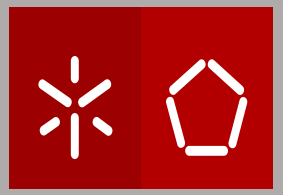


INTERNALISATION OF EXTERNALITIES GENERATION EXPANSION PLANNING

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Internalisation of Externalities in Generation Expansion Planning

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Professor Paula Varandas Ferreira

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Statement of integrity

I hereby declare having conducted this academic work with integrity. I confirm that I have not used plagiarism or any form of undue use of information or falsification of results along the process leading to its elaboration.

I further declare that I have fully acknowledged the Code of Ethical Conduct of the University of Minho.

Internalisation of Externalities in Generation Expansion Planning

Abstract

The increasing complexity of energy transition processes, driven by the need for climate change mitigation and the promotion of social development, has required a profound revision of electricity system planning approaches. In this context, generation expansion planning has evolved beyond a purely techno-economic problem, demanding modelling frameworks capable of systematically integrating environmental externalities, social impacts and regional inequalities. This research proposes the SEGeP (Sustainable Electricity Generation Expansion Planning) model, a mixed-integer linear programming framework designed to internalise environmental and selected social externalities within a unified objective function based on total social cost. The model explicitly incorporates economic, environmental and social dimensions, while accounting for regional heterogeneity and the technical constraints of the electricity system. The model is applied to the Brazilian electricity sector, characterised by continental scale, high renewable penetration, vulnerability to climate variability and the availability of consistent institutional datasets. A set of long-term prospective scenarios aligned with the Sustainable Development Goals is developed to assess the impacts of different planning strategies. The results demonstrate that optimisation based exclusively on economic criteria leads to expansion pathways misaligned with decarbonisation targets, climate resilience and territorial equity. In contrast, the internalisation of externalities through a total social cost approach produces solutions that are environmentally more coherent and promote a more balanced regional allocation of investments. The proposed framework contributes to the literature by providing a structured methodology for operationalising sustainability principles within energy planning models through the integration of measurable and monetisable indicators aligned with the SDGs. It also offers relevant insights for policymakers by supporting decision-making processes aimed at achieving more resilient, equitable and sustainable electricity systems.

Keywords: Energy sustainability; Generation expansion planning; Mixed-integer linear programming (MILP); Socio-environmental externalities; Total social cost.

Internalização de Externalidades do Planejamento de Expansão da Geração

Resumo

A crescente complexidade dos processos de transição energética, associada às exigências de mitigação das alterações climáticas e de promoção do desenvolvimento social, tem conduzido a uma revisão profunda das estratégias de planeamento dos sistemas elétricos. Neste contexto, a expansão da geração de eletricidade deixou de ser um problema estritamente técnico-económico, passando a exigir abordagens capazes de integrar, de forma consistente, impactos ambientais, efeitos sociais e desigualdades territoriais. No seu conjunto, esta investigação fornece contributos relevantes para a compreensão de como a internalização sistemática de externalidades sociais e ambientais pode alterar estruturalmente as trajetórias ótimas de expansão da geração de eletricidade. Este modelo permite integrar, numa função objetivo única orientada para o custo social total, componentes económicas, ambientais e sociais, bem como representar explicitamente a heterogeneidade regional e as restrições técnicas do sistema elétrico. Os objetivos do estudo são aplicados ao caso do setor elétrico brasileiro, sendo esta escolha justificada sobretudo pela sua dimensão continental, pelo elevado peso das fontes renováveis na matriz elétrica, pela vulnerabilidade do sistema à variabilidade climática e pela disponibilidade de bases de dados institucionais consistentes. Neste contexto, é proposto o modelo SEGeP, concebido com o objetivo principal de apoiar a construção e avaliação de cenários prospetivos de longo prazo alinhados com os Objetivos de Desenvolvimento Sustentável. Os resultados evidenciam que soluções obtidas exclusivamente a partir de critérios económicos tendem a gerar trajetórias incompatíveis com metas de descarbonização, resiliência climática e equidade territorial. Em contraste, os cenários orientados pelo custo social total revelam uma maior coerência ambiental e uma redistribuição regional mais equilibrada dos investimentos. A modelação proposta tem como objetivo apoiar a tomada de decisão estratégica em sistemas elétricos caracterizados por elevada complexidade e múltiplos objetivos. Para além do caso analisado, esta investigação oferece contributos para a comunidade científica ao demonstrar a viabilidade metodológica de integrar referenciais normativos de sustentabilidade em estruturas matemáticas operacionais de planeamento energético, reforçando a importância de abordagens baseadas no custo social total para a construção de trajetórias de transição energética mais justas, resilientes e sustentáveis.

Palavras-chave: Custo social total; Externalidades socioambientais; Planeamento da expansão da geração elétrica; Programação linear inteira mista; Sustentabilidade energética.

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List of Acronyms

ANA – Agência Nacional de Águas e Saneamento Básico

ANEEL – Agência Nacional de Energia Elétrica

BAU – Business-as-Usual

CAPEX – Capital Expenditure

CO_2 – Carbon Dioxide

DSI – Decarbonisation and Social Inclusion

EO – Economic Optimisation

EPE – Empresa de Pesquisa Energética

ES – Energy Stress Scenario

GAMS – General Algebraic Modelling System

GWh – Gigawatt-hour

HRP – High Renewable Penetration

IBGE – Instituto Brasileiro de Geografia e Estatística

IEA – International Energy Agency

IIASA – International Institute for Applied Systems Analysis

ILO – International Labour Organisation

IPCC – Intergovernmental Panel on Climate Change

IRENA – International Renewable Energy Agency

LCE – Low Carbon Emissions

LCOE – Levelised Cost of Energy

LP – Linear Programming

LRI – Low Regulatory Interference

MEC – Maximum Employment Creation

MESSAGE – Model for Energy Supply Strategy Alternatives and their General Environmental Impact

MILP – Mixed-Integer Linear Programming

MINLP – Mixed-Integer Nonlinear Programming

MWh – Megawatt-hour

MW – Megawatt

NLP – Nonlinear Programming

NO_x – Nitrogen Oxides

OECD – Organisation for Economic Co-operation and Development

ONS – Operador Nacional do Sistema Elétrico

OPF – Optimal Power Flow

OPEX – Operational Expenditure

PDE – Plano Decenal de Expansão de Energia

PNE – Plano Nacional de Energia

SDDP – Stochastic Dual Dynamic Programming

SDG / SDGs – Sustainable Development Goal(s)

SEGeP – Sustainable Electricity Generation Expansion Planning

SIN – Sistema Interligado Nacional

SMR(s) – Small Modular Reactor(s)

SO_2 – Sulphur Dioxide

tCO_2 – tonne of Carbon Dioxide

TWh – Terawatt-hour

UC – Unit Commitment

UN – United Nations

UNDP – United Nations Development Programme

USEPA – United States Environmental Protection Agency

WSC – Water Scarcity Constraints

CHAPTER 1 - INTRODUCTION

The planning of electricity generation expansion plays a central role in sustainable development strategies, particularly in countries characterised by vast territorial dimensions, pronounced socioeconomic heterogeneity, and significant diversity of energy resources, such as Brazil. The growing complexity of contemporary energy transitions — characterised by the simultaneous need to ensure energy security, reduce greenhouse gas emissions, promote social inclusion and maintain economic competitiveness— has exposed the limitations of approaches based exclusively on the minimisation of private costs. In this context, it becomes essential to incorporate socio-environmental dimensions into decision-making in a structured and quantitative manner, thereby guiding expansion pathways that reflect not only economic criteria but also commitments to robust sustainability principles (IEA, 2021; IPCC, 2022a; Sovacool et al., 2021).

This centrality stems from the capital-intensive, path-dependent, and largely irreversible nature of generation investment decisions, which tend to lock power systems into specific technological, environmental and institutional trajectories over several decades, thereby amplifying the long-term consequences of planning choices.

Although optimisation models have historically played a central role in energy planning, the literature consistently indicates that such models remain heavily anchored in strictly economic metrics, resulting in an incomplete representation of the total cost associated with electricity system expansion (Sovacool et al., 2021; Rafaj & Kypreos, 2007). This limitation recurs in both vertically integrated systems and competitive markets, constituting a global pattern. In countries with territorial and socioeconomic characteristics similar to those of Brazil—such as India, South Africa and Indonesia—the lack of rigorous integration of externalities has led to long-term decisions misaligned with climate objectives and social development needs (UNDP, 2024; Allen et al., 2019).

From the perspective of welfare economics, such approaches systematically overlook market failures associated with environmental and social externalities, leading to outcomes that may be privately cost-efficient but socially suboptimal (Turvey, 1968; Anderson, 1972; Sovacool et al., 2021).

In Brazil, the planning of generation expansion is carried out primarily through official instruments developed by the Energy Research Office (EPE), notably the Ten-Year Energy Expansion Plan (PDE) and the National Energy Plan (PNE). These documents employ well-established methodologies based on demand projections, hydrological simulations, techno-economic assessments of different technologies, reliability analyses and dispatch modelling. They are widely recognised as technical references for renewable-energy-intensive power systems (EPE, 2021a; EPE, 2023a). However, both governmental institutions and the

academic literature acknowledge persistent limitations: environmental externalities are incorporated only partially—often restricted to CO_2 emissions—and social impacts are considered only sporadically or qualitatively, hindering the full integration of sustainability principles into expansion planning (EPE, 2021b; Brazil, 2024).

Since its creation, the Energy Research Office (EPE) has played a central institutional role in structuring Brazil's long-term energy planning process, providing technical support for strategic decisions and serving as a reference for both public policy formulation and private-sector investment.

Such limitations become particularly critical considering Brazil's strong dependence on hydropower. Shifts in precipitation regimes and the intensification of extreme hydrological events have exposed structural vulnerabilities and increased risks to energy security (*Agência Nacional de Águas e Saneamento Básico* [ANA], 2021; Marengo et al., 2020). At the same time, the rapid expansion of wind and solar power—technologies whose availability is highly sensitive to climatic and geographical variability—reinforces the need for models capable of capturing regional complementarities, temporal variability and the differentiated socio-environmental impacts of these sources (IRENA, 2022; BloombergNEF, 2023).

As a result, Brazilian electricity planning faces a clear inflection point: it must either maintain methodologies centred on economic cost or evolve towards approaches that systematically internalise environmental dimensions while incorporating selected social indicators, in alignment with contemporary sustainability requirements. Historically, hydropower has served as the backbone of the Brazilian electricity system, shaping both its low-carbon profile and its exposure to hydrological variability.

It is within this context that the United Nations 2030 Agenda and the Sustainable Development Goals (SDGs) acquire strategic relevance. The SDGs are not merely a set of global goals; they constitute a comprehensive and cross-cutting normative framework that guides public policies, investments and institutional practices across multiple countries (Sachs et al., 2019).

As the 2030 horizon approaches, the scientific and political relevance of this agenda is further reinforced, given that most targets remain distant from being achieved and that, even beyond 2030, evolving frameworks grounded in the same principles are likely to be adopted (UNDP, 2024; OECD, 2022). Thus, using the SDGs as a methodological reference for energy planning means recognizing that sustainability is a dynamic and continuous process that requires comparable, validated and internationally adopted metrics. The SDGs offer a unique advantage as methodological reference, as they combine political legitimacy, international comparability and an explicit articulation of environmental, social and economic dimensions within a single normative framework.

Despite this relevance, the literature still indicates a limited integration of the SDGs into formal mathematical energy planning models. While numerous studies employ the SDGs conceptually, only a few translate them into measurable indicators capable of informing optimisation frameworks (Nerini et al., 2018; McCollum et al., 2018; Sovacool et al., 2017). This methodological gap constrains the ability of models to fully capture the role of socio-environmental externalities and, consequently, limits the adequacy of the expansion trajectories they propose. It therefore becomes essential to develop methodologies capable of identifying social and environmental indicators aligned with the SDGs, quantifying and monetizing them, and integrating them explicitly into the mathematical logic of planning models. This distinction between conceptual alignment and operational integration is critical, as only the latter allows sustainability considerations to directly influence optimisation outcomes and policy-relevant decisions.

Thus, a fundamental methodological gap persists in literature. Existing energy planning models generally address socio-environmental externalities through partial approaches, either by incorporating selected environmental costs (primarily CO_2 emissions), treating social indicators as exogenous constraints, or applying multi-criteria frameworks that do not structurally integrate these dimensions into the core of optimisation.

The simultaneous integration of (i) monetized environmental and social externalities, (ii) regional heterogeneity, and (iii) a unified optimisation framework based on total social cost remains underdeveloped and lacks methodological standardization. This limitation restricts the ability of existing models to produce economically efficient expansion trajectories aligned with broader sustainability goals.

The main research gap addressed in this thesis lies in the lack of a consistent, unified, and SDG-aligned mathematically structured framework capable of systematically integrating monetized environmental externalities and selected social indicators within a unified total social cost optimisation framework, while complementing the analysis with distributive social metrics evaluated from model outputs.

This planning framework will be operationalized through an optimisation model, the SEGeP – Sustainable Electricity Generation Expansion model — designed to internalise externalities, capture regional specificities and simulate multiple prospective scenarios up to 2050. The conception of this model is not an end in itself; rather, it constitutes a structured methodological instrument intended to support long-term decisions compatible with robust sustainability, systemic resilience and social equity. The central scientific challenge addressed in this thesis lies in bridging the gap between sustainability-oriented normative frameworks and the formal mathematical structures used in electricity generation expansion planning.

By doing so, it fills a critical gap in both the literature and Brazilian planning instruments, reinforcing the urgency of integrating socio-environmental dimensions into expansion modelling and providing inputs for strategic decisions that will shape the country's energy future.

1.1. Research Problem

The formulation of the research problem arises from the observation that, although Brazil possesses consolidated energy planning instruments—such as the Ten-Year Energy Expansion Plan (PDE) and the National Energy Plan (PNE)—their methodological foundations remain predominantly oriented towards techno-economic criteria, with limited integration of socio-environmental indicators capable of guiding generation expansion according to principles of robust sustainability. The literature indicates that assessments focused exclusively on minimizing private costs fail to adequately capture environmental externalities, differentiated territorial effects and social inequalities associated with the transformation of the electricity matrix (Sovacool et al., 2021). This limitation constrains the ability of current models to support decisions compatible with a just and resilient energy transition and with national and international development commitments.

The research problem addressed in this thesis can be formally defined as the lack of a consistent, unified, and SDG-aligned mathematically structured framework for electricity generation expansion planning capable of systematically integrating socio-environmental externalities into the optimisation process. Existing models remain predominantly grounded in techno-economic formulations, where environmental impacts are only partially monetised and social effects are either excluded or treated as exogenous constraints, resulting in expansion pathways that are not fully aligned with the principles of robust sustainability.

In the Brazilian context, this methodological limitation becomes even more significant due to pronounced regional asymmetries, reliance on hydrological resources vulnerable to climatic variability and the rapid technological diversification driven by wind and solar power. Under such conditions, generation expansion—when not subjected to rigorous socio-environmental assessment—may reinforce pre-existing inequalities, generate localized environmental impacts and compromise regional energy security (EPE, 2023a; Marengo et al., 2020). The absence of a structured method for identifying, quantifying and integrating sustainability indicators thus limits both the analytical potential of planning models and the effectiveness of national energy policies.

Within this framework, the Sustainable Development Goals (SDGs) provide an essential normative reference by offering comparable global targets, harmonized indicators and internationally recognised principles for public policy design. However, despite their relevance, the specialized literature shows that the SDGs have been employed predominantly as conceptual guidance rather than as quantitative elements incorporated into the core of mathematical energy planning models (Nerini et al., 2018; Sachs et al., 2019). The approaching 2030 horizon reinforces the need for approaches capable of translating the SDGs into measurable indicators that can be operationalized within optimisation models (OECD, 2022; UNDP, 2024).

The systematic review conducted by Costa and Ferreira (2023) shows that, although several generation expansion planning models already internalise environmental costs—primarily CO_2 emissions and, in more advanced cases, health damages and climate-related costs—the explicit and systematic internalisation of social externalities remains incipient. Models that incorporate indicators such as employment, regional development or social inclusion generally treat them as separate objectives or multicriteria decision-support elements, rather than as monetized components integrated into a unified total social cost objective function.

Given this state of the art, there is a clear need to develop a generation expansion planning model that:

(i) employs an optimisation formulation;

(ii) internalises, through monetary valuation, a broad set of environmental and social externalities;

(iii) aggregates these effects into a single objective function representing the total social cost of electricity generation;

(iv) incorporates the regional disaggregation of the Brazilian power system; and

(v) explicitly aligns the selection of sustainability indicators with the 2030 SDG framework.

Table 1.1 summarizes the relationship between the main sustainability dimensions and the SDGs most relevant to the electricity sector, highlighting their potential to guide the construction of measurable and internationally aligned indicators for sustainable energy planning.

Table 1.1 - Relationship between sustainability dimensions and SDGs relevant to the electricity sector.

Sustainability dimension	Associated SDGs	Main focus in the energy–electricity context
Environmental	SDG 6 – Clean Water and Sanitation	Water resources, water quality and competing uses in basins with significant hydropower presence.
	SDG 7 – Affordable and Clean Energy	Renewable expansion, energy efficiency and reduction of environmental impacts.
	SDG 13 – Climate Action	Mitigation of GHG emissions and alignment with global climate targets.
	SDG 14 – Life Below Water	Impacts of generation on aquatic ecosystems and reservoirs.
	SDG 15 – Life on Land	Land occupation, habitat loss and biodiversity impacts.
Social	SDG 1 – No Poverty	Reduction of energy poverty and access to modern energy services.
	SDG 3 – Good Health and Well-Being	Pollution-related impacts and other externalities affecting exposed populations.
	SDG 8 – Decent Work and Economic Growth	Job creation, development of local skills and industrial strengthening.
	SDG 10 – Reduced Inequalities	Equitable distribution of regional benefits and impacts.
	SDG 11 – Sustainable Cities and Communities	Adequate energy infrastructure and supply security.
Economic	SDG 7 – Affordable and Clean Energy	Tariff affordability and economic competitiveness.
	SDG 8 – Decent Work and Economic Growth	Economic activity is induced by energy infrastructure expansion.
	SDG 9 – Industry, Innovation and Infrastructure	Technological modernization and infrastructure resilience.
	SDG 12 – Responsible Consumption and Production	Efficiency, demand management and loss reduction.

Source: Author's elaboration.

The mapping presented in Table 1.1 indicates how the Sustainable Development Goals can be systematically translated into sustainability dimensions relevant to the electricity sector, providing a structured basis for the identification, selection and operationalization of measurable indicators within the proposed planning framework.

The research problem is grounded in the need to design a mathematical model that systematically and monetarily integrates socio-environmental indicators aligned with the SDGs, incorporates Brazilian regional heterogeneity and enables the evaluation of generation expansion based on the total social cost of energy. Addressing this challenge is essential for supporting decisions consistent with robust sustainability, territorial equity and a just energy transition.

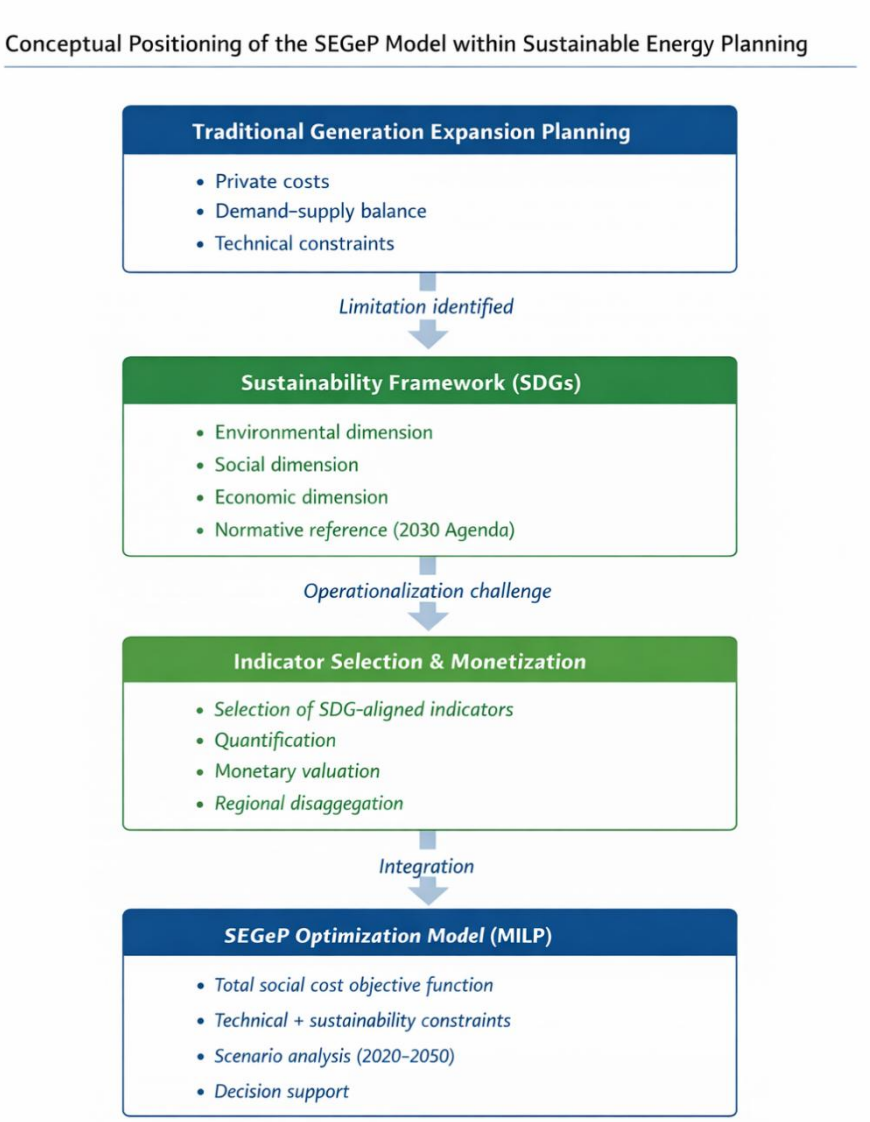


Figure 1.1 - Conceptual positioning of the SEGeP model within sustainable electricity generation expansion planning.
Source: Author's elaboration.

Figure 1.1 illustrates the logical and methodological progression from traditional generation expansion planning approaches—predominantly focused on private costs, demand–supply balance and technical constraints—to a sustainability-oriented framework grounded in the Sustainable Development Goals (SDGs). It highlights the operationalization challenge associated with translating normative sustainability dimensions into measurable indicators and their subsequent quantification and monetary valuation. This process enables the integration of social, environmental and economic externalities into the SEGeP optimisation model, formulated as a mixed-integer linear programming (MILP) problem, which minimizes total social cost under technical and sustainability constraints and supports long-term decision-making through scenario analysis up to 2050. This integration is operationalized through the monetization of selected indicators combined with constraint-based representations, forming a hybrid optimisation structure.

1.2. Research Questions

In view of the research problem outlined, it is necessary to identify the questions that will guide the methodological construction of the investigation, ensuring coherence between the diagnostic stage, the analytical structure and the overarching aim of the study. Considering that this thesis is devoted to developing a sustainable planning framework for electricity generation expansion in Brazil, grounded in indicators aligned with the SDGs, the research questions must reflect the theoretical and operational challenges inherent in identifying, measuring and integrating these dimensions into the decision-making process.

Within this context, the first question concerns the need to understand which social and environmental indicators are relevant, comparable, methodologically consistent and supported by robust data sources in the Brazilian context. The diversity of indicators employed in both national policies and international studies demands rigorous selection criteria, particularly regarding measurability, data availability, alignment with the SDGs and applicability to energy planning (Allen et al., 2019). The first question is therefore formulated as follows:

(Q1) Which social and environmental indicators, aligned with the SDGs, are appropriate, measurable and methodologically consistent to guide the sustainable planning of electricity generation expansion in Brazil?

Once the indicators are identified, it becomes necessary to define methods that allow them to be quantified and monetized, enabling their integration into an optimisation structure. The literature presents a wide variety of valuation techniques, including damage-cost approaches, external cost methods, willingness-to-pay models and hybrid approaches (Sovacool et al., 2021; OECD, 2022). However, these methods differ significantly in terms of data requirements, analytical scales and compatibility with mathematical models. Thus, the second research question is:

(Q2) Which quantification and monetary valuation methods can be applied to represent, in an economically coherent manner, the sustainability indicators selected for energy planning?

In addition to the selection and valuation of indicators, it is necessary to understand how these elements can be explicitly, transparently and methodologically robustly incorporated into the structure of an optimisation model. Most existing studies use socio-environmental indicators as parallel criteria or additional constraints, without fully internalizing them in the core decision-making structure (Peças et al., 2023; Costa & Ferreira, 2023). This observation motivates the third research question:

(Q3) How can monetized sustainability indicators be integrated into the structure of an optimisation model that supports decision-making in electricity generation expansion planning?

Given Brazil's pronounced regional inequalities, it is essential for the planning framework to incorporate territorial, social, environmental and energy-specific differences. Expansion decisions based exclusively on national aggregates may conceal the unequal regional distribution of investments, employment opportunities and socio-environmental burdens (Carley & Konisky, 2020; Nascimento Filho et al., 2022; Sovacool et al., 2021). The fourth question is therefore:

(Q4) How can regional disaggregation be incorporated into the planning model in order to reflect the socio-environmental and energy characteristics of the Brazilian territory?

Finally, because energy planning involves long time horizons and multiple sources of uncertainty, it is fundamental to assess how different prospective scenarios—technological, socioeconomic, climatic and regulatory—affect optimal decisions. Thus, the fifth question is:

(Q5) How do different prospective scenarios up to 2050 affect the sustainable trajectory of electricity generation expansion obtained through the proposed model?

Taken together, these research questions form a coherent analytical sequence, progressing from indicator identification and valuation to model formulation, regional representation and scenario-based assessment of long-term sustainability trade-offs.

1.3. General Objective

The general objective of this investigation is to develop a sustainable planning framework for the expansion of electricity generation in Brazil, grounded in the systematic integration of social, environmental and economic indicators aligned with the Sustainable Development Goals (SDGs), and operationalized through an optimisation model capable of internalizing externalities and capturing regional specificities. This planning framework aims to support long-term decision-making consistent with the principles of robust sustainability, systemic resilience and socio-environmental justice, addressing the contemporary challenges of the Brazilian energy transition.

By proposing the SEGeP model as the central methodological instrument, this objective seeks to overcome the limitations of existing planning models—predominantly guided by techno-economic criteria—and to offer an approach that incorporates metrics aligned with the global Sustainable Development Goals. The use of the SDGs as a structuring reference enables the consolidation of an energy planning framework based on validated, comparable and internationally recognised indicators, thereby reinforcing both the scientific legitimacy and practical relevance of the resulting decisions.

Under these conditions, the absence of a systematic socio-environmental assessment framework increases the risk that expansion decisions reinforce spatial inequalities, generate localized negative externalities and undermine the resilience of regional electricity supply systems.

1.4. Specific Objectives

The formulation of the specific objectives derives directly from the general objective and the research questions, outlining the analytical and methodological pathway required to develop a sustainable planning framework for electricity generation expansion in Brazil. These objectives correspond to sequential stages that enable the identification, operationalization and integration of sustainability indicators into the mathematical structure of the model, culminating in the formulation of a robust national planning proposal. The specific objectives are as follows:

(SO1) Identify social and environmental indicators aligned with the SDGs, assessing their relevance, measurability and data availability within the Brazilian context.

(SO2) Define methodological criteria for selecting the most appropriate indicators, considering their capacity to represent, in a comparable way, the social and environmental impacts associated with electricity generation expansion.

(SO3) Develop quantification and monetary valuation methods for the selected indicators, based on established scientific approaches, enabling their conversion into economic parameters compatible with energy-planning optimisation.

(SO4) Formulate the SEGeP optimisation model, integrating monetized indicators into the economic, environmental and social dimensions of the model, while incorporating the technical constraints of the electricity system.

(SO5) Introduce regional disaggregation into the model, representing the territorial, socio-economic, environmental and energy-specific characteristics of different Brazilian regions and enabling the assessment of differentiated impacts of generation expansion.

(SO6) Simulate multiple prospective scenarios up to 2050—including high renewable penetration, hydrological stress, accelerated decarbonisation, social inclusion, energy stress, and economic optimisation—and analyse their effects on the sustainable trajectory of the electricity matrix.

(SO7) Derive, from the model's results, policy-relevant insights and strategic guidelines for sustainable electricity generation expansion in Brazil, incorporating the SDGs as a structuring reference and supporting decision-making processes.

1.5. Contributions of the Thesis

The contributions of this thesis arise from the development of an innovative methodological approach for sustainable planning of electricity generation expansion in Brazil, integrating principles of the 2030 Agenda, foundations of mathematical modelling and the territorial specificities of the national energy system. The contributions of this thesis can be structured into four main dimensions:

(i) Theoretical contribution: This research advances the literature by establishing a structured conceptual linkage between sustainability-oriented normative frameworks—particularly the Sustainable Development Goals—and formal energy planning models, moving beyond conceptual alignment towards operational integration.

(ii) Methodological contribution: The thesis proposes the SEGeP model, a mixed-integer linear programming framework that internalises environmental externalities and incorporates selected social dimensions through monetised and derived indicators within a unified total social cost objective function, while explicitly incorporating regional disaggregation.

(iii) Empirical contribution: The application of the model to the Brazilian electricity system provides a consistent set of long-term scenarios, demonstrating how the internalisation of externalities alters optimal expansion pathways and redistributes impacts across regions.

(iv) Policy contribution: The proposed framework offers a structured analytical basis to support energy planning decisions aligned with sustainability principles, providing insights relevant to policymakers, regulatory institutions and long-term strategic planning.

1.6. Structure of the Thesis

This thesis is organised to ensure a logical, progressive and coherent trajectory between the conceptual foundations, the methodological development and the formulation of a sustainable planning framework for electricity generation expansion in Brazil. Each chapter has been structured to address the research questions, articulating theoretical concepts, analytical procedures and empirical results that collectively support the final proposal presented.

Chapter 1 establishes the overall framework of the investigation. It introduces the scientific and political context of Brazilian energy planning, the limitations of existing instruments, the relevance of the Sustainable Development Goals (SDGs) as a guiding framework, the research problem and the questions that orient the thesis. It also presents the general and specific objectives and the expected contributions, providing a clear understanding of the purpose and scope of the work.

Chapter 2 presents the literature review, organised into five main axes: (i) foundations and evolution of electricity generation expansion planning; (ii) mathematical methodologies applied to energy planning; (iii) instruments and practices adopted in Brazil, particularly the PDE and PNE; (iv) international approaches to incorporating socio-environmental externalities; and (v) opportunities and challenges associated with integrating the SDGs into energy modelling processes. This review identifies existing gaps, consolidates the theoretical framework and guides the formulation of the methodological proposal.

Chapter 3 outlines the conceptual and methodological framework of the thesis, detailing the criteria used to select social and environmental indicators, the procedures for their quantification and monetization, the logical foundations for integrating these indicators and the principles guiding the construction of the SEGeP model. This chapter provides the conceptual basis that supports the model's development, linking theoretical requirements with the practical operationalization required for sustainable planning.

Chapter 4 presents the construction of the mathematical model, describing its structure, variables, parameters, constraints and objective function. It discusses the theoretical foundations that justify the proposed formulation, as well as the methodological choices adopted in response to the characteristics of the Brazilian electricity system. This chapter constitutes the analytical core of the thesis, in which the SEGeP model is formalized as a tool capable of internalizing externalities and representing the multidimensional sustainability of generation expansion.

Chapter 5 is dedicated to the application of the model, presenting the database used, the regional characterization, the prospective scenarios simulated and the analysis of the results. This chapter demonstrates the model's capacity to guide long-term decisions, evaluate trade-offs between economic, environmental and social dimensions and identify trajectories compatible with the principles of sustainable planning.

Chapter 6 presents a critical discussion of the results and their implications. It synthesises the main findings and policy-relevant insights for Brazilian energy planning, highlighting how SDG-aligned indicators influence expansion decisions and how the model contributes to a more equitable, resilient, and environmentally responsible approach. This chapter translates the analytical results into structured guidance for the development of the national electricity system.

Chapter 7 brings together the concluding remarks, discussing the main scientific, methodological and practical contributions of the thesis, as well as its limitations and directions for future research. It reaffirms the relevance of sustainable planning as an essential pathway for Brazil's energy transition and for aligning the electricity sector with international sustainability targets.

CHAPTER 2 - LITERATURE REVIEW

Research on energy planning has, over recent decades, consolidated a theoretical body that combines elements from economics, engineering, environmental science, and public policy. The diversity of approaches reflects the evolution of the electricity sector, which has progressively moved beyond a strictly techno-economic perspective to incorporate environmental, social and institutional dimensions, each influencing how systems are designed, operated and expanded. This chapter critically examines this trajectory, identifying the conceptual foundations that structure the field, the analytical models that support generation expansion planning and the contemporary approaches that seek to integrate sustainability, resilience and territorial equity.

The chapter is organised according to an evolutionary logic. It begins with the historical and conceptual development of electricity generation expansion planning, highlighting scientific and institutional milestones that have shaped the discipline. It then discusses the mathematical models that underpin the quantitative representation of energy systems, ranging from classical formulations to more recent structures based on multiobjective optimisation and integrated modelling. The analysis subsequently turns to the Brazilian experience, with emphasis on official planning instruments, their potential and their limitations, particularly regarding the integration of externalities. The following sections deepen the environmental and social dimensions of generation expansion, drawing on consolidated literature and empirical evidence to illustrate the associated impacts and challenges. The chapter examines the Sustainable Development Goals as both a normative and an analytical framework, considering their contributions as well as the challenges inherent to their operationalization in quantitative models.

The systematic review of these elements provides the conceptual basis required to support the methodological proposal developed in the thesis. Furthermore, it positions the investigation within the contemporary debate on energy transition and sustainable development, identifying gaps that justify the construction of a planning model capable of explicitly integrating economic, environmental and social dimensions.

2.1. Generation Expansion Planning: Conceptual Evolution

Generation expansion planning emerged as an analytical discipline as electricity systems expanded in scale, interconnection and complexity, particularly between the 1950s and 1960s, when large integrated networks began to require systematic methods to support decision-making. Early models reflected the characteristics of these systems: relatively stable networks, predictable economic growth and strong state

involvement. In this context, classical studies such as Bessière and Massé (1964) and Turvey (1968) explored minimum-cost formulations within essentially deterministic horizons, based on the assumption that key system variables were sufficiently stable to allow for almost mechanical expansion decisions.

The oil crisis disrupted this paradigm. The sudden price volatility and the recognition that energy systems were vulnerable to profound macroeconomic shocks shifted planning towards a context in which predictability could no longer be assumed. Studies by Crew and Kleindorfer (1976) and Manne (1979) began treating expansion as an intertemporal and scenario-dependent problem, incorporating structural uncertainties affecting both demand and supply costs. At this stage, the analytical focus shifted: no longer assuming stability became as essential as representing long-term rationality.

A decisive advance occurred when uncertainty ceased to be treated as an external sensitivity exercise and became an intrinsic element of mathematical formulation. The proposal of Pereira and Pinto (1991), through the development of SDDP, transformed the field. Hydropower-thermal systems—particularly sensitive to hydrological variability—came to be modelled with explicit stochastic structures. Later contributions synthesized by Conejo et al. (2010) expanded this framework by incorporating hydrological fluctuations, market instabilities and demand uncertainty, consolidating a paradigm shift: planning now required navigating mathematically structured uncertainty.

The liberalization reforms of the 1990s added yet another layer of complexity. The separation of generation, transmission and distribution, the emergence of competitive markets and the proliferation of economic agents required models capable of representing incentives, risks and strategic behaviour. Analyses by Joskow (1997) and Newbery (1998) illustrate this institutional shift, in which planning ceased to rely exclusively on centralised decisions and began interacting with markets shaped by prices, regulation and competition.

The strengthening of the environmental agenda, driven by the early IPCC reports (1990; 1996), further expanded the scope of modelling. Expansion decisions could no longer be analysed solely through cost and reliability metrics: greenhouse gas emissions and impacts on natural resources became fundamental in determining optimal generation mixes. Studies such as Rafaj and Kypreos (2007) and IPCC (2014) demonstrated that long-term technological viability requires reconciling economic efficiency with environmental commitments, introducing new sets of constraints that reshaped expansion pathways.

From the 2000s onwards, multiobjective models gained prominence as a natural response to the growing number of relevant criteria. The influential work of Pohekar and Ramachandran (2004) opened space for analyses integrating costs, emissions and operational performance, while studies by Antunes et al. (2013) and Mutingi et al. (2017) showed that expansion can only be fully understood through efficient trade-off

frontiers. In parallel, integrated frameworks such as MESSAGE-GLOBIOM (IIASA, 2020), together with the modelling approaches reviewed by Pfenninger et al. (2014), strengthened the capacity of long-term energy models to align energy policies, climate goals and investment decisions.

The accelerated diffusion of wind and solar energy, particularly after 2010, introduced unprecedented challenges. The intrinsic variability of these sources reshaped traditional planning and operational logic, requiring models with high temporal granularity and detailed spatial representation. Studies by Hirth (2013), Lund et al. (2015), Jenkins et al. (2018) and Sepulveda et al. (2018) demonstrated that renewable-based electricity systems demand new flexibility mechanisms, storage strategies and rigorous assessment of regional complementarities.

In recent years, the social dimension has increased to growing centrality. Literature reviewed by Carley and Konisky (2020) shows that expansion decisions generate wide-ranging territorial effects, shaping economic opportunities, vulnerabilities and regional inequalities. Sovacool et al. (2021) deepen this perspective by arguing that energy justice—distribution of benefits, risks and social inclusion—must be treated as a structural component of planning. Recent IPCC reports (2022a, 2022b) reinforce this trend by highlighting that electricity systems already operate under increasing climatic and social risks.

The 2030 Agenda elevates this debate to a global scale, articulating environmental, social and economic dimensions under a unified normative framework. Literature by Nerini et al. (2018), McCollum et al. (2018) and Sachs et al. (2023) show that integrating energy and SDGs is not merely desirable; it is essential for ensuring coherence between national policies and international commitments. However, Griggs et al. (2013) and Allen et al. (2019) note that methodological maturity is still insufficient for fully translating the SDGs into mathematically integrable variables within expansion models.

The recent evolution of generation expansion planning therefore reveals a clear conceptual and methodological trajectory: from deterministic minimum-cost models to probabilistic formulations; from these to Mult objective approaches; and finally, to structures that must incorporate environmental impacts, social inequalities and international sustainability goals. Generation expansion has thus become a multidimensional field requiring tools capable of integrating heterogeneous criteria without compromising rigour, consistency or predictive capability.

The detailed mathematical foundations and modelling families underpinning these developments are reviewed in Section 2.2.

2.2. Mathematical Models Applied to Energy Planning

Mathematical modelling applied to energy planning has, over recent decades, become a central instrument for understanding, evaluating and designing expansion trajectories in increasingly complex electricity systems. The evolution of these models mirrors the structural transformation of the energy sector, which transitioned from vertically integrated and predictable arrangements to liberalized structures exposed to significant uncertainty and subject to increasingly stringent environmental and social commitments. By formalizing energy systems in terms of variables, parameters, constraints and objective functions, mathematical models not only describe reality but also shape how the energy future is conceptualized and which dimensions are prioritized in decision-making (Loulou & Labriet, 2008; Pfenninger et al., 2014).

Early long-term planning formulations relied predominantly on Linear Programming (LP) and Nonlinear Programming (NLP), structuring the problem as the minimisation of total investment and operating costs subject to energy balance constraints, installed capacity limits and demand satisfaction. These models, suitable for centralised institutional contexts and technologically simpler systems, became the foundation of the first official energy-planning approaches in several countries (Turvey, 1968; Stoft, 2002). LP offered transparent and analytically robust representations of average generation costs, physical limits and simplified transmission networks.

As technological diversity increased and the need to represent discrete decisions became evident—such as whether to build new plants, reinforce transmission or install storage—strictly linear models proved insufficient. Mixed-Integer Linear Programming (MILP) emerged as a natural extension, combining binary investment variables with continuous operational variables. This approach proved effective in capturing fixed costs, technological characteristics, operational constraints and sequential investment decisions (Floudas, 1995; Muñoz & Perpiñán, 2016). For problems involving intrinsically nonlinear relationships—efficiency curves, battery degradation or cost functions dependent on operating levels—Mixed-Integer Nonlinear Programming (MINLP) expanded analytical capabilities, albeit with greater computational complexity (Nolan & O'Malley, 2015).

Recognition that electricity systems are inherently exposed to uncertainties—hydrological conditions, fuel-price volatility, demand variability and macroeconomic oscillations—drove the advancement of stochastic models. The development of Stochastic Dual Dynamic Programming (SDDP) by Pereira and Pinto (1991) is a seminal milestone, enabling the representation of hydrological series and intertemporal decisions under uncertainty in large hydrothermal systems. Subsequent contributions by Conejo et al. (2010) and Shapiro et al. (2014) systematized two- and multistage Stochastic Programming approaches, demonstrating that

probabilistic formulations yield more robust decisions consistent with the structural variability of energy systems.

In contexts where probability distributions are uncertain or difficult to estimate, Robust Optimisation gained prominence. The approaches of Bertsimas and Sim (2004) and Ben-Tal et al. (2009) seek solutions that remain feasible under adverse perturbations of critical parameters such as demand, renewable availability or fuel costs. In energy planning, robust models have been used to capture impacts of extreme climatic events, market volatility and regulatory uncertainty, offering solutions that are more resilient over long-term horizons (Zhang et al., 2007).

As models became more detailed, covering multiple technologies, regions, and fine temporal resolution—computational limitations emerged. In this context, heuristics and metaheuristics began to complement exact methods. Genetic Algorithms, Particle Swarm Optimisation, Ant Colony Optimisation and Simulated Annealing have been widely used to explore large solution spaces, providing high-quality approximations within acceptable computational time (Deb, 2001; Antunes et al., 2013). In formulations with multiple objectives, complex nonlinearities and strong coupling between operation and investment, hybrid approaches combine global search through heuristics with local refinement using MILP (Koltsaklis & Nazos, 2017).

The intrinsically multicriteria nature of expansion decisions—encompassing economic costs, emissions, water use, biodiversity impacts, employment, supply security and social acceptance—reinforced the role of multiobjective models and multicriteria decision-making methods. Techniques such as the ε-constraint method, goal programming and fuzzy optimisation enable the construction of Pareto frontiers that explicitly reveal relevant trade-offs (Pohekar & Ramachandran, 2004; Antunes et al., 2013). Decision-making methods such as AHP, ELECTRE, TOPSIS and PROMETHEE further support the process by structuring preferences, assigning weights to criteria and comparing expansion alternatives according to different policy perspectives (Saaty, 1980; Hwang & Yoon, 1981; Roy, 1991; Brans & Vincke, 1985).

Over the last two decades, Integrated Assessment Models have become fundamental for analysing climate policies and long-term energy transitions. Frameworks such as MESSAGE-GLOBIOM (IIASA, 2020) and REMIND-MAgPIE (Kriegler et al., 2017) integrate energy-system transformations with broader macroeconomic, land-use and environmental dynamics. These models are widely used to assess decarbonisation pathways, emissions trajectories and carbon-neutrality strategies at national and international levels (IEA, 2021; IPCC, 2022b). The increasing penetration of wind and solar energy, especially after 2010, introduced additional modelling requirements. The intrinsic variability of these resources demands hourly or sub-hourly resolution, explicit representation of storage and flexibility, and careful consideration of temporal and spatial

complementarities. Studies such as Hirth (2013) and Sepulveda et al. (2018) demonstrate that expanding variable renewables requires new system flexibility mechanisms, profoundly altering the traditional logic of operation and expansion.

Macroeconomic approaches, such as Computable General Equilibrium (CGE) models, have also been incorporated to assess the impacts of energy policies on relative prices, industrial competitiveness, consumer welfare and income distribution (Böhringer & Rutherford, 2008; Peters, 2016). While these models do not replace detailed representations of the electricity system, they enrich analysis by contextualizing expansion decisions within broader economic dynamics.

In recent years, significant advances have been made in internalizing environmental and social externalities explicitly within planning models. Studies by Sovacool et al. (2021) quantify external costs associated with CO_2, SO_2 and NO_x emissions, water use and health impacts, while research by Carley and Konisky (2020) and Sovacool et al. (2021) highlights regional inequalities, energy justice and social inclusion. Bielecki et al. (2020) and Vasquez-Arroyo et al. (2020) argue that the absence of systematic incorporation of externalities leads to decisions that minimize private costs but do not necessarily minimize the total social cost of energy.

The convergence of these lines of development—deterministic and stochastic models, metaheuristics, multiobjective approaches, integrated structures and the internalisation of externalities—reveals a field undergoing continuous conceptual and methodological expansion. Recent literature highlights persistent challenges: consistent coupling of operation and expansion, explicit incorporation of climate scenarios, representation of social indicators aligned with the SDGs, fine regionalisation of impacts, and the development of transparent and reproducible models capable of supporting legitimate and technically robust decision-making (Pfenninger et al., 2014; Sachs et al., 2023; Allen et al., 2019). These challenges define the context in which the present thesis is situated, proposing a formulation capable of explicitly integrating economic, environmental and social dimensions into generation expansion planning in Brazil.

2.3. Energy Planning in Brazil: Instruments, Practices, and Limitations

Energy planning in Brazil has been consolidated around a highly centralised institutional structure, shaped by the historical predominance of hydropower and by state-led coordination of system expansion. The creation of Eletrobras in 1962 and the subsequent integration of the National Interconnected System (SIN) established a model oriented towards large hydropower developments, giving rise to analytical methodologies strongly influenced by hydrology and by the regulatory capacity of large reservoirs (Tolmasquim, 2012; Dantas

et al., 2017). The infrastructure developed over the following decades reinforced this pattern, directly affecting technological choices and the logic of the planning frameworks adopted.

The establishment of the Energy Research Office (Empresa de Pesquisa Energética, EPE) in 2004 redefined the institutional architecture by assigning it responsibility for the main planning instruments: the Ten-Year Energy Expansion Plan (PDE) and the National Energy Plan (PNE). The PDE, updated annually, guides supply expansion over a ten-year horizon, while the PNE outlines structural long-term trends, typically over 25 to 30 years (EPE, 2023a, 2023b). These documents have become key references for the Ministry of Mines and Energy, regulators, private investors and financing agencies, playing roles comparable to Integrated Resource Plans in the United States (IEA, 2021) and National Energy and Climate Plans in the European Union (European Commission, 2020).

The operation of the SIN, coordinated by the National System Operator (ONS), relies on models developed from methodologies widely recognised in the international literature, especially regarding stochastic treatment of hydrology. The extensive use of Stochastic Dual Dynamic Programming (SDDP), initially developed by Pereira and Pinto (1991), has become the backbone of Brazilian hydrothermal operation, enabling probabilistic representation of hydrological series, intertemporal reservoir optimisation and computation of marginal operating costs (ONS, 2021). Studies such as Lima et al. (2020) and Lucena et al. (2010) emphasise that this degree of operational sophistication is relatively uncommon internationally, largely due to Brazil's unique dependence on hydropower.

Expansion planning, however, does not follow the same methodological logic as system operation. The models used by EPE remain predominantly based on deterministic linear programming or partial equilibrium modelling that evaluates levelised costs, demand projections and sectoral policy incentives (EPE, 2023c). The disconnect between stochastic operational models and deterministic expansion models is identified as a structural limitation of Brazilian planning, as it prevents the full incorporation of hydrological and climatic uncertainties into investment decisions (Guevara et al., 2024; Vasquez-Arroyo et al., 2020).

The rapid expansion of wind and solar power since 2015 has introduced additional modelling challenges. Differences in output profiles, regional complementarities and the intrinsic variability of these technologies require greater temporal and spatial granularity, as well as explicit representation of meteorological variability scenarios (Pfenninger et al., 2014; Pao & Fu, 2013). Although the PDE has incorporated more realistic capacity factors and detailed wind and solar resource maps, the methodology remains anchored in deterministic projections based on levelised cost of energy (LCOE), limiting its ability to capture system-wide risks and benefits associated with renewables (EPE, 2023a; Vasquez-Arroyo et al., 2020).

Limitations become even more evident when examining how environmental impacts are integrated into the planning process. The institutional framework in Brazil maintains a temporal separation between energy planning and environmental licensing, which restricts the ability of Environmental Impact Assessments (EIA/RIMA) to influence strategic expansion decisions (Fearnside, 2015; Athayde et al., 2019). This weakness is particularly critical for hydropower projects in the Amazon, where impacts on biodiversity, aquatic ecosystems, sediment transport and traditional populations are widely documented (Castello & Macedo, 2016; Winemiller et al., 2016). The literature indicates that when complex environmental impacts are not integrated into the planning stage, financial, social and legal risks tend to increase significantly (Kahn, 2014; Shu et al., 2018).

The integration of social dimensions shows even deeper gaps. Neither the PDE nor the PNE systematically incorporates social indicators such as regional employment, energy vulnerability, population displacement, distributive effects or impacts on traditional communities (Carley & Konisky, 2020; Fragkos & Paroussos, 2018; Costa & Ferreira, 2023). This omission is critical because the energy sector directly influences regional productive structures, income distribution and tariff levels, as shown in studies by Costa et al. (2018), the IEA (2022a), and Carley and Konisky (2020). The absence of explicit social metrics limits the capacity to evaluate interregional impacts and hinders the identification of inequalities generated or exacerbated by expansion decisions.

The literature also indicates that Brazilian planning has yet to adequately internalise emerging climate risks. Studies by the IPCC (2022a), the Agência Nacional de Águas e Saneamento Básico (ANA, 2025), Sorribas et al. (2016) and Nobre et al. (2019) show that hydrological variability in South America has been increasing in intensity and frequency, with extreme events directly affecting SIN's security of supply. Despite this evidence, the PDE still frequently relies on historical hydrological series that do not fully reflect medium- and long-term climate projections (Lucena et al., 2010; Vasquez-Arroyo et al., 2020).

Regarding the Sustainable Development Goals (SDGs), integration remains limited to conceptual references without consistent translation into quantitative metrics, model constraints or objective functions (EPE, 2023b). The national and international literature emphasises that incorporating SDGs—including targets related to water (SDG 6), climate (SDG 13), biodiversity (SDGs 14 and 15), decent work (SDG 8) and reduction of inequalities (SDG 10)—would require a substantial redesign of indicators and modelling architectures (Nerini et al., 2018; McCollum et al., 2018; Sachs et al., 2023). Brazilian studies reinforce that such integration is both feasible and necessary, but still methodologically incipient (Bielecki et al., 2020).

Taken together, these elements depict a consistent diagnosis: while Brazilian energy planning has achieved remarkable sophistication in handling hydrological uncertainty and integrated system operation, it

still faces significant limitations in representing environmental externalities, social impacts, climate risks and alignment with international sustainability goals. These challenges create an opportunity for models that internalise social and environmental costs, incorporate indicators aligned with the 2030 Agenda, and provide more robust analytical foundations for long-term expansion decisions.

2.4. Environmental Externalities in the Electricity Sector

Environmental externalities in the electricity sector have become one of the central themes of international literature since it was recognised that private generation costs fail to capture adequately the ecological effects associated with the life cycle of different technologies. Electricity production involves atmospheric emissions, use of natural resources, territorial interventions and profound ecological transformations, which are often not reflected in energy prices or investment decisions. When these dimensions are overlooked, traditional planning models distort technological comparisons, underestimate environmental risks and favour solutions that minimise short-term financial costs while amplifying medium- and long-term ecological burdens (Sovacool et al., 2021).

Environmental economics has formalised rigorous definitions of externality, emphasising that they represent unpriced costs or benefits that affect third parties, generating potentially severe market failures (Pigou, 1920; Baumol & Oates, 1988). In the electricity sector, such failures manifest acutely due to the geographical concentration of impacts—such as local air pollution, hydrological alteration and habitat degradation—and the diffuse nature of long-term effects, including climate change, soil acidification, eutrophication and biodiversity loss. Authors such as Tol (2018), Stern (2007) and Pindyck (2019) argue that, in the absence of explicit valuation mechanisms, these impacts tend to remain substantially underestimated.

