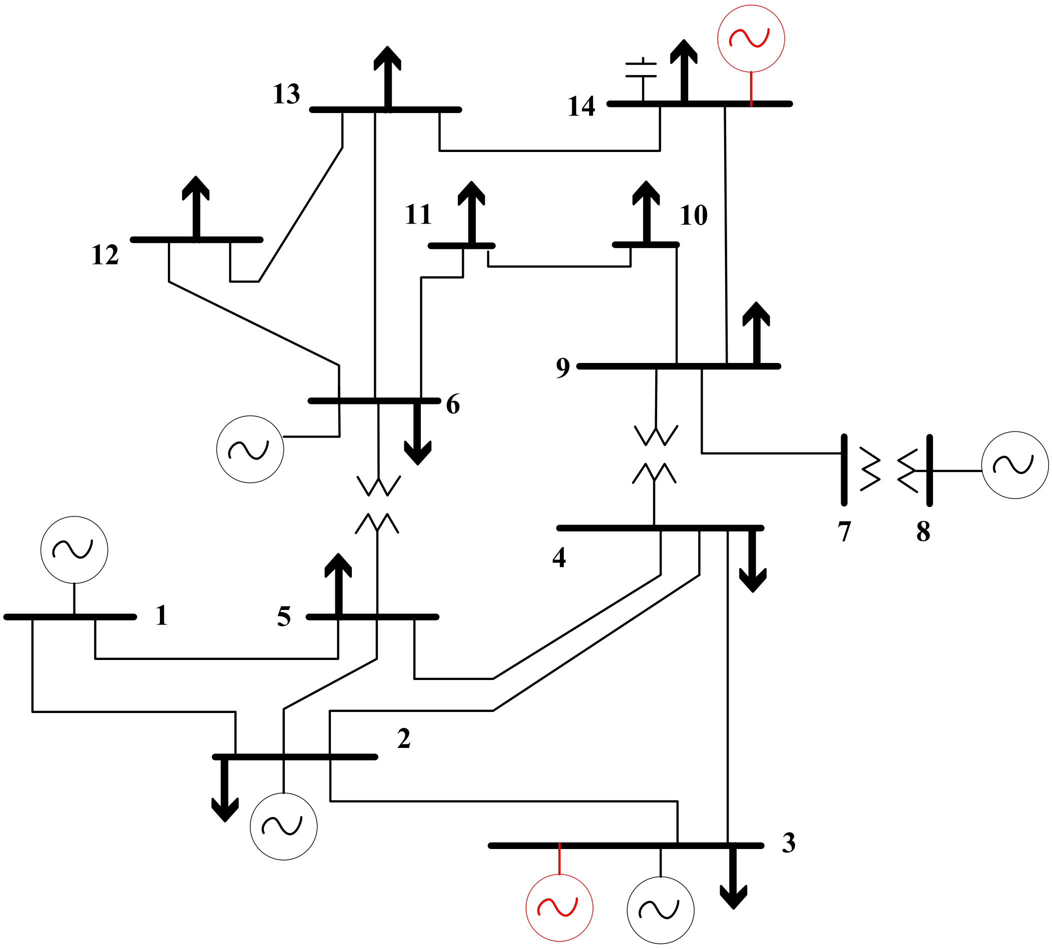

Figure 9. One-line diagram, Case 2: 5%.