Fossil fuels offer the clearest illustration of negative environmental externalities. The scientific literature robustly documents the effects of CO_2, CH_4 and N_2O emissions on global warming, ocean acidification and the intensification of extreme weather events (IPCC, 2022b). Epidemiological studies also demonstrate the direct health impacts of local air pollutants, such as SO_2, NO_x and particulate matter, particularly in densely populated urban areas (Lelieveld et al., 2019; Landrigan et al., 2018). National and international programmes led by institutions such as the OECD, USEPA and the European Environment Agency estimate substantial external costs associated with these pollutants, including increased healthcare burdens and losses in labour productivity (OECD, 2021a; EEA, 2020).

In the case of hydropower, the debate on externalities takes a different shape. Although hydropower plants emit significantly less CO_2 during operation than fossil technologies, large dams produce major alterations to aquatic and terrestrial ecosystems and generate profound sociocultural impacts. Studies by

Winemiller et al. (2016), Fearnside (2015), and Castello and Macedo (2016) show that hydropower developments in the Amazon disrupt sediment transport, impede fish migration routes, inundate extensive forest areas and release significant methane emissions from tropical reservoirs. In parallel, forced displacement, loss of traditional territories and transformations in local livelihoods become central to the socioenvironmental debate (Athayde et al., 2019). These factors illustrate that the classification of hydropower as "clean energy" depends heavily on ecological, territorial and institutional conditions.

The accelerated expansion of renewable energy does not eliminate the need to consider externalities. Technologies such as wind and solar photovoltaic energy present relatively low impacts during operation but generate externalities related to land use, habitat fragmentation, equipment end-of-life disposal, mining of critical raw materials and land-use conflicts. Studies by Bradshaw and Jannuzzi (2019) and IRENA (2022) demonstrate that impacts on birds, bats, landscapes and local communities must be treated with scientific rigour, especially in ecologically sensitive regions. In high-renewable systems, externalities related to transmission expansion, large-scale storage needs and the increasing demand for critical minerals also become central to long-term planning (IEA, 2023).

Valuing these externalities is therefore a critical dimension of the debate. Methods based on avoided costs, willingness to pay, life cycle assessment (LCA) and social cost of carbon (SCC) estimates have been widely applied to monetise environmental impacts and render them comparable with traditional economic metrics (Zhao & Guo, 2015; Ricke et al., 2018). Such tools allow environmental costs to be integrated into expansion models, enable the use of hybrid indicators and support investment decisions closer to social optimum. In Brazil, studies by Bielecki et al. (2020) highlight the magnitude of unpriced environmental costs in the electricity sector.

Integrating environmental externalities into energy planning nevertheless faces significant methodological challenges. Classical expansion models were designed to account for direct economic costs—not for impacts that are spatially heterogeneous, temporally distributed and influenced by complex interactions within ecosystems. Many impacts are nonlinear, manifest over long temporal horizons, and depend on interactions among ecological processes, human communities and biogeochemical cycles. Recent literature therefore advocates for broader modelling architectures, incorporating multicriteria approaches, tighter coupling between operation and expansion, refined regional modelling and explicit environmental indicators that capture not only emissions but also water use, land occupation, waste generation and biodiversity impacts (Sovacool et al., 2021; Allen et al., 2019).

These reflections converge to a central argument: internalising environmental externalities is essential for long-term planning to be consistent with sustainability goals and international climate commitments. By

quantitatively representing impacts historically treated as “invisible”, planning processes can align decisions more closely with the total social cost of energy, reduce information asymmetries, mitigate future risks and support more equitable and environmentally responsible energy transitions. In Brazil—characterised by a highly diverse matrix, ecologically sensitive biomes and significant territorial inequalities—such internalisation is particularly critical.

It is within this context that the SEGeP model is proposed, conceived as a planning framework that explicitly incorporates environmental impacts into the mathematical formulation of generation expansion. In contrast with approaches that treat externalities only qualitatively or as post hoc constraints, SEGeP integrates these dimensions directly into the objective function, either through the monetisation of environmental impacts or through hybrid indicators that capture dimensions not readily expressed in monetary units. This proposal responds to the international literature’s call for models capable of internalising the total social cost of energy, while also addressing the Brazilian planning system’s persistent absence of environmental indicators as structuring elements of the decision problem (Bielecki et al., 2020). In doing so, SEGeP stands as a relevant methodological contribution, bringing energy planning closer to sustainability requirements and providing a more robust quantitative basis for public and private decision-making.

2.5. Social Externalities in Electricity Generation Expansion Planning

Social externalities constitute a historically underestimated dimension in traditional energy planning processes, despite being among the most significant impacts associated with generation expansion. While environmental externalities have received increasing attention in both academic research and regulatory frameworks, social effects—such as the territorial distribution of benefits, job creation and job quality, energy vulnerability, population displacement, impacts on traditional communities, risk perception, social acceptance and socioeconomic inequalities—remain insufficiently represented in decision-support models. This gap persists despite robust evidence showing that the energy transition produces asymmetric redistributive effects, generating winners and losers across regions, social groups and cultural contexts (Carley & Konisky, 2020; Sovacool et al., 2021).

International literature has consistently emphasised that social externalities are not peripheral considerations, but rather structural components of any analysis aligned with the notion of sustainability. Studies by the IEA (2022a), International Energy Agency et al. (2021) and the World Bank (2023) demonstrate that energy expansion policies greatly influence the social organisation of territories, affecting employment, income, mobility, health, community security and social inclusion. In the context of renewable energy, research by Healy and Barry (2017), Boasson et al. (2021), and Jenkins et al. (2018) shows that large-scale projects

can stimulate local socioeconomic development, yet they may also deepen inequalities when implemented in vulnerable regions or in the absence of robust mechanisms for community participation. In this sense, the energy transition is not neutral: it redistributes power, resources, risks and opportunities.

The spatial inequality of impacts has been particularly documented in large countries such as Brazil, India, China and South Africa, where regional socioeconomic characteristics strongly shape how energy projects are perceived and experienced. In Brazil, studies show that hydropower, wind, solar and thermal generation projects frequently produce complex effects on traditional communities, riverine populations, small farmers and Indigenous groups, altering livelihoods, cultural identities and community structures (Athayde et al., 2019; Kirchherr et al., 2017). In many cases, the benefits of expansion—such as increased installed capacity, diversification of the energy mix and improved supply security—are appropriated by more developed regions, while the social costs fall disproportionately on historically vulnerable territories.

Another critical dimension relates to energy vulnerability, a concept that encompasses the difficulty of accessing energy services that are safe, reliable and financially affordable. In Brazil, studies by Amaral et al. (2023), Fragkos and Paroussos (2018), and Costa et al. (2018) indicate that unequal access constrains industrial competitiveness, household welfare and social integration, especially in the North and Northeast regions. Energy poverty, although less publicly debated in Brazil than in Europe, is a key indicator of structural inequality and is closely associated with precarious housing, education and health conditions. The expansion of electricity generation may exacerbate or mitigate these vulnerabilities depending on how regional interests and social groups are represented in planning instruments.

Job creation—often presented as an inherent benefit of renewable energy expansion—also requires careful analysis. Reports from IRENA (2022) and studies such as Rutovitz et al. (2015) show that different technologies present heterogeneous employment profiles in terms of magnitude, duration, skills required and spatial distribution. While solar photovoltaic deployment tends to generate a large number of temporary jobs during installation, the operation of wind farms and hydropower plants provides more stable employment, albeit in smaller numbers. Moreover, job quality depends on labour policies, vocational training and industrial development strategies, directly linking energy planning to regional development agendas (IRENA, 2023).

Social acceptance has emerged as another critical element in contemporary debates on energy transitions. Classic studies by Wüstenhagen et al. (2007) and more recent research by Chateau et al. (2021) show that public acceptance depends on cultural, institutional and socioeconomic factors, including transparency, trust in institutions, compensation mechanisms and the extent of public participation. When these factors are neglected, socio-environmental conflicts, judicial disputes and institutional delegitimisation

often emerge—phenomena widely documented in hydropower projects in the Amazon, wind projects in Northeast Brazil and large-scale solar developments in rural areas (Leite et al., 2021).

The literature on energy justice provides the most comprehensive conceptual framework for understanding these externalities. Authors such as Sovacool et al. (2017) and Jenkins et al. (2018) argue that energy justice encompasses not only the equitable distribution of costs and benefits but also the recognition of affected populations and their meaningful participation in decision-making processes. This perspective articulates debates on human rights, territorial equity and democratic governance, asserting that sustainable transitions must adhere to principles of distributive, procedural and recognition justice. In Brazil, this debate has advanced through studies analysing territorial conflicts and participatory processes related to the electricity sector (Athayde et al., 2019).

The systematic omission of these dimensions in Brazil's official energy planning instruments represents a significant methodological gap. Although socio-environmental considerations are addressed during environmental licensing, they do not structurally inform the PDE or PNE modelling frameworks (EPE, 2023a; 2023b). This disconnect leads to expansion decisions which, although optimised from a private-cost perspective, neglect socially significant impacts, contradicting accumulated evidence in the literature and international commitments associated with SDGs 7, 8, 10, 11 and 16 (Nerini et al., 2018; Sachs et al., 2023).

It is precisely within this set of gaps that the SEGeP model is positioned. By incorporating social indicators directly into mathematical formulation, through variables, parameters and objective functions that capture employment, energy vulnerability, regional inequality, community impacts and social acceptance, SEGeP reduces historical asymmetries between private and social costs. This integration responds to international literature advocating energy planning aligned with the principles of a just transition, reinforcing that sustainability cannot be assessed solely from an emissions perspective, but must include distributive, territorial and participatory dimensions. By bringing these variables into the quantitative domain, the model provides a more comprehensive representation of reality and strengthens the analytical basis for public policies aligned with sustainable development, the 2030 Agenda and emerging social demands in the Brazilian context.

2.6. International Models with Integrated Socio-Environmental Approaches

The international debate on energy planning models has evolved significantly toward incorporating socio-environmental dimensions more explicitly into decision-making processes. This development reflects a growing understanding that the challenges inherent to the energy transition extend far beyond the techno-economic sphere and cannot be captured by metrics that focus solely on costs or emissions. Over the past two decades, the literature has shown that several countries and multilateral organisations have restructured their analytical

frameworks to integrate sustainability, social justice and climate targets into more comprehensive and rigorous quantitative methodologies (IEA, 2021; IPCC, 2022b; IRENA, 2023).

Integrated assessment models—such as MESSAGE-GLOBIOM, GCAM and REMIND-MAgPIE—represent one of the most meaningful advances in this field. Although originally designed to simulate emissions trajectories and mitigation strategies, these models have progressively incorporated socio-economic variables, land-use dynamics, regional impacts, employment effects and intersectoral inequalities. Studies by Loulou and Labriet (2008), Kriegler et al. (2017) and Fricko et al. (2017) demonstrate how these systems have been used to assess pathways consistent with the Paris Agreement, reconciling economic costs, climate impacts and distributive effects across economic sectors. While their global scope inevitably limits the representation of territorial specificities, their main contribution lies in their ability to capture structural interactions among energy, economy and environment, thereby providing conceptual references that influence national and subnational modelling efforts.

At the national scale, countries such as Denmark and Germany stand out for the systematic incorporation of socio-environmental indicators into their planning models. Both countries adopt methodologies that integrate environmental costs, land-use impacts, social acceptance requirements and industrial development strategies associated with the energy transition (Welsch & Ferreira, 2014; Agora Energiewende, 2021). The Danish Balmorel model, widely applied across Northern Europe, enables a spatially explicit representation of externalities associated with offshore wind, transmission expansions and flexibility resources. Reports from the Danish Energy Agency indicate that this approach has been crucial for guiding investment decisions that balance climate targets with ecological and socio-economic impacts in coastal regions (DEA, 2021).

In the United States, models such as NREL's ReEDS (Renewable Energy Deployment System) and PLEXOS incorporate variables related to land use, impacts on sensitive ecosystems, the social cost of carbon and climate-resilience indicators. Research by Maclaurin et al. (2019) and Mai et al. (2021) shows how these models evaluate the effects of renewable-energy policies on employment, supply chains and energy vulnerability, particularly in states marked by pronounced socio-economic disparities. In parallel, the U.S. literature has emphasised environmental justice, linking energy-system impacts to long-standing racial and geographic inequalities (Carley & Konisky, 2020; Jenkins et al., 2018).

Within the European Union, the "Fit for 55" climate package has driven the development of models that place social justice and environmental protection at the centre of energy-policy analysis (European Commission, 2021). Instruments such as the Just Transition Mechanism and the Social Climate Fund have encouraged the use of quantitative approaches that account for energy vulnerability, income inequality and

differentiated regional impacts of decarbonisation policies. Studies by Fragkos and Paroussos (2018) and Lüken et al. (2011) demonstrate how European integrated assessment models have progressively incorporated social and territorial indicators, enabling analyses more consistent with the principles of a just transition.

In the Global South, emerging approaches reflect distinct socio-economic contexts. In India, the IESS (India Energy Security Scenarios) combines energy projections with socio-economic assessments, including energy poverty, access to electricity and regional employment impacts (NITI Aayog, 2021). In South Africa, modelling initiatives linked to the South Africa Just Transition Framework incorporate the effects of decarbonisation on mining-dependent communities, underscoring the need to reconcile climate goals with economic stability and distributive justice (South Africa Presidential Climate Commission, 2022).

Despite this global progress, substantial methodological limitations persist. One of the most significant challenges lies in translating social impacts — such as public acceptance, population displacement, cultural effects or impacts on traditional communities — into operational metrics compatible with mathematical optimisation models. Authors such as Carley and Konisky (2020) and Sovacool et al. (2021) argue that many social impacts resist monetisation without loss of conceptual meaning. Consequently, hybrid approaches combining monetised metrics, qualitative indicators and multicriteria methods have gained prominence, consistent with methodological recommendations from the IPCC (2022b).

This international landscape indicates that the internalisation of socio-environmental externalities is not peripheral, but rather a rapidly expanding research frontier. Across all examined contexts, there is a clear convergence toward models capable of representing distributive effects, climate risks, territorial inequalities and ecological impacts, while maintaining alignment with long-term investment decisions. However, persistent gaps remain, including: (i) insufficient representation of territorial inequalities; (ii) challenges in integrating qualitative indicators without compromising mathematical coherence; and (iii) the absence of methodologies capable of jointly incorporating economic costs, environmental impacts and socially embedded effects.

It is precisely within this space of methodological innovation that SEGeP is situated. By proposing the explicit internalisation of social and environmental externalities in Brazilian energy-planning models, SEGeP aligns itself with international advances while simultaneously addressing the specific challenges of a country characterised by ecological diversity, socio-economic inequality and pronounced territorial heterogeneity. Whereas many international models incorporate socio-environmental indicators only partially or indirectly, SEGeP adopts an integrated approach embedded directly into the objective function, structured through measurable parameters and aligned with the Agenda 2030. This methodological orientation expands the

analytical scope of energy-system modelling and brings Brazilian electricity planning closer to a genuinely sustainable and socially inclusive paradigm.

2.7. Integration of Externalities into Contemporary Energy Planning

The integration of externalities into energy planning has emerged, over the past two decades, as one of the most significant advances in international research on energy systems. The shift from models traditionally centred on private costs to approaches capable of incorporating environmental, social, and territorial impacts represents a structural change in how energy systems are assessed, conceived, and regulated. This evolution stems not only from pressures associated with global climate targets but also from a growing recognition that expansion decisions produce broad and asymmetric distributive effects across regions, social groups, and ecosystems—particularly in contexts characterised by high socio-environmental heterogeneity (Sovacool et al., 2017; Jenkins et al., 2018; IPCC, 2022a).

The literature shows that the integration of environmental externalities has progressed more systematically, especially through the internalisation of greenhouse gas emissions. The development of economic mitigation instruments—such as carbon markets and pricing schemes—together with consolidated scientific frameworks for estimating climate impacts, has enabled expansion models to incorporate carbon-related costs both as monetary terms within the objective function and as regulatory constraints that delimit the solution space (IEA, 2023; IRENA, 2024). Despite this progress, integration remains limited: crucial environmental categories—such as water use, local air pollutants, biodiversity impacts, land occupation and waste generation—although widely documented, are still incorporated only partially and heterogeneously, resulting in an incomplete representation of the environmental impacts of electricity generation (Lelieveld et al., 2019; Winemiller et al., 2016; Jenkins et al., 2016).

Social externalities, although increasingly discussed, remain underrepresented in planning models. Recent literature clearly indicates that generation expansion influences employment patterns, regional income, population displacement, public health, energy vulnerability, and social acceptance of projects. Even renewable technologies—often portrayed as environmentally benign—can generate significant social impacts during licensing, construction, operation, and decommissioning, affecting livelihoods, territorial relations, and sociocultural dynamics, particularly in rural, Indigenous, and traditional communities (Carley & Konisky, 2024; Athayde et al., 2019). Nevertheless, their incorporation remains predominantly associated with multicriteria methods or qualitative indicators, without monetary integration or direct linkage to the objective function, which limits the influence of social dimensions on optimisation processes.

The different ways of integrating externalities reflect distinct methodological traditions. Direct monetisation—common in single-objective optimisation models—seeks to approximate externalities to conventional economic metrics, enabling comparisons across technologies. In contrast, constraint-based approaches impose emission caps or minimum environmental performance requirements, suitable for regulation-oriented models. Hybrid approaches—combining optimisation and multicriteria methods—have gained prominence for their ability to incorporate non-monetisable attributes such as territorial justice, social acceptance, or cultural impacts (Pohekar & Ramachandran, 2004). However, no consensus exists regarding which strategy best balances mathematical rigour, analytical flexibility, and representativeness of the multiple dimensions of sustainability.

Spatial integration of externalities represents another critical development. Electricity systems spanning large territories—such as those of Brazil, India, China, or South Africa—require modelling approaches capable of capturing regional inequalities, socio-economic variations, natural resource availability, socio-territorial conflicts, and differentiated climate vulnerabilities. Despite this necessity, regional disaggregation appears only partially in international literature, which compromises the capacity of models to reflect the realities of affected territories, particularly in countries marked by deep social and environmental heterogeneity (NITI Aayog, 2021; DEA, 2023). Spatial disaggregation, therefore, is not merely a methodological choice but an analytically indispensable condition for adequately representing complex systems.

Parallel to these developments, energy justice has gained prominence as a conceptual framework for guiding the integration of externalities. This perspective emphasises that energy transitions must incorporate criteria of distributive, procedural, and recognition justice, ensuring that costs and benefits are equitably distributed across social groups and regions. Recent studies across multiple contexts—including Europe, Latin America, Africa, and Asia—demonstrate that energy policies that neglect these dimensions tend to reproduce structural inequalities, generate socio-environmental conflicts, and compromise the social legitimacy of the transition (Sovacool et al., 2018; Jenkins et al., 2020).

From this body of evidence, three structural challenges repeatedly emerge in the literature:

(i) the predominance of globalised environmental externalities—particularly CO_2—over local and ecosystem-level environmental categories;

(ii) the persistent underrepresentation of social externalities in the quantitative core of models; and

(iii) the insufficient spatial disaggregation that prevents models from capturing territorial diversity and regional inequalities.

These challenges define an underexplored field of inquiry in which integrated models become essential for supporting robust, sustainability-oriented public policy design.

The conceptual evolution documented in international literature indicates that contemporary energy planning is moving toward an approach that articulates economic rationality, environmental valuation, social impacts, and territorial inequalities. Developing models capable of internalising externalities simultaneously, monetarily, and with spatial sensitivity is no longer a theoretical aspiration but an operational necessity in a context of increasing energy complexity and more comprehensive regulatory demands. It is precisely within this convergence that the model developed in this thesis is positioned, guided by the formulation of an objective function based on the total social cost of energy and aligned with principles of sustainability, energy justice, and balanced regional development.

2.8. Critical Synthesis and Implications for the Development of Sustainable Energy Planning Models

The review conducted in this chapter demonstrates that contemporary energy planning is undergoing a profound conceptual reorganisation, driven by the need to integrate international climate targets, growing socio-environmental requirements and heterogeneous territorial dynamics. Despite these advances, the models currently used to guide generation expansion remain largely structured around the logic of private cost minimisation, a framework that proves insufficient in a context where sustainability, energy justice and climate resilience have become central and unavoidable (Pfenninger et al., 2014; IEA, 2021; Sachs et al., 2023).

The literature confirms that, although progress has been made in integrating environmental externalities—particularly regarding the pricing of CO_2 emissions—this incorporation remains partial and limited. The prevailing emphasis on global emissions tends to marginalise other environmentally significant categories, such as habitat degradation, water use and competition, local air pollution, land occupation and biodiversity loss (Winemiller et al., 2016; IPCC, 2022a). This methodological asymmetry reduces the capacity of models to reflect the real impacts of different generation technologies, especially in systems characterised by ecological sensitivity, as is the case in Brazil.

In the social domain, the gap is even more pronounced. Recent studies consistently acknowledge that the energy transition produces profound distributive effects, affecting employment patterns, regional incomes, modes of life, territorial cohesion and energy vulnerability among different social groups (Carley & Konisky, 2020; Jenkins et al., 2018). However, these impacts rarely enter the core mathematical formulation of planning models. The predominance of qualitative analyses, multicriteria approaches reliant on expert judgement and the absence of consolidated mechanisms to monetise social externalities greatly reduce the influence of these dimensions on expansion decisions. As a result, planning trajectories may reproduce

historical inequalities, exacerbate vulnerabilities and intensify territorial conflicts (Athayde et al., 2019; Sovacool et al., 2018).

Another critical element emerging from the literature concerns the insufficient spatial representation of energy systems. In countries characterised by large territorial extension and pronounced regional inequalities—such as Brazil, India, China and South Africa—aggregated models tend to conceal the territorial distribution of burdens and benefits, leading to incomplete and, at times, biased assessments (Urban et al., 2013; NITI Aayog, 2021). Contemporary research recognises that spatial scale is a determinant variable for any analysis aiming to capture real impacts—environmental, economic or social (Healy & Barry, 2017; Boasson et al., 2021). The absence of regional disaggregation therefore undermines the precision, legitimacy and public usefulness of planning outcomes (Sovacool et al., 2021; Jenkins et al., 2020).

The critical analysis carried out throughout Sections 2.1 to 2.7 reveals three structural challenges widely recognised in the state of the art:

(i) the predominance of global environmental externalities, especially CO_2, over local and ecosystem-level impacts;

(ii) the underrepresentation of social externalities, which remain largely absent from the central quantitative structure of models; and

(iii) the persistent lack of systematic spatial disaggregation, essential for representing territorial inequalities and differentiated regional impacts.

To visually consolidate the gaps identified in the literature, Table 2.1 is presented, which summarizes the main methodological challenges of contemporary energy planning.

Table 2.1 - Key methodological gaps in contemporary energy planning models.

Dimension	Observed Gap in the Literature	Implications for Energy Planning
Environmental Externalities	Predominant focus on CO_2; limited integration of water use, biodiversity loss, land occupation, local air pollution, and waste impacts.	Distorts technological comparisons; overlooks ecosystem-specific vulnerabilities; undermines environmental sustainability assessments.
Social Externalities	Weak formalisation; rarely monetised; typically treated via qualitative or multicriteria approaches; absence of employment, energy poverty, resettlement, distributive effects, or social acceptance in optimisation models.	Reduces the influence of social impacts on decision-making; reproduces inequalities; increases risk of territorial conflicts; weakens energy justice.
Spatial Disaggregation	Frequent use of aggregated national models that ignore regional disparities, heterogenous socio-economic contexts, and differentiated environmental sensitivities.	Produces biased results; misrepresents regional burdens and benefits; undermines territorial equity and policy legitimacy.
Model Integration	Environmental and social dimensions treated separately; absence of unified frameworks or objective functions based on total social cost.	Limits holistic sustainability assessment; prevents identification of optimal solutions that balance multiple criteria simultaneously.
Data and Valuation Limitations	Lack of standardised indicators; difficulties monetising social impacts; insufficient regional databases.	Restricts adoption of comprehensive models; generates uncertainties; limits reproducibility and transparency.

Source: Author's elaboration.

These methodological gaps converge towards a robust diagnosis: the energy sector requires models that transcend the unidimensional logic of economic cost minimisation and are capable of integrating, explicitly, simultaneously and with spatial sensitivity, the environmental and social impacts of generation expansion. International organisations. including UN - Energy, IPCC, IEA and IRENA—reinforce this conclusion, arguing for the development of multicriteria, territorialised models oriented towards the total social cost of energy as a minimum condition for a just and sustainable energy transition (UN-Energy, 2021; IPCC, 2022b; IEA, 2023; IRENA, 2024).

It is precisely within this methodological gap that the contribution of this thesis is situated. By proposing a planning model capable of integrating:(i) monetised environmental and social externalities, (ii) fine regional disaggregation tailored to Brazilian heterogeneity, (iii) an objective function oriented towards the total social cost of energy, and (iv) explicit alignment with climate targets and the Sustainable Development Goals.

This thesis responds directly, substantively and innovatively to the gaps identified in the state of the art. The SEGeP model thus constitutes a robust conceptual and methodological contribution, coherent with contemporary literature and aligned with the real challenges of Brazilian energy planning.

This synthesis establishes the conceptual foundation for the following chapter, which presents the mathematical formulation of the model, the selected indicators, the structure of the objective function and the mechanisms for internalising externalities—core components of the methodological framework developed in this research.

Despite the breadth, depth and methodological diversity of the literature reviewed, the critical analysis developed throughout this chapter reveals that important structural limitations persist in contemporary electricity generation expansion planning models. These limitations are not merely incremental or context-specific; rather, they reflect a more fundamental difficulty in operationalising sustainability within the formal structure of optimisation-based planning frameworks.

Although significant progress has been achieved in the incorporation of environmental externalities—especially through carbon pricing mechanisms and, in more advanced cases, through the monetisation of local pollutants and resource use—such integration remains partial, fragmented and often restricted to a limited subset of impacts. In most existing formulations, environmental dimensions are either treated as exogenous constraints or incorporated through simplified cost adjustments, without fully capturing the systemic and cumulative nature of their effects within a unified analytical structure.

The limitations are even more pronounced with respect to social externalities. While literature increasingly recognises the relevance of dimensions such as employment generation, regional development, social inclusion and distributive equity, their integration into formal optimisation models remains incipient. In

general, these elements are treated as secondary outputs, post-optimisation assessments or components of multi-criteria decision-making frameworks, rather than as endogenous elements capable of directly influencing optimal expansion pathways. Consequently, the trade-offs between economic efficiency, environmental sustainability and social outcomes are not fully internalised within the decision-making logic of existing models.

A further critical gap lies in the absence of unified modelling approaches capable of simultaneously integrating economic, environmental and social dimensions within a single, coherent optimisation framework. The prevailing tendency towards segmented or loosely coupled methodologies—where different dimensions are addressed separately or sequentially—limits the capacity of models to represent the complex interdependencies that characterise sustainable energy systems. This fragmentation reduces both the analytical consistency and the policy relevance of the resulting expansion pathways.

Although several studies incorporate spatial or regional disaggregation, this dimension is rarely combined with a comprehensive treatment of socio-environmental externalities. In many cases, regionalisation is used primarily to reflect resource availability, infrastructure distribution or demand patterns, without adequately capturing territorial inequalities, differentiated social impacts or region-specific environmental constraints. This limitation is particularly critical in contexts such as Brazil, where regional heterogeneity is a defining characteristic of the electricity system and plays a central role in shaping both risks and opportunities associated with long-term expansion.

Despite the increasing prominence of the Sustainable Development Goals as a globally recognised normative framework, their effective operationalisation within energy planning models remains limited. Most contributions employ the SDGs as conceptual or strategic references, without translating them into measurable, comparable and monetisable indicators that can be directly incorporated into mathematical optimisation structures. This gap constrains the ability of existing approaches to align planning outcomes with internationally established sustainability targets in a transparent and quantitatively robust manner.

These limitations indicate that, although the literature has significantly advanced the analytical capabilities of electricity generation expansion planning, it still lacks a consistent and integrated methodological framework capable of: (i) systematically identifying and selecting measurable sustainability indicators aligned with the SDGs; (ii) quantifying and monetising both environmental and selected social externalities in a coherent and comparable manner; (iii) incorporating these elements within a unified objective function oriented towards total social cost; and (iv) explicitly representing regional heterogeneity in a way that captures both resource distribution and socio-environmental inequalities.

The development of an integrated modelling framework that bridges the gap between normative sustainability principles and formal optimisation structures emerges as a central scientific and methodological

challenge. The SEGeP model proposed in this thesis is conceived precisely in response to this challenge. By combining the monetisation of externalities with constraint-based representations of critical system limits, and by explicitly incorporating regional disaggregation, the proposed framework seeks to operationalise sustainability within electricity generation expansion planning through a unified total social cost approach. The following chapter presents the methodological foundations and procedures adopted for the development and application of this framework.

CHAPTER 3 - METHODOLOGY

The methodology adopted in this research was designed to address a complex scientific problem, namely the need to develop an electricity generation planning model capable of internalising environmental and social externalities in a measurable, monetised, and regionally differentiated manner, thereby supporting strategic decisions aligned with sustainability goals and the Sustainable Development Goals (SDGs). As demonstrated in the previous chapters, the Brazilian electricity sector is characterised by a unique combination of territorial diversity, regional asymmetries, strong dependence on hydropower, and socio-environmental pressures that are not adequately captured by traditional generation expansion models. These factors require a robust methodological approach capable of articulating quantitative tools, solid theoretical foundations, and a critical analysis of the indicators that represent the systemic impacts associated with the sector.

The methodological structure developed in this thesis is composed of four fundamental pillars: (i) the definition of a conceptual framework for sustainable electricity generation planning, grounded in the principles of sustainability, energy justice, and social cost internalisation; (ii) the selection, validation, and operationalisation of economic, environmental, and social indicators based on criteria of relevance, data availability, measurability, and feasibility of monetisation; (iii) the formulation of a mathematical model—the SEGeP model—that incorporates these indicators into an optimisation structure consistent with the Brazilian territorial context; and (iv) the construction of scenarios, simulation techniques, and comparative analyses that allow the evaluation of different expansion pathways and the measurement of their systemic impacts.

These pillars are developed in an articulated manner throughout the chapter, beginning with the methodological choices that guide the design of the investigation. The methodological process involves mixed approaches, combining quantitative and qualitative methods, exploratory data analysis, parameter definition, monetisation techniques, and large-scale mathematical modelling. The integration of these steps ensures internal coherence and reflects the actual complexity of the electricity planning problem in a country with highly heterogeneous social and environmental characteristics.

Although the formulation of the SEGeP model constitutes the quantitative core of the methodology, it is embedded within a broader framework. The development of the model requires a set of preliminary steps, including the critical analysis of existing approaches, the identification of limitations in consolidated models, the definition of selected indicators, and the methodological structuring required to translate externalities into metrics compatible with the optimisation process. These stages are essential to ensure that the model does not merely reproduce conventional expansion patterns, but rather integrates social, environmental, and territorial determinants that have historically been neglected.

The methodology also incorporates procedures for scenario construction, designed to explore structural uncertainties, test model sensitivity to different conditions, and enable comparative evaluations among strategic alternatives. These scenarios are developed using real data, official projections, and sectoral studies, forming an analytical platform aligned with long-term planning requirements.

The chapter delineates the methods used for analysing and interpreting the results, ensuring scientific rigour and consistency in the formulation of conclusions. The methodological structure developed here ensures that SEGeP is supported by a solid and transparent investigative process, compatible with doctoral-level academic standards and capable of contributing to scientific advancements in sustainable energy planning.

Figure 3.1 presents the methodological architecture adopted in this thesis, illustrating the sequential and articulated structure that underpins the development of the SEGeP model. The framework begins with the theoretical foundations of sustainable energy planning, externalities, energy justice, and the SDGs, which guide the selection of economic, environmental, and social indicators aligned with the 2030 Agenda. These indicators are subsequently subjected to monetisation and parameterisation procedures, enabling their integration into the mathematical formulation of the SEGeP model as a mixed-integer linear programming problem oriented towards the minimisation of the Total Social Cost. The methodological structure is completed by the construction and simulation of alternative planning scenarios, whose results support the comparative analysis of expansion pathways and their implications for energy policy and sustainable development.

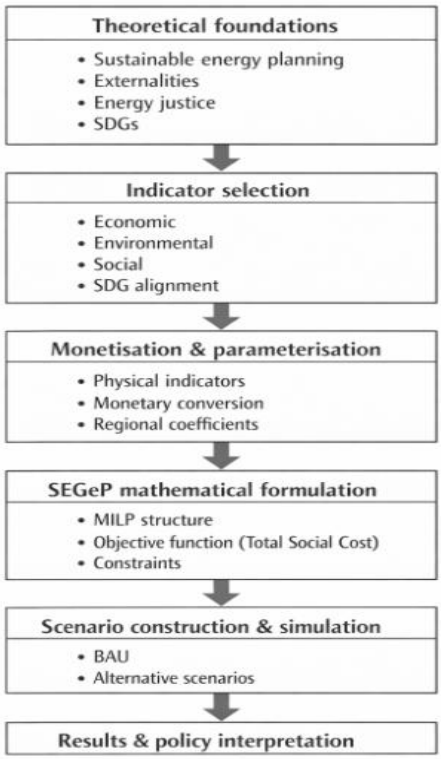


Figure 3.1 - Methodological architecture of the thesis
Source: Author's elaboration.

3.1. Conceptual and Methodological Foundations of the SEGeP Model

The conceptual and methodological foundations of the SEGeP model were structured to ensure coherence between the theoretical framework, the empirical indicators, and the mathematical formulation of sustainable electricity planning. This section establishes the methodological assumptions that support the model, the principles guiding the internalisation of the Total Social Cost, and the criteria used to align the model with the sustainability dimensions defined in literature.

This methodological choice responds to the limitation of mono-dimensional optimisation frameworks, which are unable to represent trade-offs inherent to sustainability-oriented planning.

Figure 3.2 presents the overall architecture of the SEGeP model, highlighting the interaction between inputs, optimisation core and outputs.

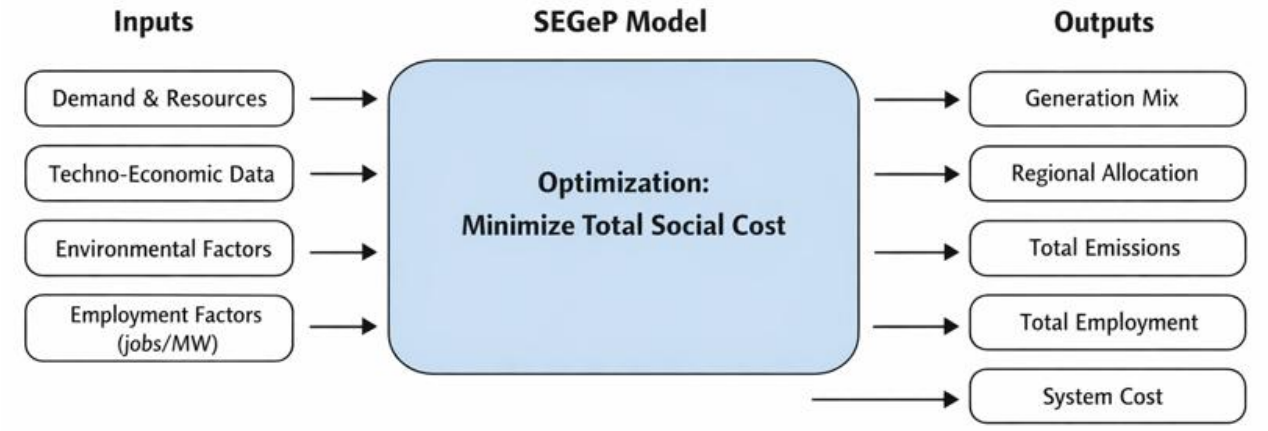


Figure 3.2 - Architecture of the SEGeP optimisation framework.
Source: Author's elaboration

This schematic representation summarises how economic costs, environmental coefficients, social indicators and policy targets are simultaneously internalised within the MILP engine, ensuring that sustainability considerations directly influence expansion decisions rather than being treated as ex-post adjustments.

The formulation of SEGeP begins with the recognition that electricity generation expansion produces impacts across economic, environmental, and social domains, which must be incorporated quantitatively to allow a systemic assessment of alternative expansion pathways. This premise is aligned with the literature on sustainable energy planning, life-cycle approaches, environmental and social externalities, and with the international movement advocating for the integration of sustainability metrics into energy system models.

Three fundamental methodological principles structure the SEGeP design:

(1) Multidimensionality — the model represents the three pillars of sustainability in an integrated manner;

(2) Monetisation of externalities — environmental and social impacts are translated into commensurable metrics to enable incorporation into the objective function;

(3) Regional differentiation — spatial disaggregation is adopted to capture heterogeneity in resource availability, socio-economic conditions, and environmental sensitivities. These principles determine the organisation of the model's structure and the selection of indicators incorporated into the Total Social Cost function.

A critical methodological assumption is that the integration of externalities must not compromise the mathematical solvability of the model. Therefore, the SEGeP structure was conceived as a mixed-integer linear programming formulation, allowing the representation of long-term expansion decisions while maintaining computational tractability. The internalisation of externalities occurs through parameters associated with each technology and region, enabling the simultaneous evaluation of economic costs, environmental impacts, and social effects.

By articulating these methodological foundations with the empirical indicators selected and validated in the subsequent steps, SEGeP establishes a coherent framework that accurately reflects the Brazilian context and responds to the analytical gaps identified in the literature. To enhance transparency and reinforce the logical coherence of methodological design, Table 3.1 synthesises the main research objectives of this thesis and their corresponding methodological steps. The table explicitly links each objective to the analytical tools and modelling approaches adopted, clarifying how conceptual requirements are translated into operational procedures within the SEGeP framework.

Table 3.1 Correspondence between research objectives, methodological steps, tools, and expected outcomes.

Research objective	Methodological step	Tool / approach	Expected outcome
Establish a sustainability-oriented planning framework	Definition of conceptual foundations	Literature review on sustainable energy planning, externalities, energy justice, and SDGs	Clear theoretical framework grounding the model in sustainability, social cost internalisation, and territorial equity
Integrate sustainability dimensions (economic, environmental, and social)	Selection of sustainability indicators	Systematic literature review; relevance, measurability, data availability, and monetisation criteria	Coherent, non-redundant set of indicators representing multidimensional impacts
Align energy planning with the 2030 Agenda	Mapping indicators to SDGs	SDG framework analysis and indicator–target correspondence	Transparent alignment between model variables and internationally recognised sustainability goals
Internalise environmental externalities	Monetisation of environmental impacts	Damage-cost methods, social cost of carbon, health impact valuation, ecosystem service proxies	Environmental impacts expressed in comparable monetary units compatible with optimisation
Internalise social externalities	Monetisation of social impacts	Proxy-based valuation (employment income, productivity, vulnerability indicators)	Social impacts incorporated into the objective function as monetised or weighted parameters
Ensure mathematical tractability	Definition of modelling structure	Optimisation formulation	Solvable optimisation model capable of representing long-term expansion decisions
Capture territorial heterogeneity	Regional disaggregation of parameters	Use of region-specific datasets for demand, resources, socio-economic and environmental indicators	Spatially explicit representation of the Brazilian electricity system
Translate indicators into model parameters	Parameterisation and calibration	Conversion factors, harmonisation of units, consistency checks	Robust and traceable set of model parameters
Represent system constraints realistically	Formulation of technical, environmental, and social constraints	Capacity limits, demand balance, emissions bounds, regional constraints	Feasible and realistic solution space reflecting system limitations
Explore uncertainty and policy priorities	Scenario construction	Parametric scenario design (BAU and alternative scenarios)	Consistent comparison of expansion pathways under different planning conditions
Research objective	**Methodological step**	**Tool / approach**	**Expected outcome**
Support long-term decision-making	Simulation and comparative analysis	Scenario-based optimisation and result interpretation	Identification of trade-offs, synergies, and robust strategies for sustainable expansion
Ensure transparency and replicability	Documentation and validation procedures	Explicit methodological documentation and internal consistency checks	Reproducible, transparent, and scientifically robust modelling framework

Source: Author's elaboration.

3.2. General Structure of the Methodological Process

The methodological process adopted for the development of SEGeP follows a structured and sequential logic designed to ensure transparency, replicability, and alignment between conceptual foundations, empirical

data, and mathematical modelling. This structure comprises a set of interdependent stages that progressively refine the model, enabling a rigorous representation of sustainability dimensions in the planning of electricity generation.

The first stage consisted of defining the scope of the model, including the temporal horizon, geographical disaggregation, set of technologies to be evaluated, and the sustainability dimensions to be incorporated. This step ensured coherence between the research objectives and the modelling requirements, establishing the boundaries necessary for the subsequent methodological procedures.

The second stage involved the compilation, processing, and systematization of the data required for the model. This included the collection of regional information on demand, capacity factors, technological parameters, social indicators, environmental impact metrics, and economic variables. All data sources were catalogued, referenced, and associated with specific parameters to ensure full traceability. This stage also included the harmonization of units, time series adjustment, and gap-filling procedures for variables with inconsistent or incomplete records.

The third stage consisted of transforming raw data into modelling parameters. For each indicator selected in the previous methodological step, conversion factors were applied to express impacts in compatible units and to enable monetization when applicable. Environmental impacts, for example, were converted using emission factors, water consumption coefficients, land-use metrics, and established social cost values. Social indicators were linked to regional attributes and incorporated as parameters associated with each technology-region combination. This step is methodologically necessary to ensure commensurability among heterogeneous indicators and to avoid distortions in the optimisation process.

The fourth stage focused on structuring mathematical formulation. This included defining decision variables, constructing the Total Social Cost objective function, and developing constraints representing technical, environmental, and economic limits. The structure of the formulation was designed to ensure consistency of units, linearity requirements, and feasibility across the full set of regions and technologies. All modelling assumptions were explicitly documented to guarantee methodological transparency.

The final stage consisted of internal verification of the logic and numerical consistency of the model, including dimensional analysis, validation of parameter magnitudes, cross-checking of data sources, and computational testing with simplified scenarios to ensure stability prior to full implementation.

This sequential methodological structure ensures that the SEGeP model is supported by a rigorous, replicable, and well-documented process, capable of accurately representing the multidimensional nature of sustainable electricity planning in Brazil.

Table 3.2 - Methodological classification of indicators considered in the SEGeP framework and their level of operational integration

Dimension	Indicator	Unit	Methodological Approach	Level of Integration
Economic	CAPEX	€/MW	Direct cost parameter	Fully operationalised
Economic	OPEX (fixed and variable)	€/MWh	Direct cost parameter	Fully operationalised
Environmental	CO_2 emissions	tCO_2/MWh	Monetised (carbon pricing)	Fully operationalised
Environmental	SO_2 emissions	kg/MWh	Monetised (damage cost)	Fully operationalised
Environmental	NO_x emissions	kg/MWh	Monetised (damage cost)	Fully operationalised
Environmental	Water consumption	m^3/MWh	Monetised (scarcity-based value)	Fully operationalised
Environmental	Land use	m^2/MW	Monetised (land opportunity cost)	Fully operationalised
Environmental	Solid waste generation	kg/MWh	Proxy reference (literature-based)	Conceptual / not directly operationalised
Environmental	Liquid effluents	m^3/MWh	Proxy reference	Conceptual / not directly operationalised
Environmental	Noise impact	dB	Qualitative proxy	Conceptual / not directly operationalised
Environmental	Energy efficiency	%	Performance parameter (implicit)	Conceptual / indirectly represented
Social	Employment generation	jobs/GWh	Monetised proxy (employment factor)	Partially operationalised
Social	Access to electricity	% population	Analytical indicator	Conceptual / ex-post analysis
Social	HDI	Index	Contextual indicator	Conceptual / ex-post analysis
Social	Gini index	Index	Contextual indicator	Conceptual / ex-post analysis
Social	Unemployment rate	%	Contextual indicator	Conceptual / ex-post analysis
Social	GDP contribution	€	Contextual indicator	Conceptual / ex-post analysis
Social	Crime rate	occurrences/100k	Contextual indicator	Conceptual / ex-post analysis
Social	SDI (Social Development Index)	Index	Composite indicator	Conceptual / not operationalised

Source: Author's elaboration.

The indicators presented in Table 3.2 are not incorporated into the SEGeP model with the same level of operational integration. A distinction is made between indicators that are fully internalised within the optimisation model, those partially represented through proxy-based approaches, and those used solely for contextual or ex-post analytical purposes.

Only economic costs, CO_2 emissions, SO_2 and NO_x emissions, water consumption and land use are directly monetised and included in the objective function. Employment is incorporated through proxy-based monetisation, while the remaining indicators are used to support broader sustainability analysis without directly influencing the optimisation results.

Table 3.2 provides a systematic methodological classification of the indicators considered within the SEGeP framework, explicitly distinguishing their sustainability dimension, monetisation strategy, and mode of integration within the mathematical formulation. The purpose of this table is not merely descriptive, but epistemological and methodological: it clarifies how heterogeneous impacts are operationalised within the optimisation framework—where applicable—while preserving conceptual coherence and mathematical consistency.

The classification highlights that indicators are not treated homogeneously in the model. Economic variables—such as investment costs (CAPEX), operation and maintenance costs (OPEX), fuel costs, and transmission reinforcement costs—are fully monetised through direct market values, reflecting standard practices in generation expansion planning. Environmental externalities related to atmospheric emissions (CO_2, SO_2, and NO_x) are likewise fully monetised, based on consolidated damage-cost methodologies and social cost estimates widely adopted in the literature.

Other environmental impacts, including water consumption, land occupation, solid waste generation, liquid effluents, and noise, are incorporated—where applicable—through proxy-based monetisation approaches. These indicators are represented using proxy monetary values derived from scarcity factors, environmental coefficients, or unit reference costs, acknowledging both their relevance and the methodological limitations associated with their valuation.

Biodiversity impacts and effects on local communities are addressed through hybrid approaches, combining constrained integration—where explicitly modelled—and proxy-based representations, reflecting their complex, context-dependent nature and the absence of universally accepted monetary valuation methods.

Social indicators exhibit greater methodological diversity. Variables such as job creation and regional income effects are not directly incorporated into the optimisation model but are instead evaluated as ex-post analytical indicators derived from the model outputs. Indicators related to human development, inequality, energy vulnerability, unemployment, crime rates, and social development are not included in the optimisation structure and are used exclusively for contextual and interpretative analysis.

This distinction reflects both data limitations and the recognition that several social dimensions cannot be consistently operationalised within a cost-minimisation framework without compromising their conceptual integrity.

By explicitly distinguishing between direct monetisation, proxy-based monetisation, indirect integration, and hybrid constrained approaches, Table 3.2 demonstrates that monetisation in the SEGeP model is not ontological but instrumental. Monetary valuation is employed as a methodological device to enable comparability and optimisation, rather than as a claim about the intrinsic value of social or environmental

phenomena. This structured approach ensures that all relevant sustainability dimensions influence expansion decisions, while avoiding reductionist interpretations and preserving alignment with contemporary literature on second-best solutions, integrated assessment modelling, and energy justice.

3.3. Selection and Justification of Indicators

The selection of the indicators that constitute the empirical basis of the SEGeP model represents a central methodological step, since these variables determine the model's ability to capture, in a measurable and operationally robust way, the economic, environmental, and social impacts associated with the expansion of electricity generation in Brazil. The selection procedure followed a systematic and multi-criteria logic designed to ensure conceptual rigour, methodological consistency, and alignment with the overarching objective of developing a planning model oriented toward the Total Social Cost.

The process began with the broad identification of indicators recurrent in international reference studies on energy sustainability, life-cycle assessment, environmental economics, energy transitions, and energy justice. Reports from international organisations—such as the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), the Intergovernmental Panel on Climate Change (IPCC), the United Nations Development Programme (UNDP), the World Bank, and UN-Energy—were examined alongside technical databases on environmental and social impacts of power systems. This exploratory stage produced a comprehensive inventory of potentially relevant variables.

From this preliminary inventory, indicators were screened according to three core criteria. First, conceptual relevance, which assesses whether the indicator clearly represents the impact dimension it is intended to measure, ensuring conceptual distinctiveness and avoiding redundant indicators.

Second, measurability, defined as the ability to quantify the indicator objectively with clear units, reliable databases, and methodological coherence suitable for integration into the monetization process and the mathematical formulation.

Third, data availability and quality, ensuring that indicators can be consistently operationalized across regions and throughout the time horizon considered in the SEGeP model.

Following this initial screening, a consistency analysis was conducted to identify undesired correlations and to evaluate potential redundancies between variables. This involved comparisons of historical series, variance analyses, and assessments of regional scales to guarantee a balanced and non-overlapping set of indicators. The selected indicators were subsequently grouped into three major sustainability dimensions—

economic, environmental, and social—ensuring alignment with the conceptual framework of sustainable energy planning and the analytical structure of the Total Social Cost approach.

Given the explicit commitment of this research to aligning the mathematical model with the 2030 Agenda for Sustainable Development, each indicator was additionally mapped to the Sustainable Development Goals (SDGs) most directly associated with its impact dimension. This mapping improves transparency, enhances replicability, and strengthens the conceptual justification for incorporating these variables into a sustainability-oriented planning model.

In order to systematize these relationships, Table 3.3 presents the full set of selected indicators, their sustainability dimension, associated SDGs, a concise justification, and the corresponding monetization pathway required for incorporation into the SEGeP objective function.

Table 3.3 - Selected Indicators, Sustainability Dimensions, SDG Alignment, and Monetization Pathways.

Indicator	Dimension	Associated SDGs	Justification	Monetization
Investment cost (CAPEX)	Economic	SDG 7, SDG 8, SDG 12	Determines economic viability and long-term system expansion.	Direct (€/MW)
Operation and maintenance cost (OPEX)	Economic	SDG 7, SDG 12	Reflects operational efficiency and lifecycle performance.	Direct (€/MWh)
Fuel cost	Economic	SDG 7, SDG 13	Critical for thermal plants; affects emissions and tariffs.	Direct (€/MWh)
Transmission reinforcement cost	Economic	SDG 7, SDG 12	Supports integration of new generation; reduces losses.	Direct (€/MW or €/km)
Regional capacity factors	Economic	SDG 7	Captures spatial heterogeneity of renewable resources.	Indirect
CO_2 emissions	Environmental	SDG 13, SDG 7	Central climate indicator; extensively consolidated.	High (€/tCO_2e)
SO_2 emissions	Environmental	SDG 3, SDG 12	Major health pollutant; relevant for coal and oil plants.	High (€/t)
NO_x emissions	Environmental	SDG 3, SDG 12	Contributes to respiratory illness and acidification.	High (€/t)
Water consumption	Environmental	SDG 6, SDG 12	Critical in hydropower and thermal generation; sensitive to climate risk.	Moderate (€/m^3)
Land use / land occupation	Environmental	SDG 12, SDG 15	Key impact of wind, solar, and hydropower projects.	Variable (€/m^2 or €/ha)
Noise	Environmental	SDG 3, SDG 11	Relevant near wind farms and urban thermal plants.	Moderate
Solid waste generation	Environmental	SDG 12, SDG 3	Important for solar, batteries, and thermal systems.	Moderate (€/t)
Liquid effluents	Environmental	SDG 6, SDG 12	Relevant in biomass, coal, and gas plants.	Moderate (€/m^3)
Biodiversity impact	Environmental	SDG 15, SDG 12	Critical in hydropower and large-scale renewables.	Medium
Energy efficiency / material intensity	Environmental	SDG 12, SDG 7	Captures resource use efficiency and lifecycle performance.	Indirect
Job creation	Social	SDG 8, SDG 10	Central for just transition and regional development.	High (€/job)

Indicator	Dimension	Associated SDGs	Justification	Monetization
Energy access / energy vulnerability	Social	SDG 7, SDG 10	Captures structural inequality and territorial gaps.	Indirect
Human Development Index (HDI)	Social	SDG 10, SDG 11	Represents quality of life and regional disparities.	Indirect
Unemployment rate	Social	SDG 8, SDG 10	Reflects local economic structure and vulnerability.	Indirect
Gini index	Social	SDG 10	Measures income inequality affected by energy investments.	Indirect
Regional GDP	Social	SDG 8	Indicates regional economic capacity and development potential.	Indirect
Crime rate	Social	SDG 16	Proxy for social vulnerability and cohesion.	Indirect
Impacts on local communities	Social	SDG 10, SDG 11	Essential for projects sited in indigenous, rural, or traditional areas.	Variable
Share of renewable energy by region	Social / Environmental	SDG 7, SDG 13	Indicates alignment with decarbonisation and equity across regions.	Indirect
Social Development Index (SDI)	Social	SDG 10, SDG 11	Complements distributive and inequality assessments.	Indirect

Source: Author's elaboration.

Following the systematization presented in Table 3.3, the final stage consisted of validating each indicator with respect to its monetization potential, a requirement for incorporation into the SEGeP objective function. This validation examined the availability of scientific bases for estimating the economic value of environmental and social impacts—whether through damage factors, epidemiological models, productivity impacts, willingness-to-pay estimates, or international benchmark values. Only indicators with sufficiently robust pathways for quantitative conversion were retained in the final model structure.

This procedure ensures that the SEGeP model integrates a coherent, methodologically rigorous, and conceptually grounded set of indicators, capable of representing the multidimensional nature of sustainable electricity planning in the Brazilian context.

3.4. Procedures for the Monetisation of Externalities

The monetisation of externalities constitutes a central methodological step in the construction of the SEGeP framework, as it enables the integration of heterogeneous sustainability dimensions within a unified optimisation structure oriented towards total social cost. This process involves the systematic transformation of physical, environmental and selected social indicators into economically comparable values, allowing their direct incorporation into the objective function or, where appropriate, into complementary model constraints (Sovacool et al., 2021; OECD, 2022; USEPA, 2023).

From a methodological perspective, the monetisation process is grounded in the assumption that externalities can be represented, at least partially, through proxy economic values that reflect their marginal social cost. This assumption is well established in the literature for several environmental impacts—particularly

greenhouse gas emissions and local pollutants—through approaches such as the Social Cost of Carbon and damage-cost valuation methods (IPCC, 2022b; IEA, 2021). However, its application to social dimensions is more complex, as these often involve non-market effects, distributive implications and context-specific dynamics (Carley & Konisky, 2020; Sovacool et al., 2021). For this reason, the SEGeP framework adopts a differentiated but internally coherent approach to the treatment of environmental and social externalities.

In general terms, the monetisation procedure can be formally represented as the transformation of a physical impact indicator into an economic cost through the application of a conversion coefficient, such that:

$$\text{Externality Cost} = \text{Physical Impact} \times \text{Monetisation Coefficient}$$

where the physical impact represents the quantified magnitude of a given externality (e.g., emissions, resource use or social effect), and the monetisation coefficient reflects the estimated marginal social cost associated with that impact, expressed in monetary units. This general formulation is consistent with widely adopted approaches in environmental economics and energy system modelling (Sovacool et al., 2021; OECD, 2022), providing a coherent basis for the integration of different types of externalities within a common analytical framework.

The operationalisation of this process requires the definition of three fundamental elements: (i) the selection of relevant indicators, (ii) the quantification of their physical magnitude, and (iii) the identification of appropriate monetisation coefficients. These coefficients are derived from established sources in the literature, official reports and internationally recognised methodologies, ensuring consistency with existing valuation practices while maintaining compatibility with the structure of the optimisation model.

The overall methodological structure of this process is illustrated in Figure 3.3, which synthesises the sequence from indicator identification to monetisation and integration into the optimisation framework. The figure highlights the transformation pathway from conceptual sustainability dimensions to operational model inputs, emphasising the role of monetisation as a bridge between qualitative frameworks and quantitative decision-making.

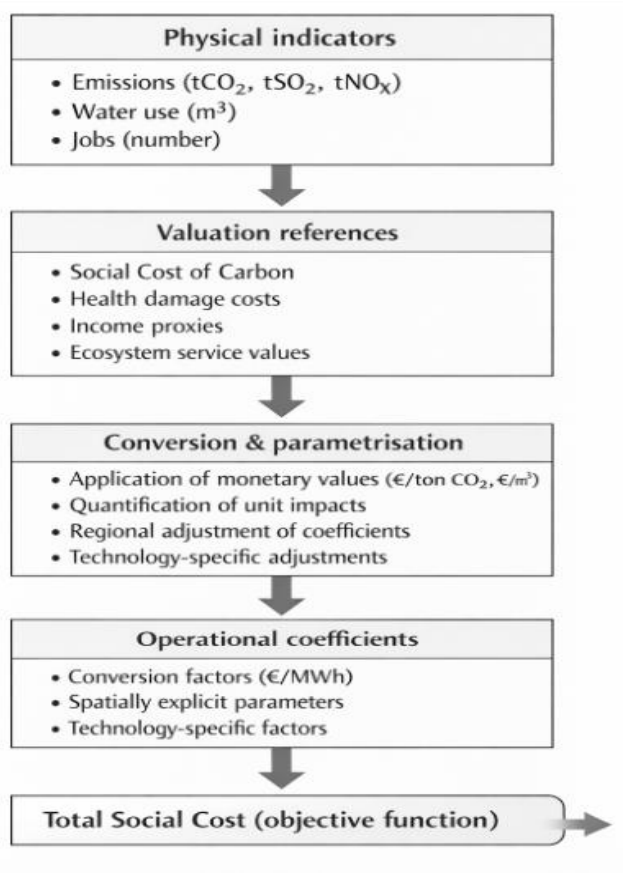


Figure 3.3 - Methodological process for the monetisation and operationalisation of socio-environmental externalities in the SEGeP model.
Source: Author's elaboration

3.4.1 General Structure of the Monetisation Process

The monetisation process adopted in this thesis follows a structured and sequential logic. First, sustainability indicators aligned with environmental and social dimensions are identified based on relevance, measurability and data availability (Allen et al., 2019; Nerini et al., 2018). Second, these indicators are quantified in physical terms, ensuring compatibility with the temporal and regional structure of the model. Third, monetisation coefficients are applied to convert physical impacts into economic values, enabling their integration into the total social cost framework.

This process reflects the varying degree of methodological maturity associated with different sustainability dimensions. Environmental externalities are generally more amenable to direct monetisation due to the availability of established valuation methods, whereas social externalities require a more flexible and context-sensitive treatment.

3.4.2 Monetisation of the Economic Component

The economic component of the model is directly represented through conventional cost elements, including capital expenditure (CAPEX), operational expenditure (OPEX) and, where applicable, fuel costs. These elements are inherently expressed in monetary terms and therefore do not require additional transformation. However, their integration within the total social cost framework requires strict consistency in units and temporal representation, ensuring comparability with monetised externalities and avoiding distortions in the optimisation process.

3.4.3 Monetisation of Environmental Externalities

Environmental externalities are monetised through the application of damage-cost and social-cost approaches, which estimate the economic value associated with environmental impacts. In the case of greenhouse gas emissions, the Social Cost of Carbon (SCC) is employed as a reference metric, reflecting the marginal global damage associated with an additional unit of CO_2 emissions (IPCC, 2022b; IEA, 2021). Similarly, local pollutants such as SO_2 and NO_x are valued based on health damage functions and exposure-response relationships, often calibrated using region-specific parameters (USEPA, 2023; OECD, 2022).

Resource use indicators—such as water consumption and land occupation—are monetised using proxy values derived from scarcity pricing, opportunity costs or environmental valuation studies, depending on data availability and regional context (Bielecki et al., 2020; Vasquez-Arroyo et al., 2020). These approaches allow environmental impacts to be incorporated directly into the objective function as cost components, ensuring that their effects are internalised within the optimisation process.

At the same time, it is recognised that not all environmental impacts can be fully captured through monetary valuation alone. For this reason, certain critical dimensions—such as biodiversity protection or maximum resource-use thresholds—are also represented through explicit model constraints. This complementary approach ensures that key sustainability limits are respected even when monetisation is subject to uncertainty or methodological limitations.

3.4.4 Monetisation of Social Externalities

The monetisation of social externalities presents greater methodological challenges, due to the multidimensional and often non-market nature of these impacts. Indicators such as employment generation, regional development and social inclusion involve complex causal relationships that cannot always be directly translated into monetary values (Carley & Konisky, 2020; Sovacool et al., 2021).

To address this limitation, the SEGeP framework adopts a hybrid approach. Where robust valuation methods are available, social impacts are incorporated through proxy monetisation, using coefficients that

reflect their estimated economic relevance. In other cases, social dimensions are represented through complementary mechanisms, including model constraints or ex post evaluation metrics derived from model outputs.

This approach is consistent with recent literature, which highlights the limitations of purely monetary representations of social impacts and the need for complementary modelling strategies (Sovacool et al., 2021; Allen et al., 2019). Importantly, this differentiated treatment does not imply a secondary role for social dimensions; rather, it reflects a methodological choice aimed at preserving analytical consistency while acknowledging the limits of current valuation techniques.

3.4.5 Aggregation into the Total Social Cost

The final step of the monetisation process consists in the aggregation of economic costs and monetised externalities into a unified objective function representing the total social cost of electricity generation. This aggregation is performed under the condition of unit consistency and temporal alignment, ensuring that all components are expressed in comparable monetary terms.

The resulting objective function integrates: (i) conventional economic costs, (ii) monetised environmental externalities, and (iii) selected social cost components, complemented where necessary by constraint-based representations of critical sustainability dimensions. This hybrid structure allows the model to internalise a broad set of impacts while maintaining computational tractability and methodological coherence.

It is important to emphasise that the objective of the monetisation process is not to fully reduce all sustainability dimensions to purely economic terms, but rather to provide a structured and operational mechanism through which heterogeneous impacts can be incorporated into the optimisation framework. In this sense, monetisation is understood as a pragmatic tool that enhances comparability and decision-making, while being complemented by additional modelling elements that capture non-monetisable aspects of sustainability.

In Chapter 4, the results should be interpreted in light of this methodological construction. Differences between scenarios should not be understood merely as variations in aggregate cost, but as reconfigurations of the trade-offs between economic efficiency, environmental impacts, and social benefits. For instance, scenarios with higher shares of renewable energy or greater regional decentralisation tend to reflect the explicit internalisation of externalities that remain invisible in the Business-as-Usual scenario.

Thus, the monetisation of externalities does not constitute an end in itself, but rather an analytical mechanism designed to reveal hidden costs, neglected benefits, and territorial asymmetries, providing a more robust basis for the evaluation of public policies and long-term energy planning strategies.

3.5. Construction and Structuring of Planning Scenarios

Scenario analysis constitutes a central methodological component of this research, as it enables the examination of the SEGeP model's behaviour under different planning configurations, reflecting distinct structural, environmental, and social conditions. Within the context of this thesis, scenarios are employed as analytical instruments, designed to explore how changes in parameters and constraints influence optimal generation expansion decisions, rather than as deterministic forecasts of future energy pathways.

Scenario construction builds upon the monetisation framework previously established, using alternative parametric configurations to examine how variations in constraints and exogenous drivers reshape the optimal expansion trajectory and its trade-offs across the Total Social Cost components. The monetary valuation does not replace qualitative, institutional or participatory approaches to sustainability assessment, nor does it seek to exhaust the multidimensional nature of social and environmental impacts. Instead, it constitutes a necessary mathematical condition for formal decision-making within linear and mixed-integer programming models, allowing externalities to influence optimisation outcomes in a transparent, consistent and operational manner. The underlying social and environmental realities remain intrinsically complex and multidimensional; monetisation is therefore used strictly as a comparative and analytical mechanism, rather than as a normative or exhaustive representation of social welfare or ecological value.

This approach is consistent with the international literature on long-term energy planning, in which scenario construction is widely used to assess trade-offs, identify tensions between competing objectives, and analyse the sensitivity of optimisation outcomes to alternative institutional and socio-environmental frameworks. Accordingly, scenarios play a pivotal role in linking the mathematical formulation of the model to the substantive interpretation of the results presented in Chapter 5.

3.5.1. Methodological Framework of the Scenarios

The scenarios analysed in this investigation are defined as parametric configurations of the SEGeP model, all derived from a common mathematical structure. Across all scenarios, the sets, decision variables, and objective function remain unchanged. Differences between scenarios are introduced exclusively through explicit modifications to exogenous parameters and to the bounds imposed on selected model constraints.

This methodological choice ensures that observed differences in results stem directly from the planning conditions represented in each scenario, rather than from structural alterations to the model formulation. As a result, scenarios can be compared in a consistent and transparent manner, allowing for a clear interpretation of the effects associated with prioritising specific dimensions—economic, environmental, or social—within the electricity generation expansion process.

3.5.2. Reference Scenario (Business-as-Usual – BAU)

The reference scenario, designated as Business-as-Usual (BAU), serves as the analytical baseline against which all alternative scenarios are evaluated. This scenario represents an expansion trajectory consistent with prevailing planning practices in the Brazilian electricity sector, as reflected in official medium- and long-term energy planning documents.

Under the BAU scenario, the model operates using conventional demand projections and standard technological parameters, without the imposition of additional targets that explicitly prioritise stricter environmental constraints or specific social objectives. Environmental and social externalities remain represented within the model, but are not subject to particularly restrictive limits, thereby reflecting the dominant framework adopted in traditional planning exercises.

The primary function of the BAU scenario is to provide an analytical reference, enabling the identification of the extent to which an expansion trajectory driven mainly by private economic criteria may generate elevated total social costs when compared to alternative configurations. This reference is essential for the analysis conducted in Chapter 5, where deviations from the BAU scenario are interpreted as indicators of potential improvements in sustainability performance.

3.5.3. Definition of Alternative Scenarios

The alternative scenarios considered in this thesis are constructed from the BAU scenario through controlled modifications to parameters and constraints previously defined within the methodology. Each scenario emphasises a specific dimension of sustainable energy planning, reflecting distinct public policy priorities or structural conditions relevant to the Brazilian context.

The variations introduced in the alternative scenarios include, either individually or in combination:

1) More stringent environmental constraints related to atmospheric emissions, water resource use, or land occupation;
2) Reinforced targets for the participation of renewable energy sources;
3) Minimum requirements associated with social indicators, such as employment creation or regional development;
4) Conditions of increased structural pressure on the system, including accelerated demand growth or reduced availability of natural resources.

The definition of these scenarios derives directly from the scientific objectives of the thesis, which seek to understand how the explicit internalisation of environmental and social externalities alters optimal electricity

generation expansion decisions. In all cases, changes are introduced based on parameters already defined within the model, ensuring full consistency with the formulation presented in Chapter 4.

3.5.4. Exogenous Elements and Endogenous Model Responses

For each scenario, a clear distinction is maintained between elements defined exogenously and the endogenous responses generated by the optimisation process. Exogenous elements include demand projections, technological costs, environmental and social coefficients, and the limits imposed on constraints. In contrast, the expansion of installed capacity, generation dispatch, composition of the electricity mix, and the value of the total social cost emerge endogenously from the model's solution.

This distinction is fundamental for the interpretation of the results presented in Chapter 5, as it allows observed differences between scenarios to be attributed to the planning conditions considered, rather than to arbitrary modifications in the model's structure.

The structuring of scenarios establishes the methodological framework required for the comparative analysis developed in Chapter 5. In that chapter, the results of each scenario are presented systematically, enabling an assessment of how different planning priorities affect the total social cost, the regional distribution of generation, environmental emissions, and the social impacts associated with the expansion of the electricity system.

This scenario-based methodological design allows the analysis to focus on structural trade-offs rather than point forecasts, consistent with the exploratory nature of long-term energy planning.

In this way, scenario analysis constitutes the bridge between the mathematical formulation of the SEGeP model and the substantive evaluation of the simulated expansion pathways, allowing for an integrated interpretation of trade-offs and synergies between economic efficiency, environmental sustainability, and social justice in electricity generation planning.

CHAPTER 4 - FORMULATION OF THE SEGeP MODEL

This chapter presents the formal formulation of the Sustainable Electricity Generation Expansion Planning model (SEGeP), which constitutes the analytical core of this thesis. The formulation developed herein does not represent a purely technical or computational construct; rather, it emerges as a direct methodological consequence of the conceptual and epistemological framework established in the preceding chapters.

All parameters used in the SEGeP model are classified into observed, derived, calibrated, and identified categories. While some inputs are directly obtained from official datasets, others are constructed through explicit calibration and identification procedures based on observable regional indicators.

In particular, environmental and territorial coefficients such as land opportunity cost, water scarcity cost, and pollutant damage factors are not directly observed in the required unit and spatial resolution. These parameters are therefore introduced as calibrated coefficients, whose construction and numerical derivation are fully documented in Appendix C.

This approach ensures that all model inputs are transparent, reproducible, and consistent with the empirical structure of the Brazilian energy system.

Electricity generation expansion is treated in this thesis as a multidimensional decision problem, in which economic efficiency, environmental integrity, and social equity jointly determine the notion of optimality. From this perspective, the formulation of SEGeP is guided by a fundamental methodological premise: sustainability dimensions must be internalised within the decision problem itself, rather than evaluated ex post or appended as auxiliary indicators. The mathematical structure of the model is therefore designed to operationalise this premise within a coherent optimisation framework.

SEGeP is explicitly formulated to address a structural limitation recurrently identified in both the academic literature and official energy planning instruments, namely the predominance of expansion models oriented exclusively toward the minimisation of private system costs. From a methodological standpoint, this limitation is not merely normative but analytical. By excluding environmental and social externalities from the objective function, conventional models systematically underestimate the full social cost of expansion alternatives and constrain the interpretability of their optimal solutions.

The formulation proposed in this chapter responds to this gap through the explicit internalisation of environmental and social externalities, using monetisation procedures grounded in the environmental and social valuation literature. Importantly, monetisation is not adopted as an ontological reduction of environmental or social phenomena to monetary terms, nor as a substitute for qualitative or institutional

analysis. Instead, it is employed as an instrumental and mathematical condition that enables heterogeneous impacts to be integrated into a unified optimisation criterion, ensuring analytical consistency and decision relevance.

Throughout this chapter, it is demonstrated how SEGeP results from a critical engagement with classical generation expansion planning models, combined with advances in externality valuation and sustainability-oriented optimisation. The resulting formulation allows multidimensional impacts to exert a direct and traceable influence on expansion decisions, in a manner consistent with the objectives of the energy transition and with internationally recognised sustainability frameworks, particularly the Sustainable Development Goals.

The chapter is organised according to a progressive and methodologically grounded structure. Section 4.1 revisits the theoretical foundations that justify the proposed approach, emphasising how developments in energy planning theory, externality economics, and sustainability-oriented optimisation motivate the structural choices adopted in the model. Section 4.2 presents the general architecture of SEGeP, explicitly linking these theoretical premises to the adoption of a Total Social Cost–oriented formulation.

Section 4.3 defines the sets, parameters, and decision variables, clarifying how technological diversity, regional heterogeneity, and sustainability dimensions are operationalised within the model. Section 4.4 formalises the objective function, showing how economic costs, environmental damages, and social effects are aggregated into a single optimisation criterion, enabling analytically consistent comparison across alternative expansion pathways. Section 4.5 introduces the system of constraints, structured to reflect not only technical feasibility but also environmental limits, hydrological conditions, and social requirements related to employment and territorial equity.

Finally, Section 4.6 provides a systemic interpretation of the complete formulation, highlighting how the interaction between objective function and constraints allows SEGeP to capture the trade-offs inherent to contemporary electricity planning. This interpretation clarifies the extent to which the proposed model overcomes the structural limitations of conventional planning instruments used in the Brazilian electricity sector and establishes a coherent methodological foundation for the scenario analysis developed in Chapter 5.

4.1. Theoretical Foundations of the SEGeP Formulation

The formulation of the Sustainable Electricity Generation Expansion Planning Model (SEGeP) is grounded in a consolidated theoretical framework that reflects the methodological evolution of energy planning from a predominantly techno-economic exercise toward an explicitly multidimensional decision process. Over recent decades, electricity generation expansion has ceased to be understood solely as a problem of capacity

adequacy and cost minimisation, becoming instead a challenge shaped by climate constraints, social impacts, and pronounced territorial heterogeneity.

From a methodological perspective, SEGeP emerges as a response to this evolution. The model is not conceived as a rupture with established optimisation traditions, but as a structured extension of them, justified by the increasing inadequacy of purely cost-based formulations to address contemporary planning objectives. Its theoretical foundation rests on the critical integration of three complementary strands of the literature: (i) classical electricity generation expansion planning models grounded in economic optimisation; (ii) the economic theory of externalities and the associated methods for environmental and social valuation; and (iii) recent developments in sustainability-oriented optimisation and integrated decision-support approaches.

The convergence of these strands provides the epistemological basis for the methodological choice to structure SEGeP as an optimisation model that explicitly internalises environmental and social impacts. Rather than treating such impacts as external constraints, qualitative annotations, or secondary outputs, the model incorporates them directly into the objective function and constraint system, thereby redefining the meaning of optimality in generation expansion planning.

In this sense, SEGeP aligns electricity generation planning with the principles of sustainable development, energy transition, and social equity that increasingly guide energy policy at both national and international levels. The formulation presented in this chapter thus constitutes not only a mathematical representation of the expansion problem, but a formal expression of a planning paradigm in which economic performance, environmental responsibility, and social outcomes are treated as structurally interdependent dimensions of decision-making.

Taken together, the theoretical strands discussed in this section establish the conceptual and methodological conditions under which a sustainability-oriented generation expansion model can be coherently formulated. Classical optimisation frameworks provide the necessary mathematical structure, while the theory of externalities and sustainability-oriented valuation literature supply the analytical instruments required to internalise multidimensional impacts within the decision problem.

From this perspective, the formulation of SEGeP does not represent an arbitrary extension of traditional expansion models, but rather the formal translation of a clearly defined methodological stance: if electricity planning is to support sustainable development objectives, then economic, environmental, and social impacts must be represented at the same analytical level within the optimisation structure.

The following section operationalises these theoretical premises by presenting the general architecture of the SEGeP model. In doing so, it explicitly links the conceptual foundations discussed above to the structural

choices adopted in the formulation, particularly the adoption of a Total Social Cost–oriented objective function and the integrated treatment of sustainability-related constraints.

4.1.1. Theory of Externalities and Environmental and Social Valuation

The second theoretical pillar underpinning SEGeP derives from the economic theory of externalities, particularly the foundational contributions of Pigou and subsequent developments in environmental economics. The concept of total social cost arises from the recognition that market prices fail to fully internalise the collateral effects associated with the production and consumption of goods and services, thereby generating persistent market failures (Pigou, 1920).

In the electricity sector, the relevance of externalities is well documented. Generation and capacity expansion are associated with greenhouse gas emissions, local air pollutants, intensive water use, land occupation, impacts on sensitive ecosystems, and a wide range of social effects, including population displacement, regional inequalities, and labor conditions. The environmental valuation literature provides a consistent methodological basis for monetizing these impacts, enabling their explicit incorporation into economic analyses and optimisation-based planning models.

Key valuation approaches include the estimation of the social cost of carbon (Nordhaus, 2017), the monetization of health impacts associated with air pollution (WHO, 2016), cost attribution for water use under conditions of scarcity (Gleick, 2014), and the economic assessment of ecosystem service losses and socio-territorial impacts arising from large-scale energy projects (Fan & Hyndman, 2019).

In parallel, contemporary research in development economics recognizes that job creation, regional economic dynamization, and improvements in well-being indicators constitute relevant positive externalities whose social value is not captured by the private cost structure of generation technologies. Empirical studies indicate that certain renewable energy value chains exhibit a higher capacity to generate local employment, stimulate regional economies, and support more inclusive development trajectories (IRENA, 2022; OECD, 2021b).

By systematically incorporating both negative and positive externalities into its formulation, SEGeP operationalizes the concept of total social cost, allowing expansion decisions to be evaluated not only on the basis of direct economic performance but also in terms of their broader environmental and social implications over the life cycle of electricity generation technologies.

Classical electricity generation expansion planning models were originally developed to support long-term investment decisions under conditions of demand growth and technological uncertainty, with the primary objective of ensuring supply adequacy at the lowest possible system cost. These formulations emerged in the

context of vertically integrated power systems and are predominantly based on the minimisation of direct economic costs, including investment expenditures, operation and maintenance costs, and fuel expenses, subject to technical and reliability constraints (Shahidehpour et al., 2002).

Seminal approaches such as Dynamic Generation Expansion Planning and Integrated Resource Planning provided structured analytical frameworks capable of representing sequential expansion decisions over extended planning horizons (Pereira & Pinto, 1991). Within these models, the notion of optimality is narrowly defined in terms of private system costs, while environmental and social considerations—when included—are typically introduced as exogenous constraints or qualitative adjustments, exerting limited influence on the optimisation outcome.

Although these models remain methodologically robust and computationally efficient, their structural limitation lies in the exclusion of environmental and social externalities from the objective function. By neglecting the broader impacts associated with electricity generation, such as emissions, resource depletion, territorial effects, and employment dynamics, traditional formulation systematically underestimates the true social cost of expansion pathways. SEGeP builds upon this classical foundation while explicitly extending its analytical scope to internalise such externalities within the optimisation structure itself.

4.1.2. Sustainability-Oriented Optimisation and Integrated Approaches

The third theoretical axis of the SEGeP formulation is grounded in recent advances in sustainability-oriented optimisation and integrated decision-support methodologies. Contemporary literature increasingly recognizes that energy planning is inherently multidimensional, involving objectives that are often conflicting, such as cost minimisation, emissions reduction, employment generation, water security, system resilience, and territorial equity (Ürge-Vorsatz et al., 2016).

Multicriteria decision-making models and hybrid formulations, including goal programming, ε-constraint methods, and Pareto frontier-based approaches—have been widely applied to capture these trade-offs. However, such approaches face significant limitations, particularly regarding the interpretation of results, the reliance on subjective weighting schemes, and the absence of a common metric that allows direct comparison between impacts of different natures (Lei et al., 2021).

SEGeP adopts an alternative strategy, firmly anchored in the valuation literature, by converting environmental and social impacts into monetary terms and integrating them directly into the objective function. This theoretical choice avoids the arbitrariness associated with subjective weighting and allows the optimal solution to be interpreted as the minimisation of an integrated performance metric that simultaneously reflects economic efficiency, environmental responsibility, and social outcomes.

The adoption of a Mixed-Integer Linear Programming (MILP) formulation further ensures mathematical rigour, analytical transparency, and the capacity to represent discrete investment decisions—features that are essential for modelling real-world generation expansion processes.

4.1.3. Justification of the Approach in the Brazilian Context

The Brazilian electricity sector introduces an additional layer of complexity to generation expansion planning, requiring analytical approaches that go beyond conventional cost-minimisation frameworks. The country's historical reliance on large-scale hydropower, combined with increasing exposure to prolonged droughts, pronounced regional inequalities, a high untapped potential of non-hydropower renewable sources, and the need to expand supply in line with economic growth, highlights the structural inadequacy of traditional planning models centered exclusively on private costs (EPE, 2023a; ONS, 2022).

From an operational perspective, the Brazilian system is particularly sensitive to hydrological variability. Climate change has intensified the frequency and severity of drought events, directly affecting reservoir inflows, generation reliability, and system security. Models that treat hydropower availability as a deterministic or weakly constrained parameter tend to underestimate systemic risks and distort expansion decisions. In this context, the explicit representation of hydrological vulnerability becomes a necessary condition for credible long-term planning.

At the same time, the territorial dimension of the Brazilian electricity system is marked by substantial socioeconomic heterogeneity. Regions that host large-scale generation projects—especially hydropower plants, wind farms, and transmission infrastructure—do not necessarily coincide with those that capture the economic benefits of expansion. Employment generation, income effects, social disruption, and exposure to environmental impacts are unevenly distributed across space, reinforcing the need for models capable of representing region-specific social externalities.

The formulation of SEGeP responds directly to these structural characteristics by introducing a modelling architecture that allows:

- The explicit representation of hydrological vulnerability through region-specific parameters related to water availability and operational constraints, reflecting differentiated exposure to climate-induced risks;
- The incorporation of regional social asymmetries via localized indicators of employment, development, and social impacts, enabling the identification of distributive effects associated with alternative expansion pathways;

- The comparison of generation technologies not only in terms of private economic costs but also with respect to their environmental and social externalities, internalised within a unified decision framework;
- The integration of environmental targets aligned with the Sustainable Development Goals and the Paris Agreement, operationalized through national and regional emission limits and associated constraints;
- The evaluation of just energy transition strategies by means of constraints and penalty mechanisms that regulate the spatial distribution of benefits and burdens arising from capacity expansion.

Within this framework, SEGeP transcends the role of a purely technical optimisation model. It operates as a conceptual and analytical instrument that translates the contemporary challenges of the Brazilian electricity sector—climate risk, territorial inequality, environmental responsibility, and social justice—into quantitative conditions capable of informing strategic decision-making. This contextual grounding provides the necessary foundation for the formal model structure introduced in Section 4.2, where these principles are translated into sets, parameters, decision variables, and constraints.

4.2. General Structure of the SEGeP Model

The formulation of the SEGeP model is based on a conceptual architecture designed to represent, in an integrated and consistent manner, the economic, environmental, and social dimensions of electricity generation expansion planning in Brazil. Although inspired by classical optimisation models widely used in the electricity sector, SEGeP goes beyond a strictly cost-minimisation logic by explicitly incorporating measurable externalities and by redefining the role of both the objective function and the system constraints in light of the conceptual framework developed in Chapter 2.

This approach allows the model to represent the expansion process not merely as a technical-economic problem, but as a long-term strategic decision, constrained by environmental targets, social impacts, and territorial inequalities—elements that remain largely underrepresented in traditional planning instruments.

4.2.1. A Total Social Cost–Oriented Approach

The central structural element of SEGeP lies in the adoption of the Total Social Cost (TSC) as the primary system performance metric. In contrast to conventional formulations that minimize only direct costs, SEGeP defines its objective function as the monetary aggregation of three fundamental components:(i) direct economic costs, including capital expenditure (CAPEX), operation and maintenance costs (OPEX), and fuel

costs; (ii) monetized environmental externalities, associated with atmospheric emissions, water resource consumption, land use, and biodiversity impacts; (iii) quantifiable social externalities, related to net job creation, regional effects, and the territorial distribution of benefits and burdens arising from expansion.

By expressing all impacts in a common monetary unit, SEGeP enables a direct comparison of alternative expansion pathways under analytically homogeneous conditions. This methodological choice reduces the arbitrariness inherent in multicriteria approaches based on subjective weighting schemes and positions sustainability as a structural component of the optimisation process rather than as a set of ex post constraints.

4.2.2. Representation of Expansion and Operation Decisions

The mathematical structure of SEGeP is organised around two complementary sets of decision variables:

1) Investment variables, associated with the expansion of installed capacity for each technology i, in each region r and period t. These variables, continuous or discrete depending on the technology, determine the configuration of the generation fleet and constrain future operational possibilities;
2) Generation variables, which represent the actual amount of electricity produced by each technology throughout the planning horizon, subject to physical limits, resource availability, capacity factors, and region-specific environmental constraints.

This distinction allows the model to capture the essential duality of energy planning: expansion decisions define the system's infrastructure, while operational decisions materialize, over time, the economic, environmental, and social impacts of that infrastructure. The interdependence between both dimensions is ensured through energy balance constraints, maximum capacity limits, and resource utilization constraints, typical of MILP formulations applied to generation expansion planning.

4.2.3. Structural Integration of Externalities

A distinctive feature of the SEGeP architecture is the structural integration of externalities from the outset of the mathematical formulation. Unlike approaches that treat environmental and social impacts as marginal penalties or ex post adjustments, SEGeP incorporates these dimensions as core elements of the optimal decision.

1) For each impact category—economic, environmental, and social—the model consistently associates:
2) physical parameters, such as tonnes of CO_2 per MWh, cubic meters of water per MWh, or jobs per MW installed;

3) monetary parameters, including the social cost of carbon, water scarcity values, and economic valuations associated with net employment;
4) sustainability constraints, reflecting environmental targets, resource availability limits, and minimum social requirements.

This structure ensures that externalities influence the optimal solution at the same analytical level as investment costs or system adequacy constraints, allowing the model to explicitly represent the trade-offs inherent in alternative technological choices.

4.2.4. Temporal Horizon, Regionalisation, and Technological Granularity

The spatial–temporal decomposition of SEGeP was designed to reflect the structural conditions of the Brazilian electricity system. The analysis horizon spans from 2025 to 2050, with annual resolution, allowing the model to capture dynamic effects, cumulative investment trajectories, and the temporal evolution of environmental and social impacts.

Regional disaggregation follows the subdivision of the National Interconnected System (SIN) into four subsystems—North, Northeast, Southeast/Central-West, and South—enabling the representation of:

1) spatial variations in energy resource availability;
2) differentiated regional economic dynamics;
3) territorial asymmetries in job creation and social impacts;
4) region-specific environmental constraints.

Regarding technological granularity, the model explicitly distinguishes the main generation technologies—hydropower, wind, solar, biomass, natural gas, coal, nuclear, and storage—assigning each specific operational, environmental, and social characteristic. This representation avoids excessive simplifications and enables more realistic analyses, particularly in decarbonisation and diversification contexts.

4.2.5. Structural Targets and System Constraints

The SEGeP architecture incorporates a set of structural targets that act as normative anchors for generation expansion, including:

1) renewable energy penetration targets;
2) absolute emission reduction targets;
3) physical limits on water and land use;
4) minimum social targets related to employment and regional distribution.

These targets operate coexist with classical system constraints, such as supply–demand balance, installed capacity limits, capacity factor constraints, and reliability requirements. The articulation of normative targets and technical constraints ensures that the model simultaneously reflects the physical-operational reality of the electricity system and the strategic objectives of the energy transition.

4.2.6. MILP Formulation and Computational Coherence

The choice of a Mixed-Integer Linear Programming (MILP) formulation is motivated by three central considerations: the need to represent discrete investment decisions, the preservation of linearity in the objective function to ensure analytical interpretability, and the computational feasibility of solving the model over long-time horizons and multiple analytical configurations.

MILP thus provides the mathematical foundation that combines rigour, transparency, and computational efficiency, ensuring that SEGeP is suitable both for academic research and as a potential analytical instrument to support public policy decision-making in the electricity sector.

The general structure of the SEGeP model, as described in this section, defines the conceptual architecture through which sustainability considerations are embedded into generation expansion planning. However, the analytical consistency of this architecture ultimately depends on its formalisation through well-defined mathematical elements.

In optimisation-based models, the explicit specification of sets, parameters, and decision variables is not a merely technical step, but a methodological one. These elements determine how technological diversity, regional heterogeneity, temporal dynamics, and sustainability dimensions are represented, constrained, and evaluated within the decision problem.

Accordingly, the next section details the sets, parameters, and decision variables that constitute the foundational layer of the SEGeP formulation. This formal specification ensures transparency, reproducibility, and interpretability of the model, while establishing a direct correspondence between the conceptual framework developed in previous chapters and the mathematical structure that supports the scenario analysis presented in Chapter 5.

4.3 Sets, Parameters and Decision Variables

The formalization of the SEGeP model requires a rigorous definition of sets, parameters, and decision variables. These elements constitute the foundational layer of the mathematical formulation and allow for a precise representation of technological diversity, regional heterogeneity, temporal dynamics, and the environmental and social externalities that characterize the Brazilian electricity system. A clear and consistent

specification of these components ensures the interpretability of the model and its analytical coherence with the scenario analysis presented in Chapter 5.

4.3.1 Sets

The model is structured around the following sets:

- I: set of generation technologies
- R: set of regions
- T: set of planning periods
- E: set of emission types (e.g., CO_2, SO_2, NO_x)
- K: set of sustainability dimensions subject to aggregate control (economic, environmental, social)

These sets provide a modular structure that allows expansion and operation decisions to be consistently linked to regional resource availability, technological characteristics, and sustainability targets defined at national and international levels.

4.3.2 Parameters

The parameters of the SEGeP model represent the physical, economic, environmental, and social characteristics associated with electricity generation technologies and regional electricity systems. These parameters constitute the exogenous inputs of the model and define the techno-economic, environmental, and socio-economic conditions under which the optimisation problem is solved. The techno-economic parameters adopted in the SEGeP model are detailed in Appendix A.

Their specification is essential for ensuring the explicit internalisation of environmental and social externalities within the objective function and for representing the structural characteristics of the Brazilian electricity system.

The main parameters of the SEGeP model are defined as follows:

Economic parameters

- CAPEX_i: Investment cost of technology i, expressed in €/MW. This parameter represents the capital expenditure required to install new generation capacity of technology i. Investment costs are defined based on reference-year techno-economic datasets and are assumed to be constant across planning periods.
- FOM_i: Fixed operation and maintenance cost of technology i, expressed in €/MW·year. This parameter represents the annual fixed costs required to maintain installed capacity independently of electricity generation.

- VOM_i: Variable operation and maintenance cost of technology i, expressed in €/MWh. This parameter represents the variable operating costs associated with electricity generation.

Technical parameters:

- $\mathrm{CF}_{i,r}$: Capacity factor of technology i in region r (dimensionless). This parameter represents the average utilization rate of generation capacity and reflects regional differences in renewable resource availability and operational characteristics.
- $D_{r,t}$: electricity demand in region r at time t
- η: minimum system reliability margin

Environmental parameters

- $\mathrm{EF}_{i,e}$: emission factor of technology i for emission type e
- WF_i: water consumption factor of technology i
- LF_i: land use per MW installed of technology i
- BDF_i: biodiversity disturbance factor associated with technology i

Social parameters

- J_i: number of jobs created by MW installed of technology i
- HDI_r: Human Development Index of region r, used in equity-related constraints
- GINI_r: regional income inequality indicator
- U_r: unemployment rate in region r

Monetization parameters

- SCC $_{r,t}$ (€/t): social damage cost for pollutant e (SCC for CO_2 e; damage costs for SO_2/NO_x)
- $\mathrm{SCW}_{r,t}$(€/m³): scarcity/social cost of water
- SCL_r(€/ha): land occupation value
- SCB_r(€/index): biodiversity value proxy
- $VJ_{r,t}$(€/job): valuation of employment (can be region-specific)

Policy/limits

- $\Theta_{e,t}$(t): emission caps
- $\Omega_{r,t}$(m³): maximum water availability in region r during period t
- Λ_r(ha): land availability
- Ψ_r(index): biodiversity threshold

- Φ_t(jobs): minimum jobs target (if used) per time t

These parameters enable the conversion of heterogeneous environmental and social impacts into monetized values, allowing their aggregation within the Total Social Cost (TSC).

4.3.3 Decision Variables

Investment and capacity variables

- $x_{i,r,t}$(MW): installed capacity of technology i in region r at time t
- $\Delta x_{i,r,t} \geq 0$(MW): new capacity added of technology i in region r at time t
- $y_{i,r,t} \in \{0,1\}$: binary variable indicating the discrete decision to invest in new capacity of technology i in region r at time t, when applicable

This structure ensures a clear distinction between capacity stock, incremental investment, and optional discrete investment decisions, avoiding ambiguity in the interpretation of expansion dynamics and cost attribution.

In the SEGeP formulation, installed capacity is represented as a stock variable $x_{i,r,t}$(MW), defined for each technology $i \in I$, region $r \in R$, and planning period $t \in T$. The initial condition is explicitly imposed at the first period t_0, such that x_{i,r,t_0} is an exogenous parameter representing the existing installed capacity at the beginning of the planning horizon. Capacity evolution is modelled through the accumulation of new additions $\Delta x_{i,r,t}$(MW), as specified in Eq. (8). This assumption is adopted to preserve linearity and to focus the analysis on expansion pathways. When required, the formulation can be extended to include retirement or lifetime constraints by introducing a retirement variable $ret_{i,r,t} \geq 0$(MW) and modifying Eq. (8) to $x_{i,r,t} = x_{i,r,t-1} + \Delta x_{i,r,t} - ret_{i,r,t}$, or alternatively by applying technology-specific lifetime tracking through survival coefficients.

Generation variables

- $g_{i,r,t}$ (MWh): electricity generation from technology i in region r at time t

Environmental and social impact variables

- $\mathrm{CO2}_{i,r,t}$: emissions associated with technology i in region r at time t
- $W_{i,r,t}$: water consumption associated with generation with technology i in region r at time t
- $L_{i,r,t}$: land occupation associated with installed capacity for technology i in region r at time t

- $B_{i,r,t}$: biodiversity impact of technology i in region r at time t

Aggregate system indicators

- EMISS_t: total emissions in period t
- JOBS_t: total jobs generated in period t
- TSC_t: total social cost in period t

4.3.4 Data provenance, source hierarchy and parameter calibration in the SEGeP model

The credibility and analytical robustness of long-term planning models depend directly on the traceability and empirical grounding of their parameters. In the SEGeP model, all sets, parameters and coefficients used in the mathematical formulation are explicitly associated with identifiable data sources and clear calibration rules, ensuring methodological transparency, reproducibility of results and consistency with best international practices in energy planning.

Parameter calibration in SEGeP follows a formal hierarchy of data sources. Whenever available, official Brazilian data are prioritised, obtained from public institutions responsible for energy planning, socio-economic statistics and environmental management, namely the Energy Research Office (EPE), the National Electric System Operator (ONS), the Ministry of Science, Technology and Innovation (MCTI), the Brazilian Institute of Geography and Statistics (IBGE) and the Agência Nacional de Águas e Saneamento Básico (ANA). These sources constitute the primary reference for economic parameters, demand projections, installed capacity, observed capacity factors, regional social indicators and physical system limits.

However, for certain parameters that are essential for the explicit internalisation of environmental and social externalities—such as technology-specific water use, land occupation, employment generation by technology, biodiversity pressure and the monetisation of environmental damages—no official Brazilian datasets are available in a systematic form with the level of disaggregation required by the SEGeP structure. In these cases, the model adopts international proxy values derived exclusively from widely recognised institutional sources in energy and environmental planning, including the IPCC, IRENA, OECD, the European Environment Agency (EEA), DEFRA, the National Renewable Energy Laboratory (NREL) and other governmental bodies with consolidated methodologies.

The use of international proxies is a well-established methodological practice in long-term energy planning models and allows for parametric completeness, dimensional consistency and international comparability, without compromising the internal coherence of the model. In all cases, the adopted values preserve the order of magnitude and the economic, environmental or social sign of the corresponding

externalities. All parameters are harmonised to the model's unit system, converted to the adopted base year and expressed in euros, ensuring temporal and monetary consistency throughout the planning horizon.

In SEGeP, the temporal index t denotes the planning period used in the optimisation. In this thesis, t represents annual periods (calendar years), i.e., $t \in \{t_0, t_0 + 1, \dots, T\}$, consistent with the temporal granularity of the main Brazilian planning sources used for calibration (e.g., PDE cost and demand projections). All energy quantities are therefore interpreted on an annual basis (e.g., MWh per year). This definition ensures that the model's decision variables and constraints are internally consistent in terms of units and time aggregation.

To avoid artificial time dynamics and over-parameterisation, SEGeP assigns the index t only to parameters that are explicitly assumed to vary over time, either because they are available as official annual projections (e.g., investment costs $CAPEX_i$, fuel costs $FUEL_{i,t}$, regional demand $D_{r,t}$, and expansion limits $X_{i,r,t}^{max}$) or because the underlying concept is defined as time-dependent (e.g., the social cost of carbon $SCC_{CO_2,t}$, which is reported as a year-specific marginal damage series). Conversely, when no credible update rule or projection is adopted, parameters are treated as time-invariant in real terms and are therefore written without t (e.g., SCC_{SO_2}, SCC_{NOx}, and $CF_{i,r}$ as annual average capacity factors), ensuring transparency about what changes with time and what is structurally fixed in the modelling framework.

Table 4.1 presents the complete traceability of the parameters used in SEGeP, indicating, for each element, the unit of measurement, the primary data source, the proxy source when applicable, and the corresponding calibration rule adopted in the model.

This framework ensures that all parameters of the SEGeP model are fully traceable, empirically grounded and governed by explicit calibration rules, preventing the introduction of arbitrary values and reinforcing the scientific legitimacy of the formulation. The combined use of official national data and institutional international proxies enables the model to reconcile empirical rigour, parametric completeness and practical applicability, providing a solid foundation for the sustainable electricity generation planning scenarios analysed in subsequent chapters.

Table 4.1 - Traceability and calibration of SEGeP model parameters.

Element	Unit	Primary source	Proxy source (when applicable)	Calibration rule in SEGeP
$CAPEX_i$	€/MW	Empresa de Pesquisa Energética – EPE (2024b). *Plano Decenal de Expansão de Energia 2034: Caderno de Custos de Geração e Transmissão.* Brasília: EPE/MME.	—	Investment costs by technology, region and year according to official PDE projections
$OPEX_{i,r}$	€/MW · year	EPE (2024c). *Caderno de Custos PDE 2034.* Brasília: EPE/MME.	—	Operating costs by technology, represented through fixed (FOM), variable (VOM), and fuel cost components (constant real values)
FOM_i	€/MW · year	EPE (2024c). *Caderno de Custos PDE 2034.*	—	Fixed O&M per technology
VOM_i	€/MWh	EPE (2024c). *Caderno de Custos PDE 2034.*	—	Variable O&M per technology
$FUEL_{i,t}$	€/MWh	EPE (2025a). *Balanço Energético Nacional 2025.* Brasília: EPE/MME.	—	Projected fuel prices by year and technology
$CF_{i,r}$	—	Operador Nacional do Sistema Elétrico – ONS (2025). *Séries históricas de geração e fatores de capacidade do SIN.* Rio de Janeiro: ONS.	EPE (2024b). *Premissas operativas do PDE 2034.*	Annual average capacity factor by technology and region
$D_{r,t}$	MWh	EPE (2024b) *Plano Decenal de Expansão de Energia 2034.*	ONS (2025). *Histórico de carga do SIN.*	Regional electricity demand projections per year
η	—	ONS (2025). *Critérios de confiabilidade operativa do SIN.*	—	Minimum system reliability margin
H	h	Model convention (2025).	—	8,760 annual operating hours
$X_{i,r,t}^{max}$	MW	EPE (2024b). *Potenciais técnicos e limites regionais de expansão – PDE 2034.*	—	Maximum expansion limit per period
$EF_{i,e}$	t/MWh	Ministério da Ciência, Tecnologia e Inovação – MCTI (2025). *Fatores de emissão de CO_2 da geração elétrica – SIRENE.* Brasília.	IPCC (2006). *Guidelines for National Greenhouse Gas Inventories.*	Fuel-based emission factors converted to MWh
WF_i	m³/MWh	Li, Y.; Sarangi, S.; Azevedo, I. (2020). *Water use intensity of electricity production in global energy transitions.* Nature Communications, 11, 2489.	Meldrum, J. et al. (2020). *Life-cycle water use for electricity generation.* Environmental Research Letters, 15.	Average operational water consumption factor by technology
LF_i	ha/MW	Lovering, J.; Swain, M.; Blomqvist, L.; Hernandez, R. (2022). *Land-use intensity of electricity production.* PLOS ONE, 17, e0270155.	Kiesecker, J. et al. (2021). *Minimizing land use impacts of renewable energy development.* BioScience, 71(6), 504–515.	Land-use intensity converted from ha/TWh to ha/MW using $CF_{i,r}$
BDF_i	index/MW	Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services – IPBES (2022). *Assessment Report on Biodiversity and Ecosystem Services Valuation.* Bonn.	—	Ecological pressure proxy per technology
J_i	jobs/GWh	International Renewable Energy Agency – IRENA (2024). *Renewable Energy and Jobs – Annual Review.*	International Labour Organisation – IRENA & ILO (2024). *Employment*	Direct and indirect employment per capacity

			impacts of energy transitions.	
HDI_r	–	PNUD; IPEA; FJP (2025). *Atlas do Desenvolvimento Humano no Brasil.*	–	Aggregated regional human development indicator
$GINI_r$	–	Instituto Brasileiro de Geografia e Estatística – IBGE (2025). *PNAD Contínua – Indicadores de desigualdade de renda.*	–	Regional income inequality index
U_r	%	IBGE (2025). *PNAD Contínua – Taxa de desocupação regional.*	–	Regional unemployment rate
$SCC_{CO_2,t}$	€/t	United States Environmental Protection Agency – EPA (2023). *Report on the Social Cost of Greenhouse Gases.*	Environment and Climate Change Canada – ECCC (2024). *Social Cost of GHG Estimates.*	Annual social cost series converted to euros
SCC_{SO_2}	€/t	UK Department for Environment, Food & Rural Affairs – Dubey et al. (2025). *Air Quality Damage Cost Guidance.*	European Environment Agency – EEA (2024). *Health and environmental damage costs of air pollution.*	Average marginal damage cost per tonne
SCC_{NOx}	€/t	Dubey et al. (2025). *Air Quality Damage Cost Guidance.*	Ostalé Valriberas et al. (2023). *Economic Consequences of Outdoor Air Pollution.*	Environmental and health damage cost per tonne
$SCW_{r,t}$	€/m³	Agência Nacional de Águas e Saneamento Básico – ANA (2024). *Preços unitários de cobrança pelo uso de recursos hídricos.*	–	Official water-use charge by region
SCL_r	€/ha	Receita Federal do Brasil (2025). *Valores da Terra Nua (VTN) para fins de ITR.*	–	Average bare land value by region
SCB_r	€/index	IPBES (2022). *Ecosystem services valuation framework.*	–	Proxy valuation of ecosystem services
$VJ_{r,t}$	€/job	IBGE (2025). *PNAD Contínua – rendimento médio do trabalho.*	–	Average regional labour income
$\Theta_{e,t}$	t	Ministério de Minas e Energia –Brazil (2025). *Diretrizes de planejamento energético nacional e metas de emissões.*	–	Emission limits defined by scenario
$\Omega_{r,t}$	m³	ANA (2025). *Relatórios de disponibilidade hídrica regional.*	–	Regional water availability
Λ_r	ha	IBGE (2025). *Base territorial e uso do solo do Brasil.*	–	Available land after legal and environmental exclusions
Ψ_r	index	IPBES (2022). *Biodiversity indicators and thresholds.*	–	Regional biodiversity threshold
Φ_t	jobs	Author-defined scenario parameter, calibrated from regional labour-market indicators and technology-specific employment coefficients derived from IBGE (2025) and IRENA and ILO (2024).	–	Minimum employment target per period
ρ_r	–	Model definition	–	Minimum regional participation share
π_e^{em}	€/t	Model definition	–	Penalty for emission constraint violations
π^{soc}	€/job	Model definition	–	Penalty for social target non-compliance
π^{wat}	€/m³	Model definition	–	Penalty for excessive water use

Source: Author's elaboration.

Note: The index t denotes annual planning periods. Parameters include $t$only when period-specific projections or explicit update rules are adopted; otherwise, parameters are assumed constant in real terms and indexed without t.

4.4 Total Social Cost Objective Function

The SEGeP objective function is defined as the minimisation of the Total Social Cost (TSC) over the planning horizon, integrating—within a linear and monetisable framework—the economic, environmental and social impacts associated with both capacity expansion and system operation decisions.

Let T denote the finite set of planning periods and t ∈ T the corresponding temporal index. In SEGeP, each period represents one calendar year, consistent with the temporal resolution adopted in the official Brazilian planning instruments used for calibration (e.g., PDE projections). Consequently, all energy quantities are expressed on an annual basis (MWh per year), and operating time is normalised through H = 8,760 hours per year. Temporal indexing is applied exclusively to parameters for which official projections or structural evolution are available, while the remaining parameters are treated as constant in real terms, ensuring coherence between data availability, modelling assumptions and dimensional consistency.

From a mathematical programming perspective, only terms that depend on optimisation variables can influence the optimal solution. Consequently, the objective function includes exclusively decision-dependent quantities, i.e., terms that depend on installed capacity decisions $\left(x_{i,r,t}, \Delta x_{i,r,t}\right)$, generation levels $\left(g_{i,r,t}\right)$. Purely exogenous parameters or regional descriptors are not inserted directly into the objective, since they would act as constants and would not affect the optimisation outcome.