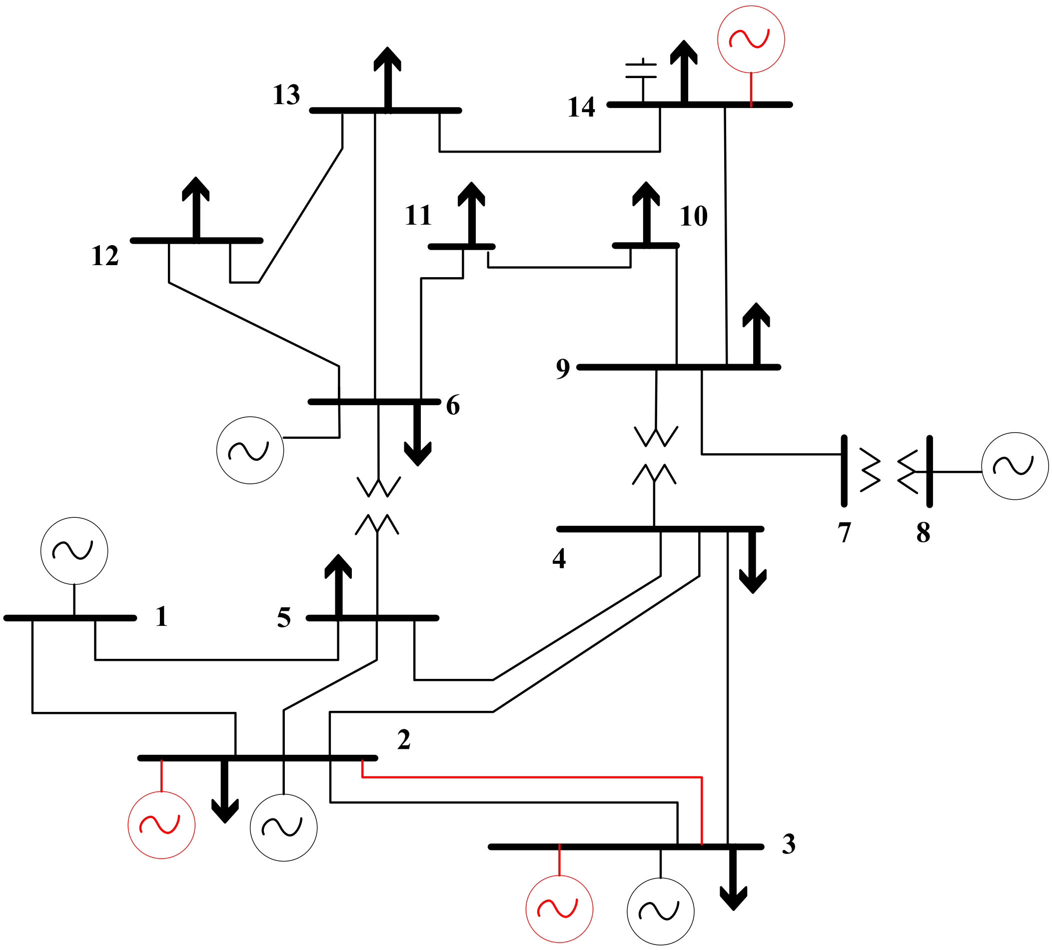

Figure 10. One-line diagram, Case 2: 7 and 9%.

The voltage results for each load scenario are shown in Table 16, and the power flows for each network link in the simulated grid are presented in Appendix B.

Table 16. Voltages per load scenario, Case 2.

Node	5%		7%		9%	
	Voltage [pu]	Angle [degree]	Voltage [pu]	Angle [degree]	Voltage [pu]	Angle [degree]
1	1.020	0	1.020	0	1.020	0
2	1.011	-3.53	1.011	-3.53	1.012	-3.54
3	0.997	-5.32	0.998	-7.54	0.998	-7.56
4	0.986	-5.68	0.986	-5.69	0.986	-5.66
5	0.991	-7.21	0.991	-7.23	0.991	-7.18
6	1.002	-13.05	1	-13.66	0.999	-13.23
7	0.989	-13.20	0.989	-14.46	0.988	-14.23
8	0.998	-12.58	1.001	-13.42	1.002	-13.04
9	0.977	-13.29	0.971	-14.72	0.968	-14.57
10	0.973	-13.61	0.967	-14.91	0.964	-14.73
11	0.983	-13.49	0.979	-14.45	0.976	-14.15
12	0.989	-14.18	0.986	-14.89	0.984	-14.52
13	0.987	-14.43	0.983	-15.20	0.981	-14.85
14	0.998	-16.08	0.993	-17.29	0.989	-17.12

Taking into account the results of the electrical variables, the operating costs of the power generation from the existing generators are determined, along with the annualized investment costs of the incorporated links. These results are presented in Table 17.

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Table 17. Costs per load scenario.

	Costs in million US dollars [MUSD]		
Scenario	Network	Operation of G_o	Operation of G_n
5%	-	262.04	194.94
7%	1.61	297.84	142.49
9%	1.61	308.92	211.09
Scenario		Investment in G_n	Total
5%		7.46	464.44
7%		7.74	449.67
9%		10.25	531.88

6. Conclusions

The proposed nonlinear mixed-integer optimization model enables the simultaneous expansion of both the generation stage and the transmission system in order to meet demand using optimal AC power flows. This approach makes it possible to determine the power delivered by new generation units and new network links—two components which, when interacting, ensure economic supply of demand over the analysis period. All of this is done while considering the constraints associated with the operational characteristics of the PS

Based on the results obtained for each case study and considering the dynamic load scenarios, it can be stated that when the analysis period is shorter, the model prioritizes network investments and optimization of the existing generation resources to minimize associated costs while still complying with network constraints, as evidenced in the results of Case 1. Likewise, as the analysis period increases and demand grows significantly, the model introduces new generation and transmission links simultaneously into the electric system—an outcome reflected in the results of Case 2. Therefore, it is confirmed that the model achieves simultaneous expansion of the generation park and transmission system, while also modeling network-specific constraints.

The decisions to expand generation capacity or to include new transmission links consider the system's technical constraints but, more importantly, take into account the associated costs. Consequently, it is concluded that careful incorporation of unit cost data is essential to ensure that the model produces consistent results and accurately determines required investments. Otherwise, poor planning could lead to overcosts that, depending on the market structure in each country, must be compensated—typically resulting in increased tariffs for the end user.

The proposed mathematical model integrates the nonlinear conditions of AC power flow with binary variables that define investment decisions in both generation and transmission. Furthermore, its formulation is scalable and adaptable to various electric systems, making it a valuable tool for short-, medium-, and long-term planning.

Since the model proposes a novel methodology for the simultaneous expansion of generation and transmission stages, it is recommended that future work includes a stochastic analysis comparing the classical methodology with the approach presented herein, in order to establish technical and economic parameters that allow the electric system to optimally serve demand over the medium and long term.

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Appendix A. Power flows through the network, Case 1

Appendix A.1. Active power flow 1

Table A.1. Active power flow [MW].

$Node_i$	$Node_j$	5%	7%	9%
1	2	102.42	102.26	102.61
1	5	57.58	57.74	57.39
2	1	-100.43	-100.26	-100.60
2	3	72.00	71.17	71.28
2	4	47.30	46.72	46.55
2	5	37.20	37.53	36.99
3	2	-70.81	-70.01	-70.11
3	4	8.42	8.39	8.19
4	2	-43.50	-43.55	-43.27
4	3	-8.37	-8.33	-8.14
4	5	-43.53	-39.82	-41.30
4	9	45.22	38.90	37.97
5	1	-55.85	-56.01	-55.67
5	2	-36.43	-36.74	-36.23
5	4	43.79	40.03	41.54
5	6	40.11	44.02	41.34
6	5	-40.11	-44.02	-41.34
6	11	6.77	9.65	10.78
6	12	8.19	8.86	9.31
6	13	19.13	21.28	22.50
7	8	-6.04	-10.12	-11.70
7	9	6.04	10.12	11.70
8	7	6.04	10.12	11.70
9	4	-45.22	-38.90	-37.97
9	7	-5.97	-9.97	-11.51
9	10	7.13	4.83	4.28
9	14	11.55	10.27	10.15
10	9	-7.11	-4.82	-4.27
10	11	-2.81	-5.48	-6.43
11	6	-6.69	-9.53	-10.63
11	10	2.84	5.52	6.47
12	6	-8.11	-8.77	-9.20
12	13	1.38	1.78	1.96
13	6	-18.89	-20.98	-22.16
13	12	-1.38	-1.77	-1.95
13	14	5.38	7.29	8.06
14	9	-11.15	-9.92	-9.82
14	13	-5.27	-7.14	-7.88

Appendix A.2. Reactive power flow 1

Table A.2. Reactive power flow [Mvar].

$Node_i$	$Node_j$	5%	7%	9%
1	2	-17.85	-18.16	-18.41
1	5	0.24	0.54	0.56
2	1	18.50	18.79	19.08
2	3	-4.45	-4.94	-4.99
2	4	-1.02	-0.74	-0.53
2	5	-1.11	-0.67	-0.49
3	2	0.63	1.00	1.06
3	4	1.47	1.99	2.26
4	2	1.15	0.78	0.54
4	3	-4.73	-5.25	-5.52
4	5	1.13	1.46	1.36
4	9	6.74	7.48	8.26
5	1	1.91	1.66	1.55
5	2	0.05	-0.34	-0.59
5	4	-1.56	-2.02	-1.87
5	6	-2.17	-1.13	-0.99
6	5	6.31	6.11	5.38
6	11	6.30	6.03	6.06
6	12	1.26	1.27	1.36
6	13	1.87	2.01	2.29
7	8	-5.23	-7.02	-7.48
7	9	5.23	7.02	7.48
8	7	5.34	7.29	7.83
9	4	-2.76	-2.99	-3.93
9	7	-5.16	-6.85	-7.26
9	10	2.35	3.05	3.41
9	14	-12.74	-12.22	-11.94
10	9	-2.30	-3.02	-3.39
10	11	-4.09	-3.62	-3.51
11	6	-6.13	-5.77	-5.75
11	10	4.14	3.71	3.62
12	6	-1.08	-1.06	-1.13
12	13	-0.68	-0.77	-0.77
13	6	-1.39	-1.41	-1.63
13	12	0.68	0.78	0.78
13	14	-5.69	-6.00	-6.05
14	9	13.58	12.95	12.65
14	13	5.91	6.32	6.41

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Appendix B. Power flows through the network, Case 2

Appendix B.1. Active power flow

Table B1. Active power flow [MW].