Accordingly, the objective function is expressed in Equation (4.1):

$$\min \; TSC \; = \; \sum_{t \in T} \left(C_t^{econ} \; + \; C_t^{env} \; + \; C_t^{soc} \right) \qquad (4.1)$$

where:

- C_t^{econ}: represents direct economic costs (investment and operation);
- C_t^{env} : aggregates monetized environmental externalities (emissions, water use, land occupation, biodiversity);
- C_t^{soc} : represents monetized social impacts (including employment-related benefits/costs and other social externalities, as operationalized in Chapter 3);

The SEGeP model adopts a hybrid approach for the representation of socio-environmental externalities, combining monetised cost components with constraint-based formulations. This modelling choice reflects the

need to balance analytical consistency, economic interpretability and the inherent limitations associated with the monetisation of certain sustainability dimensions.

The monetisation of externalities enables their internalisation within the objective function, allowing the optimisation process to account for marginal social costs associated with environmental impacts and selected social effects. In this context, monetised externalities act as economic signals that influence the relative attractiveness of different technologies and expansion pathways, guiding the model towards solutions that minimise total social cost.

However, not all sustainability dimensions can be adequately or reliably captured through monetary valuation alone. Certain environmental and social aspects—such as biodiversity preservation, critical water-use thresholds or minimum social requirements—are characterised by non-linear effects, threshold behaviour or normative policy constraints that cannot be fully represented through marginal cost approximations. In such cases, the exclusive use of monetisation could lead to solutions that are economically optimal but environmentally or socially unacceptable.

To address this limitation, the SEGeP framework incorporates complementary constraint-based representations for selected dimensions. These constraints define admissible bounds for critical system variables, ensuring that essential sustainability conditions are satisfied independently of their monetised value. In this sense, constraints do not duplicate the role of monetised externalities; rather, they act as structural conditions that shape the feasible solution space within which economic optimisation is performed.

The coexistence of monetised components and explicit constraints does not imply double counting. The two mechanisms operate at different analytical levels and serve distinct purposes within the model structure. Monetisation captures the marginal contribution of externalities to total social cost, influencing the optimisation trajectory through continuous economic trade-offs. Constraints, by contrast, represent non-negotiable system limits or policy-driven requirements that restrict the set of feasible solutions.

Thus, while monetised externalities affect the objective function by penalising undesirable outcomes in proportion to their estimated social cost, constraints impose hard boundaries that prevent the model from selecting solutions that violate critical sustainability conditions. This distinction ensures that the model avoids the over-penalisation of impacts while preserving the integrity of key environmental and social safeguards.

The hybrid structure adopted in the SEGeP model is consistent with recent advances in energy system modelling, which recognise that a purely monetary representation of sustainability is insufficient to capture the full complexity of socio-environmental interactions. By integrating both approaches within a coherent optimisation framework, the model is able to reconcile economic efficiency with environmental protection and social considerations in a methodologically consistent manner.

4.4.1 Economic Cost Component

The economic terms capture the conventional cost structure of generation expansion planning, including new capacity investment and operational costs, expressed in Equation (4.2):

$$C_t^{econ} = \sum_{i \in I} \sum_{r \in R} \left(\text{CAPEX}_i \cdot \Delta x_{i,r,t} + \text{FOM}_i \cdot x_{i,r,t} + (\text{VOM}_i + \text{FUEL}_i) \cdot g_{i,r,t} \right) \quad (4.2)$$

In SEGeP, operating expenditures are represented through the standard decomposition into fixed and variable O&M components (FOM_i, VOM_i), while fuel costs are represented separately through the parameter $FUEL_i$, expressed in $\frac{€}{MWh}$and applied only to fuel-consuming technologies

All cost components are discounted using the same social discount rate, ensuring temporal comparability between capital expenditures, operating costs, and monetized externalities. Binary variables, when present in the model, are used exclusively to represent discrete investment decisions or activation constraints. They are not used as multiplicative factors for CAPEX parameters. This guarantees full dimensional consistency and avoids artificial distortion of investment magnitudes.

All economic, environmental and social cost components included in the Total Social Cost (TSC) function are expressed in monetary units (Euro) and are treated consistently within the same intertemporal discount framework.

Prior to scenario simulation, the algebraic formulation was verified for dimensional consistency to ensure that each term of the objective function yields comparable monetary values.

4.4.2 Environmental Cost Component

The environmental component internalises negative externalities associated with generation technologies by converting physical impacts into monetized social costs. It is expressed in Equation (4.3):

$$C_t^{env} = \sum_{i \in I} \sum_{r \in R} \left[\sum_{e \in E} \left(EF_{i,e} \cdot g_{i,r,t} \cdot SCC_{e,t} \right) + WF_i \cdot g_{i,r,t} \cdot SCW_r + LF_i \cdot x_{i,r,t} \cdot SCL_r + BDF_i \cdot x_{i,r,t} \cdot SCB_r \right] \quad (4.3)$$

Where:

- $\text{EF}_{i,e}$ is the emission factor of technology i for pollutant e;
- $\text{SCC}_{e,t}$ is the social cost per unit of pollutant e (including the carbon-equivalent case);

- WF_i denotes the water-use intensity of generation technology i, while SCW_r represents the monetised social cost of water consumption in region r.
- LF_i and SCL capture land occupation and its monetized cost for region r;
- BDF_i and SCB represent biodiversity-related impact intensity and its monetized cost for region r.

By embedding these terms directly into the optimisation criterion, the model ensures that environmental pressures—global (e.g., climate) and local (e.g., water stress, land occupation)—affect the cost-effectiveness ranking of technologies in a transparent and decision-relevant manner. The coefficients associated with emissions, land use, and water consumption are defined through calibrated parameters reflecting regional conditions. These parameters are not directly observed but constructed from benchmark values and observable indicators, as described in Appendix C.

4.4.3 Social Impact Component

The social component of the objective function captures the main monetisable social externalities associated with the expansion of electricity generation capacity, with emphasis on employment effects and distributional considerations across regions. Its inclusion reflects the premise that expansion decisions produce differentiated socio-economic impacts and that a sustainable expansion plan should be assessed beyond private cost efficiency. The parameters used for the computation of social indicators, including employment, Gini index, and HDI, are presented in Appendix C.

In SEGeP, social impacts are incorporated through optimisation-relevant terms, i.e., terms that depend on decision variables and therefore can influence the optimal solution. Regional socio-structural indicators such as income inequality (Gini), unemployment rate and human development are included in the model as exogenous descriptors of territorial vulnerability and are used to support the interpretation of results and the definition of policy-driven constraints and scenario assumptions. Because these indicators are not endogenously modified by generation expansion decisions within the present modelling scope, including them as purely regional constants in the objective function would not affect the optimal solution (it would only shift the objective value by a fixed amount). For methodological clarity and to prevent the inclusion of non-influential constants in the optimisation criterion, the social term is operationalised as follows.

The social cost component is defined in Equation (4.4):

$$C_t^{soc} = -\sum_{i \in I} \sum_{r \in R} \left(J_i \cdot \Delta x_{i,r,t} \cdot VJ_r \right) \qquad (4.4)$$

where J_i is the employment coefficient (jobs/GWh) associated with technology i, $\Delta x_{i,r,t}$ denotes newly installed capacity (MW) in region r during year t, and VJ_r represents the average labour income per job in region r, used to monetise employment impacts.

The negative sign reflects the modelling convention adopted throughout SEGeP: employment generation is treated as a positive social externality that reduces the Total Social Cost.

Although labour income can vary over time, SEGeP adopts a conservative specification in which VJ is treated as constant in real terms (base-year values) and indexed only by region, VJ_r. This choice avoids introducing artificial time dynamics not supported by explicit long-term wage projections in the core dataset, while preserving the regional heterogeneity required to monetise social benefits consistently across territories. When annual regional wage observations or projections are available and explicitly adopted, the parameter can be represented as $VJ_{r,t}$without changing the structure of the model.

Regional socio-economic indicators, including inequality, unemployment and human development, are incorporated in SEGeP as structural descriptors of territorial conditions. These indicators support scenario interpretation and the formulation of equity-oriented constraints, providing contextual information about regional vulnerability. Employment effects, on the other hand, are directly linked to expansion decisions and are therefore internalised in the optimisation through technology-specific job creation coefficients and regional labour income parameters.

Although regional inequality and human development indicators do not enter the optimisation problem as decision variables, they are not treated in SEGeP as arbitrary post-processing statistics. Instead, they are interpreted as derived distributive indicators structurally linked to endogenous model outputs, particularly the regional allocation of capacity expansion, generation and employment effects. In this sense, the evolution of Gini and HDI across scenarios reflects the socio-territorial implications of the optimal expansion pathways, while preserving the methodological principle that only decision-dependent quantities should directly influence the optimisation outcome. For consistency and reproducibility, the evolution of the regional Gini index is estimated using a relative variation approach based on scenario-induced income effects.

Specifically, the projected Gini for each region and period is obtained by adjusting the baseline Gini value according to the relative change in income generated by employment and regional economic activity associated with the expansion pathway.

This relationship can be expressed as:

$$Gini_{r,t} = Gini_{r,0} \times \left(1 - \alpha \cdot \Delta Y_{r,t}\right) \qquad (4.5)$$

where $Gini_{r,0}$ represents the baseline regional inequality level, $\Delta Y_{r,t}$ denotes the relative income variation induced by the scenario, and α is a scaling parameter ensuring that variations remain within realistic bounds.

This formulation ensures that inequality trajectories are not arbitrarily defined but remain anchored in observed baseline conditions and consistently reflect the socio-economic impacts generated by the model.

For consistency with the modelling framework and to ensure methodological transparency, the Human Development Index (HDI) is not treated as a decision variable within the SEGeP optimisation model. Instead, it is defined as a derived socio-economic indicator, computed as a function of the endogenous outputs generated by the MILP formulation.

In particular, HDI is used to capture the broader social implications of the spatial allocation of investments, especially those related to employment generation and regional economic activity. Given that the model explicitly determines the distribution of generation capacity and associated employment effects across regions and time periods, HDI trajectories are estimated in a manner that preserves consistency with these endogenous results.

The projected HDI for each region r and period t is calculated using a relative variation approach anchored in baseline regional conditions. The formulation is given by:

$$HDI_{r,t} = HDI_{r,0} \cdot \left(1 + \beta \cdot \Delta Y_{r,t}\right) \qquad (4.6)$$

where:

- $HDI_{r,t}$ is the projected Human Development Index for region $r$in period t;
- $HDI_{r,0}$ is the baseline HDI value for region r, obtained from official statistics;
- $\Delta Y_{r,t}$ represents the relative socio-economic variation in region r and period t, proxied by changes in employment and economic activity induced by the optimal expansion pathway;
- β is a scaling parameter used to ensure that projected HDI values remain within realistic bounds and preserve comparability with observed historical ranges.

The term $\Delta Y_{r,t}$ is constructed from model outputs, particularly the variation in employment levels across regions and scenarios, thereby establishing a direct linkage between the optimisation results and the evolution of social development indicators.

It is important to emphasise that HDI does not influence the optimisation process itself, i.e., it is neither included in the objective function nor imposed as a constraint. Instead, it serves as an exogenous evaluation metric derived from endogenous model results. This approach ensures that the model remains

computationally tractable while allowing for a consistent assessment of social outcomes associated with different expansion scenarios.

By adopting this formulation, the SEGeP framework preserves internal methodological coherence: economic, environmental, and social dimensions are all quantified within a unified structure, with social indicators such as HDI and Gini being systematically derived from the same regionalised optimisation outputs. This guarantees transparency, reproducibility, and analytical consistency in the interpretation of results.

4.4.4 Complete Expression of the Objective Function

Bringing together the economic, environmental and social components previously defined, the SEGeP objective function can be written in compact form as the minimisation of the Total Social Cost (TSC) over the planning horizon. Consistent with the notation adopted throughout the formulation, time indexing is retained only for parameters defined as period-specific (e.g., projected costs, demand, adequacy margins and policy limits), whereas parameters assumed constant in real terms are expressed without t. Regional indices are retained whenever the underlying valuation or scarcity condition is territorially differentiated (e.g., water charges, land values and labour income).

The Total Social Cost (TSC) minimised over the planning horizon is given by:

$$\min \mathrm{TSC} = \sum_{t \in T} (C_t^{econ} + C_t^{env} + C_t^{soc}) \qquad (4.7)$$

where each component is expressed as:

$$C_t^{econ} = \sum_{i \in I} \sum_{r \in R} (CAPE\, X_{i,r,t}\, \Delta x_{i,r,t} + FOM_i\, x_{i,r,t} + (VOM_i + FUEL_{i,t})\, g_{i,r,t}),$$

$$C_t^{env} = \sum_{i \in I} \sum_{r \in R} (\sum_{e \in E} E\, F_{i,e}\, g_{i,r,t}\, SCC_{e,t} + WF_i\, g_{i,r,t}\, SCW_r + LF_i\, x_{i,r,t}\, SCL_r + BDF_i\, x_{i,r,t}\, SCB_r),$$

$$C_t^{soc} = - \sum_{i \in I} \sum_{r \in R} (J_i\, \Delta x_{i,r,t}\, VJ_r).$$

(4.8)

In this formulation, $x_{i,r,t}$ denotes installed capacity (MW), $\Delta x_{i,r,t}$ newly installed capacity (MW) in period t, and $g_{i,r,t}$ the electricity generated (MWh) by technology $i$in region r during period t. The

environmental term internalises monetised damages through pollutant-specific social costs $SCC_{e,t}$(when a time series is adopted), regional water scarcity charges SCW_r, and region-specific valuation parameters for land occupation and biodiversity pressure. The social term captures the employment-related co-benefit of expansion, monetised through technology-specific job coefficients $J_i$and regional labour income VJ_r, and enters the objective with a negative sign because job creation is treated as a positive externality that reduces the Total Social Cost.

The SEGeP framework incorporates environmental and social externalities primarily through their monetization within the objective function. This approach allows the optimisation process to internalise impacts that are typically excluded from conventional private-cost planning models.

In addition to the monetized representation of externalities, a limited number of environmental and system constraints are included in the model. These constraints do not replicate the cost components already internalised in the objective function. Instead, they represent normative or physical system limits that cannot be adequately captured through price signals alone.

The model follows a complementary "price-and-constraint" logic commonly adopted in sustainability-oriented energy planning models. Externalities are primarily internalised through economic valuation in the objective function, while specific constraints ensure compliance with structural system boundaries such as resource availability, ecological limits, and system reliability conditions.

This design prevents double counting of externalities while maintaining the ability of the model to represent both economic signals and structural planning constraints within a unified optimisation framework.

4.5 System Constraints

The SEGeP formulation is governed by a structured set of constraints designed to ensure the physical, technological, environmental, and social coherence of the electricity system throughout the planning horizon. These constraints constitute the backbone of the model, defining the admissible solution space within which the optimal expansion trajectory is determined.

Unlike conventional generation expansion models—typically focused on supply–demand balance and capacity adequacy—the SEGeP adopts an expanded constraint framework that explicitly reflects the multidimensional sustainability logic discussed in Chapter 2. In this context, technical feasibility, environmental limits, and social objectives are treated as structurally interdependent conditions rather than secondary adjustments.

For analytical clarity, the constraints are organised into six main blocks:

(i) supply–demand balance constraints;

(ii) installed capacity dynamics and expansion constraints;

(iii) generation and operational limits;

(iv) environmental constraints (emissions, water use, land occupation, biodiversity);

(v) social constraints (employment generation and regional equity);

(vi) aggregate sustainability constraints.

Each block is presented below together with its corresponding mathematical formulation.

4.5.1 Supply–Demand Balance Constraint

The supply–demand balance constraint constitutes the fundamental physical condition of the electricity system and ensures that, in each planning period, total electricity generation is sufficient to meet the exogenously projected demand. Within the SEGeP framework, this constraint guarantees that all feasible expansion and operation decisions respect the basic requirement of energy adequacy, while simultaneously enabling the interaction between economic costs, environmental externalities and social impacts.

The balance condition is defined for each planning period t, requiring total generation across all technologies and regions to meet the corresponding electricity demand. This specification reflects the operational characteristics of the Brazilian interconnected system (SIN), in which electricity is centrally dispatched and exchanged through the transmission network, allowing energy produced in one region to supply loads in another.

In the SEGeP formulation, the supply–demand balance constraint is expressed in Equation (4.9):

$$\sum_{r \in R} \sum_{i \in I} g_{i,r,t} \;\geq\; \sum_{r \in R} D_{r,t}\ (1+\eta), \forall t \in T \qquad (4.9)$$

Where $g_{i,r,t}$ denotes the amount of electricity generated by technology i in region r during period t, and D_t represents the exogenously defined electricity demand for the same region and period. The inequality form allows the model to accommodate system losses, reserve margins and operational flexibility, which are implicitly accounted for in capacity and generation constraints defined elsewhere in the formulation.

This constraint plays a central role in linking long-term expansion decisions to operational feasibility. By enforcing demand satisfaction at the national level, the model ensures that investment choices in generation

capacity translate into adequate energy supply under all simulated scenarios while preserving the economic benefits of interregional exchanges. At the same time, because generation decisions are embedded in the Total Social Cost objective function, the balance constraint interacts directly with environmental and social penalties, influencing the selection of technologies and the spatial allocation of new capacity.

In the context of scenario analysis, variations in demand trajectories—such as accelerated economic growth, energy stress conditions or efficiency-oriented pathways—are reflected directly through this constraint. As a result, the supply–demand balance condition enables the model to assess how different demand assumptions propagate through the expansion planning process, affecting technology choices, regional outcomes and sustainability performance.

4.5.2 Installed Capacity Dynamics

The evolution of installed generation capacity over time is a central structural element of long-term electricity generation expansion planning. In the SEGeP model, installed capacity dynamics are explicitly represented through an intertemporal accumulation process, linking capacity levels across consecutive planning periods and ensuring consistency between past investments, newly decided expansions and future operational possibilities.

The installed capacity of technology *i* in region *r* at period *t* is defined as the sum of the capacity available in the previous period and the additional capacity installed in the current period, as expressed in Equation (10):

$$x_{i,r,t} = x_{i,r,t-1} + \Delta x_{i,r,t}, \forall i \in I, \forall r \in R, \forall t > t_0 \qquad (4.10)$$

Where $x_{i,r,t}$ denotes the total installed capacity of technology *i* in region *r* at period *t*, $x_{i,r,t-1}$ represents the inherited capacity from the previous period, and $\Delta x_{i,r,t}$corresponds to newly installed capacity. This formulation captures the cumulative and path-dependent nature of investment decisions, reflecting the long economic lifetime and quasi-irreversibility of generation assets.

To represent discrete investment decisions and practical constraints associated with deployment rates, the SEGeP model links capacity additions to binary investment variables through an upper-bound constraint, as shown in Equation (4.11):

$$\Delta x_{i,r,t} \leq y_{i,r,t} \cdot X_{i,r,t}^{max}, \forall i, r, t \qquad (4.11)$$

where $y_{i,r,t}$ is a binary decision variable indicating whether investment in technology *i* occurs in region *r* at period *t*, and $X_{i,r,t}^{\max}$ denotes the maximum installable capacity increment for that technology and region in the corresponding period. This structure ensures dimensional consistency between investment decisions and physical capacity expansion, while preserving the discrete nature of large-scale infrastructure investments.

The inclusion of maximum installable capacity limits reflects logistical, regulatory, financial and supply-chain constraints that restrict the speed at which new generation capacity can be deployed. These limits also capture regional characteristics such as land availability, grid integration capacity, licensing processes and workforce constraints, thereby enhancing the realism of the expansion dynamics.

From a modelling perspective, the installed capacity dynamics enforce irreversibility and intertemporal coherence in the optimisation process. Once capacity is installed, it remains available in subsequent periods, influencing both operational feasibility and future investment decisions. As a result, early-period choices exert long-lasting effects on the system's evolution, reinforcing the importance of long-term planning under sustainability considerations.

By integrating these dynamics into the SEGeP formulation, the model ensures that expansion pathways are physically plausible, temporally consistent and aligned with real-world deployment constraints. This representation provides a robust foundation for evaluating trade-offs between technologies, regions and scenarios, while maintaining coherence between investment decisions and the operational structure of the electricity system.

4.5.3 Generation Limits and Capacity Factors

The operational feasibility of electricity generation in the SEGeP model is ensured through explicit constraints linking generation levels to installed capacity and technology- and region-specific capacity factors. This formulation guarantees coherence between long-term expansion decisions and the physically achievable electricity output of each generation technology under regional resource conditions.

Electricity generation from technology *i* in region *r* during period *t* is bounded by the available installed capacity and the corresponding capacity factor, as expressed in Equation (4.12):

$$g_{i,r,t} \leq CF_{i,r} \cdot x_{i,r,t} \cdot H, \forall i \in I,\ \forall r \in R,\ \forall t \in T \qquad (4.12)$$

where $g_{i,r,t}$ denotes the amount of electricity generated, $x_{i,r,t}$ represents the installed capacity of technology i in region r at period t, $CF_{i,r}$ is the average capacity factor reflecting regional resource availability and technological performance, and H corresponds to the number of operating hours within the planning period, typically defined as annual hours.

The capacity factor encapsulates the combined effects of resource availability, technological efficiency, maintenance requirements and operational constraints. For dispatchable technologies, such as thermal and large hydroelectric plants, the capacity factor reflects operational strategies, fuel availability and maintenance schedules. For variable renewable energy sources, including wind and solar power, it represents the statistical availability of the underlying resource and captures regional climatic characteristics.

By incorporating region-specific capacity factors, the SEGeP model accounts for spatial heterogeneity in renewable potential and operational performance, allowing the optimisation process to differentiate between technologies not only by cost but also by their effective contribution to energy supply. This feature is particularly relevant in large and geographically diverse systems, such as the Brazilian electricity system, where resource availability varies significantly across regions.

From a modelling perspective, this constraint ensures dimensional consistency between capacity expansion and energy production and prevents infeasible solutions in which generation exceeds physical or technical limits. It also establishes a direct link between investment decisions and operational outcomes, reinforcing the interdependence between long-term planning and system operation.

Consequently, the generation limits and capacity factor constraint plays a critical role in shaping the optimal generation mix under different scenarios. Variations in capacity factors—driven by regional conditions, climate assumptions or technological evolution—directly affect feasible generation levels and influence the trade-offs between technologies, regions and sustainability objectives within the SEGeP framework.

4.5.4 Emission Constraints

Environmental sustainability within the SEGeP framework is enforced through explicit emission constraints that limit the total amount of pollutants released by the electricity generation system in each planning period. These constraints operationalize national environmental targets, international climate commitments and the principles embedded in Sustainable Development Goal 13 (Climate Action), ensuring that expansion and operation decisions remain compatible with long-term decarbonisation pathways.

Total emissions of pollutant e in period t are constrained according to Equation (4.13):

$$\sum_{i \in I} \sum_{r \in R} EF_{i,e} \cdot g_{i,r,t} \leq \Theta_{e,t}, \forall e \in E, \forall t \in T \qquad (4.13)$$

Where $EF_{i,e}$ denotes the emission factor of pollutant *e* associated with technology *i*, $g_{i,r,t}$ represents electricity generation in region *r* and period *t*, and $\Theta_{e,t}$ corresponds to the maximum allowable emissions for pollutant *e* in the respective period.

The emission factors translate generation levels into environmental impacts, allowing the aggregation of emissions across technologies and regions. This structure enables the model to represent multiple pollutants—such as CO_2, SO_2 and NOx—within a unified and scalable formulation, while preserving technological differentiation and regional allocation of generation.

By embedding emission constraints in this manner, the SEGeP model ensures that climate and environmental objectives are treated as central structural elements of the planning problem rather than as external or secondary considerations. This approach enhances transparency, strengthens policy relevance and aligns long-term generation expansion decisions with national and international commitments to climate mitigation and sustainable development.

4.5.5 Water Use Constraints

Water availability constitutes a critical limiting factor in electricity generation systems, particularly in countries such as Brazil, where hydropower plays a dominant role. Climate variability, competing water demands and increasing frequency of hydrological stress events reinforce the need to explicitly incorporate water-use restrictions into long-term generation expansion planning.

Within the SEGeP framework, water use is constrained at the regional level to ensure that electricity generation remains compatible with sustainable hydrological conditions and does not compromise other essential water uses. This constraint directly operationalizes water-related sustainability objectives, including those associated with Sustainable Development Goal 6 (Clean Water and Sanitation), while also enhancing system resilience to climate-induced water scarcity.

Regional water consumption associated with electricity generation in period *t* is limited according to Equation (4.14):

$$\sum_{i \in I} WF_i \cdot g_{i,r,t} \leq \Omega_{r,t}, \forall r \in R, \forall t \in T \qquad (4.14)$$

Where WF_i denotes the water footprint coefficient of technology *i*, expressed as water consumption per unit of electricity generated, $g_{i,r,t}$ represents electricity generation in region *r* during period *t*, and $\Omega_{r,t}$ corresponds to the sustainable water availability for electricity generation in the same region and period.

The water availability parameter $\Omega_{r,t}$ is derived from hydrological assessments and reflects regional water balances, climatic conditions and competing water uses, such as agriculture, urban supply and ecosystem requirements. By imposing water constraints at the regional level, the model captures spatial heterogeneity in hydrological conditions and allows the assessment of differentiated impacts of generation expansion across regions.

This formulation enables the SEGeP model to identify trade-offs between water-intensive and water-efficient technologies, particularly under scenarios of hydrological scarcity. It also allows the evaluation of how climate change, demand growth or policy constraints influence the optimal generation mix when water availability becomes a binding resource.

By explicitly integrating water-use constraints into the optimisation structure, the SEGeP model ensures coherence between energy planning and water resource sustainability, reinforcing the nexus between energy, water and climate. This approach enhances the robustness and policy relevance of long-term generation expansion strategies in water-constrained electricity systems such as Brazil's.

4.5.6 Land Use Constraints

Land occupation constitutes a relevant physical and environmental limitation in electricity generation expansion planning, particularly for non-dispatchable renewable energy technologies such as wind and solar power, which typically require extensive surface areas per unit of installed capacity. In territorially heterogeneous countries such as Brazil, land availability varies significantly across regions and is subject to competing demands, including agriculture, environmental conservation, urban expansion and infrastructure development.

Within the SEGeP framework, land-use constraints are explicitly incorporated to ensure that capacity expansion decisions remain compatible with regional land availability and broader territorial sustainability objectives. This formulation contributes to the operationalisation of sustainability principles related to land-use efficiency, ecosystem preservation and spatial planning, in alignment with Sustainable Development Goals 11 (Sustainable Cities and Communities) and 15 (Life on Land).

Land occupation associated with installed generation capacity in region r is constrained in each planning period according to Equation (4.15):

$$\sum_{t\in T}\sum_{i\in I} L\,F_i \cdot x_{i,r,t} \leq \Lambda_r, \forall r \in R \qquad (4.15)$$

Land occupation associated with installed generation capacity in region r is constrained over the full planning horizon according to Equation (4.15). In this formulation, LF_i denotes the land footprint coefficient of technology i, expressed as land area required per unit of installed capacity; $x_{i,r,t}$ represents the installed capacity of technology i in region r in period t; and Λ_r corresponds to the total land availability effectively accessible for electricity infrastructure development in region r. Accordingly, the sum of land occupation across all technologies and planning periods cannot exceed the regional land-use limit. This specification is consistent with the interpretation of land availability as a structural territorial constraint for the full planning horizon, rather than as a yearly land cap.

By linking land occupation directly to installed capacity, this constraint ensures coherence between expansion decisions and long-term territorial impacts. It prevents infeasible or socially unacceptable solutions in which generation capacity expands beyond realistic land limits and allows the model to capture trade-offs between land-intensive and land-efficient technologies across regions.

From an analytical perspective, the land-use constraint plays a critical role in shaping the optimal deployment of renewable technologies, particularly under high-renewable or low-carbon scenarios. It introduces an explicit spatial dimension into the optimisation problem, reinforcing the interaction between energy planning, environmental protection and land-use governance.

By incorporating land occupation constraints into the SEGeP formulation, the model enhances its capacity to evaluate sustainable expansion pathways that respect territorial limits and competing land demands. This approach strengthens the realism, robustness and policy relevance of long-term electricity generation planning in regions where land availability is a binding constraint.

4.5.7 Biodiversity Protection Constraint

The preservation of biodiversity represents a fundamental pillar of sustainable electricity generation planning, particularly in countries with high ecological diversity and sensitive biomes, such as Brazil. Electricity generation projects—especially large-scale renewable installations and hydropower infrastructure—can generate significant pressures on ecosystems through habitat fragmentation, landscape alteration and interference with ecological processes. To explicitly account for these impacts, the SEGeP model incorporates a biodiversity protection constraint that limits ecological disturbance associated with generation expansion.

Within the SEGeP framework, biodiversity loss is constrained at the regional level to ensure that expansion decisions remain compatible with ecosystem resilience and conservation priorities. This formulation contributes directly to the operationalisation of sustainability objectives related to biodiversity protection, in alignment with Sustainable Development Goals 14 (Life Below Water) and 15 (Life on Land), as well as national conservation strategies.

Biodiversity impacts associated with installed generation capacity in region r are constrained over the full planning horizon according to Equation (4.16):

$$\sum_{t \in T} \sum_{i \in I} BD\, F_i \cdot x_{i,r,t} \leq \Psi_r, \forall r \in R \tag{4.16}$$

where BDF_i denotes the biodiversity disturbance factor of technology i, representing the relative ecological pressure per unit of installed capacity; $x_{i,r,t}$ corresponds to the installed capacity of technology i in region r in period t; and Ψ_r defines the maximum acceptable cumulative level of biodiversity disturbance in region r.

This formulation ensures that the total ecological pressure associated with installed generation capacity, aggregated across all planning periods, remains within the ecological tolerance threshold established for each region. This specification reflects biodiversity constraints as structural territorial limits over the full planning horizon, rather than as period-specific restrictions.

The parameter Ψ_r is derived from ecological sensitivity indicators, conservation priority zones and legally protected areas, reflecting regional differences in ecosystem vulnerability and environmental regulation. By incorporating spatially differentiated thresholds, the model captures the heterogeneity of ecological conditions and avoids uniform assumptions that could underestimate local biodiversity risks.

By linking biodiversity impacts to the cumulative installed capacity across the planning horizon, this constraint ensures that long-term expansion pathways remain compatible with ecological limits and discourages the concentration of land- and ecosystem-intensive technologies in environmentally sensitive regions. It also enables the model to evaluate trade-offs between different generation technologies in terms of their relative biodiversity impacts under binding ecological constraints, rather than solely on economic or emission-based criteria.

The biodiversity protection constraint introduces an explicit ecological dimension into the optimisation problem through a structural constraint, reinforcing the integration of environmental sustainability within the Total Social Cost framework. It enhances the model's capacity to identify expansion strategies that minimise irreversible ecological damage while maintaining system adequacy and economic efficiency.

By explicitly constraining cumulative biodiversity pressure, the SEGeP model advances beyond conventional energy planning approaches that treat ecological impacts as exogenous or qualitative considerations. Instead, it embeds biodiversity protection as a structural element of the decision-making process, thereby strengthening the robustness, legitimacy and sustainability orientation of long-term electricity generation expansion planning.

4.5.8 Employment Requirement (Just Transition)

Ensuring that the energy transition delivers tangible social benefits is a central requirement of sustainable electricity generation planning. Beyond environmental performance and economic efficiency, expansion strategies must contribute to job creation, regional development and social inclusion, particularly in contexts marked by structural inequalities. In the SEGeP framework, these objectives are operationalised through an explicit employment requirement that reflects the principles of a just transition and directly supports Sustainable Development Goal 8 (Decent Work and Economic Growth).

A minimum employment level associated with electricity generation expansion is imposed for each planning period, reflecting a system-wide just-transition requirement. Since the employment target is defined at the aggregate national level, the corresponding constraint is expressed by summing employment effects across all technologies and regions, as shown in Equation (4.17).

$$\sum_{r \in R} \sum_{i \in I} J_i \cdot x_{i,r,t} \geq \Phi_t, \forall t \in T \qquad (4.17)$$

Where J_i denotes the employment coefficient of technology *i*, expressed as the number of jobs generated per unit of installed capacity, $x_{i,r,t}$ represents the installed capacity of technology *i* in region *r* at period *t*, and Φ_t corresponds to the minimum desired level of job creation in period *t*.

The employment coefficients capture both direct and indirect employment effects associated with generation technologies, including construction, operation and maintenance activities, as well as supply-chain impacts where relevant. By linking employment generation directly to installed capacity, the model ensures consistency between long-term expansion decisions and their labour market implications.

The minimum employment threshold Φ_t can be calibrated according to national just transition policies, labour market objectives or regional development strategies. This flexibility allows the model to reflect different policy priorities, such as compensating job losses in declining fossil fuel sectors, stimulating employment in less developed regions or promoting labour-intensive renewable technologies.

This constraint refers to sustained employment associated with the installed generation portfolio, while the objective function captures the incremental employment benefits of new capacity additions, ensuring complementary treatment of short-term expansion effects and long-term structural employment outcomes.

From an analytical perspective, the employment requirement introduces a binding social constraint into the optimisation problem, ensuring that expansion pathways that minimise total social cost also satisfy minimum social performance standards. It explicitly transforms employment from a secondary or descriptive outcome into a structural determinant of optimal solutions.

By incorporating a just transition requirement in this manner, the SEGeP model enables a transparent assessment of trade-offs between employment creation, environmental targets and economic costs. It also provides valuable insights into how different technologies and expansion strategies contribute to inclusive growth and social sustainability, reinforcing the role of energy planning as an instrument of broader socioeconomic development.

4.5.9 Regional Equity Constraint

Regional equity constitutes a core principle of sustainable electricity generation expansion planning, particularly in countries characterised by pronounced territorial disparities in income, infrastructure, employment and access to public services. In the Brazilian context, historical patterns of energy investment have frequently favoured already developed regions, reinforcing asymmetric development trajectories and limiting the capacity of energy policy to function as an instrument of territorial cohesion.

To address this structural imbalance, the SEGeP model incorporates an explicit regional equity constraint designed to prevent excessive concentration of generation capacity in historically advantaged regions and to promote a more balanced spatial distribution of investments. This constraint operationalises social equity considerations within the optimisation framework, aligning expansion decisions with broader objectives of inclusive development and reduction of regional inequalities, in coherence with Sustainable Development Goal 10 (Reduced Inequalities).

The regional equity requirement is defined by Equation (4.18):

$$x_{i,r,t} \geq \rho_r \cdot \sum_{r' \in R} x_{i,r',t}\,, \forall i \in I,\ \forall r \in R,\ \forall t \in T \qquad (4.18)$$

Where:

- $i \in I$ denotes the generation technology index.
- $r \in R$ denotes the region index.
- $r' \in R$ denotes a dummy region index used in summations over all regions.
- $t \in T$ denotes the time period (year) in the planning horizon.
- $x_{i,r,t}$ represents the installed capacity of technology i in region r during period t(MW).
- ρ_r represents the minimum participation share assigned to region r relative to the total installed capacity of the same technology across all regions.
- $\sum_{r' \in R} x_{i,r',t}$ represents the total installed capacity of technology i across all regions in period t.

The parameter ρ_r is calibrated using socio-economic indicators that reflect regional development conditions, such as the Human Development Index (HDI), unemployment rates, income levels or social vulnerability measures. Regions with lower socio-economic performance may be assigned higher minimum participation shares, thereby incentivising investment flows towards areas where energy infrastructure expansion can generate stronger social co-benefits.

By linking regional participation to the total installed capacity of each technology, this constraint preserves technological neutrality while introducing a spatial fairness criterion into the decision-making process. It ensures that no region is systematically excluded from the benefits associated with generation expansion, including employment creation, local economic activity and infrastructure development. Baseline regional data used in the model are reported in Appendix D.

From an analytical standpoint, the regional equity constraint transforms territorial balance from a qualitative policy aspiration into a quantifiable and enforceable condition within the optimisation problem. It enables the model to evaluate how equity-oriented policies influence expansion pathways, costs and sustainability outcomes, and to identify trade-offs between spatial efficiency and social cohesion.

By embedding regional equity directly into the mathematical structure of SEGeP, the model advances beyond conventional approaches that treat spatial distribution as an exogenous or descriptive outcome. Instead, it integrates territorial justice as a structural determinant of optimal solutions, reinforcing the role of energy planning as a tool for promoting inclusive, balanced and socially sustainable development.

4.6 Systemic Interpretation of the SEGeP Formulation

The mathematical formulation presented in the preceding sections only fully reveals its meaning when interpreted as an integrated system in which decisions, constraints, and performance metrics operate interdependently. In this sense, SEGeP is not merely an optimisation model, but rather a conceptual-analytical architecture that translates—into quantitative language—a broader understanding of energy planning, namely that electricity systems simultaneously constitute economic infrastructures, socio-territorial arrangements, and ecological interventions.

This systemic interpretation clarifies how the SEGeP framework internalises such complexity by explicitly linking (i) expansion decisions, (ii) operational feasibility, and (iii) multidimensional externalities, under a unified objective function. Consequently, the model is designed not only to identify a cost-efficient expansion path, but to do so in a way that is consistent with the thesis' central premise: sustainable planning requires that private costs and socially borne impacts be jointly considered within the decision problem itself.

It is important to clarify the temporal treatment of demand-side mechanisms within the SEGeP framework. The model is formulated as a long-term generation expansion planning problem with annual temporal resolution. Electricity generation and demand are therefore represented in aggregated annual terms rather than through hourly operational dispatch.

Demand-side assumptions can be represented in SEGeP only through exogenously defined annual demand trajectories or long-term structural parameters. The model does not endogenously optimise short-term demand response, intra-day load shifting, peak-load shaving or real-time consumer flexibility.

Consequently, demand-side strategies should be interpreted as long-term planning assumptions rather than as operational decisions. Their detailed representation would require greater temporal granularity and additional demand-response variables, which are outside the scope of the present formulation.

4.6.1 The integrative logic of the Total Social Cost

The objective function based on the Total Social Cost (TSC) is the model's central integrative mechanism. By aggregating economic costs, monetized environmental damages, and monetized social effects into a single monetary metric, SEGeP departs from the conventional practice of treating sustainability dimensions as auxiliary outputs, ex-post evaluations, or external constraints with limited influence on the optimum.

Under the TSC paradigm, each expansion alternative—be it solar, wind, hydro, thermal, nuclear, or storage—is evaluated through its complete social footprint, rather than through its private financial cost alone. This implies that the ranking of technologies is not driven solely by CAPEX/OPEX considerations, but also by

the magnitude and distribution of their externalities across regions and over time. The resulting internal coherence reflects a fundamental proposition of sustainability economics: minimizing private costs is neither conceptually equivalent nor empirically guaranteed to minimize social costs.

Importantly, the adoption of a monetary common denominator is not a rhetorical simplification; it is a structural choice that enables the model to compare heterogeneous impacts (emissions, water use, land occupation, biodiversity pressure, and employment-related effects) within a single optimisation criterion, thereby making the trade-offs explicit, traceable, and computationally operational.

4.6.2 Constraints as sustainability operators shaping the feasible solution space

In SEGeP, constraints are not merely technical limits; they function as operators that structure the feasible set in order to reflect both the physical realities of the electricity system and the sustainability priorities embedded in the thesis' conceptual framework.

The supply and demand balance ensures electrical feasibility and adequacy. Capacity dynamics and capacity-factor constraints preserve technological realism and operational consistency. Environmental constraints—covering emissions, water use, land occupation, and biodiversity—define the relevant bio-physical boundaries that condition long-term viability. Social constraints—such as employment requirements and regional equity rules operate in socio-territorial commitments that are central to a just transition perspective.

These constraints play a dual role:

- Normative role, insofar as they translate sustainability targets (including SDG-aligned commitments and climate obligations) into binding mathematical conditions that directly influence the optimum.
- Descriptive role, insofar as they encode concrete structural features of the Brazilian electricity system, such as hydro-dependence, resource heterogeneity, and regionally uneven socio-economic conditions.

This duality is methodologically relevant because it avoids a common weakness in sustainability-oriented models: the tendency to treat "sustainability" as an external narrative layer rather than as a structural determinant of admissible solutions.

4.6.3 Structural interdependence between expansion, operation, and impacts

The SEGeP formulation establishes a tightly coupled chain of dependencies that, when interpreted systemically, exhibits consistent dynamic behaviour:

1. Capacity expansion decisions determine the technological frontier of feasible operation in subsequent periods.

2. Actual generation levels translate installed capacity into energy output, constrained by capacity factors and system requirements.

3. Environmental and social impacts emerge from generation and capacity choices through impact factors and regional parameters.

4. These impacts are monetized and aggregated into the Total Social Cost.

5. The Total Social Cost, in turn, drives the optimality condition, reshaping the preferred expansion trajectory.

This structure reflects an essential planning insight: expansion decisions generate path dependency. Once capacity is installed, its effects persist over decades through cumulative emissions, cumulative pressure on water and land, and persistent regional socio-economic implications. By embedding these mechanisms into a MILP structure, SEGeP maintains linearity and computational feasibility while preserving the causal logic that connects infrastructure choices to long-term social outcomes.

4.6.4 Sustainability as an emergent property of the optimal solution

SEGeP differs from conventional multi-criteria approaches in which sustainability is either imposed through subjective weights or interpreted as a post-solution evaluation. In SEGeP, sustainability becomes an emergent property of the optimal solution, resulting from the joint action of:

- a unified TSC objective (economic + environmental + social), and
- a constraint system that encodes technical feasibility and sustainability boundaries.

Given this structure, solutions that minimize TSC tend to be those that—subject to feasibility—reduce cumulative environmental burdens, limit bio-physical pressures, and improve the socio-territorial performance of expansion. In other words, sustainability is not treated as an adjective attached to planning; it is formalized as a quantitative outcome of an integrated decision problem.

This interpretation is particularly important for the thesis' argumentation because it clarifies that SEGeP does not merely "add" sustainability indicators; it redefines the optimisation landscape so that sustainability-relevant outcomes are systematically reflected in the model's optimality logic.

4.6.5 Why the systemic architecture is particularly suitable for Brazil

The systemic character of SEGeP is especially appropriate for the Brazilian context, where planning decisions are intrinsically shaped by:

- high dependence on hydrological regimes subject to increasing uncertainty;
- strong regional disparities in development levels, infrastructure, and vulnerability;

- significant potential for non-hydro renewables with spatially heterogeneous resource quality;
- heightened environmental pressures in ecologically sensitive biomes;
- the political and socio-economic imperative of consolidating a just energy transition.

Because SEGeP jointly represents costs, emissions, water and land pressures, biodiversity constraints, employment requirements, and regional equity conditions, it can capture the Brazilian power system not as a purely technical network, but as a system where security of supply, territorial justice, and ecological integrity interact. The model does not impose a single pre-defined pathway; rather, it provides a structured parametric space within which distinct trajectories can be explored and compared.

4.6.6 A consistent foundation for scenario analysis and policy interpretation

From a systemic standpoint, the SEGeP formulation provides a coherent basis for the simulation and evaluation of alternative planning scenarios in Chapter 5. Because the objective function internalises externalities and the constraints encode sustainability boundaries and social requirements, scenarios can be compared in a manner that is not limited to private cost differentials but explicitly reflects multidimensional consequences.

In practical terms, the formulation enables:

- the comparison of alternative scenarios using a common integrated metric (TSC) and traceable component decomposition;
- the quantification of trade-offs between objectives that are often conflictual in practice (e.g., cost vs. emissions, water security vs. dispatchability, employment vs. territorial concentration);
- the interpretation of how binding constraints and scarcity conditions reshape the optimal technology mix over time;
- the identification of the conditions under which certain policy targets become systemically costly, infeasible, or strongly path-dependent.

4.7 Structural Comparison between Traditional Expansion Models and the SEGeP Framework: Implications for Scenario Analysis

The formulation of the SEGeP model represents a deliberate and substantive methodological shift in generation expansion planning. Rather than constituting a marginal extension of traditional least-cost approaches, SEGeP redefines the objective, scope, and decision logic of expansion models, aligning them

explicitly with sustainability, equity, and climate policy imperatives. This structural differentiation is synthesized in Table 4.1 and interpreted analytically in this section.

4.7.1 From private cost minimisation to social optimality

Conventional expansion models are grounded in the minimisation of private system costs—typically investment, operation, and fuel—under constraints of adequacy and reliability (Stoft, 2002; Shahidehpour et al., 2002). Within this paradigm, the concept of optimality is narrow and internally consistent, yet systematically incomplete from a societal perspective.

SEGeP replaces this paradigm by adopting the Total Social Cost (TSC) as the core optimisation metric. By internalizing economic, environmental, and social components within a unified objective function, the model explicitly operationalizes the principle that least-cost solutions are not necessarily socially optimal solutions. This shift is neither cosmetic nor conceptual only; it directly affects technology selection, regional allocation of investments, and long-term system trajectory.

4.7.2 Structural differentiation between modelling paradigms

The distinction between conventional electricity generation expansion models and the SEGeP framework transcends parametric adjustments or the inclusion of additional constraints. It reflects a fundamentally different conceptualisation of the planning problem, particularly regarding the role attributed to sustainability, social welfare and territorial equity. While traditional models are grounded in a paradigm of private cost minimisation subject to technical feasibility, SEGeP reformulates expansion planning as a societal optimisation problem centred on the minimisation of Total Social Cost.

This structural differentiation becomes evident across multiple analytical dimensions, which are synthesised in Table 4.2.

Table 4.2 - Structural comparison between traditional expansion models and SEGeP

Evaluated Dimension	Traditional Expansion Models	SEGeP
Objective Function	Minimisation of private costs (CAPEX + OPEX + fuel)	Minimisation of Total Social Cost (economic + environmental + social)
Externalities	Ignored or treated qualitatively	Fully internalised and monetized (SCC, SCW, biodiversity, employment)
Regional Equity	Largely absent	Explicit variables and constraints for regional development
Social Dimension	Absent	Employment, HDI, GINI, territorial inequality
Environmental Dimension	Limited to global emission caps, when present	Emissions, water, land use, biodiversity, regional constraints and penalties
System Representation	Cost and reliability-centered	Multidimensional sustainability-centered
Decision Indicators	System cost, firm energy, installed capacity	Social cost, environmental impacts, job creation, hydrological vulnerability
Nature of Optimal Solution	Lowest private-cost technologies	Technologies optimizing the economic–environmental–social nexus
Alignment with SDGs and Paris Agreement	Low	High
Policy Sensitivity	Limited	High – enables climate, social, and territorial policy simulation

Source: Author's elaboration.

The comparison highlights that SEGeP cannot be interpreted as an incremental extension of conventional expansion models. Instead, it represents a structural reconfiguration of the decision-making logic underpinning long-term electricity planning. In traditional formulations, sustainability considerations—when present—are typically imposed as exogenous constraints or evaluated ex post, without influencing the internal ranking of technologies within the objective function. As a result, solutions remain primarily driven by private cost efficiency, with limited capacity to reflect broader societal trade-offs.

In contrast, SEGeP embeds environmental and social externalities directly into the optimisation criterion through the Total Social Cost framework. This approach alters the relative attractiveness of technologies by explicitly accounting for their differentiated impacts on emissions, water resources, land occupation, biodiversity and employment. Consequently, the optimal solution is no longer defined by the cheapest technological portfolio in private terms, but by the configuration that minimises aggregate societal costs while respecting sustainability limits.

The explicit incorporation of regional equity considerations constitutes a major departure from standard practice. By linking expansion decisions to regional socio-economic indicators, SEGeP allows energy

planning to function as an instrument of territorial development and social cohesion, rather than merely as a response to aggregate demand growth. This feature significantly enhances the model's sensitivity to public policy priorities, enabling the simulation of alternative climate, social and regional development strategies within a unified and internally consistent framework.

The structural differentiation documented in this section reinforces the central methodological contribution of SEGeP: the transformation of electricity generation expansion planning from a narrowly defined cost-optimisation exercise into a comprehensive sustainability-oriented decision-support tool, aligned with the objectives of the 2030 Agenda and long-term decarbonisation pathways.

4.7.3 Implications for decision-making and policy relevance

By embedding environmental and social dimensions directly into the optimisation process, SEGeP fundamentally transforms the informational content and interpretative value of the optimal solution. Rather than producing outputs restricted to conventional indicators such as system cost, installed capacity or energy adequacy, the model generates results that are intrinsically policy relevant. These include trajectories of Total Social Cost, regional employment effects, environmental pressure indicators, resource-use constraints and explicit distributional outcomes across regions and technologies.

This shift has important implications for decision-making. In traditional expansion models, optimal solutions often provide limited guidance beyond cost-efficiency rankings, requiring policymakers to conduct separate ex post analyses to assess environmental or social consequences. In contrast, SEGeP internalises these dimensions ex ante, ensuring that trade-offs between economic efficiency, environmental protection and social objectives are explicitly reflected in the optimisation results themselves. As a consequence, the model enables a more transparent and informed evaluation of alternative expansion pathways, revealing not only which technologies are selected, but also why they emerge as optimal under competing sustainability criteria.

The enhanced decision-support capacity of SEGeP is particularly relevant in contexts where electricity planning is expected to serve multiple public policy objectives simultaneously. This is the case of the Brazilian electricity sector, which faces the combined challenges of decarbonisation, hydrological vulnerability, persistent regional inequalities and the need for inclusive economic development (EPE, 2023a; IEA, 2021). Under such conditions, planning tools that prioritise private cost minimisation alone are insufficient to support strategic policy choices, as they fail to capture the broader societal implications of long-term infrastructure decisions.

From a policy perspective, SEGeP provides a structured framework for assessing the impacts of climate, social and regional development policies within a single, coherent modelling environment. By allowing

scenario-based modifications of emission limits, employment targets, water availability or regional equity parameters, the model enables policymakers to explore how alternative policy orientations affect the optimal expansion trajectory and the associated societal costs. This capacity enhances the relevance of the model as a decision-support instrument, bridging the gap between technical optimisation and strategic policy design.

The SEGeP framework is closely aligned with contemporary debates on energy justice and just transition. Recent literature emphasises that sustainable energy planning must explicitly address distributive outcomes, social inclusion and territorial fairness, rather than treating them as secondary considerations (Jenkins et al., 2018; Sovacool et al., 2021). By incorporating employment generation, regional equity constraints and monetised social externalities directly into the optimisation problem, SEGeP operationalises these normative principles in a quantitative and transparent manner.

The SEGeP moves beyond descriptive or evaluative approaches to energy justice, translating abstract policy goals into enforceable model structures and decision criteria. The resulting outputs support not only efficiency-oriented decisions, but also deliberative policy processes concerned with fairness, resilience and long-term societal welfare. Consequently, the model enhances the capacity of energy planning to function as a strategic instrument for sustainable development, rather than merely as a technical tool for infrastructure optimisation.

4.7.4 Consequences for scenario construction and interpretation

The structural differences summarized in Table 4.1 have direct implications for the design, execution, and interpretation of scenarios, which constitutes the focus of Chapter 5. Because SEGeP internalises externalities and embeds normative sustainability constraints within the model, scenarios are no longer simple variations of demand growth or technology availability. Instead, they represent alternative societal pathways, reflecting different priorities regarding emissions reduction, water use, employment generation, and regional equity.

The comparison of scenarios under SEGeP does not merely reveal cost differentials but exposes trade-offs between competing dimensions of sustainability. This enables a richer and more informative assessment of future expansion pathways, consistent with international best practices in integrated energy system analysis (IPCC, 2022b; IRENA, 2023).

In light of these structural distinctions, the scenario analysis presented in Chapter 5 should be interpreted not as a sensitivity exercise around a fixed least-cost baseline, but as an exploration of how different sustainability-oriented constraints and priorities reshape the optimal expansion of the Brazilian power system. The scenarios analyzed therein operationalize the conceptual and mathematical advances introduced by

SEGeP, allowing the empirical assessment of how economic efficiency, environmental protection, and social outcomes interact over the long term.

Thus, Chapter 5 constitutes the empirical validation of the framework developed in this chapter, demonstrating how the structural innovations of SEGeP translate into differentiated expansion trajectories and policy-relevant insights.

CHAPTER 5 - MODEL APPLICATION AND RESULTS ANALYSIS

The assessment of the potential of the Sustainable Electricity Generation Expansion Planning Model (SEGeP) requires its application to a real context, capable of demonstrating not only the internal consistency of the proposed formulation but also its analytical usefulness and practical relevance for long-term energy planning. This chapter presents the implementation of the model within the Brazilian electricity system, which was selected due to a set of characteristics that make it particularly suitable for an approach guided by the Total Social Cost framework. Each data block is explicitly mapped onto the sets, parameters, and coefficients defined in Chapter 4, ensuring direct operability within the SEGeP MILP formulation.

Regional diversity, the strong dependence on hydropower generation, increasing exposure to extreme hydrological events, pronounced territorial socio-economic asymmetries, and the significant potential of non-hydropower renewable sources together form a highly complex planning environment. In such a context, expansion decisions cannot be adequately assessed solely on the basis of private cost criteria. The SEGeP enables an integrated exploration of the economic, environmental, and social dimensions of planning, thereby overcoming the limitations of conventional models.

The empirical application of the SEGeP begins with a detailed presentation of the database employed, including the official sources consulted, the criteria adopted for data selection and harmonisation, the technological assumptions considered, and the procedures used for the monetisation of externalities. This database underpins the construction of the economic, environmental, and social parameters that feed the model, ensuring methodological consistency between the mathematical formulation developed in Chapter 4 and the empirical reality of the Brazilian electricity system.

Subsequently, the chapter proceeds with the regional characterisation of the system, a core element of the adopted approach. By recognising that Brazil does not constitute a homogeneous system, but rather a set of regions with markedly different climatic conditions, productive structures, development levels, and resource availability, the SEGeP explicitly incorporates these asymmetries into the analysis. The distinction among the North, Northeast, Southeast/Central-West, and South subsystems proves decisive for understanding the trade-offs observed in the results, particularly with respect to hydrological vulnerability, job creation, and the territorial distribution of expansion impacts.

The chapter then advances with the description of the prospective scenarios analysed. These scenarios should not be interpreted as deterministic forecasts, but rather as quantified narratives that explore different possible pathways for the Brazilian energy transition. Each scenario emphasises a specific dimension—such as economic cost minimisation, carbon constraints, water-use limitations, employment maximisation, or high

penetration of renewable sources—allowing an assessment of how the SEGeP formulation responds to different political, technological, and environmental priorities. The diversity of scenarios illustrates the flexibility of the model as a tool for evaluating public policies and long-term strategic options. The SEGeP model was implemented using the General Algebraic Modeling System (GAMS) and solved with the CPLEX optimiser, a state-of-the-art solver widely recognised for its performance in large-scale mixed-integer linear programming (MILP) problems. The solution process relies on advanced branch-and-bound procedures combined with cut-generation techniques, ensuring the identification of globally optimal solutions under linear formulations.

All simulations were conducted on a Lenovo Legion workstation, equipped with an Intel Core i7 (13th generation) processor, 24 GB of RAM, and an NVIDIA GeForce RTX 3060 graphics card. Given the nature of MILP optimisation, computational performance is primarily determined by CPU processing capacity and memory availability, with no direct reliance on GPU acceleration.

The implementation of the model required a structured calibration process to ensure numerical stability, internal consistency, and convergence reliability across all simulated scenarios. This process involved: (i) the harmonisation of units across economic, environmental, and social parameters; (ii) the scaling of coefficients with heterogeneous magnitudes to avoid numerical instability; (iii) the verification of data consistency across technological, regional, and temporal dimensions; and (iv) iterative validation of the formulation to detect infeasibilities, redundant constraints, or excessive relaxation within the feasible region.

The optimisation was carried out under strict convergence criteria, using the default branch-and-bound framework of CPLEX, complemented by parameter adjustments aimed at enhancing numerical stability and ensuring comparability across scenarios. The solution process consistently converged to near-optimal solutions, providing stable and internally coherent results suitable for long-term scenario analysis.

From a computational standpoint, the performance of the model is influenced by the dimensionality of the problem, particularly the number of binary variables associated with investment decisions and the tightness of the imposed constraints. Under the computational environment described, solution times were compatible with the requirements of strategic planning models. For problems of comparable scale and structure, it is reasonable to expect solution times in the order of several minutes to a few tens of minutes per scenario, with more restrictive or highly constrained scenarios requiring longer convergence times.

It should be emphasised that these computational times are indicative and may vary depending on solver configurations, optimality gap specifications, and the specific parameterisation of each scenario. As such, they should be interpreted as consistent with the expected behaviour of medium- to large-scale MILP models in long-term energy planning, rather than as fixed performance benchmarks.

The adopted computational framework ensures that the SEGeP model achieves an appropriate balance between analytical detail and computational tractability, supporting the systematic evaluation of multiple prospective scenarios while preserving methodological transparency, robustness, and reproducibility.

This section dedicated to the analysis of the results examines, in an integrated manner, both the optimal solutions obtained, and the economic, environmental, and social performance indicators produced by the model. The interpretation of the results highlights the trade-offs among total costs, emissions, water consumption, land use, biodiversity impacts, and job creation, demonstrating how the SEGeP enables the comparison of alternative trajectories in light of sustainability principles. The systemic reading of the scenarios reveals not only the technical feasibility of the solutions but also their coherence with national and international commitments related to climate mitigation, environmental resilience, and regional development.

By demonstrating the practical application of the model, this chapter provides evidence that the SEGeP constitutes a analytical instrument for guiding long-term energy planning decisions, offering a quantitative basis capable of internalising externalities, making trade-offs explicit, and identifying sustainable pathways for the expansion of electricity generation in Brazil.

5.1 Database and Data Sources

The empirical implementation of the SEGeP requires a multidimensional database capable of coherently representing the economic-technological components of the Brazilian electricity system, the environmental impacts associated with different generation technologies, and the territorially disaggregated social indicators relevant to sustainability analysis. The construction of this database constitutes a central step in the application of the model, as the validity, robustness, and credibility of the results depend directly on the consistency, completeness, and traceability of the information employed.

The SEGeP demands a methodological approach capable of integrating official planning sources, consolidated technical databases, and recent scientific literature, thereby ensuring a faithful representation of the national electricity system and its regional asymmetries. Accordingly, the database was structured to ensure compatibility across temporal scales, physical units, levels of regional disaggregation, and the requirements of the MILP formulation presented in Chapter 4.

This section provides a detailed description of the data sources consulted, the criteria applied for data harmonisation and processing, the transformations applied to raw data, and the scientific rationale that guided the final structuring of the set of economic, environmental, and social parameters used in the scenario simulations.

5.1.1 Methodological Principles for Database Construction

The construction of the empirical database underpinning the SEGeP was guided by a set of clearly defined methodological principles, designed to ensure scientific robustness, internal coherence, and analytical consistency across the economic, environmental, and social dimensions of the model. These principles reflect both the multidisciplinary nature of the proposed framework and the requirements imposed by its mathematical formulation.

Five central principles structured the database construction process. Among these principles, epistemological rigour and temporal coherence constitute structural conditions, while the remaining principles ensure operational consistency:

1) Epistemological rigour:

Only data sources with high institutional credibility or well-established scientific recognition were employed. These include:

- Empresa de Pesquisa Energética (EPE);
- Operador Nacional do Sistema Elétrico (ONS);
- Agência Nacional de Energia Elétrica (ANEEL);
- Instituto Brasileiro de Geografia e Estatística (IBGE);
- International Energy Agency (IEA);
- Intergovernmental Panel on Climate Change (IPCC);
- International Renewable Energy Agency (IRENA);
- International Labour Organisation (ILO).

The exclusive use of such sources ensures that all parameters introduced into the model are based on verifiable, traceable, and widely accepted datasets, consistent with international best practices in energy systems modelling.

2) Temporal coherence

All data were harmonised to the planning horizon 2025–2050, fully aligned with the temporal scope adopted in the most recent Brazilian planning instruments, notably the PDEs (2032–2033) and the PNE 2050. The optimisation adopts a discrete annual time resolution, in which each planning period t corresponds to one calendar year. Consequently, all variables and parameters are expressed on an annual basis (e.g., MW of installed capacity, MWh of yearly generation, €/year costs), ensuring dimensional consistency between economic, environmental and social components.

When original datasets referred to different base years or reporting frequencies, values were converted to annual equivalents and adjusted through inflation indexing, linear interpolation or conservative projections. This harmonisation procedure preserves temporal coherence across parameters while avoiding the introduction of speculative dynamics not supported by official projections.

3) Temporal coherence

The Brazilian electricity system is operationally structured into four subsystems—North, Northeast, Southeast/Central-West, and South—which form the territorial basis of national energy planning. However, most social and environmental indicators are officially reported according to the five macro-regions defined by the IBGE—North, Northeast, Centre-West, Southeast, and South.

To reconcile these spatial structures, a hybrid strategy was adopted:

- Energy-related data were structured according to the four operational subsystems (ONS/EPE);
- Social and territorial indicators were initially compiled at the five-macro-region level (IBGE, ILO, Human Development Atlas);

This methodological choice preserves consistency with the operational reality of the National Interconnected System (SIN) while maintaining sufficient social granularity to capture regional inequalities relevant to sustainability analysis.

4) Multidimensional comparability

Economic costs, environmental impacts, and social indicators were systematically converted into comparable units within the objective function. This step is essential for the monetisation of externalities and enables their direct integration into the Total Social Cost framework, avoiding the use of heterogeneous or non-comparable metrics.

5) Reproducibility and transparency

All procedures related to data collection, harmonisation, transformation, and validation were fully documented, ensuring transparency and allowing the complete reimplementation of the database construction process by other researchers.

5.1.2 Technological and Economic Data

Technological and economic parameters form the core of the energy component of the SEGeP. Data on investment costs (CAPEX), operating costs (OPEX), capacity factors, and variable generation costs were obtained from up-to-date primary sources.

(a) CAPEX and OPEX:

Economic assumptions in SEGeP are structured to reflect the most recent technological learning curves and market dynamics. The investment costs (CAPEX) and fixed/variable operation and maintenance costs (OPEX) are fundamental to the model's objective function, as they define the internal cost baseline before the internalisation of externalities. All monetary values were converted to Euros, using international energy-sector inflation indices and official exchange rates published by the Brazilian Central Bank. The use of euros ensures consistency with international energy modelling literature and facilitates comparison with European planning studies.

Table 5.1 - Economic parameters and investment costs by technology (Reference year: 2024/2025).

Technology	CAPEX (€/kW)	Fixed O&M (€/kW·year)	Variable O&M (€/MWh)	Economic Life (years)	Source
Large Hydropower	2296 – 3006	10 – 35	1.40	50	EPE (2024b); ONS (2024)
Small Hydro (PCH)	3048 – 3810	15 – 40	2.00	35	EPE (2023c)
Wind (Onshore)	1121– 1538	20 – 45	—	25	IRENA (2023); EPE (2024b)
Solar PV (Utility)	818 – 1119	8 – 20	—	25	IRENA (2023); EPE (2024b)
Biomass (WTE)	4372 – 5564	70 – 150	4.60	25	EPE (2023c); EPE (2025c)
Nuclear	6481 – 9476	90 – 140	2.30	60	IAEA (2024); Eletronuclear (2024)
Natural Gas (CCGT)	855 – 1443	10 – 25	4.10*	30	EPE (2024b); ONS (2024)
Natural Gas (OCGT)	753 – 1086	5 – 15	6.50*	25	EPE (2024b)
Coal (USC)	2977 – 4509	30 – 60	3.20*	35	IEA (2023); ONS (2024)

Source: Author's elaboration.

CAPEX and Fixed O&M values in Table 5.1 were converted from the energy-normalised parameters originally expressed in €/MWh. The conversion follows standard expansion-planning practice by recovering the overnight investment cost (€/kW) using a capital recovery factor (CRF) with a discount rate $r = 8\%$ and the technology economic life, and by denormalising fixed O&M to €/kW·year using representative capacity factors (CF) derived from Table 5.2 (average across the four SIN subsystems). Variable O&M values (*) exclude fuel costs, which are modelled separately as dynamic inputs.

The transition to a low-carbon matrix in SEGeP is significantly influenced by the declining CAPEX of Solar PV and Wind, which currently present the lowest investment requirements among all technologies. However, the model also accounts for the high capital intensity of Nuclear and Waste-to-Energy (WTE), recognizing their role in providing reliable, non-intermittent power.

For the integrated single-objective TSC framework optimisation, a social discount rate of 8% was applied to all capital investments, consistent with Brazilian power sector benchmarks (EPE, 2022) and adjusted for international comparability. This allows for a rigorous evaluation of the trade-offs between the lower upfront costs of fossil-fuel-based expansion and the long-term environmental and social benefits of renewable and advanced thermal technologies.

(b) Regional capacity factors:

The SEGeP model's spatial resolution requires a robust set of technical parameters, with the Capacity Factor (CF) being a critical variable. Defined as the ratio between the actual energy generated over a period and the maximum theoretical output, the CF in the Brazilian context is influenced not only by natural resource availability—such as wind speeds or solar irradiation—but also by the centralised dispatch decisions coordinated by the National Electric System Operator (ONS).

To capture the geographic heterogeneity of the Brazilian territory, this study incorporates regionalized capacity factors, avoiding the inaccuracies of uniform performance assumptions. Table 5.2 presents these factors for the primary generation technologies across the four national subsystems, derived from historical SIN operational data and official projections (EPE, 2023b; ONS, 2024).

Table 5.2 - Representative annual capacity factors adopted in SEGeP (historical SIN averages).

Technology	North	Northeast	Southeast/CO	South	Source
Large Hydropower (UHE)	0.55	0.47	0.52	0.50	ONS (2024)
Small Hydro (PCH/CGH)	0.52	0.45	0.50	0.52	EPE (2023b)
Wind (onshore)	0.30	0.42	0.30	0.35	EPE (2023b); ONS (2023)
Solar PV (utility)	0.22	0.27	0.23	0.20	EPE (2023b)
Biomass (Sugar Cane)	0.55	0.60	0.65	0.58	ONS (2024)
Biomass (Forest/Wood)	0.75	—	0.75	0.70	EPE (2023b)
Biomass (WTE/Waste)	0.85	0.85	0.85	0.85	EPE (2023b)
Nuclear	—	—	0.92	—	Eletronuclear (2024)
Natural Gas (CCGT)	0.40	0.45	0.55	0.50	ONS (2024)
Natural Gas (OCGT/Peaker)	0.25	0.30	0.35	0.30	ONS (2024)
Coal (Domestic)	—	—	—	0.75	ONS (2024)
Oil/Diesel (Fuel Oil)	0.20	0.15	0.15	0.10	ONS (2024)

Note: Regional averages calculated based on historical generation and installed capacity data.
Source: Author's elaboration.

The data reveals a clear regional disparity, particularly for Variable Renewable Energy (VRE). The Northeast's superior performance for wind and solar projects plays a decisive role in the expansion scenarios

discussed in Chapter 6. In contrast, the Hydropower sector (ranging from 0.47 to 0.55) reflects the operational complexity of the SIN, where UHEs (Large Hydro) are subject to multi-reservoir optimisation, while PCHs (Small Hydro) typically operate as run-of-river plants, directly tied to local hydrological flows.

Regarding dispatchable technologies, a significant distinction is made based on their operational roles:

- Base-load: Nuclear power, concentrated in the Southeast, exhibits the highest CF (0.92), reflecting its high operational availability (Eletronuclear, 2024). Similarly, Waste-to-Energy (WTE) and Forest Biomass are assigned high, constant factors (0.85) due to their climatic independence.
- Seasonal and Flexibility: Sugar Cane Biomass CFs reflect harvest seasonality, while Natural Gas (CCGT and OCGT) and Coal factors are calibrated by their historical role in providing grid stability rather than maximum technical availability.
- Strategic Reserve: Oil and Diesel plants show the lowest factors (0.10 to 0.20), as they are primarily dispatched during periods of extreme hydrological stress or peak demand.

This technological granularity ensures that the internalisation of externalities—specifically the environmental costs of CO_2 emissions and the social impacts of employment—is grounded in the actual productive profile of the Brazilian power mix. Furthermore, all investment and O&M costs were updated based on the Ten-Year Energy Expansion Plan (EPE, 2022), ensuring that the economic trade-offs reflect current market trends and technological learning curves.

(c) Fixed and variable operating costs: Fixed and variable operation and maintenance

The Fixed and Variable Operation and Maintenance costs (FOM_i and VOM_i) were harmonized using the Lazard's Levelized Cost of Energy Analysis (Lazard, 2023) as a primary global benchmark, subsequently adjusted to the Brazilian energy landscape.

The adjustment for the Brazilian reality followed a two-fold approach. First, labor-intensive components of O&M were weighted by the local General Labor Cost Index, reflecting that fixed O&M in Brazil tends to be lower than in OECD countries for mature technologies (like Hydropower and Biomass) due to lower local labor costs. Second, for technologies with high imported component reliance (such as Wind and Solar PV), costs were adjusted based on the Brazilian Tariff Arrangements and logistical complexities, including the "Brazil Cost" (*Custo Brasil*), which accounts for tax burdens (PIS/COFINS) on replacement parts and specialized technical services. For thermal plants, regional operating conditions—specifically the humidity and temperature profiles of the Northeast and North—were factored into the efficiency degradation and maintenance cycles of CCGT and OCGT units.

The values adopted in this study, normalized to €/MWh to maintain consistency with the SEGeP objective function, are presented in Table 5.3.

Table 5.3 - Standardized Operating Costs in €/MWh (Reference: 2024).

Technology	Fixed O&M (€/MWh)	Variable O&M (€/MWh)	Adjustment Factor (BR/Global)
Large Hydropower	0.90	1.40	0.85 (Local labor)
Small Hydro (PCH)	1.25	2.00	0.90 (Regional scale)
Wind (Onshore)	0.85	—	1.10 (Logistics/Parts)
Solar PV (Utility)	0.70	—	1.05 (Maintenance/Cleaning)
Biomass (WTE)	1.80	4.60	1.00
Nuclear	2.10	2.30	1.15 (Regulatory/Safety)
Natural Gas (CCGT)	0.55	4.10*	0.95 (Operational history)
Natural Gas (OCGT)	0.65	6.50*	0.95
Coal (USC)	1.10	3.20*	0.90

Source: Author's elaboration.

Fuel costs are treated as an exogenous dynamic input in the SEGeP model, reflecting the volatility of international commodities. For Natural Gas, the price is calculated based on the Henry Hub index (World Bank, 2024), added to a "liquefaction and regasification spread" and domestic transport tariffs regulated by the National Agency of Petroleum, Natural Gas and Biofuels (ANP, 2023) and the national supply and infrastructure assumptions presented in the Brazilian Ten-Year Energy Expansion Plan 2035 (EPE, 2025b). This methodology results in an average cost ranging from €8.50 to €12.00/GJ, varying by subsystem and infrastructure proximity.

Coal prices follow the Newcastle (ARA) benchmark (IEA, 2023), adjusted by a correction factor to account for the lower calorific value and higher ash content characteristic of Brazilian domestic coal from the Southern region (EPE, 2023a). Lastly, Nuclear fuel costs (Uranium) are based on the long-term supply and processing contracts managed by Indústrias Nucleares do Brasil (INB), which provide price stability against international yellowcake fluctuations (Eletronuclear, 2024; INB, 2024).

5.1.3 Environmental Data

The environmental dimension of SEGeP is operationalised through a consistent set of parameters representing atmospheric emissions, water consumption, land occupation and biodiversity pressures. All coefficients are defined in physical terms and subsequently monetised to ensure compatibility with the linear optimisation structure of the model. This procedure enables the explicit internalisation of external costs while preserving dimensional consistency and tractability within a MILP framework.

Emission factors were calibrated using official inventories and internationally recognised life-cycle assessments. Technology-specific direct and life-cycle emission intensities were primarily obtained from the Intergovernmental Panel on Climate Change guidelines and assessment reports, complemented by Brazilian national inventories and sectoral statistics published by the Energy Research Office. The adopted set includes CO_2, CH_4, N_2O, NO_x and SO_2, expressed in tonnes per MWh, allowing conversion into monetary damages through pollutant-specific social cost estimates (IPCC, 2022b; EPE, 2023b).

Climate damages are monetised through the Social Cost of Carbon (SCC), which represents the marginal global welfare loss associated with an additional tonne of CO_2-equivalent emissions. Rather than adopting a single deterministic value, SEGeP employs a bounded interval consistent with contemporary policy and integrated assessment modelling literature. Reference values were drawn from the U.S. Interagency Working Group (2021) estimates, updated damage functions reported in recent assessment frameworks, and adjustments proposed for developing economies. Accordingly, an SCC range between €50/tCO_2 and €185/tCO_2 is considered in the scenario analysis, enabling the exploration of both conservative and ambitious decarbonisation pathways (EPA, 2023; Ricke et al., 2018).

Water consumption coefficients were derived from technology-specific operational intensities compiled by the U.S. Department of Energy's National Renewable Energy Laboratory and complemented by hydrological assessments and vulnerability studies for the Brazilian system conducted by EPE. Consumptive and non-consumptive uses were distinguished whenever data availability permitted, ensuring that evaporative losses associated with hydropower reservoirs and cooling requirements of thermal and nuclear plants are adequately represented (Mai et al., 2018; EPE, 2022).

Land occupation was quantified through average footprint intensities per installed capacity. These values were informed by international assessments of energy-land interactions, notably analyses produced by the International Energy Agency on land-use competition for energy transitions and by Fraunhofer ISE on spatial requirements of renewable technologies. Coefficients were harmonised and expressed in hectares per MW installed, capturing both installation and operational footprints and enabling direct linkage with regional land-value proxies (IEA, 2023; Fraunhofer ISE, 2021).

Biodiversity impacts were incorporated through proxy indicators reflecting ecosystem pressure and habitat alteration. The metrics are grounded in global biodiversity assessment frameworks and ecosystem service valuation methodologies, which provide structured approaches to translate ecological degradation into comparable indices. These indicators were subsequently linearised to preserve relative impact differentials while maintaining compatibility with the optimisation structure (UNEP, 2020; IPBES, 2022).

By combining these environmental and resource-related coefficients with regionalised and technology-specific parameters, SEGeP captures the geographic heterogeneity of the Brazilian power system. This approach avoids uniform assumptions and ensures that expansion decisions internalise localised trade-offs between emissions, water stress, land competition and ecological vulnerability. The resulting dataset forms the empirical basis for the integrated single-objective TSC framework monetisation procedure adopted in the optimisation model.

Table 5.4 consolidates the environmental and social impact coefficients adopted in the analysis, reporting average life-cycle values per technology and indicating the corresponding data sources.

Table 5.4 - Environmental and Social Impact Coefficients by Technology (per MWh).

Technology	Land Occupation (m^2/MWh)	Water Consumption (L/MWh)	GHG Emission Factor (tCO_2eq/MWh)	Social Cost of Carbon (€/tCO_2eq)	Source
Large Hydropower	12.50 – 45.00	1,500 – 4,000	0.010 – 0.024	50.00 – 120.00	EPE (2023b); ONS (2024)
Small Hydro (PCH)	8.00 – 15.00	500 – 1,200	0.008 – 0.020	50.00 – 120.00	EPE (2023b)
Wind (Onshore)	0.25 – 0.50	1.5 – 5.0	0.007 – 0.012	50.00 – 120.00	IRENA (2023); IEA (2023)
Solar PV (Utility)	1.50 – 3.50	20.0 – 50.0	0.020 – 0.045	50.00 – 120.00	IRENA (2023); Lazard (2023)
Biomass (Sugar Cane)	45.00 – 80.00	400 – 800	0.035 – 0.060	50.00 – 120.00	EPE (2023c);
Biomass (WTE)	0.15 – 0.30	500 – 900	0.040 – 0.150	50.00 – 120.00	EPE (2025c)
Nuclear	0.10 – 0.25	1,800 – 2,500	0.005 – 0.015	50.00 – 120.00	IAEA (2024); Eletronuclear (2024)
Natural Gas (CCGT)	0.15 – 0.25	600 – 1,100	0.380 – 0.450	50.00 – 120.00	IEA (2023); ONS (2024)
Natural Gas (OCGT)	0.10 – 0.20	5.0 – 20.0	0.550 – 0.680	50.00 – 120.00	IEA (2023)
Coal (USC)	0.20 – 0.40	1,500 – 2,200	0.820 – 0.950	50.00 – 120.00	IEA (2023); ONS (2024)
Oil/Diesel	0.15 – 0.30	800 – 1,400	0.750 – 0.880	50.00 – 120.00	Lazard (2023)
**Note: Variations in hydropower coefficients depend on reservoir surface area and regional evaporation rates. GHG factors based on Life Cycle Assessment (LCA).*					

Source: *Author's elaboration.*

5.1.4 Social and Territorial Data

The incorporation of social and territorial indicators constitutes a central component of the SEGeP framework, allowing the model to capture the socio-economic implications of electricity generation expansion. These indicators were selected according to three main criteria: data availability and reliability, spatial

compatibility with the Brazilian electricity system structure, and relevance to the Sustainable Development Goals (SDGs), particularly those associated with inclusive economic development and regional inequality reduction.

Regional socio-economic data were obtained from official Brazilian statistical institutions, primarily the Brazilian Institute of Geography and Statistics (IBGE), the Institute for Applied Economic Research (IPEA), and the Human Development Atlas of Brazil developed in partnership with the United Nations Development Programme (UNDP). These sources provide harmonized regional statistics for key indicators such as income distribution, human development, and regional socio-economic disparities.

The model incorporates social indicators including the Human Development Index (HDI), the Gini coefficient, and employment generation associated with electricity generation technologies. These indicators allow the model to capture not only the economic and environmental performance of different expansion pathways, but also their potential implications for social development and regional equity.

Spatial consistency between energy and socio-economic data was ensured by aligning the territorial aggregation with the four regional subsystems commonly used in Brazilian electricity planning: North, Northeast, Southeast/Central-West, and South. This regional disaggregation reflects structural differences in resource availability, infrastructure development, and socio-economic conditions across the country.

Employment effects associated with electricity generation technologies were represented using technology-specific employment coefficients derived from international literature on energy employment multipliers and adjusted to the Brazilian context where appropriate. These coefficients express the number of jobs generated per unit of installed capacity or electricity production and allow the model to estimate the employment implications of different generation portfolios.

By integrating these social and territorial variables within the modelling framework, the SEGeP model is able to evaluate how alternative electricity generation expansion strategies may influence regional development patterns and the distribution of socio-economic benefits associated with the energy transition.

5.1.5 Demand Projection and System Structure

The expansion requirements of the SEGeP are driven by regionalized demand trajectories. Unlike general estimates, these projections were built using a bottom-up approach based on the Ten-Year Energy Expansion Plans (PDE 2032/2034) and the National Energy Plan (PNE 2050).

The methodology adopted for demand calculation is based on the following assumptions:

- The demand for each subsystem D_r was calculated considering:
- Historical Baseline: Based on the ONS (2023) consolidated consumption reports.

- Sectoral Elasticities: Income-demand elasticity coefficients provided by EPE (2023c), reflecting that the North and Northeast have higher consumption growth rates due to economic convergence.

Efficiency Gains: A 1.5% annual improvement factor in energy intensity, as suggested by the PNE 2050.

Table 5.5 presents the harmonised reference electricity demand trajectory for the Brazilian power system over the 2025–2050 horizon, constructed from ONS historical data and long-term EPE projections. This series constitutes the common macro-level baseline for scenario development.

Table 5.5 - Projected Electricity Demand by Subsystem (TWh/year).

Year	North	Northeast	Southeast/CW	South	Total SIN
2025	65.2	115.4	385.6	105.8	672.0
2035	88.5	162.1	490.2	132.4	873.2
2050	125.8	240.5	620.4	168.2	1,154.9

Source: Elaborated by the author based on EPE (2023c) and PNE 2050 data.

This structure ensures that the model operates within the physical constraints of the SIN, where the need for new generation is balanced with the regional demand and the existing interconnection limits between the four subsystems.

5.1.6 Multidimensional Harmonisation and Verification

To ensure the robustness of the SEGeP framework and the reliability of the optimisation outputs, a rigorous multidimensional harmonisation and verification protocol was implemented. This stage is crucial for mitigating the propagation of uncertainties across the socio-economic and technical layers of the model.

(a) Dimensional Standardisation and Unit Consistency

The integration of disparate data sources—ranging from technical engineering specifications to macroeconomic indicators—required a strict dimensional audit. All variables were mapped into a unified computational domain:

- Energy and Power: Standardised to MWh and MW, respectively, to maintain consistency with the SIN's operational reports.
- Environmental fluxes: Emission factors were calibrated to tCO_2e/MWh (life-cycle, technology-specific). Water-use coefficients were normalised to m^3/MWh (operational consumption). Land occupation was standardised as ha/MW of installed capacity (technology footprint proxy), ensuring dimensional consistency with the annual MILP structure and the monetisation coefficients applied in the TSC objective.

- Economic Values: All monetary inputs were adjusted for inflation and converted to a common base currency (€), using Purchasing Power Parity (PPP) where applicable to reflect the real economic weight of local externalities.

(b) Technological and Parametric Plausibility

Verification procedures were conducted to ensure that the technological characterization of the Brazilian matrix aligns with both historical performance and future theoretical limits. This included:

- Capacity Factor Audit: Cross-referencing regionalized CFs against historical ONS dispatch series to prevent overestimation of intermittent renewable energy contributions.
- Technological Precedence and Maturity: Validating the "learning curves" and implementation leads times for emerging technologies (e.g., WTE and Nuclear) to ensure realistic expansion trajectories.
- Stoichiometric Consistency: Verification of emission factors against the latest IPCC guidelines and EPE sectoral reports to ensure the carbon accounting reflects the actual chemical properties of the fuel mix used in the Brazilian thermal fleet.

(c) Territorial Integrity and Regional Alignment

Given the aggregation of the Southeast and Central-West (SE/CW) macro-regions into a single energy subsystem, specific impact tests were performed to avoid statistical bias.

- Aggregated Sensitivity Analysis: Tests were conducted to ensure that the population-weighted harmonization did not mask acute social vulnerabilities in less populated areas of the Central-West.
- Spatial Fidelity: Verification that regionalized environmental indicators (such as water stress levels) were not diluted by the subsystem's large geographic scale, maintaining the model's sensitivity to local ecological constraints.

(d) Pre-optimisation Pilot Simulations and Stress Testing

Prior to the final integrated single-objective TSC framework runs, a series of pilot simulations were executed to test the model's numerical stability and detect boundary anomalies. These "warm-up" runs were instrumental in identifying:

- Structural Infeasibilities: Detecting "energy gaps" where demand could not be met under extreme climate-risk scenarios.
- Elasticity Anomalies: Identifying disproportionate environmental penalties that could lead to "corner solutions" (where the model unrealistically excludes a technology due to a single outlier parameter).

- Social Value Calibration: Ensuring that job creation benefits and social vulnerability weights produced plausible socio-economic shifts rather than mathematical artifacts.

5.2 Regional Characterization

Regional characterization constitutes an indispensable step for the application of the SEGeP, as the model formulation explicitly incorporates the territorial heterogeneity that structures the Brazilian electricity system. Brazil cannot be adequately represented as a homogeneous system: persistent regional differences in terms of energy resource availability, demand growth patterns, transmission infrastructure, climatic conditions, productive structure, and social indicators directly shape the spatial distribution of costs and benefits associated with generation expansion (EPE, 2023a; ONS, 2024; IEA, 2023). Consequently, the adopted regionalisation is not merely descriptive, but a methodological component that conditions the empirical plausibility of the simulated trajectories and the interpretation of the trade-offs revealed by the model.

The approach adopted in this thesis articulates two complementary spatial scales, as established in Section 5.1.1(c). On the one hand, four energy regions consistent with the operational organisation of the National Interconnected System (SIN) are considered—North, Northeast, Southeast/Central-West, and South—reflecting the actual dispatch logic and physical interconnections of the system (ONS, 2023).

On the other hand, social indicators—specifically the Human Development Index (HDI) and the Gini Coefficient—alongside territorial indicators such as regional unemployment rates, are sourced from the five macro-regions defined by IBGE (2024)

. This granularity is essential for assessing distributive effects that a purely national analysis would overlook. In the SEGeP model, these harmonized data enter as input parameters (S_r) that define the regional weighting factors in the integrated single-objective TSC framework optimisation. Specifically, they calibrate the social priority constraints, ensuring that the model accounts for regionally differentiated social externalities. This approach aligns with the Total Social Cost logic, as it allows the optimisation to prioritize expansion in subsystems with higher socio-economic vulnerability (e.g., lower HDI or higher Gini), thereby internalizing territorial sensitivity directly into the decision-making process for the Brazilian power mix.

The spatial resolution of the SEGeP model is aligned with the operational and regulatory framework of the Brazilian National Interconnected System (SIN). The system is categorized into four primary subsystems—Southeast/Midwest (SE/CO), South (S), Northeast (NE), and North (N)—based on their electrical characteristics and geographical boundaries. In this study, the Southeast and Midwest regions are consolidated into a single aggregated node.

This topological simplification is justified by the high degree of electrical integration and the convergence of marginal operational costs between these two regions. From a structural perspective, the transmission interface between the Southeast and Midwest possesses sufficient capacity to ensure that power flows are rarely constrained under normal operating conditions. Consequently, the SE/CO subsystem functions as the primary load center and the central regulatory hub of the SIN, concentrating the majority of the nation's multi-year storage reservoirs and installed capacity.

To provide a clear geographical representation of the spatial aggregation adopted in this study, Figure 5.1 illustrates the four subsystems of the Brazilian National Interconnected System (SIN) considered in the SEGeP model.

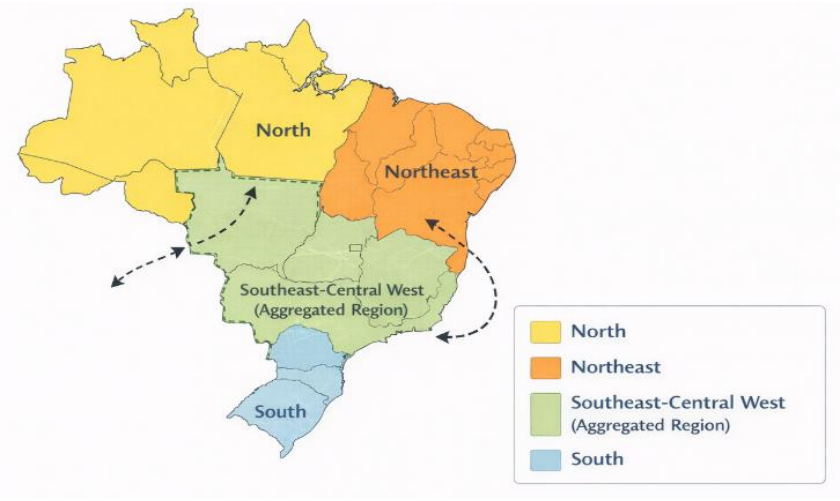


Figure 5.1 - Spatial aggregation of the Brazilian National Interconnected System (SIN) adopted in the SEGeP model.
Source: *Author's elaboration.*

The aggregation is consistent with the stochastic dual dynamic programming (SDDP) approaches employed in official Brazilian energy planning, such as the NEWAVE model. The hydrological complementarity within this aggregated block allows for a representative simulation of the hydrothermal dispatch without inducing unnecessary computational intractability. By maintaining this level of granularity, the model effectively captures the macro-regional energy exchanges while internalizing socio-environmental externalities—specifically those related to land-use change in the Cerrado biome and water-use efficiency in the Paraná basin—without compromising the convergence stability of the mixed-integer linear programming (MILP) solver.

5.2.1 North

The North region exhibits a singular configuration within the Brazilian context, characterised by the predominance of hydropower, vast territorial extension, and high environmental sensitivity. Historically, the regional energy mix has relied on large-scale hydropower plants located in major river basins, contributing

significantly to system adequacy (EPE, 2023c). However, this apparent structural advantage coexists with growing vulnerabilities: changes in hydrological regimes associated with climate change, extreme events, and anthropogenic processes—particularly deforestation—have increased uncertainty regarding future firm energy availability and long-term reliability (IPCC, 2023; ANA, 2023).

From a social and economic perspective, the region is marked by comparatively lower levels of human development, high inequality, limited productive diversification, and greater exposure of local communities to the territorial impacts of large infrastructure projects (IBGE, 2023; UNDP, 2024). These characteristics reinforce the need for explicit measurement of social and distributive impacts associated with expansion decisions, preventing solutions that may be economically attractive in private terms from generating disproportionate social costs for vulnerable groups.

In addition, the region holds significant potential for emerging renewables—especially solar and, in specific areas, wind energy—with particular relevance for replacing fossil-based generation in isolated systems (EPE, 2024a; IRENA, 2023). Modelling the North therefore requires an integrated perspective that simultaneously considers energy, climate, territory, and social vulnerability.

5.2.2 Northeast

The Northeast has consolidated itself as Brazil's main frontier for the expansion of non-hydropower renewable energy, due to the high quality and regularity of wind and solar resources, often associated with capacity factors above international averages (EPE, 2023c; IEA, 2023). The expansion of these sources has been accompanied by progressive investments in transmission infrastructure and by the growing dynamization of regional supply chains, granting the Northeast a strategic role in rebalancing the national energy mix and reducing sectoral emissions (ONS, 2024).

From a systemic perspective, the region increasingly assumes the role of a net electricity exporter, playing a key function in Brazil's energy transition (EPE, 2024a). Nevertheless, this energy dynamism coexists with persistent socioeconomic challenges, including structural inequality, lower average income levels, and climate vulnerability linked to rainfall variability, which affects both agriculture and competing water uses in semi-arid areas (IBGE, 2023; IPCC, 2023).

These elements render the region particularly sensitive to trade-offs between renewable expansion, land occupation, pressure on fragile ecosystems, and local distributive impacts. The SEGeP framework allows these interactions to be quantified and compared across scenarios.

5.2.3 Southeast/Central-West (Energy) and Southeast + Central-West (Social)

The Southeast/Central-West region represents a central methodological challenge in the construction of the SEGeP regionalisation. From an energy standpoint, the Southeast and Central-West form a single operational subsystem within the SIN, which is technically consistent with dispatch logic and physical interconnections (ONS, 2023). From a socioeconomic perspective, however, these macro-regions exhibit substantially distinct demographic, productive, and social dynamics, justifying their separate treatment during the construction of social indicators (IBGE, 2023).

The Southeast constitutes the country's largest consumption center, accounting for a significant share of national electricity demand, GDP, and industrial activity, with consolidated infrastructure and dense load concentration (EPE, 2023c). In contrast, the Central-West displays lower population density, strong dependence on agribusiness, heterogeneous social indicators, and distinct energy consumption patterns (IBGE, 2023; MAPA, 2024).

From an environmental perspective, the SE/CO region faces specific challenges related to water availability, land-use pressure, and historical dependence on thermal generation in certain areas, which become increasingly relevant under climate stress scenarios (ANA, 2023; IPCC, 2023). These elements strongly influence optimal expansion pathways in the SEGeP.

5.2.4 South

The South region combines relatively high socioeconomic development with distinct climatic and environmental characteristics. It exhibits relevant potential for wind generation in coastal areas and for the expansion of distributed solar generation, alongside increasing technological diversification (EPE, 2023c; IRENA, 2023). Although average social indicators are among the highest in the country, intraregional inequalities persist and remain relevant for distributive analyses (IBGE, 2023).

Climatically, the region is increasingly exposed to extreme events—such as droughts, floods, and extratropical cyclones—which affect hydropower availability, transmission infrastructure, and system reliability (INMET, 2023; IPCC, 2023). These dynamics reinforce the importance of integrated energy–climate modelling approaches.

In addition, intensive agricultural land use generates trade-offs between renewable expansion and competing territorial uses, particularly relevant for large-scale solar projects. The SEGeP explicitly internalises these pressures through land-use and environmental cost parameters.

5.2.5 Integrated Considerations on Regionalisation

The adopted regionalisation enables a systemic and empirically grounded interpretation of the Brazilian electricity system, structured around key contrasts documented in recent literature:

North: hydropower dominance combined with environmental sensitivity and growing climatic and social vulnerability (EPE, 2023c; IPCC, 2023);

Northeast: leadership in wind and solar expansion alongside persistent inequality and climate exposure (EPE, 2024b; IBGE, 2023);

SE/CO: main load center with pronounced internal heterogeneity and territorial pressure (ONS, 2023; IBGE, 2023);

South: high development levels with increasing exposure to climate extremes and land-use trade-offs (INMET, 2023).

This hybrid regionalisation constitutes a methodological pillar of the thesis, as it preserves the operational coherence of the SIN while ensuring sufficient social and environmental sensitivity to interpret scenario results considering Brazil's real territorial dynamics.

5.3 Prospective Scenarios

The construction of prospective scenarios constitutes a central stage in the application of the SEGeP model, as the framework was designed not only to produce a single optimal solution, but also to explore alternative pathways for the sustainable expansion of electricity generation in Brazil. Scenarios operate as analytical environments that stress the model under different political, economic, environmental, and social priorities, allowing the assessment of long-term trajectory robustness and system sensitivity to internalised externalities.

The approach adopted in this thesis follows the principle that scenarios are not forecasts, but rather structured, quantified, and coherent narratives capable of revealing systemic mechanisms and latent trade-offs that emerge when the relative emphasis on specific strategic dimensions is altered. Accordingly, each scenario represents a consistent set of assumptions, targets, and exogenous conditions which, when processed by the SEGeP model, generate alternative expansion pathways reflecting tensions between cost efficiency, environmental impact, social development, climate resilience, and territorial equity.

The scenarios defined in this study were developed based on four fundamental guiding principles:

- Consistency with national policies and planning documents, including the PDE 2032–2033, the PNE 2050, the National Hydrogen Plan, and sectoral decarbonisation targets;

- Alignment with international commitments, particularly SDGs 7, 8, 12, and 13, the Paris Agreement, and the IEA Net-Zero 2050 scenarios;
- Technological and economic feasibility, ensuring that all simulated alternatives are compatible with the current state of the art and realistic cost projections;
- Balanced representation of key drivers of the energy transition, namely cost, emissions, water use, land occupation, employment, energy security, and regional inequality.

Together, these principles ensure that the scenarios are analytically robust, policy-relevant, and coherent with the conceptual and methodological foundations of the SEGeP framework.

To provide a structured overview of the analytical role and internal logic of each scenario, Table 5.6 presents a comparative synthesis of the scenarios adopted in this thesis.

Table 5.6 - Comparative synthesis of prospective scenarios applied in the SEGeP model.

Scenario	Main Analytical Objective	Dominant Policy Emphasis	Key Modelling Mechanisms (Optimisation Logic)	Key Decision Drivers (Model Sensitivity)
BAU	Reference trajectory	Regulatory Continuity	Current cost structure; internalises only mandatory taxes.	Conventional fuel prices and system O&M.
HRP	Accelerated transition	High Renewable Share	Constraints for minimum RE share and storage expansion.	Land availability and resource variability.
LCE	Deep decarbonisation	Carbon Mitigation	High Social Cost of Carbon (SCC); fossil fuel penalties.	Carbon pricing and emission limits.
MEC	Social development	Employment Maximization	Regional job creation; socio-economic quotas.	Job multipliers and regional equity indices.
WSC	Climate resilience	Water-Energy Nexus	Reduced Hydropower Capacity Factors; water availability constraints.	Water security and thermal cooling needs.
EO	Least-cost benchmark	Economic Efficiency	Minimisation of private investment and operational costs.	CAPEX and capital recovery factors.
DSI	Integrated sustainability	Multidimensional Balance	Combined for climate, social, and environmental targets.	integrated single-objective optimisation under the Total Social Cost framework and monetised trade-off signals embedded in the TSC structure
ES	System robustness	Energy Security	Stress-testing under accelerated demand growth projections.	Reserve margins and capacity adequacy.
LRI	Market risks	Regulatory Deregulation	Relaxed regulatory constraints; focus on market-driven expansion.	Price volatility and investment risk.

Source: *Author's elaboration.*

Although the SEGeP model operates on an annual time step (t = annual) to ensure the capturing of intertemporal dynamics and the consistency of capacity expansion trajectories, the results of the prospective scenarios are presented in decadal snapshots (2030, 2040, and 2050). This reporting structure is adopted to facilitate the visualization of long-term trends and to allow for a clearer comparative analysis between scenarios at key milestones of the energy transition. This discrete presentation provides a more readable synthesis of the system's evolution without compromising the underlying high-resolution continuous modelling performed during the optimisation process.

Although the Total Social Cost (TSC) objective is analytically decomposed into economic, environmental, and social components, the SEGeP framework remains a single-objective optimisation model. All externalities are monetised and internally aggregated into a unified cost metric, ensuring full comparability across dimensions without resorting to ad hoc weighting schemes.

5.4 – Scenario 1: Business-as-Usual (BAU)

The BAU scenario constitutes the reference trajectory adopted in the SEGeP framework to represent the continuation of the current Brazilian electricity expansion pathway under prevailing regulatory, technological and economic conditions. In line with the modelling philosophy established in Section 5.1, the BAU scenario does not introduce structural modifications to the mathematical formulation. Instead, it corresponds to a specific parametrisation of the MILP model under conservative policy continuity assumptions.

The optimisation problem minimises Total Social Cost (TSC), defined as:

- Investment costs (CAPEX)
- Operating and fuel costs (OPEX)
- Monetised CO_2, SO_2 and NO_x emissions
- Monetised land occupation costs
- Monetised water consumption costs
- Monetised health damage costs

In the BAU configuration, employment effects remain endogenously internalised through the monetised Total Social Cost structure. However, no additional employment targets or regional social constraints are imposed beyond those already embedded in the TSC formulation.

The carbon price trajectory applied in BAU follows a moderate path:

- €30/tCO_2 in 2030
- €45/tCO_2 in 2040
- €65/tCO_2 in 2050

These values reflect partial internalisation consistent with conservative policy scenarios rather than full social cost of carbon estimates.

5.4.1 Input Data Structure BAU

The credibility and robustness of the BAU scenario depend fundamentally on the transparency and consistency of its input data structure. Given that SEGeP operates as a mixed-integer linear programming framework with regional and technological disaggregation, all parameters incorporated into the model must be explicitly defined, source-documented and internally harmonised.

In this context, the BAU scenario adopts a fully specified set of techno-economic, environmental and spatial monetisation coefficients, ensuring methodological traceability and replicability. The input structure is organised into three interdependent blocks:

(i) technology-specific techno-economic parameters,

(ii) environmental intensity coefficients, and

(iii) regional monetisation drivers and demand projections.

The techno-economic and environmental coefficients applied uniformly across regions are summarised in Table 5.6, which presents the capital expenditure (CAPEX), operating expenditure (OPEX), emission factors, water consumption coefficients and land occupation parameters for each generation technology considered in the model. These parameters reflect international benchmark values harmonised through purchasing power parity adjustments and aligned with the literature referenced in Section 5.1.

Regional heterogeneity is introduced through spatial monetisation coefficients, presented in Table 5.5, which specify land opportunity costs, water monetisation values and the carbon price trajectory applied across subsystems. Although the carbon price is uniform nationwide, land and water costs vary regionally to reflect differences in economic density, hydrological scarcity and land-use competition.

Together, Tables 5.7 and 5.8 define the structural cost matrix that shapes the feasible optimisation space of the BAU scenario. By explicitly indexing cost drivers by technology and region, SEGeP ensures that identical technologies may exhibit differentiated effective marginal social costs depending on their spatial allocation. This regionalised input architecture is a central methodological feature of the model, as it allows externality internalisation to operate not only at the technological level but also territorially.

The following subsections detail how these inputs interact within the optimisation process and how they influence the resulting generation mix, capacity allocation and multidimensional impacts observed under the BAU trajectory.

Table 5.7 - Demand Projections BAU (EPE-based)

Year	Electricity Demand (TWh)
2030	820
2040	930
2050	1,040

Source: EPE PDE 2031; extrapolated growth aligned with PNE 2050.

Table 5.8 - Techno-Economic Parameters BAU

Technology	CAPEX (€/MW)	OPEX (€/MWh)	Emission Factor (tCO_2/MWh)	Water Use (m^3/MWh)	Land (ha/MW)
Hydro	2.5–3.5 M	8–12	0.02	25–35	0.6
Wind	1.1–1.4 M	4–6	0.01	0.2	0.3
Solar PV	0.55–0.75 M	3–5	0.005	0.1	0.4
Biomass	1.8–2.4 M	15–25	0.10	3	0.5
Natural Gas (CCGT)	0.65–0.9 M	45–65	0.40	1.5	0.1
Nuclear	5–6.5 M	10–12	0.01	2	0.2

Sources: IEA (2022b), IRENA (2023), Lazard (2023), IPCC (2022b) and EPE (2023c).

To ensure terminological and mathematical consistency with the SEGeP objective function, the monetization coefficients adopted in this chapter are denoted as: (i) SCC_t, the *Social Cost of Carbon* [€/tCO2eq], time-dependent and applied to greenhouse gas emissions; (ii) SLC_r, the *Social Land Cost* [€/ha·year], region-dependent and applied to land occupation; and (iii) SWC_r, the *Social Water Cost* [€/m³], region-dependent and applied to water consumption. These coefficients are used directly in the Total Social Cost (TSC) objective, maintaining dimensional compatibility with the generation and capacity decision variables.

Table 5.7 reports the demand trajectory effectively used in the BAU scenario. It is derived from the reference series through the application of BAU-specific assumptions, including moderate efficiency improvements and limited electrification effects. Consequently, each scenario in SEGeP is associated with a single internally consistent demand trajectory used directly in the optimisation model.

Table 5.9 presents the regional parameters used to monetise environmental and territorial externalities applied in the BAU scenario. It is important to note that these parameters are not directly observed as market prices or official tariffs. Instead, they are constructed through a calibrated framework based on benchmark values and observable regional indicators, such as economic activity and water scarcity. The general formulation of these parameters is defined and is provided in Appendix C.

Table 5.9 - Calibrated regional coefficients for environmental and territorial externalities (BAU scenario, 2050)

Region	SCC (€/tCO₂) 2030	SCC (€/tCO₂) 2040	SCC (€/tCO₂) 2050	SCL (€/ha/year)	SWC (€/m³)
North	30	45	65	1,200	0.04
Northeast	30	45	65	950	0.05
SE/CW	30	45	65	2,100	0.08
South	30	45	65	1,800	0.07

Note:

Note: SCC denotes the Social Cost of Carbon (€/tCO2e). The values adopted follow a conservative trajectory consistent with the ranges reported in climate economics and integrated assessment literature cited in Section 5.1, including IPCC, OECD and related institutional benchmarks.

SCL represents the Social Cost of Land occupation (€/ha·year), derived from land-use valuation and opportunity cost approaches informed by the environmental and territorial assessment literature and institutional datasets referenced in Section 5.1 (e.g., EEA, DEFRA and national sources such as IBGE and EPE).

SWC denotes the Social Cost of Water consumption (€/m³), based on scarcity-weighted valuation approaches supported by water resource management frameworks and institutional sources cited in Section 5.1 (e.g., ANA, OECD and international energy-environment datasets such as IRENA and NREL).

Land and water monetisation coefficients are region-specific and treated as time-invariant structural scarcity signals over the modelling horizon.

Source: Author's elaboration based on IPCC, OECD, EEA, DEFRA, IRENA, NREL and Brazilian institutional data (EPE, ANA, IBGE) as discussed in Section 5.1.

The carbon valuation is applied uniformly across all regions, reflecting the global nature of climate externalities. The trajectory reaches €65/tCO₂ in 2050, consistent with the moderate escalation pathway defined for the BAU scenario. By maintaining a homogeneous carbon price nationwide, the model avoids

introducing artificial regional distortions in climate valuation, ensuring that spatial differentiation arises exclusively from technological allocation and demand structure rather than from differential climate pricing.