$Node_i$	$Node_j$	5%	7%	9%
1	2	104.31	101.82	100.34
1	5	55.69	58.18	59.66
2	1	-102.27	-99.88	-98.45
2	3	36.00	72.00	72.00
2	4	43.29	47.15	50.35
2	5	34.42	38.37	40.96
3	2	-35.19	-70.65	-70.56
3	4	0.04	5.53	8.03
4	2	-42.20	-45.87	-48.88
4	3	0.14	-5.46	-7.91
4	5	-38.64	-38.33	-40.87
4	9	19.70	22.61	24.11
5	1	-54.06	-56.40	-57.79
5	2	-33.76	-37.54	-40.01
5	4	38.86	38.53	41.10
5	6	39.26	44.75	45.00
6	5	-39.26	-44.75	-45.00
6	11	11.50	13.03	15.31
6	12	5.74	6.55	7.41
6	13	7.73	9.46	11.37
7	8	0	0	0
7	9	0	0	0
8	7	0	0	0
9	4	-19.70	-22.61	-24.11
9	7	0.30	0.23	0.30
9	10	4.65	4.77	4.28
9	14	-22.90	-23.76	-25.85
10	9	-4.63	-4.75	-4.26
10	11	-6.86	-7.87	-9.59
11	6	-11.37	-12.84	-15.06
11	10	6.90	7.93	9.68
12	6	-5.70	-6.49	-7.34
12	13	-2.09	-2.06	-2.04
13	6	-7.69	-9.40	-11.28
13	12	2.10	2.08	2.06
13	14	-11.64	-11.61	-11.55
14	9	23.79	24.82	27.13
14	13	12.00	12.00	12.00

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Appendix B.2. Reactive power flow

Table B2. Reactive power flow [Mvar].

$Node_i$	$Node_j$	5%	7%	9%
1	2	-11.33	-9.56	-10.85
1	5	2.86	3.60	4.81
2	1	12.13	10.06	11.18
2	3	19.26	20.94	28.00
2	4	2.11	1.13	3.11
2	5	0.29	0.19	1.85
3	2	-20.03	-23.77	-30.40
3	4	-17.02	-9.60	-11.64
4	2	-2.51	-0.93	-2.34
4	3	14.25	6.50	8.71
4	5	-6.64	-2.82	-3.84
4	9	-0.13	2.72	3.46
5	1	-1.10	-1.20	-1.99
5	2	-1.63	-1.03	-2.31
5	4	6.08	2.24	3.36
5	6	-5.39	-2.26	-1.52
6	5	9.46	7.49	6.84
6	11	3.88	4.96	4.98
6	12	1.44	1.53	1.55
6	13	-0.35	-0.49	-0.91
7	8	-17.64	-15.06	-17.18
7	9	17.64	15.06	17.18
8	7	18.19	15.47	17.72
9	4	2.39	0.30	0.02
9	7	-17.30	-14.81	-16.84
9	10	6.26	6.28	7.50
9	14	-12.54	-15.06	-16.22
10	9	-6.21	-6.23	-7.43
10	11	-1.19	-1.91	-1.49
11	6	-3.59	-4.57	-4.46
11	10	1.29	2.04	1.69
12	6	-1.35	-1.41	-1.40
12	13	-0.69	-0.83	-1.06
13	6	0.43	0.61	1.09
13	12	0.70	0.84	1.07
13	14	-8.53	-9.59	-11.08
14	9	14.44	17.33	18.94
14	13	9.26	10.40	12.00

Abbreviations

AC	Alternating Current
CENS	Cost of Energy Not Supplied
DC	Direct Current
ENS	Energy Not Supplied
GEP	Generation Expansion Planning
GTEP	Generation and Transmission Expansion Planning (Simultaneous or Integrated)
IEEE	Institute of Electrical and Electronics Engineers
MILP	Mixed-Integer Linear Programming
MINLP	Mixed-Integer Nonlinear Programming
OPF	Optimal Power Flow
PS	Power System / Electric Power System
TEP	Transmission Expansion Planning

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