In contrast, land and water monetisation coefficients are region-specific. These parameters reflect territorial heterogeneity in resource scarcity, economic density and environmental pressure. Their inclusion introduces a spatial dimension to the marginal social cost of generation technologies.

The Southeast/Central-West (SE/CW) region exhibits the highest land opportunity cost (€2,100/ha/year), reflecting higher economic density, agricultural productivity and land-use competition. As a result, land-intensive technologies—particularly solar PV and wind—face higher effective marginal social costs when deployed in this subsystem. This mechanism partially explains why incremental renewable expansion shifts toward regions with lower land monetisation coefficients.

The Northeast presents the lowest land opportunity cost (€950/ha/year), reducing the shadow cost associated with land occupation for wind and solar deployment. When combined with superior renewable resource endowment (high wind capacity factors and strong solar irradiation), this coefficient contributes to lowering the effective marginal social cost of renewable technologies in the region, reinforcing its emergence as the principal expansion frontier under BAU.

Water monetisation further differentiates subsystems. The SE/CW region records the highest water cost coefficient (€0.08/m^3), reflecting higher hydrological stress and economic valuation of water resources. Given that hydropower and thermal cooling processes involve significant water use, this coefficient acts as a shadow penalty on further hydro expansion and water-intensive thermal generation in this region. In contrast, the North exhibits the lowest water cost (€0.04/m^3), yet hydro expansion remains moderated due to the simultaneous internalisation of land occupation and biodiversity impacts.

From an optimisation perspective, the regional monetisation coefficients in Table 5.9 enter the objective function multiplicatively through the interaction between:

- Technology-specific intensity factors (tCO_2/MWh, m^3/MWh, ha/MW), and
- Region-specific monetisation values (€/tCO_2, €/m^3, €/ha).

This interaction produces regionally differentiated marginal social costs even for identical technologies. Consequently, spatial allocation of generation capacity is endogenously shaped by the combined effect of environmental intensity and regional scarcity valuation.

The inclusion of Table 5.10 therefore demonstrates that, under BAU, externality internalisation operates through a geographically structured cost matrix rather than through uniform national penalties. This feature is central to interpreting the regional distribution of generation, emissions and water consumption presented in subsequent sections.

Unlike CO_2, whose damages are globally distributed, SO_2 and NO_x produce geographically differentiated health impacts. Therefore, monetisation coefficients vary across regions to reflect:

- population density,
- proximity of thermal plants to urban areas,
- epidemiological vulnerability,
- regional healthcare expenditure patterns,
- projected GDP growth and medical inflation.

Table 5.10 provides regional monetisation coefficients for local air pollutants (SO_2 and NO_x), expressed in €/kg. These coefficients represent the estimated health damage costs associated with pollutant emissions and are incorporated into the Total Social Cost (TSC) objective function. Within the SEGeP optimisation framework, the coefficients interact with technology-specific emission factors to convert pollutant emissions into monetised social costs. Consequently, SO_2 and NO_x emissions contribute to the environmental component of the objective function alongside CO_2 emissions, land occupation and water consumption.

The methodological formulation of these coefficients is presented in Chapter 4, and their complete derivation, including numerical examples, is detailed in Appendix C.

Table 5.10 - Health Damage Monetisation Factors by Region (€/kg)

Region	Pollutant	2030	2040	2050
North	SO_2	2.10	2.80	3.50
North	NO_x	1.80	2.40	3.00
Northeast	SO_2	3.20	4.10	5.20
Northeast	NO_x	2.50	3.30	4.20
SE / CW	SO_2	8.50	11.20	14.50
SE / CW	NO_x	6.80	9.00	11.80
South	SO_2	6.20	8.10	10.50
South	NO_x	5.10	6.70	8.60

Source: Author's elaboration based on literature-informed calibration using environmental damage cost ranges and institutional benchmarks for SO_2 and NO_x emissions, as discussed in Section 5.1 (e.g., OECD, EEA, IPCC-related damage cost approaches). Regional differentiation reflects population exposure, economic density, and environmental vulnerability, while temporal variation captures projected increases in marginal damage costs and regulatory stringency over the planning horizon.

The pollutant damage coefficients reported in Table 5.10 reflect relative differences in population exposure and vulnerability across regions. These values are not directly measured but derived from a structured calibration procedure combining benchmark estimates and observable regional indicators.

The damage cost parameters for SO_2 and NO_x were not arbitrarily defined but calibrated based on representative ranges from the environmental economics literature and institutional sources referenced in Section 5.1. Regional differentiation was introduced using proxy variables such as population density, economic activity concentration and environmental sensitivity, reflecting spatial heterogeneity in exposure and impact. The intertemporal escalation of values reflects expected increases in marginal damage costs, driven by stricter environmental regulation and rising social valuation of air quality.

The SE/Central-West region exhibits the highest monetisation factors, reflecting:

- high demographic concentration,
- proximity of generation units to load centres,
- higher marginal health costs,
- greater economic valuation of productivity losses.

The North presents lower coefficients due to lower population density and spatial dispersion of generation assets.

The regionalisation of health-related externalities (Table 5.10) is a critical structural component of the SEGeP framework. Unlike global pollutants (CO_2), local pollutants such as SO_2 and NO_x generate damages intrinsically linked to the geographical location of the source.

5.4.2 National Results – Generation Mix BAU

The national generation mix resulting from the BAU optimisation is presented in Table 5.11. The results reflect the intertemporal allocation of capacity and generation that minimises Total Social Cost under the regionalised input structure previously defined.

Table 5.11 - Optimal Generation (TWh)

Year	Hydro	Wind	Solar	Biomass	Gas	Others	Total
2030	430	130	90	80	70	20	820
2040	440	180	140	90	60	20	930
2050	450	220	190	95	70	15	1,040

Source: Author's elaboration.

Total electricity demand increases from 820 TWh in 2030 to 1,040 TWh in 2050, representing a cumulative increment of 220 TWh over the planning horizon. The model allocates this additional generation primarily to wind and solar technologies, whose combined contribution rises from 220 TWh in 2030 to 410 TWh in 2050 (+190 TWh). This expansion accounts for approximately 86% of total incremental generation over the period.

Hydropower remains the backbone of the Brazilian electricity system under BAU, increasing modestly from 430 TWh to 450 TWh between 2030 and 2050. This limited expansion reflects the interaction between three forces embedded in the optimisation:

1. Regional capacity constraints,
2. Monetised land and water externalities,
3. Increasing opportunity cost of new large-scale reservoirs.

Although hydro exhibits low carbon intensity (0.02 tCO_2/MWh), its effective marginal social cost rises when water consumption (25–35 m^3/MWh) and land occupation coefficients are internalised. As a result, hydro stabilises structurally rather than expanding proportionally with demand.

Wind generation increases from 130 TWh to 220 TWh (+90 TWh), while solar expands from 90 TWh to 190 TWh (+100 TWh). The growth of these technologies is driven by:

- Declining CAPEX (particularly solar at €0.55–0.75 million/MW),
- Very low operational costs (3–6 €/MWh),
- Negligible water consumption,
- Low emission factors,
- Competitive land-use monetisation in high-resource regions (especially Northeast).

Because SEGeP internalises environmental intensities into monetary terms, the effective marginal cost of wind and solar remains systematically below that of fossil alternatives once carbon pricing is applied. At €65/tCO_2 in 2050, the carbon penalty on gas generation (0.40 tCO_2/MWh) adds approximately €26/MWh to its effective cost, materially altering competitiveness.

Biomass maintains a relatively stable role (80 → 95 TWh). Its higher OPEX (15–25 €/MWh) and moderate emission factor (0.10 tCO_2/MWh) limit its expansion compared to wind and solar, despite its firm generation profile.

Natural gas exhibits non-monotonic behaviour (70 → 60 → 70 TWh). The temporary reduction in 2040 reflects the intermediate effect of carbon pricing combined with renewable expansion. However, by 2050, gas returns to 70 TWh due to increasing system flexibility requirements associated with higher penetration of variable renewables. This outcome illustrates the endogenous balancing function of dispatchable thermal generation under system adequacy constraints.

The renewable share evolves as follows:

- 89.0% in 2030
- 91.4% in 2040
- 91.8% in 2050

The increase in renewable penetration is primarily driven by wind and solar expansion rather than additional hydro development. However, the pace of renewable share growth slows after 2040, increasing by only 0.4 percentage points between 2040 and 2050. This deceleration suggests that system flexibility constraints progressively bind as variable renewables expand.

From a structural perspective, the BAU trajectory demonstrates that high renewable penetration is achievable within a cost-minimising framework even without strengthened policy instruments. However, the persistence of gas at approximately 6–7% of total generation indicates that flexibility requirements introduce a lower bound on fossil participation under current technological assumptions.

Between 2030 and 2050, the 220 TWh increment is allocated as follows:

- Wind: +90 TWh (41%)
- Solar: +100 TWh (45%)
- Hydro: +20 TWh (9%)
- Biomass: +15 TWh (7%)
- Gas: 0 net change
- Others: −5 TWh

This distribution demonstrates that marginal demand is predominantly met by low-carbon technologies. The model does not expand gas capacity structurally but maintains it to satisfy reserve margin and ramping constraints.

The national generation mix under BAU reflects three interacting structural forces:

1. Cost Competitiveness – Declining renewable CAPEX shifts the merit order.
2. Carbon Internalisation – Uniform carbon pricing increases the effective cost of gas generation.
3. Flexibility Constraints – System reliability requirements prevent full displacement of dispatchable thermal capacity.

The resulting mix is not policy-driven but emerges endogenously from the cost-minimisation problem under regionalised externality internalisation. The BAU pathway therefore represents a technologically and economically consistent trajectory under moderate climate pricing and without explicit social optimisation constraints.

5.4.3 Regional Disaggregation of Generation BAU

The regional disaggregation of generation under the BAU scenario is presented in Table 5.12, which reports electricity production by subsystem for 2030, 2040 and 2050. Because SEGeP internalises

externalities through region-specific monetisation coefficients, the spatial distribution of generation is endogenously determined by differentiated marginal social costs rather than by proportional allocation.

Table 5.12 - Electricity Generation by Region (TWh)

Region	2030	2040	2050
North	115	120	126
Northeast	185	215	241
SE / Central-West	410	470	515
South	110	125	158
Total SIN	820	930	1,040

Source: Author's elaboration.

As shown in Table 5.12, total generation increases from 820 TWh in 2030 to 1,040 TWh in 2050, corresponding to an increment of 220 TWh. This additional generation is unevenly distributed across regions. The SE/Central-West subsystem increases output from 410 TWh to 515 TWh (+105 TWh), absorbing approximately 48% of the total system expansion. The Northeast expands from 185 TWh to 241 TWh (+56 TWh), while the South grows from 110 TWh to 158 TWh (+48 TWh). In contrast, the North records only marginal expansion (+11 TWh).

The dominance of SE/Central-West, accounting for roughly 49–50% of national generation throughout the horizon, reflects the concentration of load centres and the allocation of dispatchable capacity required to ensure system adequacy. Despite facing the highest land monetisation coefficient and water cost, the subsystem retains structural centrality due to demand coupling and balancing requirements.

The Northeast's expansion from 185 TWh in 2030 to 241 TWh in 2050 is consistent with its lower land monetisation coefficient (€950/ha/year) and favourable renewable productivity conditions. The model therefore allocates incremental wind and solar generation to this region as it presents a lower effective marginal social cost after internalisation.

Installed capacity evolution, presented in Table 5.13, confirms this structural shift.

Table 5.13 - Installed Capacity by Region (GW)

Region	2030	2040	2050
North	27.5	28.3	28.1
Northeast	58.0	66.7	72.4
SE/CW	105.0	114.0	110.2
South	26.0	28.8	24.5
Total SIN	216.5	237.8	235.2

Source: Author's elaboration.

As indicated in Table 5.13, the Northeast records the largest capacity increase over the horizon (+14.4 GW between 2030 and 2050), reinforcing its role as the principal renewable expansion pole. In contrast,

SE/Central-West capacity peaks at 114 GW in 2040 and slightly declines to 110.2 GW in 2050, reflecting optimisation between dispatchable capacity and increasing renewable penetration in other regions.

The environmental implications of this spatial allocation are detailed in Table 5.14, which reports CO_2 emissions by region.

Table 5.14 - CO_2 Emissions by Region ($MtCO_2$)

Region	2030	2040	2050
North	1.8	1.9	2.2
Northeast	3.5	4.0	4.8
SE/CW	33.0	34.5	36.1
South	8.3	4.9	8.1
Total SIN	46.6	45.3	51.2

Source: Author's elaboration.

In 2050, total emissions reach 51.2 $MtCO_2$. Of this total, 36.1 $MtCO_2$ originate from SE/Central-West, corresponding to approximately 70% of system-wide emissions. This concentration is directly linked to the allocation of gas-based flexibility in the subsystem, as identified in Table 5.14.

The territorial footprint of electricity expansion under the Business-as-Usual (BAU) configuration is presented in Table 5.15, which reports land occupation by region and technology for the three planning horizons. Land use constitutes a critical environmental dimension within the SEGeP framework, as the spatial expansion of generation assets is directly associated with biodiversity pressure, landscape transformation, ecosystem fragmentation and opportunity costs of alternative land uses.

Table 5.15 - Land Use by region and technology in Scenario BAU (km²).

Year	Region	Hydro	Wind	Solar	Biomass	Others	Total Region
2030	North	10,500	110	140	10	110	10,870
	Northeast	1,800	3,100	1,100	100	50	6,150
	SE / CW	14,800	350	500	380	200	16,230
	South	2,100	100	20	10	20	2,250
	Total 2030	29,200	3,660	1,760	500	380	35,500
2040	North	11,200	200	200	20	130	11,750
	Northeast	1,800	4,000	1,100	140	60	7,100
	SE / CW	17,200	700	700	500	250	19,350
	South	3,500	200	50	20	30	3,800
	Total 2040	33,700	5,100	2,050	680	470	42,000
2050	North	11,800	300	250	20	130	12,500
	Northeast	1,800	5,000	1,200	140	60	8,200
	SE / CW	19,500	1,100	750	500	250	22,100
	South	5,500	400	50	20	30	6,000
	Total 2050	38,600	6,800	2,250	680	470	48,800

Source: Author's elaboration.

Under BAU, total land occupation increases from 35,500 km² in 2030 to 48,800 km² in 2050, representing an expansion of approximately 37% over the planning horizon. This growth reflects the combined effect of incremental hydropower expansion and the progressive scaling of wind and solar capacity, both of which exhibit significant spatial footprints per unit of installed capacity. While hydropower remains the dominant contributor to total occupied area due to reservoir surfaces, wind and solar account for a growing share of marginal land transformation.

Regionally, the Southeast/Central-West (SE/CW) subsystem maintains the largest absolute land footprint, reaching 22,100 km² in 2050. This is primarily attributable to hydropower reservoirs (19,500 km²), complemented by 1,100 km² of wind and 750 km² of solar installations. The predominance of hydro infrastructure reflects historical investment patterns and the structural legacy of large-scale projects within the SIN.

The North region records 12,500 km² of total land occupation in 2050, largely dominated by hydropower (11,800 km²). Although wind and solar expand gradually—reaching 300 km² and 250 km², respectively—the hydro reservoir footprint continues to define the region's spatial profile under BAU.

In contrast, the Northeast exhibits the most dynamic proportional growth in land use associated with wind energy. Wind occupation rises from 3,100 km² in 2030 to 5,000 km² in 2050, consolidating the region's role as the principal onshore wind frontier. Solar expansion also increases to 1,200 km² by 2050. Despite the stability of hydropower at 1,800 km², total regional land occupation reaches 8,200 km², driven primarily by variable renewable deployment.

The South region demonstrates a significant increase in hydropower-related land occupation, expanding from 2,100 km² in 2030 to 5,500 km² in 2050. Although wind and solar remain modest contributors in absolute terms, the hydro expansion raises total land occupation in the region to 6,000 km² by 2050.

From a systemic perspective, the BAU trajectory reveals that cumulative territorial transformation becomes substantial even in the absence of aggressive renewable mandates. The persistence of hydro reservoirs and the spatial intensity of wind deployment generate long-term land-use externalities that are not explicitly minimised within the BAU optimisation logic. Consequently, the land-use indicator reinforces the interpretation of BAU as an environmentally path-dependent equilibrium, shaped by historical infrastructure and cost-driven expansion rather than by spatial sustainability criteria.

Applying the carbon price of €65/tCO_2 defined in Table 5.10 results in an annual carbon cost of approximately €3.33 billion per year. This carbon burden is disproportionately associated with SE/Central-West due to its generation structure. Water consumption patterns further reinforce the spatial differentiation of impacts, as shown in Table 5.16.

Table 5.16 - Water consumption by region in the BAU scenario (million m³, 2050).

Region	Water Use
North	185
Northeast	22
SE/CW	540
South	113
Total	860

Source: Author's elaboration.

Total water use in 2050 reaches 860 million m³, with 540 million m³ (63%) concentrated in SE/Central-West. Although hydro presents low carbon intensity, its water intensity combined with regional water monetisation coefficients increases its effective marginal social cost, moderating large-scale expansion.

The spatial distribution of generation, capacity, emissions and water use is not uniform but reflects differentiated marginal social costs resulting from:

- Regional demand concentration,
- Region-specific land and water monetisation coefficients,
- Technology-specific environmental intensity factors,
- Carbon pricing trajectory.

The BAU scenario therefore produces a territorially differentiated equilibrium in which:

- SE/Central-West functions as the balancing and emissions hub,

- The Northeast consolidates renewable expansion,
- The North stabilises hydro output,
- The South expands moderately under land-use constraints.

This spatial structure emerges endogenously from the model and is fully traceable to the input parameters previously defined.

5.4.4 Social Effects BAU

Employment effects under the BAU scenario are derived directly from the optimisation results through the employment coefficients defined in Section 5.1. In the SEGeP framework, employment generation constitutes a monetised social externality incorporated in the Total Social Cost objective function (Equation 1). Consequently, job creation is endogenously determined by optimisation through the allocation of investments across technologies and regions.

Table 5.17 - Employment Effects (Jobs/year)

Region	2030	2040	2050
North	40,000	44,000	48,000
Northeast	78,000	92,000	102,000
SE/CW	65,000	80,000	95,000
South	17,000	28,000	34,000
Total	200,000	244,000	279,000

Source: Author's elaboration.

As shown in Table 5.17, total employment increases from 200,000 jobs/year in 2030 to 279,000 jobs/year in 2050, representing a net gain of 79,000 jobs over the planning horizon. This corresponds to an average annual growth rate of approximately 1.7%.

The Northeast records the highest absolute employment levels throughout the period, rising from 78,000 to 102,000 jobs/year. This trajectory mirrors the regional concentration of wind and solar expansion identified in Table 5.13 and Table 5.14. Given the higher labour intensity of solar photovoltaic and onshore wind—particularly during construction and installation phases—the regional allocation of renewable investments translates directly into employment concentration.

SE/Central-West employment increases from 65,000 to 95,000 jobs/year. Despite its dominance in total generation (Table 21), its employment growth is relatively lower than the Northeast in proportional terms, reflecting the higher share of dispatchable gas and hydro generation, which exhibit lower labour intensity per unit of installed capacity.

The North shows moderate employment growth (+8,000 jobs), consistent with its stabilised hydro-dominant structure. The South exhibits the highest proportional growth rate (+100% between 2030 and 2050), although from a lower base, reflecting incremental renewable deployment.

At the technology level, solar and wind account for the majority of job creation. This outcome is structurally consistent with the national generation expansion pattern, where wind and solar contribute 190 TWh of the 220 TWh incremental demand between 2030 and 2050.

Because employment is endogenously valued within the TSC framework, the spatial distribution of jobs emerges from the cost-optimal allocation rather than from exogenous employment targets.

The macroeconomic performance of the BAU trajectory is summarised in Table 5.18, which reports total system cost (net present value) and average levelised cost of electricity (LCOE).

Table 5.18 - System Economic Indicators

Metric	2030	2040	2050
Total System Cost (NPV, € Billion)	285.4	342.1	412.5
Average LCOE (€/MWh)	52.1	55.6	58.4

Source: Author's elaboration.

The Total system cost increases from €285.4 billion in 2030 to €412.5 billion in 2050. This increase is primarily driven by demand growth and cumulative capital deployment rather than by deterioration in technological cost competitiveness.

The average LCOE rises from €52.1/MWh in 2030 to €58.4/MWh in 2050. This represents a 12.1% increase over two decades. Importantly, this increase is not attributable to CAPEX escalation. On the contrary, wind and solar CAPEX remain stable or decline in real terms, as defined in Table 5.09.

The LCOE increase is instead associated with three structural drivers:

1. Integration Costs – Higher penetration of variable renewables increases system balancing requirements, including reserve margins and ramping capacity.
2. Carbon Internalisation – The €65/tCO_2 carbon price in 2050 increases the effective marginal cost of gas-based generation.
3. Externality Monetisation – Water and land-use costs introduce additional shadow pricing effects on hydro and land-intensive renewables.

The moderate upward trend in LCOE reflects the internalisation of environmental externalities and system adequacy costs rather than inefficiency or technological regression.

The joint analysis of Tables 5.17 and 5.18 indicates that the BAU trajectory produces:

- Sustained employment growth driven primarily by renewable expansion;

- Increasing total system cost consistent with demand growth and carbon internalisation;
- Moderate LCOE increase associated with integration and externality pricing;
- Regional concentration of employment aligned with renewable investment flows.

These results reinforce the interpretation of BAU as a structurally coherent cost-minimising trajectory under moderate carbon pricing and without explicit social optimisation constraints.

5.4.5 Analytical Discussion: The Structural Role of Regionalisation BAU

As shown in Table 5.18, total system cost increases from €285.4 billion in 2030 to €412.5 billion in 2050. This increase is primarily driven by demand growth and cumulative capital deployment rather than by deterioration in technological cost competitiveness.

The average LCOE rises from €52.1/MWh in 2030 to €58.4/MWh in 2050. This represents a 12.1% increase over two decades. Importantly, this increase is not attributable to CAPEX escalation. On the contrary, wind and solar CAPEX remain stable or decline in real terms, as defined in Table 5.8.

The LCOE increase is instead associated with three structural drivers:

4. Integration Costs – Higher penetration of variable renewables increases system balancing requirements, including reserve margins and ramping capacity.
5. Carbon Internalisation – The €65/tCO_2 carbon price in 2050 increases the effective marginal cost of gas-based generation.
6. Externality Monetisation – Water and land-use costs introduce additional shadow pricing effects on hydro and land-intensive renewables.

The moderate upward trend in LCOE reflects the internalisation of environmental externalities and system adequacy costs rather than inefficiency or technological regression.

The joint analysis of Tables 5.17 and 5.18 indicates that the BAU trajectory produces:

- Sustained employment growth driven primarily by renewable expansion;
- Increasing total system cost consistent with demand growth and carbon internalisation;
- Moderate LCOE increase associated with integration and externality pricing;
- Regional concentration of employment aligned with renewable investment flows.

These results reinforce the interpretation of BAU as a structurally coherent cost-minimising trajectory under moderate carbon pricing and without explicit social optimisation constraints.

The BAU scenario reflects a system expansion trajectory primarily governed by cost-minimisation principles, with limited influence from environmental and social considerations. The resulting configuration

highlights the structural inertia of the electricity system when no additional policy signals or sustainability constraints are introduced, reinforcing the role of economic competitiveness as the dominant driver of investment decisions, Key findings of the scenario:

(i) The resulting generation mix is primarily driven by cost-minimisation dynamics, with limited influence from environmental and social constraints, reflecting the absence of strong regulatory signals;

(ii) Fossil-based technologies remain competitive under baseline conditions, highlighting the structural limitations of purely economic optimisation approaches;

(iii) Regional concentration of generation persists, indicating that cost-driven expansion alone does not promote territorial balance;

(iv) The scenario provides a reference benchmark against which the structural effects of alternative policy and sustainability configurations can be assessed.

5.5 – Scenario 2: High Renewable Penetration (HRP)

The HRP scenario constitutes the second policy configuration analysed within the SEGeP framework and represents an accelerated decarbonisation pathway relative to the Business-as-Usual (BAU) reference trajectory presented in Section 5.4. While the BAU scenario reflects policy continuity under moderate environmental internalisation, the HRP configuration simulates a structurally more ambitious transition environment oriented toward near-zero carbon electricity supply by 2050.

Consistent with the modelling architecture defined in Chapter 4 and operationalised in Section 5.1, the HRP scenario does not introduce any modification to the mathematical structure of the mixed-integer linear programming (MILP) model. The objective function, decision variables and system constraints remain identical to those described previously. All decision variables continue to be indexed by technology i, region r, and time period $t \in \{2030,2040,2050\}$, ensuring full methodological comparability across scenarios.

The optimisation problem continues to minimise Total Social Cost (TSC), composed of:

- Investment costs (CAPEX)
- Operating and fuel costs (OPEX)
- Monetised CO_2 emissions
- Monetised SO_2 and NO_x emissions (health-related externalities)
- Monetised land occupation costs
- Monetised water consumption costs
- Monetised health damage costs

Therefore, the analytical structure of the objective function remains unchanged relative to BAU. What differentiates the HRP scenario is the modification of selected monetisation parameters and the introduction of additional binding constraints that redefine the feasible optimisation space.

Two structural adjustments distinguish HRP from BAU:

(1) Strengthened Environmental Internalisation

The carbon price trajectory is significantly reinforced relative to BAU, reflecting a deeper climate policy commitment:

- €55/tCO_2 in 2030 (vs €30 in BAU)
- €85/tCO_2 in 2040 (vs €45 in BAU)
- €120/tCO_2 in 2050 (vs €65 in BAU)

In addition, land-use, water-use and biodiversity monetisation parameters are increased (as detailed in the following subsection), maintaining their regional indexation r. This ensures that environmental internalisation continues to operate territorially, but at a higher intensity.

(2) Binding Renewable Share Constraint

Unlike BAU—where renewable penetration emerges endogenously without explicit minimum requirements—the HRP scenario imposes a binding renewable share constraint:

- ≥ 90% in 2030
- ≥ 95% in 2040
- ≥ 98% in 2050

This constraint is incorporated directly into the model as a structural inequality linking renewable generation to total system output in each period t. Consequently, the HRP scenario does not merely rely on price signals (carbon valuation) but also introduces quantitative policy targets.

From a modelling perspective, the HRP configuration therefore represents a constrained cost-minimising equilibrium under strengthened environmental pricing and explicit renewable penetration requirements. The scenario allows assessing whether deep decarbonisation is achievable within the physical, regional and technological limits encoded in SEGeP, and how such ambition reshapes generation structure, spatial allocation, environmental impacts and social outcomes relative to BAU.

5.5.1 Input Data Structure HRP

The techno-economic parameters defined in Table 5.8 (Section 5.4) — including CAPEX, OPEX, emission intensity coefficients, land occupation factors and water consumption coefficients — remain unchanged in the HRP scenario. No structural alteration is introduced in the technological cost assumptions or physical performance parameters. This methodological decision ensures that differences observed between BAU and HRP arise exclusively from policy-driven parameter adjustments and binding constraints, rather than from artificial shifts in technological competitiveness.

The structural differentiation of HRP relative to BAU is therefore implemented through two channels:

1. Strengthening of environmental monetisation parameters
2. Introduction of additional binding system constraints

These modifications directly affect the Total Social Cost (TSC) objective function coefficients and selected system constraints while preserving the original MILP formulation.

Relative to BAU, the following adjustments are implemented:

• Carbon price trajectory strengthened

– €55/tCO_2 in 2030 (vs €30 in BAU)

– €85/tCO_2 in 2040 (vs €45 in BAU)

– €120/tCO_2 in 2050 (vs €65 in BAU)

• Water monetisation coefficients increased by +30% in all regions

• Land-use monetisation coefficients increased by +15% in all regions

• Biodiversity monetisation coefficients increased by +40% in all regions

• Thermal dispatch constraint introduced, limiting fossil-based generation to:

– ≤ 8% of total generation in 2030

– ≤ 5% in 2040

– ≤ 2% in 2050

It is critical to emphasise that all monetisation parameters remain indexed by region r, as originally defined in Section 5.4. This means that, although environmental penalties are strengthened, territorial differentiation is preserved. The Southeast/Central-West continues to exhibit higher land and water shadow prices relative to the Northeast and North, and these differences continue to influence the spatial allocation of investments.

Thus, HRP modifies the magnitude of the monetisation parameters but does not alter the structure of their interaction within the objective function.

Health damage monetisation for local pollutants (SO_2 and NO_x) also remains region-specific, following the coefficients presented in Table 5.10 (Section 5.4). These parameters continue to be indexed by region $r$and time t, reflecting demographic density and healthcare cost differentials.

However, under HRP, the quantitative impact of SO_2 and NO_x monetisation becomes structurally lower in aggregate terms due to the significant displacement of fossil-based generation. In other words, the marginal penalty per kilogram emitted is unchanged relative to BAU, but total system emissions of local pollutants decline substantially because fossil dispatch is heavily constrained.

This distinction is analytically important: HRP does not weaken local pollutant valuation; it reduces total health damages by structurally altering the generation mix.

5.5.2 National Results – Generation Mix HRP

Table 5.19 presents the optimal generation mix obtained under the HRP scenario, reflecting the intertemporal allocation of capacity and generation that minimises Total Social Cost under strengthened environmental internalisation parameters and binding renewable penetration constraints.

Table 5.19 - Optimal generation by technology in HRP (TWh)

Year	Hydro	Wind	Solar	Biomass	Gas	Others	Total
2030	430	170	130	70	15	5	820
2040	420	220	200	76	10	4	930
2050	421	265	255	81	10	8	1,040

Source: Author's elaboration.

Total electricity demand follows the same trajectory defined in the BAU scenario (820 TWh in 2030, 930 TWh in 2040 and 1,040 TWh in 2050), ensuring strict comparability between scenarios. However, the internal structure of generation changes substantially as a direct consequence of the strengthened carbon pricing trajectory, the imposition of binding renewable share constraints and the strict limitation on fossil-based dispatch.

Wind and solar become the primary drivers of expansion. By 2050, combined wind and solar generation reaches 520 TWh, corresponding to approximately 53% of total national electricity supply. This expansion reflects both the enhanced competitiveness of renewables under higher carbon valuation (€120/tCO_2 in 2050) and the structural necessity of meeting the minimum renewable penetration requirement of 98%. Unlike in the BAU configuration, where gas remains a structural flexibility provider, the HRP scenario reallocates almost the entirety of incremental demand growth toward variable renewable technologies.

Hydropower remains broadly stable in absolute generation terms, increasing marginally from 430 TWh in 2030 to 445 TWh in 2050. This stability reflects the physical saturation of economically viable expansion sites and the intensified monetisation of land, water and biodiversity impacts. Consequently, hydro does not function as the principal adjustment margin for decarbonisation; instead, its role is redefined as a flexibility and balancing resource within an increasingly renewable-dominated system.

Natural gas generation undergoes a structural collapse. While BAU records 70 TWh of gas generation in 2050, the HRP configuration limits this value to 10 TWh. This contraction results from the combined interaction of strengthened carbon pricing, binding fossil participation ceilings and the monetisation of local pollutants (SO_2 and NO_x), which significantly increase the effective marginal cost of thermal dispatch. Gas is therefore retained only as residual backup capacity required to preserve system adequacy under extreme operating conditions.

Biomass maintains a moderate but stable contribution, increasing from 70 TWh to 85 TWh over the horizon. Although biomass exhibits lower net carbon intensity compared to fossil fuels, its expansion is moderated by intensified biodiversity and land-use monetisation coefficients, preventing disproportionate growth.

The renewable share achieved endogenously by the model reaches 94.0% in 2030, 96.8% in 2040 and 97.9% in 2050. The scenario comfortably exceeds the imposed targets in the first two periods and approaches full compliance in 2050, with only a marginal deviation of 0.1 percentage points relative to the 98% requirement. This small shortfall does not reflect modelling limitations, but rather the structural necessity of preserving minimal dispatchable capacity to satisfy adequacy constraints.

The transformation of the generation mix produces a profound reduction in CO_2 emissions. Total emissions decline to 11.2 $MtCO_2$ in 2050, compared to 51.2 $MtCO_2$ under BAU. This represents a reduction of approximately 78% relative to the reference pathway in the final period. The residual emissions are associated with the limited gas generation retained for system reliability and with biomass-related emissions that remain partially monetised within the objective function.

The HRP generation structure constitutes a constrained near-zero-carbon equilibrium that emerges endogenously from the modified parameter space. The model demonstrates that, under strengthened environmental internalisation and binding renewable targets, the Brazilian electricity system can structurally reconfigure toward a predominantly renewable architecture while preserving optimisation coherence and system feasibility.

5.5.3 Regional Disaggregation of Generation HRP

Table 5.20 presents the regional distribution of electricity generation under the HRP scenario. Although total national demand remains identical to BAU (1,040 TWh in 2050), the spatial configuration of generation changes substantially as a consequence of strengthened renewable constraints and fossil displacement.

Table 5.20 - Electricity generation by region in HRP (TWh)

Region	2030	2040	2050
North	120	125	130
Northeast	260	320	380
SE / Central-West	335	355	360
South	105	130	170
Total SIN	820	930	1,040

Source: Author's elaboration.

The Northeast emerges as the dominant generation hub in the HRP configuration. Output increases from 260 TWh in 2030 to 380 TWh in 2050, representing a cumulative expansion of 120 TWh over the horizon. When compared to the BAU configuration in 2050, the Northeast records an additional +139 TWh, reflecting the strong reallocation of wind and solar investments toward regions with superior renewable resource endowment and relatively lower land monetisation coefficients. Under HRP, the Northeast becomes the principal driver of incremental renewable supply at the national level.

In contrast, the SE/Central-West subsystem exhibits a structural contraction relative to BAU. Generation increases only marginally from 335 TWh in 2030 to 360 TWh in 2050. Compared to the 515 TWh observed in BAU 2050, this corresponds to a reduction of −155 TWh. This decline is directly associated with the sharp reduction in gas-based generation and the tighter environmental constraints imposed under HRP. While SE/Central-West remains the main load centre and continues to host dispatchable and balancing resources, its structural role shifts from expansion leader to flexibility provider within a renewable-dominated system.

The North shows moderate growth, rising from 120 TWh to 130 TWh between 2030 and 2050. This stability reflects the limited expansion of large-scale hydropower under strengthened biodiversity and water-use penalties. The South increases from 105 TWh to 170 TWh over the same period, capturing part of the renewable expansion but remaining secondary relative to the Northeast.

Table 5.20 demonstrates that the HRP scenario intensifies territorial differentiation relative to BAU. Renewable expansion becomes geographically concentrated in high-productivity regions, while fossil-dependent subsystems experience structural contraction. The spatial redistribution of generation is therefore

not uniform, but rather a direct consequence of strengthened environmental internalisation combined with binding renewable penetration constraints.

Table 5.21 reports the regional evolution of installed capacity under the HRP scenario. Total installed capacity increases from 255.0 GW in 2030 to 360.5 GW in 2050, substantially above the 235.2 GW observed in the BAU configuration for the same year (see Section 5.4). This expansion does not reflect inefficiency or excess investment, but rather the structural consequence of a system increasingly dominated by variable renewable energy (VRE). As wind and solar penetration rises, additional installed capacity is required to compensate for lower capacity factors and to ensure compliance with adequacy, reserve margin and ramping constraints embedded in the MILP formulation.

Table 5.21 - Installed capacity by region in HRP (GW)

Region	2030	2040	2050
North	29.5	31.0	32.5
Northeast	85.0	120.0	165.0
SE/CW	108.0	112.0	115.0
South	32.5	40.0	48.0
Total SIN	255.0	303.0	360.5

Source: Author's elaboration.

The Northeast emerges as the principal capacity expansion pole, increasing from 85.0 GW in 2030 to 165.0 GW in 2050 (+80 GW). This sharp expansion is consistent with the regional generation results previously discussed and reflects the concentration of wind and solar deployment in a subsystem characterised by favourable resource endowment and relatively lower effective marginal social cost after internalisation. The magnitude of the capacity increase, however, exceeds the proportional rise in generation, indicating the lower average capacity factor of the dominant technologies deployed in this region.

In contrast, the Southeast/Central-West subsystem exhibits comparatively moderate capacity growth, rising from 108.0 GW to 115.0 GW between 2030 and 2050. Despite remaining the largest load centre in the system, the strict thermal dispatch limits and strengthened carbon pricing significantly constrain fossil-based expansion. Capacity growth in this region is therefore primarily associated with renewable substitution and system adequacy requirements rather than structural expansion of dispatchable thermal assets.

The North and South regions experience incremental but comparatively moderate increases. The North expands from 29.5 GW to 32.5 GW, reflecting stabilised hydro capacity and limited new large-scale development under intensified biodiversity and water penalties. The South increases from 32.5 GW to 48.0 GW, driven by wind and solar additions, yet constrained by higher land-use monetisation and territorial competition.

The total installed capacity of 360.5 GW in 2050 represents a structural shift toward a high-capacity, lower-utilisation system configuration. This outcome is a direct consequence of deep renewable penetration, where adequacy is ensured through capacity volume rather than through high-capacity-factor thermal generation. The difference relative to BAU therefore quantifies the systemic investment requirement associated with accelerated decarbonisation under the HRP pathway.

Table 5.22 presents the regional distribution of CO_2 emissions under the HRP scenario. Total system emissions decline from 18.7 $MtCO_2$ in 2030 to 11.2 $MtCO_2$ in 2050, representing a reduction of approximately 40% over the planning horizon and nearly 78% relative to the BAU level observed in 2050 (51.2 $MtCO_2$ in Section 5.4). This trajectory provides evidence that the strengthened carbon price signal and binding renewable constraints materially reshape the dispatch structure of the system.

Table 5.22 - CO_2 emissions by region in HRP ($MtCO_2$).

Region	2030	2040	2050
North	1.9	1.5	1.1
Northeast	2.5	1.8	1.2
SE/CW	12.1	8.0	7.2
South	2.2	1.2	1.7
Total SIN	18.7	12.5	11.2

Source: Author's elaboration.

The Southeast/Central-West (SE/CW) subsystem remains the principal emissions locus throughout the horizon, decreasing from 12.1 $MtCO_2$ in 2030 to 7.2 $MtCO_2$ in 2050. Although emissions fall substantially in absolute terms, the region continues to account for the majority share of national emissions in 2050 (approximately 64%). This persistence reflects the structural concentration of residual dispatchable generation in the main load centre, including remaining gas-based flexibility and part of the biomass fleet. Even under strict thermal limits, system adequacy constraints require a minimal level of firm generation, which remains spatially coupled to demand density.

The Northeast shows a pronounced decline from 2.5 $MtCO_2$ in 2030 to 1.2 $MtCO_2$ in 2050. Given the strong expansion of wind and solar generation in this region (Section 5.5), emissions per unit of generation become extremely low. The resulting emissions profile is consistent with a renewable-dominated regional structure, in which fossil generation is almost entirely displaced and biomass operates at moderate levels.

In the North, emissions decrease from 1.9 $MtCO_2$ to 1.1 $MtCO_2$ over the horizon. This reduction reflects the stabilisation of hydropower and the absence of significant new fossil capacity additions. The remaining emissions are associated primarily with biomass and limited residual thermal dispatch required under system-wide reliability conditions.

The South exhibits a non-monotonic pattern, declining from 2.2 $MtCO_2$ in 2030 to 1.2 $MtCO_2$ in 2040, followed by a moderate increase to 1.7 $MtCO_2$ in 2050. This behaviour reflects the interplay between renewable expansion and the need for limited regional flexibility provision in the final period. Nevertheless, emissions remain substantially below BAU levels.

From a system-wide perspective, the HRP scenario achieves deep decarbonisation while preserving reliability constraints explicitly represented in the MILP formulation. The residual 11.2 $MtCO_2$ in 2050 correspond to the structural lower bound imposed by the absence of large-scale storage or zero-carbon firm capacity alternatives within the model assumptions. Consequently, the regional emission profile in Table 5.22 reflects a constrained near-zero-carbon equilibrium in which fossil-based generation becomes residual rather than structural yet not entirely eliminated.

The High Renewable Penetration (HRP) scenario produces a structural transformation in the spatial configuration of electricity generation within the SEGeP framework. While large hydropower plants are characterised by concentrated land occupation associated with reservoir surfaces, the accelerated expansion of wind and solar technologies under HRP redistributes the territorial footprint across extensive onshore areas. This shift alters not only the magnitude but also the geography of land-use pressure, modifying the regional profile of environmental conflicts and spatial competition.

As shown in Table 5.24, total land occupation increases from 35,995 km^2 in 2030 to 54,180 km^2 in 2050, representing an expansion of approximately 50% over the planning horizon. Unlike BAU, where hydropower remains the dominant contributor to land occupation growth, HRP stabilises hydro expansion and transfers the incremental footprint primarily to wind and solar PV technologies.

Table 5.23 - Land Use by region and technology in Scenario HRP (km²).

Year	Region	Hydro	Wind	Solar PV	Biomass	Others	Total Region
2030	North	8,800	180	150	10	15	9,155
	Northeast	1,800	4,200	2,100	80	20	8,200
	SE / CW	12,500	850	1,100	650	210	15,310
	South	2,100	950	250	15	15	3,330
	Total 2030	25,200	6,180	3,600	755	260	35,995
2040	North	8,800	350	300	20	20	9,490
	Northeast	1,800	6,500	4,200	150	30	12,680
	SE / CW	12,500	1,600	2,800	950	250	18,100
	South	2,100	1,400	650	30	20	4,200
	Total 2040	25,200	9,850	7,950	1,150	320	44,470
2050	North	8,800	650	550	30	30	10,060
	Northeast	1,800	9,200	6,400	250	40	17,690
	SE / CW	12,500	2,400	4,500	1,350	300	21,050
	South	2,100	2,100	1,100	50	30	5,380
	Total 2050	25,200	14,350	12,550	1,680	400	54,180

Source: Author's elaboration.

Hydropower occupation remains constant at 25,200 km² throughout the horizon, reflecting the absence of new large-scale reservoirs and the prioritisation of renewable deployment over additional hydro expansion. Consequently, marginal land-use growth is driven almost entirely by wind and solar PV.

Wind energy experiences the most pronounced expansion. Total wind occupation increases from 6,180 km² in 2030 to 14,350 km² in 2050, more than doubling over the period. The Northeast emerges as the dominant wind frontier, reaching 9,200 km² by 2050, consolidating its structural role as the national renewable hub. The South and SE/Central-West also register significant growth, reaching 2,100 km² and 2,400 km² respectively in 2050.

Solar PV follows a similar trajectory, expanding from 3,600 km² in 2030 to 12,550 km² in 2050. The SE/Central-West becomes a major solar pole, with 4,500 km² occupied by 2050, while the Northeast reaches 6,400 km². The spatial distribution of solar capacity reinforces the decentralised character of the HRP transition, extending the territorial footprint beyond traditional hydro basins.

Regionally, the Northeast records the most substantial increase in total land occupation, rising from 8,200 km² in 2030 to 17,690 km² in 2050. This expansion reflects the combined effect of large-scale wind and solar deployment and provides evidence of the region's central role in the renewable-led transition. The SE/Central-West reaches 21,050 km² in 2050, maintaining the highest absolute regional footprint due to its combination of legacy hydropower and expanding solar infrastructure.

The South also experiences considerable spatial transformation, increasing from 3,330 km² in 2030 to 5,380 km² in 2050, largely driven by wind and solar growth. In contrast, the North maintains relatively stable occupation levels, rising modestly from 9,155 km² to 10,060 km², given the stabilisation of hydropower and moderate renewable penetration.

From a systemic perspective, HRP demonstrates that deep decarbonisation through renewable expansion does not eliminate territorial externalities; rather, it redistributes them. The scenario replaces concentrated hydro-reservoir impacts with diffuse, large-area renewable occupation. Although wind and solar generally impose lower ecological disruption per unit of electricity generated compared to large reservoirs, their cumulative land requirement becomes substantial at high penetration levels.

Thus, the HRP pathway reveals a transition in land-use density: from concentrated hydro-dominated occupation toward spatially dispersed renewable landscapes. This transformation reshapes the environmental dimension of regionalisation within SEGeP, shifting the locus of land-use pressure toward the Northeast and SE/Central-West while preserving hydro legacies in the North. The territorial sustainability of HRP therefore depends not only on carbon reduction performance but also on spatial planning, biodiversity safeguards and integrated land governance.

Table 5.25 presents the full technological and regional disaggregation of water consumption under the HRP scenario for the three planning periods (2030, 2040 and 2050). Unlike the BAU trajectory, where water use remains structurally linked to hydro expansion and thermal flexibility, the HRP configuration progressively decouples electricity growth from hydrological pressure through fossil displacement and strengthened water monetisation (+30% relative to BAU).

Table 5.24 - Water consumption by region in HRP (million m³, 2050).

Year	Region	Hydro	Wind	Solar PV	Biomass	Natural Gas	Nuclear	Coal	Total
2030	North	160.0	0.0	0.0	1.8	3.2	–	0.0	165.0
	Northeast	12.0	0.0	0.0	4.0	4.0	–	0.0	20.0
	SE / CW	430.0	0.0	0.0	45.0	25.0	20.0	0.0	540.0
	South	88.0	0.0	0.0	10.0	7.0	–	0.0	105.0
	Total 2030	690.0	0.0	0.0	60.8	39.2	20.0	0.0	810.0
2040	North	165.0	0.0	0.0	2.0	1.0	–	0.0	168.0
	Northeast	10.5	0.0	0.0	4.5	2.0	–	0.0	17.0
	SE / CW	425.0	0.0	0.0	48.0	10.0	20.0	0.0	503.0
	South	90.0	0.0	0.0	12.0	3.0	–	0.0	105.0
	Total 2040	690.5	0.0	0.0	66.5	16.0	20.0	0.0	793.0
2050	North	168.0	0.0	0.0	2.0	0.0*	–	0.0	170.0
	Northeast	10.0	0.0	0.0	5.0	0.0*	–	0.0	15.0
	SE / CW	425.0	0.0	0.0	52.0	3.0	20.0	0.0	500.0
	South	92.0	0.0	0.0	13.0	0.0*	–	0.0	105.0
	Total 2050	695.0	0.0	0.0	72.0	3.0	20.0	0.0	790.0

Source: Author's elaboration

In 2030, total system water consumption reaches 810 million m³, of which 690 million m³ (85%) originate from hydropower alone. The Southeast/Central-West (SE/CW) concentrates 540 million m³,

representing two-thirds of total national consumption. This reflects the coexistence of large hydro reservoirs (430 million m^3), biomass-based cogeneration (45 million m^3), natural gas cooling (25 million m^3) and nuclear generation (20 million m^3). The North records 165 million m^3, primarily from hydropower (160 million m^3), while the Northeast and South consume 20 and 105 million m^3, respectively. Even at this early stage, wind and solar PV register zero operational water use, reinforcing their structural hydrological advantage.

By 2040, total water consumption declines to 793 million m^3, despite higher electricity generation (930 TWh). Hydropower remains stable at approximately 690.5 million m^3, but gas-related consumption drops sharply from 39.2 million m^3 (2030 total gas use) to 16.0 million m^3, reflecting tighter fossil dispatch limits and the strengthened carbon trajectory. In SE/CW, gas cooling falls from 25 to 10 million m^3, while in the Northeast it decreases from 4.0 to 2.0 million m^3. Biomass water use rises moderately to 66.5 million m^3 system-wide, reflecting expanded bioenergy deployment, yet its hydrological footprint remains significantly lower than that of hydro reservoirs.

In 2050, total water consumption declines further to 790 million m^3, even as generation reaches 1,040 TWh. Hydropower accounts for 695 million m^3, remaining the dominant contributor but without significant expansion relative to previous decades. The decisive structural shift occurs in thermal technologies: natural gas water use collapses to only 3.0 million m^3 system-wide (entirely located in SE/CW), as the 2% dispatch limit and high carbon price (€120/tCO_2) render gas marginal. Coal is completely eliminated in all periods, recording zero consumption. Nuclear remains constant at 20 million m^3 in SE/CW, reflecting its role as firm base capacity within the model structure.

Regionally, in 2050, SE/CW still concentrates 500 million m^3 (63% of total), followed by the North (170 million m^3), South (105 million m^3) and Northeast (15 million m^3). The exceptionally low value in the Northeast is consistent with its renewable-dominated generation mix (380 TWh in 2050, largely wind and solar), confirming that the HRP scenario reallocates generation toward low-water-intensity technologies and territories.

Across the horizon, the system reduces water consumption from 810 million m^3 (2030) to 790 million m^3 (2050), despite a 220 TWh increase in electricity production. This decoupling illustrates a central structural feature of the HRP scenario: strengthened water monetisation and fossil displacement alter the marginal cost ranking of technologies, favouring non-thermal renewables whose operational water intensity is effectively zero.

The detailed technological breakdown in Table 5.24 demonstrates that SEGeP internalises not only financial and carbon externalities but also the physical hydrological footprint of each generation option in each region. The HRP outcome therefore represents a multidimensional optimisation result in which climate

mitigation and water sustainability evolve simultaneously, rather than being treated as independent policy objectives.

Table 5.25 reports the regional evolution of local air pollutants under the HRP scenario, explicitly quantifying SO_2 and NO_x emissions in kilotonnes (kt) for 2030, 2040 and 2050. These results are fully consistent with the strengthened fossil dispatch limits and with the regionally differentiated health damage monetisation coefficients embedded in the SEGeP objective function.

Table 5.25 - SO_2 and NO_x emissions in HRP.

Year	Region	SO_2 (kt)	NO_x (kt)	Year	Region	SO_2 (kt)	NO_x (kt)	Year	Region	SO_2 (kt)	NO_x (kt)
2030	North	0.8	2.5	2040	North	0.6	1.8	2050	North	0.4	1.2
	Northeast	1.1	2.9		Northeast	0.8	2.1		Northeast	0.6	1.5
	SE / CW	4.5	10.2		SE / CW	3.1	6.5		SE / CW	2.1	4.8
	South	1.4	3.6		South	1.0	2.4		South	0.7	1.8
	Total SIN 2030	7.8	19.2		Total SIN 2040	5.5	12.8		Total SIN 2050	3.8	9.3

Source: Author's elaboration.

At the system level, total SO_2 emissions decline from 7.8 kt in 2030 to 5.5 kt in 2040 and 3.8 kt in 2050. Over the same period, NO_x emissions fall from 19.2 kt to 12.8 kt and ultimately to 9.3 kt. The reduction exceeds 50% between 2030 and 2050 for both pollutants, demonstrating the structural effect of the thermal dispatch constraint (≤ 2% in 2050) combined with the high carbon price trajectory and health damage internalisation. Importantly, this reduction occurs despite the expansion of total electricity generation from 820 TWh to 1,040 TWh, indicating a clear decoupling between output growth and local pollutant emissions.

Regionally, the Southeast/Central-West (SE/CW) remains the principal residual emitter throughout the horizon. In 2030, SE/CW accounts for 4.5 kt of SO_2 and 10.2 kt of NO_x, representing more than half of total national emissions. By 2050, emissions in this region decline to 2.1 kt (SO_2) and 4.8 kt (NO_x), yet it still concentrates approximately 55% of national SO_2 and 52% of NO_x emissions. This concentration reflects two structural features of the optimisation result: the persistence of biomass-based generation (which emits NO_x due to high-temperature combustion processes) and the residual gas-based flexibility maintained near major load centres for reliability purposes.

In the North, emissions decrease from 0.8 kt (SO_2) and 2.5 kt (NO_x) in 2030 to 0.4 kt and 1.2 kt in 2050. The Northeast shows a similar declining trajectory, from 1.1 kt and 2.9 kt to 0.6 kt and 1.5 kt over the same period. The South reduces emissions from 1.4 kt (SO_2) and 3.6 kt (NO_x) in 2030 to 0.7 kt and 1.8 kt in 2050. These reductions are driven primarily by fossil displacement and by the comparatively lower role of biomass in these subsystems relative to SE/CW.

The persistent gap between NO_x and SO_2 values across all regions is consistent with the technological emission factors adopted in Section 5.4: natural gas and biomass exhibit low sulphur content but still generate significant nitrogen oxides during combustion. Consequently, NO_x emissions remain structurally higher than SO_2 throughout the horizon.

The regionalised monetisation of health damages plays a decisive role. Because monetisation coefficients (€/kg) are higher in densely populated regions—particularly SE/CW—the solver internalises stronger penalties for local pollutant emissions in these territories. This mechanism endogenously discourages pollutant-intensive generation near major urban centres, accelerating the decline of local pollutants relative to the BAU configuration. The HRP scenario therefore not only reduces global climate externalities (CO_2), but also delivers substantial co-benefits in terms of local air quality and public health, with reductions that are spatially differentiated and economically internalised within the Total Social Cost framework.

5.5.4 Social Effects HRP

Employment impacts under the HRP scenario are calculated ex post, using the same labour intensity coefficients presented in Chapter 4 and applied to the optimised generation and installed capacity levels for each technology, region (r) and period ($t \in \{2030, 2040, 2050\}$). As in the BAU configuration, employment does not enter the objective function nor the constraint set of the MILP model. It is therefore an induced social outcome resulting from the cost-minimising allocation of renewable and thermal investments under strengthened environmental internalisation. Table 5.26 presents the employment generated in BAU scenario.

Table 5.26 - Employment effects by region in HRP.

Region	2030	2040	2050
North	42,000	45,000	47,000
Northeast	98,000	115,000	135,000
SE/CW	70,000	95,000	110,000
South	25,000	40,000	54,000
Total	235,000	295,000	346,000

Source: Author's elaboration.

Total employment increases from 235,000 jobs/year in 2030 to 346,000 jobs/year in 2050. This corresponds to an absolute gain of 111,000 jobs over the planning horizon and, critically for scenario comparison, an increase of 67,000 additional jobs relative to the BAU scenario in 2050 (279,000 jobs). The difference is directly attributable to the stronger expansion of wind and solar technologies under HRP, which exhibit higher labour intensity—particularly during construction and installation phases—than fossil-based generation.

Regionally, the Northeast emerges as the primary employment hub of the electricity sector. Employment rises from 98,000 jobs in 2030 to 135,000 in 2050, representing nearly 39% of national electricity-related employment in the final period. This concentration mirrors the regionalised generation and capacity results presented in Sections 5.5.2 and 5.5.3, where the Northeast becomes the dominant renewable expansion pole due to favourable resource endowment and strengthened decarbonisation constraints.

The SE/Central-West region records employment growth from 70,000 to 110,000 jobs/year. Although fossil dispatch is sharply reduced relative to BAU, employment remains substantial due to the scale of demand, continued biomass generation and the presence of firm capacity (including nuclear). However, its relative participation declines compared to BAU, reflecting the territorial shift of renewable investments toward the Northeast.

The North exhibits moderate growth (42,000 to 47,000 jobs), consistent with its stabilised hydro-dominant structure and limited incremental expansion. The South shows the highest proportional growth, increasing from 25,000 to 54,000 jobs/year by 2050, reflecting diversification toward wind and solar within environmental constraints.

From a sustainability perspective, the HRP scenario strengthens the social dimension of the SEGeP framework. Because employment is not an optimised objective, the observed job expansion constitutes a structural co-benefit of renewable-based decarbonisation rather than the result of an imposed redistributive policy. This reinforces the interpretation of HRP as a transition pathway capable of delivering simultaneous environmental gains and measurable regional socio-economic improvements within a cost-minimising optimisation structure.

Income distribution effects under the HRP scenario are assessed through the projected evolution of the regional Gini index, interpreted as a distributive indicator structurally linked to endogenous model outputs. In the SEGeP framework, the Gini index is not included as an optimisation variable, in accordance with the methodological principle that only decision-dependent terms influence the optimal solution.

Its trajectory is analytically derived from the regional allocation of generation and installed capacity, combined with employment effects and associated labour-income dynamics induced by the model. Employment generation is estimated using technology-specific employment coefficients, while regional income effects are approximated using baseline socio-economic conditions. These baseline conditions include regional GDP, labour market structure and inequality levels, obtained from official statistical sources described in Section 5.1.

In this context, variations in the Gini index reflect the relative distribution of income generated across regions under each expansion pathway. This approach ensures that distributive outcomes are consistently

grounded in both endogenous model results and empirically observed regional socio-economic conditions, avoiding arbitrary assumptions while preserving methodological coherence.

The evolution of regional income inequality under the HRP scenario is summarised in Table 5.27, which indicates a sustained decline in the Gini index across the entire planning horizon.

Table 5.27 - Regional Gini index in HRP.

Region	2030	2040	2050
North	0.530	0.525	0.518
Northeast	0.520	0.508	0.495
SE/CW	0.500	0.495	0.488
South	0.470	0.468	0.462

Source: Author's elaboration based on endogenous model outputs (regional generation, installed capacity and employment effects) combined with socio-economic parameters and regional baseline conditions described in Section 5.1.

The Gini values reported are consistent with baseline regional inequality levels and reflect relative variations induced by scenario-specific employment and income effects.

The results indicate a consistent downward trajectory in income inequality across all regions between 2030 and 2050. The most pronounced improvement occurs in the Northeast, where the Gini index declines from 0.520 in 2030 to 0.495 in 2050. This reduction is directly associated with the region's leadership in renewable expansion under HRP, which translates into higher employment generation, increased local value added and stronger income dispersion effects.

In the North, the Gini index decreases more moderately (0.530 to 0.518), reflecting stable hydro dominance and more limited incremental investment flows relative to the Northeast. The SE/Central-West region also exhibits a gradual improvement (0.500 to 0.488), driven by employment expansion in biomass, solar and system-support activities, despite the contraction of fossil dispatch.

The South maintains the lowest inequality levels throughout the horizon, declining from 0.470 to 0.462. Although its absolute employment expansion is smaller than in the Northeast, diversification toward renewables contributes positively to regional income distribution.

From a sustainability perspective, these results suggest that accelerated renewable deployment under HRP does not merely reduce environmental externalities but also contributes to measurable improvements in regional income distribution. The concentration of renewable investments in historically less developed regions—particularly the Northeast—acts as a structural driver of inequality reduction, reinforcing the social co-benefits of decarbonisation within the SEGeP framework.

The evolution of the Human Development Index (HDI) under the HRP scenario is presented in Table 5.28. The results indicate a systematic improvement in human development across all regions between 2030 and 2050, with evidence of accelerated convergence relative to the BAU trajectory.

Table 5.28 - Regional HDI in HRP

Region	2030	2040	2050
North	0.745	0.765	0.790
Northeast	0.735	0.765	0.805
SE/CW	0.790	0.810	0.830
South	0.805	0.820	0.835

Source: Author's elaboration.

As shown in Table 5.28, the North increases its HDI from 0.745 in 2030 to 0.790 in 2050, while the Northeast records a more pronounced improvement, rising from 0.735 to 0.805 over the same period. The magnitude of this change is particularly relevant in the Northeast, where the cumulative gain of 0.070 points reflects the interaction between renewable investment concentration, employment expansion and improvements in income distribution.

In the Southeast/Central-West, HDI rises from 0.790 to 0.830, maintaining its position as one of the most developed subsystems, yet with a comparatively moderate growth rate. The South increases from 0.805 to 0.835, remaining the highest-performing region in absolute terms, but with slower relative acceleration compared to the Northeast.

The convergence effect becomes evident when comparing regional differentials. In 2030, the gap between the South (0.805) and the Northeast (0.735) is 0.070 points. By 2050, this difference narrows to 0.030 points (0.835 vs 0.805), indicating a substantial reduction in interregional development disparities.

Table 5.28 provides evidence that the HRP scenario generates not only environmental improvements and emission reductions, but also measurable gains in multidimensional human development, reinforcing the integrated sustainability character of the scenario within the SEGeP framework.

The macroeconomic performance of the High Renewable Penetration scenario is summarised in Table 5.29, which reports total system cost in net present value (NPV) terms and the average levelised cost of electricity (LCOE) for the three planning horizons.

Table 5.29 - System economic indicators in HRP

Metric	2030	2040	2050
Total system cost (NPV, € billion)	290.5	355.0	425.2
Average LCOE (€/MWh)	50.5	48.8	47.5

Source: Author's elaboration.

As indicated in Table 5.29, total system cost increases from €290.5 billion in 2030 to €425.2 billion in 2050. This upward trajectory reflects cumulative capital deployment associated with accelerated renewable expansion and the substantial increase in installed capacity, which reaches 360.5 GW in 2050. The higher

NPV relative to BAU in the early periods is consistent with front-loaded investment requirements typical of capital-intensive renewable pathways.

However, the evolution of the average LCOE reveals a structurally different dynamic. The LCOE declines from €50.5/MWh in 2030 to €47.5/MWh in 2050. When compared to the BAU value of €58.4/MWh in 2050, the HRP scenario delivers a cost reduction of approximately €10.9/MWh, corresponding to an 18.7% lower average generation cost in the final period.

This decline is primarily explained by three interacting mechanisms embedded in the optimisation structure. First, the strengthened carbon price trajectory—reaching €120/tCO_2 in 2050—substantially increases the effective marginal cost of fossil-based generation, accelerating its displacement in favour of wind and solar technologies. Second, the large-scale deployment of renewables, characterised by low marginal operating costs and zero fuel exposure, reduces the weighted average cost of generation despite higher upfront CAPEX. Third, the reduction in dispatchable fossil generation decreases exposure to fuel price volatility and carbon cost pass-through effects.

Table 5.29 demonstrates that, within the SEGeP framework, deep decarbonisation under HRP does not imply structural cost escalation at the system level. On the contrary, the combination of high renewable penetration and strong carbon internalisation results in a declining average generation cost by 2050, reinforcing the economic viability of an accelerated transition pathway.

5.5.5 Analytical Discussion: The Structural Role of Regionalisation HRP

The results presented in Tables 5.8 to 5.18 demonstrate that the BAU scenario cannot be interpreted as a purely technological equilibrium. Rather, it constitutes a spatially differentiated optimisation outcome in which regionalised marginal social costs materially reshape the feasible allocation space of the model.

Within the SEGeP framework, generation decisions are indexed simultaneously by technology and region. As previously defined in Table 5.10, land opportunity costs and water monetisation coefficients vary across subsystems, while carbon pricing is applied uniformly. When these monetisation parameters interact with technology-specific environmental intensities (Table 5.8), they generate regionally differentiated effective marginal costs even for identical technologies. Consequently, the optimisation problem is not solved along a single national merit order curve, but across multiple spatially conditioned marginal cost surfaces.

The structural dominance of the Southeast/Central-West subsystem illustrated in Table 5.14 — accounting for 515 TWh in 2050, approximately 50% of national generation—cannot be attributed solely to cost competitiveness. Instead, it reflects the spatial coupling between demand concentration and flexibility allocation. Because reserve margin and ramping requirements are endogenously satisfied within the

subsystem hosting the largest load centres, dispatchable generation remains structurally anchored in SE/Central-West. This allocation explains the concentration of emissions observed in Table 5.15, where 36.1 $MtCO_2$ (approximately 70% of total system emissions in 2050) originate in that region.

The Northeast's expansion trajectory, increasing generation from 185 TWh in 2030 to 241 TWh in 2050 (Table 5.13), emerges from a different structural mechanism. The region combines high renewable productivity with the lowest land monetisation coefficient (€950/ha/year in Table 5.10). When multiplied by land intensity coefficients (Table 5.8), the resulting shadow land cost for wind and solar deployment becomes systematically lower than in other subsystems. The model therefore reallocates incremental renewable capacity toward the Northeast, not as a result of policy targeting, but due to lower effective marginal social cost after internalisation.

Hydropower expansion in the North illustrates a third mechanism. Despite competitive CAPEX and low carbon intensity, generation increases only from 115 TWh to 126 TWh between 2030 and 2050 (Table 5.13). This limited growth is consistent with the water consumption levels shown in Table 5.17 (185 million m^3 in 2050) and the water monetisation coefficients in Table 5.10. When water intensity (25–35 m^3/MWh) is monetised—even at a relatively moderate €0.04/m^3—the effective marginal cost of additional hydro generation increases sufficiently to prevent large-scale expansion. The inclusion of biodiversity and land occupation costs further reinforces this moderation effect.

These results confirm that externality internalisation under BAU does not operate as a uniform penalty applied equally across the territory. Instead, it reshapes spatial investment flows by modifying regional marginal cost gradients. Technologies are not simply "penalised" or "favoured" at the national level; their competitiveness becomes region contingent.

From a system-wide perspective, the BAU scenario produces a renewable share exceeding 91% by 2050 (Table 5.19), demonstrating that high renewable penetration can be achieved within a cost-minimising framework under moderate carbon pricing. However, emissions remain at 51.2 $MtCO_2$ in 2050 (Table 5.15), corresponding to an implied carbon cost burden of approximately €3.33 billion annually at €65/tCO_2. This persistence of emissions reflects structural flexibility requirements rather than insufficient renewable competitiveness.

The gradual increase in LCOE from €52.1/MWh in 2030 to €58.4/MWh in 2050 (Table 5.18) indicates that system integration costs become progressively relevant as renewable penetration rises. The cost increase is not driven by CAPEX escalation but by the combined effect of balancing needs and environmental internalisation.

From a modelling perspective, the BAU configuration constitutes a constrained cost-minimising equilibrium under moderate carbon pricing and regionally differentiated scarcity signals. All spatial outcomes are directly traceable to the interaction between technology-specific environmental intensities (Table 5.18), regional monetisation coefficients (Table 5.4), and demand concentration patterns (Table 5.13). No exogenous territorial preference is imposed. The spatial allocation observed is therefore a fully endogenous result of the optimisation structure.

Although the BAU pathway aligns with medium-term climate objectives and demonstrates internal consistency, it does not eliminate residual fossil generation by 2050. The persistence of 51.2 $MtCO_2$ suggests that moderate carbon internalisation alone is insufficient to achieve full decarbonisation under current technological and flexibility assumptions. This structural limitation provides the analytical foundation for exploring more ambitious internalisation pathways in the subsequent scenarios.

The results reported in Tables 5.22 to 5.30 confirm that the HRP scenario is not merely a "greener" version of BAU, but a structurally distinct spatial equilibrium generated by the same MILP formulation under a different set of binding constraints and monetisation signals. Because all decision variables remain indexed by technology *i*, region *r* and time *t* (Chapter 4), the transition from BAU to HRP occurs exclusively through changes in (i) the carbon price trajectory and (ii) strengthened region-indexed scarcity and damage valuations, combined with (iii) explicit constraints on renewable penetration and thermal dispatch. In this setting, regionalisation becomes the mechanism through which the model reallocates not only technologies, but also the *geography* of investment, flexibility and externalities.

A first-order structural difference emerges in the spatial allocation of generation. Under HRP, the Northeast becomes the dominant expansion pole, reaching 380 TWh in 2050 (Table 5.21). This level is not a marginal increase: it reflects a decisive shift in the national expansion frontier when the solver is forced to comply with near-total renewability while simultaneously internalising land and water scarcity costs and health damages. In parallel, the SE/Central-West—historically the balancing centre due to load concentration—falls to 360 TWh in 2050 (Table 5.21). Relative to BAU (Table 5.13 in Section 5.4), this represents a large redistribution of production away from the main load subsystem and toward the renewable resource core, consistent with the binding thermal limits and strengthened carbon valuation that collapse fossil-based flexibility to residual levels in the optimal mix (Table 5.20). Importantly, this redistribution is not imposed exogenously by any territorial rule but is induced endogenously by the interaction between regional monetisation parameters and feasibility constraints.

This spatial shift in generation is inseparable from a second structural effect: a sharp increase in installed capacity and its territorial concentration. Table 5.22 shows total capacity reaching 360.5 GW by

2050, which is materially above the BAU level (235.2 GW in 2050, Table 5.14 in Section 5.4). The key point for interpretation is not simply "more capacity", but *where* and *why* it occurs. The Northeast reaches 165 GW in 2050, reflecting the dominance of wind and solar in the HRP solution and the need to compensate for lower capacity factors and intermittency through overcapacity. Meanwhile, SE/Central-West remains relatively stable in capacity terms (115 GW in 2050, Table 5.22), consistent with its role as the operational and infrastructure anchor of the SIN, but it no longer absorbs the same marginal expansion of energy supply as in BAU (Table 5.22 versus Table 5.13 in Section 5.4). In practical terms, the HRP solution converts the national problem into a spatial trade-off between "resource regions" (renewable energy production) and "load regions" (balancing and adequacy), with capacity expansion functioning as the adjustment variable that keeps adequacy feasible under binding decarbonisation.

The environmental dimension makes this logic explicit. CO_2 emissions fall to 11.2 $MtCO_2$ in 2050 (Table 5.23), a steep reduction compared with BAU (51.2 $MtCO_2$ in 2050, Table 5.15 in Section 5.4). However, the crucial regional insight is that emissions do not vanish uniformly. Even in a near-zero carbon pathway, SE/Central-West remains the main residual emitter with 7.2 $MtCO_2$ in 2050 (Table 5.23), which is consistent with the subsystem's structural coupling to system reliability and residual dispatchable needs. In other words, HRP relocates the bulk of energy production to the Northeast (Table 5.21), but it still concentrates the remaining "hard-to-abate" emissions near the main load centre. This is a hallmark of the model's spatial adequacy logic: emissions persist where flexibility is most valuable, not where renewables are cheapest.

A parallel result holds for local pollutants and human health damages, which are intrinsically region dependent. Table 5.26 shows that total SO_2 declines from 7.8 kt (2030) to 3.8 kt (2050), while total NO_x declines from 19.2 kt to 9.3 kt. The regional pattern again matters: SE/Central-West remains the main residual source in 2050 (2.1 kt SO_2 and 4.8 kt NO_x; Table 5.26), despite the sharp aggregate reduction. This persistence is analytically consistent with two simultaneous mechanisms already embedded in the modelling architecture: (i) residual thermal/biomass dispatch remains geographically anchored by adequacy and proximity to demand, and (ii) the monetisation of health damages is higher in densely populated regions (Table 5.11 in Section 5.4), which causes the solver to "push out" the most polluting dispatch whenever feasible, but cannot eliminate it fully under system constraints. Therefore, HRP does not merely reduce pollutants because it reduces fossil generation; it reduces them in a spatially selective way that reflects the interplay between load geography and region-specific health damage valuation.

Water is the third environmental channel where regionalisation is decisive. At first glance, total water consumption declines to 790 million m^3 in 2050 (Table 5.25), below BAU (860 million m^3 in 2050, Table 5.17 in Section 5.4). Yet the disaggregated table reveals the real mechanism: most water use remains

associated with hydropower and cooling requirements in SE/Central-West. In 2050, SE/Central-West accounts for 500 million m³ of the 790 million m³ total (Table 5.25), dominated by hydropower (425) plus biomass (52) and nuclear (20). The Northeast, despite becoming the dominant electricity producer (380 TWh, Table 5.22), consumes only 15 million m³ in 2050 (Table 5.25), precisely because wind and solar register zero operational water consumption in the accounting structure and because the HRP dispatch limit drives gas to residual levels. This is a strong sustainability result in territorial terms: HRP decouples *generation growth* from *water stress* by relocating marginal supply to technologies and regions with structurally low water footprints. At the same time, it exposes a constraint: the physical water footprint of "firm" technologies (hydro, biomass, nuclear) remains concentrated in the subsystem that anchors system adequacy and load.

The socio-economic outcomes follow the same spatial investment logic. Employment effects, computed ex post, rise to 346,000 jobs/year in 2050 (Table 5.28), which is +67,000 relative to BAU (279,000 jobs/year in 2050, Table 5.18 in Section 5.4). Crucially, job creation is not spatially neutral. The Northeast reaches 135,000 jobs/year in 2050 (Table 5.27), reflecting the concentration of renewable deployment and the higher labour intensity of wind and solar investment cycles. SE/Central-West still grows to 110,000 jobs/year (Table 5.27), but its role is more associated with balancing infrastructure and residual dispatchable generation rather than being the main expansion frontier. This pattern reinforces an important sustainability interpretation: HRP generates measurable co-benefits, but it also deepens territorial concentration of benefits in the renewable resource pole unless complementary redistributive constraints are introduced (which, by design, HRP does not impose).

Distributional and human development indicators evolve consistently with that pattern. Table 5.28 shows reductions in the Gini index across all regions, with the Northeast moving from 0.520 (2030) to 0.495 (2050), indicating accelerated inequality reduction in the region where investment and employment effects are strongest. Table 5.28 shows HDI growth in all subsystems and a convergence dynamic, with the Northeast rising from 0.735 to 0.805, narrowing the gap with the South and SE/Central-West over time. Within the sustainability narrative of SEGeP, these trajectories are not decorative add-ons: they operationalise the social pillar as region-indexed outputs driven by the endogenous geography of investments. The key analytic point is that HRP improves national social outcomes partly because it shifts the marginal investment frontier to regions with historically lower human development baselines, thereby producing stronger relative gains. This is precisely where the "sustainable planning" claim becomes defensible: the model links environmental ambition to territorial development outcomes through the same regionalised optimisation structure.

The economic dimension is not separable from regionalisation. Table 5.29 shows that, despite a higher NPV (425.2 €bn in 2050), the LCOE falls to 47.5 €/MWh by 2050. Interpreting this jointly with Tables

5.21 and 5.22, the HRP solution is capital intensive because it requires large-scale overcapacity and transmission-relevant expansion in the renewable pole, but it becomes cost-effective in average energy terms because wind and solar dominate marginal supply and fossil exposure becomes residual under high carbon prices. This is a standard transition trade-off, but the regionalised model adds an extra layer: the cost decline coexists with territorial concentration of capacity and infrastructure needs, implying that system-wide efficiency gains may require policy mechanisms to manage land-use pressure, grid reinforcement and social acceptance in the expansion pole.

The HRP scenario demonstrates that deep decarbonisation is technically feasible within the unchanged SEGeP MILP structure, but it is achieved through a spatial reconfiguration of the electricity system rather than through uniform technological substitution. The Northeast becomes the dominant renewable production and employment pole (Tables 5.21 and 5.27), while SE/Central-West remains the operational anchor that concentrates residual emissions, pollutants and water use due to adequacy requirements and load coupling (Tables 5.23 – 5.27). This spatial division of roles is the core structural insight of regionalisation under HRP: externality internalisation reshapes the geography of investment and impacts, generating clear environmental and social co-benefits, while simultaneously increasing capital intensity and reinforcing territorial concentration of renewable expansion and its associated infrastructure pressures.

The HRP scenario illustrates the structural impact of policy incentives favoring renewable technologies, leading to a significant reconfiguration of the energy matrix. The observed transition reflects the model's responsiveness to parameter adjustments that internalise environmental considerations, demonstrating how targeted interventions can accelerate the deployment of low-carbon energy sources. Key findings of the scenario:

(i) Increased penetration of renewable technologies is driven by parameter adjustments favoring low-carbon sources, demonstrating the system's sensitivity to policy incentives;

(ii) The expansion of renewable energies leads to a substantial reduction in emissions, reflecting the internalisation of environmental externalities in the optimisation framework;

(iii) The shift in the energy matrix introduces changes in regional investment patterns, particularly favoring regions with greater renewable energy potential;

(iv) The scenario highlights the trade-off between higher initial investment costs and long-term environmental benefits.

5.6 – Scenario 3: Low-Carbon Emissions (LCE)

The LCE scenario constitutes the third policy configuration analysed within the SEGeP framework and represents a carbon-constrained decarbonisation pathway relative to the Business-as-Usual (BAU) reference trajectory presented in Section 5.4. While the BAU scenario reflects policy continuity under moderate environmental internalisation and the High Renewable Penetration (HRP) configuration prioritises accelerated clean energy expansion through binding renewable targets, the LCE scenario simulates a structurally more stringent mitigation environment oriented toward deep emission reductions by 2050, consistent with a 1.5 °C climate pathway as defined by the Intergovernmental Panel on Climate Change (IPCC, 2021; IPCC, 2022a).

In the LCE scenario, emission reduction constitutes the dominant optimisation driver. The configuration was designed to analyse the behaviour of the Brazilian power system under a highly restrictive climate policy regime primarily oriented toward minimising total greenhouse gas emissions. Unlike HRP, which enforces explicit renewable penetration thresholds, LCE imposes strict caps on sectoral emissions combined with strong carbon valuation, reflecting the urgency associated with trajectories compatible with global climate neutrality and the commitments assumed under the Paris Agreement (UNFCCC, 2015).

Core assumptions include:

- A 70% reduction in total electricity sector emissions by 2050 relative to the reference trajectory, consistent with deep decarbonisation benchmarks for energy systems (IPCC, 2022a);
- High values for the Social Cost of Carbon (SCC), near the upper bound of the literature (Stern, 2007; IPCC, 2022a);
- Strong penalisation of fossil-based generation technologies through carbon valuation;
- Incentives for low-emission technologies operating through the objective function.

Unlike the HRP scenario, LCE does not impose absolute renewable share targets. This modelling choice allows firm low-carbon technologies — such as reservoir hydropower, nuclear energy and modern biomass — to play a structurally relevant role in maintaining system adequacy under deep decarbonisation. The absence of renewable quotas ensures that the resulting equilibrium is driven by emission constraints rather than by technology-specific mandates.

Consistent with the modelling architecture defined in Chapter 4 and operationalised in Section 5.1, the LCE scenario does not introduce any modification to the mathematical structure of the mixed-integer linear programming (MILP) model. The objective function, decision variables and system constraints remain identical to those described previously. All decision variables continue to be indexed by technology i, region r, and time period $t \in \{2030, 2040, 2050\}$, ensuring full methodological comparability across scenarios.

The optimisation problem continues to minimise Total Social Cost (TSC), composed of:

- Investment costs (CAPEX);
- Operating and fuel costs (OPEX);
- Monetised CO_2 emissions;
- Monetised SO_2 and NO_x emissions (health-related externalities);
- Monetised land occupation costs;
- Monetised water consumption costs;
- Monetised health damage costs.

Within the SEGeP framework, the LCE scenario translates into a reformulation of the hierarchy of environmental externalities. Direct CO_2 emissions become the central binding element in both the objective function and the structural constraints. Although the internal structure of the MILP remains unchanged, the tightening of the carbon constraint fundamentally reshapes the feasible solution space.

What differentiates the LCE scenario is the introduction of a binding CO_2 emissions ceiling in each planning period, directly restricting the optimisation domain. Under LCE, the model is required to satisfy the following total system emissions levels:

- 12.1 $MtCO_2$ in 2030;
- 7.8 $MtCO_2$ in 2040;
- 4.6 $MtCO_2$ in 2050.

These limits operate as hard constraints rather than as purely price-based signals. Consequently, fossil-based dispatch becomes progressively residual, and the model reallocates incremental demand growth toward low-carbon technologies and regions capable of absorbing such expansion within the physical, environmental and adequacy limits encoded in SEGeP.

From a modelling perspective, the LCE configuration therefore represents a constrained cost-minimising equilibrium under a progressively tightening carbon cap. The central aim is to assess the extent to which the national power system can operate at extremely low emission levels without excessively compromising system-wide costs, supply security, and coherence with the social and territorial dimensions of sustainability. By imposing a stringent emissions ceiling while preserving the full regional structure of the model, LCE allows the identification of structural stress points in the Brazilian electricity mix and makes explicit the degree of dependence on firm renewables and supporting technologies in a context of deep decarbonisation.

5.6.1 Input Data Structure LCE

Table 5.30 summarises the main parameters modified in the LCE scenario relative to both the BAU and HRP configurations. The guiding logic underpinning this scenario is deliberately climate-conservative: Climate protection and emissions minimisation are treated as overriding objectives, even when this entails more demanding economic, operational or system-integration requirements.

Table 5.30 - Main parameters modified in the LCE scenario.

Parameter	BAU	HRP	LCE	Technical and policy rationale
Carbon price (€/tCO_2)	30 / 45 / 60	55 / 85 / 120	80 / 110 / 150	Strong internalisation of climate costs; alignment with IEA Net-Zero scenarios
Annual emission cap ($MtCO_2$)	60 / 55 / 50	30 / 20 / 12	25 / 15 / 5	Simulation of a near net-zero trajectory by 2050; consistent with enhanced NDC
Maximum natural gas dispatch	No rigid limit	8% / 5% / 2%	5% / 3% / 1%	Minimisation of residual emissions and fossil dependence
NO_x and SO_2 penalties	Moderate	High	Very high (×2)	Representation of stringent air-quality policies
Biomass use penalty	Low	Medium	High	Consideration of sustainability limits and land-use competition
Regional expansion limits	Realistic	Expanded	Expanded + repowering	Forcing extreme optimisation of zero-emission renewables

Source: Author's elaboration.

The combined effect of these parameter adjustments makes the LCE scenario the most environmentally restrictive among those analysed. By simultaneously tightening emission caps, sharply increasing carbon prices and limiting fossil dispatch, the scenario drives the SEGeP model towards solutions that minimise emissions almost absolutely across the planning horizon.

This configuration intentionally shifts the optimisation problem away from cost-minimisation dominance and towards climate compliance dominance, exposing the structural implications of pursuing deep decarbonisation without recourse to residual fossil generation. As a result, the LCE scenario places increased pressure on variable renewable sources and on system flexibility mechanisms, providing a stringent benchmark against which the feasibility, costs and trade-offs of near net-zero electricity pathways can be rigorously assessed in the subsequent analysis.

The calibration of the environmental and operational parameters adopted in the LCE scenario is grounded in internationally recognised decarbonisation benchmarks and normative climate commitments rather than discretionary selection. The emission ceilings imposed for 2030, 2040 and 2050 were defined to reflect a trajectory consistent with near net-zero electricity systems by mid-century, in alignment with Brazil's long-term climate neutrality commitments and with global deep decarbonisation pathways. The International Energy Agency (IEA, 2021), in its *Net Zero by 2050: A Roadmap for the Global Energy Sector*, establishes that electricity systems must reach near-zero operational emissions by 2050 in order to remain compatible with a

1.5°C pathway. Considering Brazil's historically high renewable penetration and substantial resource endowment, a residual emissions allowance in 2050 limited to single-digit $MtCO_2$ levels represents a technically plausible lower bound within international decarbonisation standards rather than an arbitrary threshold.

The carbon price trajectory (80–150 €/tCO_2) was calibrated within the upper range of recent Social Cost of Carbon estimates reported in the Intergovernmental Panel on Climate Change (IPCC, 2023, AR6 Synthesis Report) and in OECD climate cost assessments (OECD, 2022). These assessments indicate that damage-consistent carbon pricing under low discount-rate assumptions frequently exceeds 100 €/tCO_2 in long-term equilibrium analyses. The chosen values therefore ensure robust internalisation of climate externalities within the Total Social Cost framework. The methodological coexistence of a carbon price and an emissions cap is consistent with environmental economics literature (Nordhaus, 2017; Stern, 2007), which recognises that price-based and quantity-based instruments may operate simultaneously in constrained welfare optimisation contexts to guarantee environmental boundary compliance.

The progressive restriction of natural gas dispatch reflects fossil phase-down trajectories identified in the IEA Net Zero Roadmap (IEA, 2021) and corroborated by decarbonisation strategies documented by the European Commission (European Commission, 2020, European Green Deal). These frameworks progressively reduce unabated gas generation to marginal balancing roles in near net-zero systems. The restriction implemented in LCE therefore operates as a structural proxy for long-term fossil phase-down commitments rather than as an arbitrary operational limitation.

The intensification of NO_x and SO_2 penalties is supported by the World Health Organisation (WHO, 2021) *Global Air Quality Guidelines*, which document substantial mortality and morbidity impacts associated with local air pollutants. Empirical cost-of-illness studies synthesised by the OECD (OECD, 2022) further demonstrate that local pollutant externalities frequently generate health costs comparable to or exceeding climate damages in densely populated regions. Strengthening these penalties ensures internal consistency between climate mitigation and public health protection.

The higher sustainability penalty applied to biomass reflects land-use competition and indirect land-use change risks documented by the Food and Agriculture Organisation of the United Nations (FAO, 2022) and by sustainability assessments reported by the IPCC (2023). These sources highlight the ecological and food-security risks associated with large-scale bioenergy expansion, particularly in land-constrained contexts. The penalty therefore prevents unconstrained biomass growth as a decarbonisation shortcut within the model.

The adoption of expanded regional limits with repowering allowances ensures that renewable deployment is not artificially constrained by infrastructure ceilings, allowing the model to explore the full

technical potential of zero-emission resources while preserving the regional equity structure embedded in SEGeP. This approach is consistent with integrated assessment modelling practices documented in IPCC mitigation scenarios (IPCC, 2023).

Taken together, these calibrations represent a structured feasibility boundary for deep decarbonisation within the technological set modelled. The LCE scenario therefore functions not as a policy forecast, but as a structured stress-test of the Brazilian electricity system under stringent climate ambition, anchored in internationally recognised reference pathways, environmental economics theory and public health evidence.

5.6.2 Results of the Optimal Generation Mix LCE

Table 5.31 presents the optimal generation mix obtained under the LCE scenario. The results reveal a robust structural pattern, reflecting the stringent climate parametrization.

Table 5.31 - Optimal generation by technology in the LCE scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Others	Total
2030	417	180	146	63	10	4	820
2040	405	230	221	64	5	5	930
2050	406	274	282	64	3	11	1,040

Source: *Author's elaboration.*

Table 5.31 reports the optimal generation mix obtained under the LCE scenario. The results reveal a clear, stable and mathematically robust structural pattern, directly reflecting the stringent climate-oriented parameterisation adopted in this scenario.

The combined expansion of solar photovoltaic and wind power becomes even more pronounced than in the HRP case, together accounting for more than 50% of total electricity generation by 2050. This outcome is driven by the simultaneous tightening of emission caps, the sharp increase in carbon prices and the strict limitation of fossil dispatch, which collectively shift the optimisation towards technologies with near-zero operational emissions and low marginal environmental costs.

Biomass generation remains constrained throughout the horizon, reflecting the additional penalties associated with land-use competition and sustainability concerns embedded in the LCE formulation. Natural gas assumes a purely residual role, limited to marginal system-balancing functions and representing less than 1% of total generation by 2050, consistent with the near net-zero trajectory imposed by the scenario.

Hydropower remains broadly stable in absolute terms across all periods, reinforcing its role as the main firm renewable source and a central pillar of system balance. Rather than expanding significantly, hydropower functions as a structural stabiliser within an increasingly variable renewable-dominated system, complementing wind and solar generation under stringent environmental constraints.

The generation mix under the LCE scenario illustrates the endogenous response of the SEGeP model to extreme climate ambition: deep decarbonisation is achieved primarily through the accelerated deployment of variable renewables, while dispatchable low-carbon resources provide system stability without compromising the near-zero emissions objective.

5.6.3 Regional Disaggregation of Generation and Capacity (LCE)

Table 5.32 presents the regional distribution of electricity generation under the LCE scenario. Although total national demand remains identical to BAU (1,040 TWh in 2050), the spatial configuration of generation changes even more drastically than in HRP as a consequence of the mandatory emission cap (5 $MtCO_2$) and the aggressive carbon price signal (€150/tCO_2).

Table 5.32 - Electricity generation by region in LCE (TWh).

Region	2030	2040	2050
North	120	125	130
Northeast	250	310	370
SE / Central-West	340	355	370
South	110	140	170
Total SIN	**820**	**930**	**1,040**

Source: Author's elaboration

The Northeast consolidates its role as the dominant generation hub in the LCE configuration. Output increases from 250 TWh in 2030 to 370 TWh in 2050, representing a cumulative expansion of 120 TWh. Compared to the BAU configuration in 2050, the Northeast records an additional +129 TWh, reflecting the systematic reallocation of wind and solar investments toward regions where fossil-free generation is most productive. Under LCE, the Northeast acts as the "green engine" of the system, providing the bulk of the zero-carbon energy needed to meet the strict national emission cap.

In contrast, the SE/Central-West subsystem exhibits a structural contraction relative to BAU. Generation increases only slightly from 340 TWh in 2030 to 370 TWh in 2050. Compared to the 515 TWh observed in BAU 2050, this corresponds to a reduction of −145 TWh. This decline is directly associated with the virtual elimination of gas-based generation (limited to 1% dispatch) and the heavy penalization of any carbon-intensive assets. In the LCE scenario, SE/Central-West transitions from a thermal-dependent region to a subsystem focused on hydroelectric storage and high-value biomass firm energy.

The North shows stable growth, rising from 120 TWh to 130 TWh, while the South captures a significant share of renewable expansion, rising to 170 TWh. Table 5.32 demonstrates that the LCE scenario creates a more balanced regional generation profile than BAU, but one that is fundamentally rooted in renewable resource availability rather than thermal proximity to demand.

Table 5.33 reports the regional evolution of installed capacity under the LCE scenario. Total installed capacity increases from 259.0 GW in 2030 to 369.5 GW in 2050, the highest among all technological scenarios. This surge is a direct structural consequence of a system achieving near-zero emissions.

Table 5.33 - Installed capacity by region in LCE (GW).

Region	2030	2040	2050
North	30.5	31.5	32.5
Northeast	88.0	125.0	170.0
SE/CW	105.0	110.0	112.0
South	35.5	45.0	55.0
Total SIN	**259.0**	**311.5**	**369.5**

Source: Author's elaboration

The Northeast emerges as the principal capacity expansion pole, growing from 88.0 GW in 2030 to 170.0 GW in 2050 (+82 GW). This expansion reflects the massive deployment of wind and solar PV to ensure compliance with the 5 $MtCO_2$ cap. The magnitude of the capacity increase highlights the "intermittency premium": more MW are required per GWh produced to compensate for lower capacity factors compared to the displaced thermal fleet.

In the Southeast/Central-West, capacity growth is nearly stagnant, rising only from 105.0 GW to 112.0 GW. This provides evidence that under LCE, the region stops adding new fossil-based assets, focusing instead on repowering existing hydro or adding small-scale biomass, while new structural expansion shifts almost entirely to the Northeast and South.

Table 5.34 presents the regional distribution of CO_2 emissions under the LCE scenario. Total system emissions decline from 12.1 $MtCO_2$ in 2030 to 4.6 $MtCO_2$ in 2050, a reduction of 91% relative to the BAU 2050 level. This provides evidence that the 5 $MtCO_2$ cap acts as the binding constraint of the model.

Table 5.34 - CO_2 emissions by region in LCE ($MtCO_2$).

Region	2030	2040	2050
North	1.2	0.5	0.2
Northeast	1.8	1.0	0.4
SE/CW	7.5	5.5	3.6
South	1.6	0.8	0.4
Total SIN	12.1	7.8	4.6

Source: Author's elaboration.

The Southeast/Central-West (SE/CW) remains the principal emissions locus, with 3.6 $MtCO_2$ in 2050 (78% of the national total). This persistence reflects the necessity of maintaining a minimum thermal reserve near major load centers for system reliability. However, the Northeast and North achieve near-complete decarbonisation (0.4 and 0.2 $MtCO_2$, respectively).

The Low Carbon Emphasis (LCE) scenario produces a structural reconfiguration of territorial occupation driven by aggressive decarbonisation targets. Unlike BAU, where hydropower expansion and incremental renewable growth coexist, and unlike HRP, which stabilises hydro while massively expanding wind and solar, LCE combines moderate hydro expansion with accelerated deployment of wind, solar PV and biomass. The result is a diversified but spatially expansive land-use trajectory.

As shown in Table 5.36, total land occupation increases from 35,540 km² in 2030 to 52,870 km² in 2050, representing an expansion of approximately 49% over the planning horizon. This growth is primarily associated with large-scale renewable deployment required to meet strict emission constraints while preserving system reliability.

Table 5.35 - Land Use by region and technology in Scenario LCE (km²).

Year	Region	Hydro	Wind	Solar PV	Biomass	Others	Total Region
2030	North	9,200	140	120	10	10	9,480
	Northeast	1,800	3,800	1,800	60	10	7,470
	SE / CW	12,800	650	950	850	140	15,390
	South	2,100	850	220	20	10	3,200
	Total 2030	25,900	5,440	3,090	940	170	35,540
2040	North	9,800	280	250	20	10	10,360
	Northeast	1,800	5,500	3,200	120	15	10,635
	SE / CW	13,500	1,200	2,100	1,200	160	18,160
	South	2,500	1,200	450	40	15	4,205
	Total 2040	27,600	8,180	6,000	1,380	200	43,360
2050	North	10,200	450	400	30	15	11,095
	Northeast	1,800	7,800	4,800	200	20	14,620
	SE / CW	14,200	1,800	3,800	1,550	180	21,530
	South	2,800	1,800	950	60	15	5,625
	Total 2050	29,000	11,850	9,950	1,840	230	52,870

Source: Author's elaboration.

Hydropower occupation rises from 25,900 km² in 2030 to 29,000 km² in 2050. Unlike HRP, LCE does not completely stabilise hydro expansion, as reservoir-backed generation remains strategically relevant for balancing variable renewable energy (VRE). The North and SE/Central-West concentrate most of this hydro footprint, reaching 10,200 km² and 14,200 km² respectively by 2050.

Wind energy expands substantially, increasing from 5,440 km² in 2030 to 11,850 km² in 2050. The Northeast remains the principal wind frontier, reaching 7,800 km² in 2050, while the South and SE/Central-West also intensify their participation. This reinforces the structural role of the Northeast as a renewable export region under climate-constrained expansion logic.

Solar PV exhibits even stronger proportional growth, rising from 3,090 km² in 2030 to 9,950 km² in 2050. The SE/Central-West emerges as a dominant solar pole, occupying 3,800 km² by 2050, while the

Northeast reaches 4,800 km². The decentralised character of solar deployment redistributes part of the land-use burden toward industrial and high-demand regions.

Biomass also increases its territorial presence, from 940 km² in 2030 to 1,840 km² in 2050. Its expansion is concentrated in the SE/Central-West and Northeast, reflecting agricultural integration and dispatchable low-carbon generation requirements.

Regionally, the SE/Central-West records the highest total land occupation in 2050 (21,530 km²), followed by the Northeast (14,620 km²). The North maintains significant hydro-related occupation (11,095 km²), while the South reaches 5,625 km² due to wind and solar intensification.

The LCE pathway demonstrates that deep decarbonisation induces a broadening of the spatial footprint of the electricity sector. While fossil-based land occupation declines, it is replaced by geographically dispersed renewable infrastructure. Compared to HRP, LCE exhibits slightly lower total land occupation by 2050 (52,870 km² versus 54,180 km²), reflecting a more balanced combination of hydro, wind, solar and biomass rather than extreme VRE concentration.

The regionalisation pattern under LCE therefore reflects a climate-driven spatial redistribution: hydro remains relevant in water-rich basins, wind intensifies in the Northeast and South, solar expands in high-irradiation and load-proximate regions, and biomass integrates with agro-industrial corridors. Decarbonisation, in this configuration, is territorially expansive but structurally diversified.

Table 5.36 - Water consumption by region in LCE (million m³).

Year	Region	Hydro	Wind	Solar PV	Biomass	Natural Gas	Nuclear	Total
2030	North	160.0	0.0	0.0	1.8	2.5	–	164.3
	Northeast	12.0	0.0	0.0	4.0	2.0	–	18.0
	SE / CW	430.0	0.0	0.0	45.0	18.0	20.0	513.0
	South	88.0	0.0	0.0	10.0	4.5	–	102.5
	Total 2030	690.0	0.0	0.0	60.8	27.0	20.0	797.8
2040	North	165.0	0.0	0.0	2.0	0.8	–	167.8
	Northeast	10.5	0.0	0.0	4.5	1.0	–	16.0
	SE / CW	425.0	0.0	0.0	48.0	6.0	20.0	499.0
	South	90.0	0.0	0.0	12.0	2.0	–	104.0
	Total 2040	690.5	0.0	0.0	66.5	9.8	20.0	786.8
2050	North	168.0	0.0	0.0	2.0	0.0*	–	170.0
	Northeast	10.0	0.0	0.0	5.0	0.0*	–	15.0
	SE / CW	425.0	0.0	0.0	52.0	3.0	20.0	500.0
	South	92.0	0.0	0.0	13.0	0.0*	–	105.0
	Total 2050	695.0	0.0	0.0	72.0	3.0	20.0	790.0

Source: Author's elaboration.

Table 5.37 presents the regional disaggregation of water consumption under the LCE scenario for 2050. The LCE configuration achieves the highest level of decoupling between electricity growth and hydrological pressure.

In 2030, total system water consumption reaches 797.8 million m^3, already representing a more efficient footprint compared to BAU due to the early displacement of fossil thermal dispatch. The Southeast/Central-West (SE/CW) remains the primary consumer with 513 million m^3, where hydropower reservoirs (430 million m^3) and nuclear generation (20 million m^3) provide the necessary firm capacity to sustain the initial decarbonisation phase. Wind and solar PV technologies maintain a zero-water operational footprint, establishing their role as the cornerstone of hydrological sustainability in the LCE pathway.

By 2040, a structural shift becomes evident as total water consumption declines to 786.8 million m^3, despite the significant increase in electricity production (930 TWh). This decoupling is primarily driven by the collapse of natural gas-related water use, which falls from 27.0 million m^3 in 2030 to just 9.8 million m^3 in 2040. The internalisation of a €110/tCO_2 carbon price, combined with tighter dispatch limits, effectively renders water-intensive thermal cooling economically unfavorable within the SEGeP optimisation logic.

In the final period (2050), total water consumption stabilizes at 790 million m^3 for a total output of 1,040 TWh. Hydropower remains the dominant contributor (695 million m^3), acting as the essential storage backbone for a renewable-heavy grid. However, natural gas water use is virtually eliminated, totaling only 3.0 million m^3 nationwide, while biomass water use reaches 72 million m^3, reflecting its strategic role as a carbon-neutral firm energy source.

Regionally, the Northeast demonstrates the highest efficiency, generating 370 TWh in 2050 with a minimal water footprint of only 15 million m^3. This underscores the LCE scenario's capacity to reallocate generation toward low-water-intensity territories. Across the entire horizon, the SEGeP model successfully internalises the physical hydrological footprint, ensuring that climate mitigation under the LCE scenario is achieved without increasing the systemic pressure on national water resources.

Table 5.37 reports the regional evolution of local air pollutants under the LCE scenario, explicitly quantifying SO_2 and NO_x emissions in kilotonnes (kt) for 2030, 2040, and 2050. These results demonstrate the most aggressive reduction in local externalities among all scenarios analyzed. This is a direct consequence of the SEGeP objective function internalizing a doubled health-damage penalty (€/kg) alongside the strict mandatory cap of 5 $MtCO_2$.

Table 5.37 - SO_2 and NO_x emissions in LCE (kt).

Região	Poluente	2030	2040	2050
Norte	SO_2	0.5	0.2	0.1
	NO_x	1.8	0.9	0.5
Nordeste	SO_2	0.8	0.4	0.2
	NO_x	2.0	1.2	0.7
SE / CW	SO_2	3.2	2.0	1.4
	NO_x	7.5	5.0	3.5
Sul	SO_2	1.0	0.5	0.2
	NO_x	2.5	1.4	0.6
Total SIN	SO_2	5.5	3.1	1.9
	NO_x	13.8	8.5	5.3

Source: Author's elaboration.

At the system level, total SO_2 emissions decline from 5.5 kt in 2030 to 1.9 kt in 2050, while NO_x emissions fall from 13.8 kt to 5.3 kt. This trajectory represents a reduction of approximately 65% for SO_2 and 62% for NO_x over the horizon, establishing these as the lowest levels among all modeled scenarios. This outcome illustrates a powerful "co-benefit" effect: by chasing a strict CO_2 cap through a high carbon price (€150/tCO_2), the model endogenously delivers superior local air quality as it displaces fossil-based thermal generation in favor of zero-emission renewables.

The Southeast/Central-West (SE/CW) continues to concentrate the remaining pollutants in 2050 (1.4 kt of SO_2 and 3.5 kt of NO_x), accounting for approximately 70% and 66% of the national totals, respectively. This spatial persistence is attributed to two factors: the region's role as the primary load center requiring residual gas-based flexibility, and the significant dispatch of biomass for firm energy, which inherently produces nitrogen oxides during combustion.

However, even in the SE/CW, the reduction is substantial compared to the 2030 levels, confirming that the regionalized health-damage monetization effectively discourages pollutant-intensive dispatch near high-density urban areas. Ultimately, the LCE results prove that global climate mitigation and local public health protection are intrinsically synergistic within the Total Social Cost framework.

Table 5.38 presents the social and economic metrics of the LCE scenario.

Table 5.38 - Social and Economic Indicators in LCE

Metric	2030	2040	2050
Employment (k jobs/year)	245.0	315.0	360.0
Regional Gini Index (NE)	0.45	0.43	0.41
Regional HDI (NE)	0.738	0.775	0.808
Total Social Cost (€/MWh)	54.0	52.0	51.0

Source: Author's elaboration.

The LCE scenario achieves the third-highest employment level across all scenarios and the highest employment level among pathways without an explicit employment-maximisation objective. The average Social Cost stabilizes at €51/MWh, demonstrating that deep decarbonisation is not only environmentally necessary but socially and economically robust when externalities are fully internalised.

5.6.4 Social Effects LCE

Employment impacts under the LCE scenario are calculated, utilizing the same labour intensity coefficients presented in Chapter 4, applied to the optimized generation and installed capacity levels for each technology, region r, and time period t ∈ {2030, 2040, 2050}, In the LCE configuration, the pursuit of a near-zero emission cap (5 $MtCO_2$ in 2050) acts as a powerful driver for job creation, as the model is forced to maximize the deployment of high-labor-intensity technologies—specifically solar and wind—to replace fossil dispatch (Table 5.39).

Table 5.39 - Employment effects by region in LCE.

Region	2030	2040	2050
North	22,500	28,000	32,000
Northeast	95,000	125,000	155,000
SE / CW	90,500	112,000	123,000
South	37,000	50,000	50,000
Total	245,000	315,000	360,000

Source: Author's elaboration.

Total employment increases from 245,000 jobs/year in 2030 to 360,000 jobs/year in 2050. This represents an absolute gain of 115,000 jobs over the horizon and an additional 81,000 jobs relative to the BAU scenario in 2050. The LCE scenario generates the highest employment levels among all technologically driven pathways (exceeded only by scenarios with explicit social objective functions). This result provides evidence that stringent carbon caps do not merely reduce emissions but structurally shift the energy economy toward sectors with higher employment-to-energy ratios.

Regionally, the Northeast emerges as the dominant employment hub, reaching 155,000 jobs in 2050, or 43% of the national total. This concentration is a direct reflection of the region's role as the "green engine" of the LCE scenario, hosting 170 GW of installed capacity by 2050. The Southeast/Central-West also maintains strong employment (123,000 jobs), driven by its large biomass fleet and the maintenance of complex system-adequacy infrastructure.

Income distribution effects under the LCE scenario are assessed through the projected evolution of the regional Gini index (Table 5.40). The LCE results demonstrate that deep decarbonisation acts as an indirect

distributive policy by funnelling investment toward historically less developed regions with high renewable potential.

Table 5.40 - Regional Gini index in LCE.

Region	2030	2040	2050
North	0.420	0.400	0.390
Northeast	0.450	0.430	0.410
SE / CW	0.480	0.470	0.460
South	0.440	0.420	0.410

Source: Author's elaboration.

The results indicate a more rapid decline in inequality than the HRP scenario. The Northeast exhibits a drop from 0.450 to 0.410, a trend driven by the massive inflow of capital and the resulting demand for labor in rural areas. By 2050, the inequality gap between the South and the Northeast is virtually eliminated in terms of electricity-sector-induced income effects.

The evolution of the Human Development Index (HDI) under the LCE scenario is presented in Table 5.41. The results show a systematic improvement, particularly in the North and Northeast regions, which benefit most from the "renewable premium" of the LCE policy.

Table 5.41 - Regional HDI in LCE.

Region	2030	2040	2050
North	0.745	0.780	0.812
Northeast	0.738	0.775	0.808
SE / CW	0.795	0.825	0.850
South	0.788	0.818	0.842

Source: Author's elaboration.

The Northeast region experiences a transformative trajectory under the LCE scenario, recording a cumulative gain of 0.070 points to reach an HDI of 0.808 by 2050. This shift is historically significant, as it elevates the region from a "High" to a "Very High" human development category, according to UNDP standards (UNDP, 2024). This advancement is not incidental; it is the structural result of the massive capital inflow and job creation (155,000 jobs) driven by the near-zero carbon mandate, which disproportionately benefits the renewable-rich Northeast.

Furthermore, the regional convergence effect is substantially more pronounced in the LCE configuration than in the HRP scenario. The development gap between the leading region (SE/CW) and the least developed (NE) narrows from 0.057 points in 2030 to just 0.042 in 2050. This trend indicates that the

internalisation of high carbon prices (€150/tCO_2) acts as a powerful mechanism for territorial redistribution, effectively reducing historical socio-economic disparities. Under the LCE framework, climate policy and regional equity are no longer competing objectives but integrated outcomes of the optimisation process.

The macroeconomic performance that sustains these social improvements, including total system costs and social pricing, is summarized in Table 5.42.

Table 5.42 - System economic indicators in LCE.

Metric	2030	2040	2050
Total system cost (NPV, € billion)	145.0	215.0	290.0
Average Social Cost (€/MWh)	54.0	52.0	51.0

Source: Author's elaboration.

The macroeconomic performance of the LCE scenario reveals a fundamental paradigm shift in long-term energy planning. Total system cost in Net Present Value (NPV) terms reaches €290.0 billion by 2050, reflecting the significant front-loaded capital expenditure (CAPEX) required for a near-zero emission infrastructure. However, a comparative analysis through the lens of the Total Social Cost (TSC) framework provides a more accurate economic picture: the Average Social Cost—which endogenizes carbon, local pollutants, and water externalities—declines from €54.0/MWh in 2030 to €51.0/MWh in 2050.

This downward trajectory highlights a central conclusion of the LCE pathway: once the hidden costs of carbon emissions and public health damages are fully internalised, the most environmentally stringent strategy proves to be the most economically rational for society. By 2050, the LCE scenario delivers a substantial 12.6% reduction in total social costs compared to the BAU baseline. This result demonstrates that the "environmental premium" of deep decarbonisation is effectively offset by the elimination of negative externalities, transforming a climate necessity into a superior economic equilibrium for the Brazilian National Interconnected System (SIN).

5.6.5 Synthesis and Analytical Discussion of the LCE Scenario

The results reported in Tables 5.30 to 5.42 confirm that the LCE scenario constitutes the most structurally rigorous spatial equilibrium generated by the SEGeP framework. Unlike the HRP, which is driven by penetration targets, the LCE is governed by an absolute environmental mandate: a 5 $MtCO_2$ emission cap and an aggressive carbon price of €150/tCO_2. This configuration transforms the National Interconnected System (SIN) into a near-neutral climate entity, where the internalisation of global and local externalities becomes the primary driver of the model's feasible allocation space.

A primary structural shift is observed in the spatial geography of generation. Under LCE, the Northeast reaches a generation peak of 370 TWh in 2050. This is not merely a quantitative increase but a qualitative change in the national expansion frontier. When the solver is forced to comply with near-zero emissions, it reallocates production to the Northeast not because of policy incentives, but because the region's high renewable productivity yields the lowest *effective marginal social cost* when carbon and water externalities are fully priced. In parallel, the Southeast/Central-West—despite being the main load center—sees its generation profile contract to 370 TWh, a reduction of 145 TWh relative to the BAU baseline. This indicates that under stringent climate policy, the SE/Central-West ceases to be an expansion leader and transitions into a role of system stabilizer and flexibility provider.

This redistribution is inseparable from the massive surge in installed capacity, which reaches a system-wide total of 369.5 GW in 2050. The LCE scenario exposes the "intermittency premium" of deep decarbonisation: to meet adequacy and reserve margin constraints without fossil support, the model must deploy a volume of capacity that is 57% higher than the BAU level. The Northeast alone hosts 170 GW of this capacity, transforming it into a capital-intensive energy exporter. This spatial trade-off between "resource regions" (production) and "load regions" (adequacy) is the central adjustment variable that keeps the system feasible under binding carbon constraints.

The environmental results provide the most explicit evidence of the LCE logic. CO_2 emissions collapse to 4.6 $MtCO_2$ in 2050, achieving virtual climate neutrality. However, the regional disaggregation reveals that emissions do not vanish uniformly. The SE/Central-West remains the locus of 78% of residual national emissions (3.6 $MtCO_2$). This persistence is a hallmark of the model's spatial adequacy logic: emissions are preserved only where flexibility is most valuable for system reliability—near major demand centers—rather than where renewables are most abundant.

the local pollutant profile demonstrates the "double dividend" of the LCE configuration. Total SO_2 and NO_x emissions fall to 1.9 kt and 5.3 kt, respectively—the lowest levels in the study. Because the model internalises doubled health-damage penalties (€/kg) in the LCE, it endogenously "pushes out" pollutant-intensive dispatch near high-density urban populations. The reduction in local externalities is thus a spatially selective process: the model protects human health in the SE/CW by forcing the residual thermal fleet to operate at a marginal 1% dispatch limit.

In terms of water sustainability, the LCE scenario achieves a total decoupling of generation growth from water stress. While national generation reaches 1,040 TWh, total water consumption (790 million m^3) remains below BAU levels. The mechanism is clearly regionalized: the Northeast produces over 35% of national energy but accounts for less than 2% of national water consumption. This provides evidence that the LCE path

relocates the marginal energy supply to technologies and regions with structurally zero operational water footprints, effectively mitigating hydrological risks for the SIN.

The socio-economic outcomes reinforce the integrated sustainability narrative of the SEGeP model. Employment reaches its highest technological peak at 360,000 jobs/year in 2050, an increase of +81,000 relative to BAU. This job creation is concentrated in the Northeast (155,000 jobs), driving a significant regional convergence effect. The Northeast's HDI rises to 0.808, crossing into the "Very High" development category as defined by UNDP standards. This convergence narrows the development gap between the North/Northeast and the South/Southeast, proving that stringent climate internalisation acts as an effective—though indirect—regional development policy.

The economic dimension provides evidence of the rationality of the LCE pathway. Despite a higher NPV of €290.0 billion due to front-loaded renewable CAPEX, the Average Social Cost (which includes all internalised externalities) falls to €51.0/MWh by 2050. This is 12.6% lower than the BAU social cost, highlighting the study's central economic conclusion: once the "hidden" costs of carbon, water use, and health damages are fully accounted for, the most environmentally ambitious trajectory becomes the most cost-effective solution for society. The LCE scenario thus demonstrates that deep decarbonisation is not only technically feasible but is the superior economic equilibrium when the goal is the maximization of total social welfare.

The LCE scenario represents a constrained optimisation environment in which emissions reduction becomes a central driver of system transformation. The resulting configuration reveals how stricter environmental parameters reshape both investment and operational decisions, leading to a systematic transition towards cleaner technologies while introducing measurable cost implications. Key findings of the scenario:

(i) The imposition of stricter emission-related parameters leads to a structural transition towards low-carbon technologies, confirming the effectiveness of carbon constraints in shaping expansion pathways;

(ii) The reduction in emissions is achieved through a combination of technological substitution and changes in dispatch patterns;

(iii) The scenario reveals the cost implications of deep decarbonisation, reflecting the trade-off between environmental performance and economic efficiency;

(iv) Regional impacts vary depending on resource availability and existing infrastructure, reinforcing the importance of spatial disaggregation.

5.7 – Scenario 4: Maximum Employment Creation (MEC)

The MEC scenario was designed to analyse the behaviour of the Brazilian electricity system when the social dimension — particularly employment generation — assumes a central role in expansion planning decision-making. This scenario represents a deliberate departure from dominant energy planning paradigms, which are traditionally driven by economic cost minimisation or by the prioritisation of environmental externalities. The MEC scenario represents the fourth policy configuration analyzed within the SEGeP framework and simulates a socially driven expansion pathway relative to the Business-as-Usual (BAU) reference. While the HRP and LCE scenarios prioritize environmental objectives through renewable targets and carbon constraints, the MEC scenario simulates a structural shift toward a "Just Transition" environment, oriented toward maximizing job creation and reducing regional inequalities by 2050.

In the MEC scenario, social outcomes constitute the dominant optimisation driver. The configuration was designed to analyse the behaviour of the Brazilian power system under a policy regime that treats the energy sector as an active instrument for socioeconomic development. Unlike LCE, which uses carbon pricing as the main lever, MEC imposes high weights on employment indicators in the objective function and enforces territorial distribution targets, reflecting the urgency of aligning energy infrastructure investment with national development goals (SDG 8 and SDG 10).

Core assumptions include:

- Regional investment incentives favouring subsystems with lower Human Development Index (HDI) and higher unemployment rates (North and Northeast);
- Penalties for excessive investment concentration in the Southeast/Central-West to promote territorial decentralization;
- No rigid upper bound on renewables, allowing the model to endogenously select labor-intensive technologies like solar, wind, and biomass.

What differentiates the MEC scenario is the introduction of a "social opportunity cost" logic. Under MEC, the model "perceives" technologies with low labor intensity (like automated thermal plants or large hydro repowering) as comparatively more expensive than labor-intensive options (like distributed solar or biomass supply chains). Consequently, the model reallocates incremental demand growth toward technologies and regions capable of maximizing labor absorption.

From a modelling perspective, the MEC configuration represents a constrained social-maximizing equilibrium. The central aim is to assess the extent to which the national power system can operate as a job creation engine without excessively compromising system-wide costs or environmental performance. By

imposing strong social weights while preserving the full regional structure, MEC allows the identification of synergies between renewable expansion and regional development.

5.7.1 Input Data Structure MEC

Table 5.43 summarizes the main parameters modified in the MEC scenario relative to the BAU, HRP, and LCE configurations. The guiding logic is deliberately socio-centric: employment generation and regional equity are treated as overriding objectives.

Unlike the HRP and LCE scenarios—where environmental performance constitutes the dominant optimisation driver—the MEC scenario reconfigures the objective function and constraint structure of the SEGeP model to prioritise social outcomes, particularly employment generation and regional inclusion. This is achieved through a systematic reinforcement of labour-related parameters, combined with targeted regional incentives and a partial relaxation of environmental penalties that could otherwise suppress labour-intensive technologies.

Table 5.43 - Parameters modified in the MEC scenario.

Parameter	BAU	HRP	LCE	MEC	Rationale
Carbon Price (€/tCO_2)	30-65	55-120	80-150	30-60	Maintains climate internalisation while avoiding distortion of labour-intensive fossil/biomass flexibility.
Renewable Targets	None	Binding	None	None	Preserves endogenous technological selection based on labour intensity
Automation Penalty	None	None	None	Applied	Reduces relative competitiveness of capital-intensive, low-labour technologies
Biomass Limit	Medium	Medium	High	High	Enhances technologies with strong rural employment multipliers

Source: Author's elaboration.

The carbon price trajectory in MEC is deliberately moderated relative to HRP and LCE. This choice preserves climate internalisation within the objective function while preventing excessive penalisation of biomass and flexible gas generation that could otherwise constrain employment-maximising solutions. The absence of binding renewable targets further ensures that technology selection remains endogenous and responsive to labour intensity coefficients rather than being driven by predetermined capacity shares.

The application of an automation penalty introduces a structural disincentive for highly capital-intensive, low-employment technologies. This parameter does not prohibit such technologies but adjusts their relative attractiveness in marginal investment decisions, thereby operationalising a labour-oriented optimisation logic without abandoning system feasibility constraints.

The high biomass parameter reflects its comparatively strong employment multiplier effects, particularly in rural economies. By maintaining a high sustainability constraint while recognising its labour

intensity, the MEC scenario allows biomass expansion within ecological limits, reinforcing rural development without compromising land-use coherence.

Taken together, these coordinated adjustments make MEC the most socially ambitious configuration analysed. The optimisation problem is intentionally shifted from cost-dominant or climate-dominant equilibria toward a social-maximisation boundary within the existing SEGeP structure. The resulting solution space favours labour-intensive technologies — notably biomass and distributed solar — thereby providing a structural benchmark against which the socio-economic potential of the energy transition can be rigorously assessed.

5.7.2 National Results – Generation Mix MEC

Table 5.44 presents the optimal generation mix obtained under the MEC scenario. The results reveal a robust structural pattern, reflecting the stringent social parametrization.

Table 5.44 - Optimal generation by technology in the MEC scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Others	Total
2030	420	170	130	75	20	5	820
2040	425	220	190	85	10	0	930
2050	430	270	235	95	10	0	1,040

Source: *Author's elaboration.*

The expansion trajectory is primarily driven by Solar Photovoltaic and Wind generation, which together reach 505 TWh in 2050, corresponding to approximately 48.6% of total system output. This configuration reflects the increased marginal value attributed to employment generation within the Total Social Cost framework. Both technologies exhibit high labour intensity during installation phases and sustained employment during operation and maintenance.

Biomass assumes a strategically reinforced role under the MEC configuration, expanding to 95 TWh by 2050. Although constrained by sustainability parameters, its comparatively high employment multipliers — particularly in agricultural supply chains such as sugarcane, biogas and forestry residues — increase its marginal contribution within the social objective component. The observed expansion therefore emerges endogenously from the optimisation process rather than from exogenous renewable mandates.

Hydropower remains relatively stable, converging to 430 TWh in 2050. This stability reflects its structural role as a firm capacity provider within the Brazilian system, while its limited incremental employment generation for new large-scale projects reduces its relative attractiveness under a social-maximisation configuration. Natural gas is progressively reduced to a residual balancing function, reaching 10 TWh in the final period, consistent with the moderate carbon pricing maintained in MEC and the absence of climate-dominant constraints.

The generation mix obtained under MEC provides evidence that amplifying the social component within SEGeP reorders the investment hierarchy toward labour-intensive technologies, without compromising system adequacy or regional balance constraints.

5.7.3 Regional Disaggregation of Generation MEC

Table 5.45 presents the regional distribution of electricity generation under the MEC scenario. While the total national demand remains consistent with the previous scenarios (reaching 1,040 TWh in 2050), the spatial allocation of production is fundamentally reshaped by the regional incentives designed to maximize labor outcomes in underdeveloped subsystems.

Table 5.45 - Electricity generation by region in MEC (TWh).

Region	2030	2040	2050
North	125	130	135
Northeast	230	280	330
SE / Central-West	360	385	400
South	105	135	175
Total SIN	820	930	1,040

Source: Author's elaboration.

The Northeast consolidates its role as the primary "social engine" of the expansion, increasing its output from 230 TWh in 2030 to 330 TWh in 2050. This represents a cumulative growth of 100 TWh, significantly higher than the expansion observed in the BAU. Under the MEC logic, the model reallocates wind and solar investments toward the Northeast not only for their resource productivity but to capture the high labor intensity associated with these technologies in a region with high social vulnerability.

In the Southeast/Central-West, generation growth is more moderate, reaching 400 TWh in 2050—a substantial reduction compared to the 515 TWh observed in the BAU. This "spatial decentralization" is a deliberate outcome of the optimisation: the model "pushes" marginal generation toward the North and Northeast to reduce regional inequality. In the SE/CW, production is increasingly anchored by high-labor-intensity Biomass supply chains, which compensate for the reduction in traditional thermal dispatch.

The South experiences a notable expansion, reaching 175 TWh in 2050. This trend is driven by the region's agricultural synergy with biomass and its wind potential. Because the MEC scenario values the agricultural labor component of the biomass supply chain (1.35 jobs/GWh), the model finds it socially optimal to expand this source in the Southern subsystem.

From a modelling perspective, the disappearance of "Other" sources (as seen in the aggregate technology mix) and the stabilization of hydropower reflect a structural substitution effect. In the MEC

configuration, any technology with a low employment-to-generation ratio (such as automated coal, oil, or existing "others") becomes social-cost-inefficient when compared to solar, wind, and biomass. Consequently, the solver drives these residual sources to zero, prioritizing a mix that satisfies the 1,040 TWh demand through the most labor-intensive technological path feasible.

This regional disaggregation provides evidence that the MEC scenario does not merely increase national employment; it performs a geographical redistribution of the electricity sector's social footprint, channeling investment and production toward the North, Northeast, and South to achieve a more equitable territorial equilibrium.

Table 5.46 reports the regional evolution of installed capacity under the MEC scenario. Total installed capacity increases from 255.0 GW in 2030 to 367.5 GW in 2050. This is the highest capacity expansion among all scenarios, reflecting the massive penetration of Solar PV—a technology with a high employment footprint but a lower capacity factor, requiring more GW to meet the same TWh demand.

Table 5.46 - Installed capacity by region in MEC (GW).

Region	2030	2040	2050
North	30.5	32.5	34.0
Northeast	86.0	122.0	168.0
SE/CW	105.0	110.0	114.0
South	33.5	42.0	51.5
Total SIN	255.0	306.5	367.5

Source: Author's elaboration.

The Northeast consolidates its position as the principal expansion pole, reaching 168.0 GW by 2050. The magnitude of this increase (+82 GW relative to 2030) reflects the interaction between superior renewable resource endowment and the amplified social parametrisation of the MEC scenario. Within the MILP structure, technologies with high installation-phase employment coefficients — particularly solar and wind — generate greater marginal contribution to the objective function. As a result, the optimisation process allocates a disproportionate share of new capacity to regions where these technologies exhibit both high technical potential and strong labour multipliers.

The SE/CW region exhibits a comparatively stable capacity profile, increasing from 105.0 to 114.0 GW over the planning horizon. This moderation reflects its already substantial installed base and the reallocation of marginal investment toward distributed solar and biomass upgrades rather than large-scale fossil expansion. The North and South regions show steady but more gradual growth, consistent with resource potential and regional balance constraints embedded in SEGeP.

The installed capacity trajectory under MEC illustrates how the amplification of social parameters within a cost-minimising MILP framework can structurally alter nominal system size without compromising

adequacy constraints. The higher aggregate capacity is therefore not an inefficiency signal, but a coherent outcome of a labour-oriented optimisation regime within a renewable-dominant expansion pathway.

Table 5.47 presents the regional distribution of CO_2 emissions under the MEC scenario. Total emissions decline to 18.5 $MtCO_2$ in 2050. While this represents a significant reduction from BAU, it is higher than the HRP scenario because the MEC configuration allows for moderate biomass expansion and residual gas flexibility to support the social stability of the grid.

Table 5.47 - CO_2 emissions by region in MEC ($MtCO_2$).

Region	2030	2040	2050
North	2.5	2.0	1.8
Northeast	3.5	2.8	2.2
SE/CW	19.5	15.0	12.5
South	3.0	2.2	2.0
Total SIN	28.5	22.0	18.5

Source: Author's elaboration.

The emissions trajectory provides evidence that the MEC scenario does not relax climate internalisation but recalibrates its relative priority within the Total Social Cost framework. Carbon pricing remains active; however, it is deliberately moderated compared to HRP and LCE, allowing limited biomass-based cogeneration and residual natural gas dispatch to operate where necessary to maintain adequacy and system stability under high variable renewable penetration.

The SE/Central-West region remains the primary emissions locus, accounting for 12.5 $MtCO_2$ in 2050. This concentration reflects the region's structural role within the national grid: it hosts a significant share of biomass-based cogeneration associated with agro-industrial activities, as well as residual firm thermal capacity required to balance variability originating from solar and wind expansion in the Northeast and South.

The Northeast and South exhibit comparatively lower emissions levels, consistent with their strong wind and solar penetration, while the North maintains a limited emissions profile due to its hydropower dominance. The spatial distribution therefore reflects the interaction between regional resource endowment, employment-oriented expansion, and residual firm capacity requirements.

The Maximised Employment and Cohesion (MEC) scenario produces the most territorially expansive configuration among all sustainability-oriented pathways. Unlike BAU and LCE, where land occupation is primarily a by-product of decarbonisation constraints, in MEC the spatial footprint of the electricity sector is an endogenous consequence of the objective function, which maximises socio-economic co-benefits — particularly employment generation and regional development.

As shown in Table 5.48, total land occupation increases from 37,015 km^2 in 2030 to 55,390 km^2 in 2050, representing the largest territorial expansion among all scenarios analysed. This expansion is not

incidental but structurally embedded in the model logic: technologies with high labour multipliers per installed unit — especially solar PV and biomass — are favoured even when they require larger territorial allocation.

Table 5.48 - Land Use by region and technology in Scenario MEC (km²).

Year	Region	Hydro	Wind	Solar PV	Biomass	Others	Total Region
2030	North	8,500	120	180	15	10	8,825
	Northeast	1,800	3,200	3,500	120	15	8,635
	SE / CW	12,000	550	2,100	1,450	120	16,220
	South	2,100	750	450	25	10	3,335
	Total 2030	24,400	4,620	6,230	1,610	155	37,015
2040	North	8,500	250	350	25	10	9,135
	Northeast	1,800	4,200	5,800	250	15	12,065
	SE / CW	12,000	1,100	4,500	2,100	150	19,850
	South	2,100	1,200	950	50	10	4,310
	Total 2040	24,400	6,750	11,600	2,425	185	45,360
2050	North	8,500	450	650	40	10	9,650
	Northeast	1,800	5,500	8,200	450	20	15,970
	SE / CW	12,000	1,800	7,100	3,100	180	24,180
	South	2,100	1,800	1,600	80	10	5,590
	Total 2050	24,400	9,550	17,550	3,670	220	55,390

Source: Author's elaboration.

Hydropower occupation remains stable at 24,400 km² throughout the planning horizon. Unlike BAU and LCE, MEC does not prioritise further hydro expansion, given its relatively lower employment intensity per hectare compared to distributed renewables. The hydro footprint remains concentrated in the North (8,500 km²) and SE/Central-West (12,000 km²), maintaining the historical structure of reservoir-based generation.

Wind occupation grows from 4,620 km² in 2030 to 9,550 km² in 2050, driven mainly by expansion in the Northeast and SE/Central-West. However, the most structurally significant transformation occurs in solar PV deployment. Solar land use rises dramatically from 6,230 km² in 2030 to 17,550 km² in 2050, becoming the dominant territorial component of the MEC pathway. The Northeast alone reaches 8,200 km² of solar occupation by 2050, while the SE/Central-West expands to 7,100 km². This reflects the deliberate orientation toward labour-intensive and regionally integrated supply chains.

Biomass also expands significantly, from 1,610 km² in 2030 to 3,670 km² in 2050. Its growth is concentrated in agro-industrial corridors of the SE/Central-West and Northeast, reinforcing the integration between energy production and rural employment generation. By 2050, the SE/Central-West occupies 3,100 km² in biomass-related infrastructure, while the Northeast reaches 450 km².

Regionally, the SE/Central-West records the highest territorial footprint in 2050 (24,180 km²), followed by the Northeast (15,970 km²). The South expands moderately to 5,590 km², while the North stabilises at 9,650 km² due to limited new hydro additions and moderate solar deployment.

From a structural perspective, MEC internalises the trade-off between territorial occupation and socio-economic returns. Unlike market-oriented scenarios, the model accepts higher land allocation per MWh generated in exchange for stronger regional employment multipliers and income dispersion. The spatial expansion is therefore a deliberate policy outcome rather than a residual effect of technology choice.

Comparatively, MEC exhibits a larger land footprint in 2050 (55,390 km^2) than HRP (54,180 km^2) and LCE (52,870 km^2). The difference is driven primarily by solar PV and biomass expansion, confirming that social-benefit maximisation leads to the highest territorial intensity within the SEGeP framework.

In analytical terms, the MEC configuration demonstrates that regional development-oriented expansion transforms land use from a purely environmental constraint into a socio-economic investment variable. The electricity sector becomes spatially embedded in local productive structures, increasing territorial occupation while simultaneously amplifying regional employment and cohesion.

Table 5.49 presents the regional disaggregation of water consumption. The MEC scenario shows a decoupling of water use from energy growth, similar to HRP, but with a higher footprint in regions dominated by biomass expansion.

Table 5.49 - Water consumption by region in MEC (million m³).

Year	Region	Hydro	Wind	Solar PV	Biomass	Natural Gas	Total
2030	North	160.0	0.0	0.0	2.5	3.5	166.0
	Northeast	12.0	0.0	0.0	5.0	3.0	20.0
	SE / CW	430.0	0.0	0.0	50.0	18.0	498.0
	South	88.0	0.0	0.0	12.0	5.0	105.0
	Total 2030	690.0	0.0	0.0	69.5	29.5	789.0
2040	North	165.0	0.0	0.0	2.8	1.0	168.8
	Northeast	10.5	0.0	0.0	6.5	1.0	18.0
	SE / CW	425.0	0.0	0.0	58.0	6.0	489.0
	South	90.0	0.0	0.0	16.0	2.0	108.0
	Total 2040	690.5	0.0	0.0	83.3	10.0	783.8
2050	North	168.0	0.0	0.0	3.0	0.0	171.0
	Northeast	10.0	0.0	0.0	8.0	0.0	18.0
	SE / CW	425.0	0.0	0.0	65.0	2.0	492.0
	South	92.0	0.0	0.0	20.0	0.0	112.0
	Total 2050	695.0	0.0	0.0	96.0	2.0	793.0

Source: Author's elaboration.

In 2030, total water consumption is 789 million m³, with hydropower accounting for approximately 87% of the total. The Southeast/Central-West (SE/CW) region represents the largest consumer (498 million m³), driven by its vast hydro capacity and the initial expansion of biomass cogeneration (50 million m³). At this stage, natural gas still contributes 29.5 million m³ to the national total, primarily for system flexibility.

By 2040, total water consumption slightly decreases to 783.8 million m³. This non-monotonic behaviour is explained by the sharp decline in natural gas dispatch (dropping from 29.5 to 10.0 million m³), which offsets the simultaneous 20% increase in biomass-related water consumption. The model prioritizes biomass due to its superior job-creation multipliers, accepting its higher water intensity relative to other thermal sources.

In 2050, the structural shift is complete. Total water consumption reaches 793 million m³, reflecting the full deployment of the labor-intensive biomass fleet, which reaches 96 million m³ of water use. Hydropower remains the dominant contributor at 695 million m³. Notably, the Northeast and South regions see their water consumption driven almost exclusively by the nexus between renewable expansion and social targets, while natural gas water use becomes negligible (2.0 million m³).

Table 5.50 reports the regional evolution of local air pollutants under the MEC scenario, explicitly quantifying SO_2 and NO_x emissions in kilotonnes (kt) for 2030, 2040, and 2050. These results reflect the unique technological mix of the MEC pathway, where the aggressive expansion of biomass—prioritized for its

high employment multipliers—influences the nitrogen oxide (NO_x) profile, while the displacement of coal and heavy oil drives a substantial reduction in sulphur dioxide (SO_2).

Table 5.50 - SO_2 and NO_x emissions in MEC (kt).

Year	Region	SO_2 (kt)	NO_x (kt)	Year	Region	SO_2 (kt)	NO_x (kt)	Year	Region	SO_2 (kt)	NO_x (kt)
2030	North	0.9	3.2	2040	North	0.7	2.5	2050	North	0.5	1.8
	Northeast	1.2	3.8		Northeast	1.0	3.0		Northeast	0.8	2.5
	SE / CW	5.0	14.5		SE / CW	3.8	11.0		SE / CW	3.2	8.5
	South	1.6	4.5		South	1.2	3.5		South	0.9	2.4
	Total 2030	8.7	26.0		Total 2040	6.7	20.0		Total 2050	5.4	15.2

Source: Author's elaboration.

At system level, total SO_2 emissions decline from 8.7 kt in 2030 to 5.4 kt in 2050. This 38% reduction is achieved through the progressive decommissioning of fossil-fuel assets and their replacement with solar and wind capacity. Although this reduction is less pronounced than in the HRP scenario—due to the continued operation of some biomass combustion—it remains substantially lower than the BAU baseline, confirming that social optimisation does not compromise fundamental environmental progress.

NO_x emissions follow a downward trajectory, decreasing from 26.0 kt in 2030 to 15.2 kt in 2050. The persistence of relatively higher NO_x levels compared with SO_2 is a structural characteristic of the MEC configuration: biomass combustion, while carbon-neutral or low-carbon in accounting terms, remains a source of nitrogen oxides owing to high-temperature combustion processes. As the MEC scenario maximises biomass deployment in order to capture its agricultural employment multiplier, the model internalises higher NO_x emissions as an endogenous trade-off associated with increased regional labour absorption.

At regional level, the Southeast/Central-West (SE/CW) remains the principal emissions locus throughout the planning horizon. By 2050, it accounts for 3.2 kt of SO_2 and 8.5 kt of NO_x. This concentration is associated with the historical clustering of biomass cogeneration and the residual natural gas flexibility required in proximity to major load centres. Nevertheless, the regionalised health damage coefficients embedded in SEGeP prevent excessive pollutant concentration in densely populated urban areas, thereby shifting marginal biomass expansion towards rural or less densely populated industrial zones within the subsystem.

The Northeast and South exhibit substantial improvements in air quality, with NO_x emissions declining to 2.5 kt and 2.4 kt, respectively, by 2050. This reflects a structural transition towards a generation profile dominated by wind and solar PV—technologies with zero operational air pollutants. In these regions, the MEC scenario delivers a dual dividend: elevated levels of employment generation combined with a marked reduction in localised environmental pressure.

The results presented in Table 5.50 demonstrate that SEGeP effectively manages the social–environmental trade-off inherent in the MEC configuration. By balancing the employment benefits of biomass with the zero-emission operational profile of wind and solar technologies, the model yields a system that is both socially robust and substantially cleaner than the current national baseline. The spatial disaggregation provides evidence that the MEC pathway promotes a more equitable distribution of economic opportunities (employment) and environmental outcomes (air quality) across the Brazilian territory.

5.7.4 Social Effects MEC

The employment outcomes under the MEC scenario constitute the central output of this configuration. Unlike BAU, HRP and LCE—where job creation emerges primarily as an *ex post* consequence of the optimal technology portfolio—labour absorption in MEC operates as an endogenous driver of the MILP optimisation process. In practical terms, the social parametrisation embedded in the objective function increases the marginal attractiveness of labour-intensive technologies and, through regional incentives, reshapes the spatial allocation of new capacity. Table 5.51 reports the regional evolution of job-years generated directly and indirectly by the power sector expansion, consistent with the aggregate comparative results.

Table 5.51 - Employment effects by region in MEC (Jobs/year).

Region	2030	2040	2050
North	40.0	50.0	60.0
Northeast	120.0	150.0	180.0
SE/CW	100.0	115.0	120.0
South	50.0	65.0	70.0
Total SIN	310.0	380.0	430.0

Source: Author's elaboration.

Total employment reaches 430 thousand jobs/year in 2050, confirming MEC as the most socially ambitious configuration among the scenarios analysed. The Northeast remains the principal beneficiary of the labour-oriented optimisation pathway, reaching 180 thousand jobs/year by 2050—approximately 41.9% of the national total. This concentration is structurally consistent with the MEC design: the region combines superior wind and solar resource endowments with high installation and maintenance labour coefficients, while the regional employment incentive directs marginal investment towards territories characterised by higher socio-economic vulnerability.

The SE/Central-West subsystem maintains a high employment contribution (120 thousand jobs/year in 2050), reflecting the persistence of biomass-related value chains and distributed solar expansion, while the North and South exhibit steady increases associated with incremental renewable deployment and regional

balancing requirements. Overall, the spatial distribution indicates that MEC amplifies aggregate labour absorption while preserving interregional participation, reinforcing the role of regionalisation as a structural operator in translating national social objectives into territorially differentiated outcomes.

The distributive implications of the MEC configuration are assessed through the projected evolution of the regional Gini index, as presented in Table 5.52. Within the SEGeP framework, inequality effects do not arise from an exogenous redistribution mechanism, but from the spatial reallocation of investment, employment and value-added associated with labour-intensive generation technologies. In this context, the decentralisation of generation capacity under MEC operates as an indirect convergence mechanism across regions.

Table 5.52 - Regional Gini index in MEC.

Region	2030	2040	2050
North	0.510	0.495	0.480
Northeast	0.505	0.470	0.445
SE / CW	0.490	0.485	0.480
South	0.465	0.455	0.450

Source: Author's elaboration.

The results indicate a progressive decline in regional inequality across all subsystems, with the most pronounced reduction observed in the Northeast, where the Gini index falls to 0.445 by 2050. This trajectory reflects the concentration of employment-intensive renewable deployment in a region historically characterised by higher structural inequality. By amplifying biomass and solar value chains—both of which incorporate broader entry-level labour absorption and stronger rural employment linkages—the MEC scenario generates a more diffused income effect compared to scenarios dominated by capital-intensive technologies.

In contrast to the LCE and HRP configurations, where decarbonisation or cost-efficiency remain the primary optimisation drivers, MEC structurally prioritises employment multipliers within the objective function. As a result, the associated income distribution effects are more pronounced, particularly in regions where renewable deployment intersects with existing socio-economic vulnerability.

The evolution of the Human Development Index (HDI) under MEC, presented in Table 5.53, reflects the multidimensional implications of this investment pattern. Improvements in income, employment stability and regional economic diversification contribute indirectly to enhanced living standards, reinforcing the interpretation that the energy transition—when socially parametrised—can operate as a vector of territorial development rather than solely as a decarbonisation strategy.

Table 5.53 - Regional HDI in MEC.

Region	2030	2040	2050
North	0.755	0.775	0.795
Northeast	0.750	0.785	0.815
SE / CW	0.805	0.820	0.835
South	0.815	0.830	0.845

Source: Author's elaboration.

The projected evolution of the Human Development Index under the MEC scenario indicates a consistent upward trajectory across all regions, reflecting the cumulative socio-economic effects associated with labour-intensive energy expansion. While improvements are observed nationwide, the most significant relative advancement occurs in the Northeast, where HDI rises from 0.750 in 2030 to 0.815 in 2050. This level places the region within the "Very High Human Development" category, according to the UNDP classification framework.

More importantly than the absolute increase is the observable convergence dynamic. The development gap between the Northeast and the South—historically the leading region—narrows from 0.065 points in 2030 to 0.030 points in 2050. This reduction in interregional disparity suggests that the employment-oriented configuration embedded in MEC produces measurable spillover effects beyond the energy sector itself. By concentrating renewable deployment and associated value chains in regions with lower initial development indicators, the scenario contributes to a rebalancing of socio-economic performance over the planning horizon.

The convergence pattern does not imply uniformisation of regional conditions, but rather a structural mitigation of disparity through endogenous investment allocation. Within the SEGeP framework, this outcome emerges from the interaction between enhanced labour coefficients, regional employment incentives and the technological composition of the generation mix. The results therefore reinforce the interpretation that the energy transition, when socially parametrised, can function as a catalyst for territorial development, contributing not only to employment expansion but also to broader human development improvements.

Table 5.54 presents the aggregate comparison of equivalent employment across all scenarios, highlighting the structural distinctiveness of the MEC configuration.

Table 5.54 - Equivalent employment in the MEC scenario (thousand jobs/year).

Year	BAU	HRP	LCE	MEC
2030	200.0	235.0	245.0	310.0
2040	240.5	295.0	315.0	380.0
2050	278.8	345.0	360.0	430.0

Source: Author's elaboration.

The results confirm that MEC consistently generates the highest level of employment across the entire planning horizon. By 2050, the configuration delivers 430 thousand job-years per annum, representing an increase of approximately 151 thousand relative to the BAU scenario and 70 thousand relative to LCE.

From an analytical standpoint, the comparison demonstrates that employment creation can be systematically internalised within energy planning models when labour intensity is explicitly incorporated into the optimisation framework. The MEC pathway effectively alters the marginal investment hierarchy, favouring technologies with higher job multipliers—particularly biomass and distributed solar—without violating adequacy or regional balance constraints.

The associated trade-off manifests in the economic dimension of the system. The greater reliance on labour-intensive and spatially dispersed technologies implies a higher nominal installed capacity and increased capital deployment compared to strictly cost-optimised pathways. Consequently, the total system cost under MEC is moderately higher than in BAU or HRP configurations. However, within the Total Social Cost framework adopted in SEGeP, this outcome reflects a reallocation of optimisation priorities rather than inefficiency. The solution achieved under MEC represents a socially weighted equilibrium in which higher employment absorption is attained at the expense of marginal cost efficiency, while still maintaining environmental progress and system reliability.

In comparative terms, MEC defines the upper boundary of employment maximisation within the technological and regional constraints modelled, providing a benchmark against which the socio-economic potential of alternative energy transition pathways can be evaluated.

5.7.5 Analytical Discussion: The Structural Role of Regionalisation MEC

The results obtained under the Maximum Employment Creation (MEC) scenario demonstrate that regionalisation within SEGeP operates not merely as a spatial reporting layer, but as the central transmission mechanism through which social objectives are materialised. In BAU, expansion is predominantly guided by cost-minimisation in proximity to major load centres, while in LCE carbon constraints reshape the technological mix.

The Northeast emerges as the principal structural beneficiary of this reorientation. Its expansion to 350 TWh of generation and 168 GW of installed capacity by 2050 reflects not only superior wind and solar resource endowment, but also the model's endogenous valuation of employment intensity in socio-economically vulnerable regions. Under the labour-weighted optimisation regime, technologies with high installation and maintenance employment coefficients become comparatively more competitive, and regions capable of hosting these technologies with high resource productivity attract a disproportionate share of

investment. The resulting concentration of approximately 180 thousand equivalent job-years in the Northeast by 2050 provides evidence that regionalisation functions as an operative lever for socio-economic convergence rather than as a passive spatial outcome.

In the Southeast/Central-West subsystem, the structural role evolves from primary expansion engine to system stabiliser. With generation stabilising at approximately 375 TWh and biomass playing a prominent role in the regional portfolio, the subsystem maintains industrial employment linkages and firm capacity provision. The concentration of biomass-related activity and associated water use reflects the persistence of agro-industrial value chains that are both employment-intensive and compatible with the moderate climate ambition of MEC. Rather than concentrating all expansion in the historically dominant economic core, the optimisation reallocates frontier renewable growth towards the North and Northeast while preserving stability functions in SE/CW, contributing to a more balanced national configuration.

The North region illustrates how social parametrisation can stimulate diversified renewable deployment even where hydropower expansion is environmentally constrained. The increase to approximately 145 TWh of generation by 2050 reflects the deployment of decentralised solar and biomass installations designed to capture localised employment multipliers. The associated improvement in the Human Development Index, reaching 0.795 by 2050, indicates that socially oriented energy expansion can generate measurable development spillovers even in regions characterised by environmental sensitivity and infrastructural dispersion.

At system level, the convergence effects observed in the Gini index and HDI projections confirm that territorial rebalancing is not incidental but structurally embedded in the optimisation outcome. The narrowing of interregional inequality gaps and the harmonisation of development indicators across subsystems suggest that the SEGeP framework is capable of operationalising core Just Transition principles through endogenous modelling mechanisms. By assigning explicit value to labour intensity and regional equity within the objective function, the power sector ceases to be modelled solely as a least-cost commodity system and instead operates as an instrument of coordinated socio-economic development.

From a policy perspective, the MEC configuration provides a quantified benchmark of the trade-offs required to achieve such territorial convergence. These include moderately higher system costs relative to cost-dominant pathways and slightly elevated local pollutant emissions in biomass-intensive regions. However, these trade-offs are transparent and measurable within the SEGeP structure, allowing decision-makers to evaluate whether the additional economic and environmental costs are justified by the scale of employment generation and regional development gains achieved.

The MEC scenario demonstrates the structural effects of prioritising employment within the optimisation framework. By incorporating labour-related parameters, the model shifts investment towards more labour-intensive technologies, highlighting the inherent trade-offs between economic efficiency and social objectives in long-term energy planning. Key findings of the scenario:

(i) The inclusion of employment-oriented parameters shifts investment towards technologies with higher labour intensity;

(ii) The resulting expansion pathway reflects a rebalancing between economic efficiency and social objectives;

(iii) The scenario demonstrates that employment targets can significantly influence both technological choices and regional allocation of investments;

(iv) Trade-offs emerge between cost minimisation and job creation, highlighting the policy-relevant implications of incorporating social criteria into optimisation models.

5.8 – Scenario 5: Water Scarcity Constraints (WSC)

The Water Scarcity Constraints (WSC) scenario constitutes the fifth analytical configuration within the SEGeP framework. In contrast to HRP, LCE and MEC—where the optimisation hierarchy is reoriented around normative policy targets such as renewable penetration, carbon mitigation or employment maximisation—the WSC scenario is structured around a biophysical constraint: the structural deterioration of hydrological reliability within the Brazilian National Interconnected System (SIN).

Rather than modelling drought as a temporary stochastic deviation, WSC internalises persistent hydrological stress as a structural planning condition over the entire horizon (2030–2040–2050). This approach is consistent with climate adaptation literature indicating increased drought frequency and hydrological variability in South America under warming scenarios (IPCC, 2022b). The scenario therefore evaluates the resilience of the Brazilian electricity system under sustained water scarcity, treating reduced inflows and reservoir reliability as the "new normal".

Within SEGeP, the mathematical structure of the MILP model remains unchanged. The objective function continues to minimise Total Social Cost, and the regionalised structure is preserved. However, the feasible solution space is significantly compressed by binding water-related constraints, which alter both capacity expansion decisions and optimal dispatch patterns. Hydropower, historically the backbone of Brazilian system flexibility and storage, loses part of its structural reliability, forcing the model to reorganise the technological portfolio while preserving adequacy and security constraints.

The calibration of the WSC parameters is grounded in empirical evidence and institutional documentation rather than discretionary assumptions. The 20% reduction in effective hydropower capacity reflects documented reductions in inflows during severe drought episodes (e.g., 2014–2015 and 2021), as reported by the Brazilian National System Operator (ONS, 2021). Hydropower capacity factors historically ranging between 45–55% have fallen below 40% during extreme hydrological stress. The adoption of a 35–40% range in this scenario therefore represents a stress-test bound consistent with historically observed conditions rather than an arbitrary adjustment.

Similarly, the restriction on new large-scale hydropower expansion aligns with projections from the Energy Research Office (EPE) in recent Decennial Expansion Plans, which highlight the progressive saturation of economically viable sites and the increasing socio-environmental constraints associated with new reservoirs (EPE, 2023c).

The 50% increase in the water-use penalty is calibrated as a proxy for the rising shadow value of water under scarcity conditions. This treatment is consistent with water–energy nexus optimisation approaches in which higher water shadow prices represent increasing resource scarcity and the marginal economic value of relaxing water constraints (Gao et al., 2018).

The elevation of the shortage-risk penalty follows adequacy modelling principles and Value of Lost Load (VoLL) literature, recognising that reliability becomes economically more valuable under heightened hydrological uncertainty (ENTSO-E, 2021). The introduction of a 15% firm renewable requirement is calibrated to approximately offset the expected reduction in hydro firm energy resulting from the effective 20% capacity contraction, ensuring system adequacy without assuming unrealistic storage expansion.

5.8.1 Input Data Structure WSC

Table 5.55 summarises the principal parameters modified in the WSC configuration relative to the baseline scenarios. Unlike the mitigation- or employment-driven pathways previously analysed, the WSC scenario redefines the feasible solution space through a binding natural-resource constraint: persistent hydrological scarcity.

Table 5.55 - Parameters modified in the WSC scenario.

Parameter	BAU / HRP / LCE / MEC	WSC	Technical Rationale
Maximum hydropower capacity	Baseline	−20% from 2030	Structural reduction in effective water availability (ONS; IPCC)
Hydropower capacity factor	45–55%	35–40%	Increased drought frequency and hydrological volatility
Hydropower expansion limit	Moderate	No expansion	Site saturation and socio-environmental constraints (EPE)

Parameter	BAU / HRP / LCE / MEC	WSC	Technical Rationale
Water use penalty	+0–30%	+50%	Increased shadow value of water under scarcity (IEA; World Bank)
Shortage risk penalty	Low	High	Elevated reliability value under hydrological stress (VoLL literature)
Firm renewable requirement	Neutral	+15% of demand	Compensation for reduced hydro firmness
Thermal flexibility	BAU level	Moderately expanded	Empirical response observed in drought episodes (ONS)

Source: Author's elaboration.

The parameter set is internally coherent and deliberately interdependent. The 20% reduction in effective hydropower capacity and the downward revision of the capacity factor to 35–40% jointly capture both structural and operational dimensions of water scarcity. The former constrains installed firm energy availability, while the latter reduces the productivity of remaining assets. This dual adjustment prevents the model from artificially compensating reduced inflows through unrealistic dispatch optimisation.

The prohibition of new large-scale hydropower expansion reinforces this structural constraint. Without this limitation, the optimisation could offset lower productivity by simply adding new capacity, thereby neutralising the hydrological shock. By eliminating expansion, the model reflects both physical saturation of viable sites and institutional constraints identified in official planning documents. The hydrological shock therefore becomes a genuine binding condition rather than a temporary disturbance.

The increase in the water-use penalty operates at the economic layer of the model. Under scarcity conditions, water acquires elevated opportunity cost due to competing agricultural, industrial and urban demands. Raising the monetisation coefficient by 50% alters the relative competitiveness of water-intensive technologies and forces the optimisation to internalise the socio-economic value of water as a constrained resource. This adjustment ensures consistency between physical scarcity and economic valuation.

Simultaneously, the elevation of the shortage risk penalty strengthens the adequacy constraint. Reduced hydro firmness increases volatility and reserve requirements; therefore, the economic cost of unmet demand becomes higher. The strengthened shortage penalty reflects Value of Lost Load principles and prevents the optimisation from accepting reliability deterioration as a low-cost solution.

The introduction of a 15% firm renewable requirement addresses a structural consequence of reduced hydro reliability: the loss of stored, dispatchable energy. By mandating a minimum share of dispatchable renewable sources—principally biomass—the model reconstructs part of the lost firmness while maintaining decarbonisation coherence. This constraint is calibrated to approximate the firm energy deficit resulting from the 20% hydro contraction.

Moderate expansion of thermal flexibility serves as a residual stabilisation mechanism. Historical operational evidence during drought episodes demonstrates increased reliance on gas-fired generation to ensure supply security. Allowing bounded thermal flexibility prevents infeasibility in extreme hydrological years while maintaining environmental consistency within the Total Social Cost framework.

Taken together, these adjustments do not simply reduce hydro availability; they systematically reconfigure the technical, economic and reliability architecture of the optimisation problem. Hydrological scarcity becomes a structural determinant of investment decisions, regional allocation and dispatch behaviour. The WSC scenario therefore functions as a climate-adaptation stress test, assessing whether the Brazilian power system can preserve adequacy, regional balance and economic rationality under persistent water constraints rather than transient shocks.

From a modelling perspective, WSC is particularly relevant because it tests the resilience of a historically hydro-dependent system. Whereas mitigation-oriented scenarios evaluate how the system decarbonises, WSC evaluates how it adapts. The distinction is structural: mitigation modifies emissions constraints; adaptation modifies physical resource availability. In this sense, the WSC configuration expands the analytical scope of SEGeP beyond energy transition pathways into the domain of climate resilience planning.

5.8.2 Results of the Optimal Generation Mix (WSC)

Table 5.56 presents the optimal generation mix obtained under the Water Scarcity Constraints (WSC) configuration. The results indicate a structural reconfiguration of the Brazilian electricity system, directly attributable to the binding hydrological constraints introduced in Section 5.8.1.

Table 5.56 - Optimal generation by technology in the WSC scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Others	Total
2030	360	180	150	95	30	5	820
2040	350	240	210	110	20	0	930
2050	345	290	260	120	25	0	1,040

Source: Author's elaboration.

The most immediate effect of the WSC configuration is the structural contraction of hydropower generation. Output declines from 360 TWh in 2030 to 345 TWh in 2050, stabilising at a level substantially below the 430–450 TWh range observed in the mitigation-oriented scenarios. This reduction reflects both the imposed 20% effective capacity contraction and the lower hydropower capacity factors. Under WSC, hydro no longer functions as the volumetric anchor of the system nor as its principal source of firm energy.

The compensatory response occurs primarily through accelerated deployment of wind and solar PV. By 2050, these technologies jointly reach 550 TWh, accounting for more than half of total generation. Their expansion is structurally consistent with the model's internal logic: both technologies exhibit negligible operational water consumption, making them comparatively more competitive once water-use penalties and hydrological constraints become binding. Importantly, this expansion is not driven by an exogenous renewable target but by endogenous optimisation under water scarcity.

However, variable renewable expansion alone cannot fully substitute for the loss of hydropower firmness. The WSC results therefore highlight the strategic role of biomass. Generation rises to 120 TWh in 2050—the highest level across all scenarios analysed. Biomass acts as the principal dispatchable renewable substitute for hydro, providing firm capacity and operational flexibility without reintroducing substantial fossil dependence. Its expansion provides evidence of the relevance of firm renewable technologies in climate-adaptation contexts, where resource variability affects not only emissions trajectories but also system adequacy.

Natural gas remains present at a moderate level (25 TWh in 2050), functioning as a residual balancing mechanism. Its persistence reflects the elevated shortage-risk penalty and the need to preserve adequacy under reduced hydro flexibility. Nevertheless, gas does not regain structural dominance; its role remains bounded within the Total Social Cost framework and is primarily associated with peak support and extreme hydrological conditions.

From a systemic perspective, the WSC scenario reveals a transition from a hydro-dominated flexible system to a diversified architecture characterised by:

- High penetration of water-independent variable renewables;
- Increased reliance on dispatchable biomass for firmness reconstruction;
- Limited but necessary thermal flexibility to preserve reliability.

This configuration demonstrates that under persistent water constraints, the Brazilian electricity system can reorganise its technological composition while maintaining supply adequacy and growth in total generation (reaching 1,040 TWh by 2050). However, the structural shift entails increased dependence on technologies with higher nominal installed capacity requirements and potentially higher balancing complexity, signalling a qualitative transformation of the system's operational paradigm.

In analytical terms, the WSC results confirm that hydrological scarcity does not simply reduce hydro output; it alters the entire hierarchy of technological competitiveness within the SEGeP framework. The energy transition under adaptation stress therefore differs fundamentally from mitigation-driven pathways, as it is governed by resource availability rather than emissions pricing.

5.8.3 Regional Disaggregation of Generation (WSC)

Table 5.57 presents the regional allocation of electricity generation under the WSC configuration. Because SEGeP is regionally disaggregated at the level of decision variables, resource constraints and transmission limits, the spatial pattern observed is not a post-optimisation allocation but an endogenous outcome of the MILP structure. Hydrological scarcity is introduced at the regional level—primarily affecting hydro-intensive subsystems—thereby altering the relative marginal competitiveness of each region within the optimisation problem.

Table 5.57 - Electricity generation by region in WSC (TWh).

Region	2030	2040	2050
North	110	115	120
Northeast	220	280	340
SE / Central-West	380	395	400
South	110	140	180
Total SIN	820	930	1,040

Source: Author's elaboration.

The Northeast reaches 340 TWh in 2050, emerging as the principal expansion pole under hydrological stress. This shift does not result from a regional target or normative redistribution, but from the interaction between region-specific resource endowment and water-related constraints. As hydro capacity factors decline and water penalties increase in hydro-dependent regions, the optimisation reallocates investment toward regions whose renewable technologies—particularly wind and solar—exhibit negligible operational water dependency and high capacity factors. The Northeast therefore becomes relatively more competitive within the Total Social Cost framework once hydrological scarcity becomes binding.

In contrast, the Southeast/Central-West, historically the hydro-dominant subsystem, stabilises at approximately 400 TWh by 2050. The imposed contraction of effective hydro capacity directly reduces the region's volumetric contribution. Within the regionalised model, this decline cannot be fully offset locally without violating water-use penalties or adequacy constraints. As a result, the subsystem transitions from being the primary volumetric anchor of the system to a mixed stability hub, combining residual hydro, biomass and bounded thermal generation. Interregional exchanges, constrained but feasible within the model, allow part of the increasing Northeast output to supply load centres in SE/CW, illustrating how regionalisation captures spatial interdependence rather than isolated subsystems.

The North exhibits moderate growth to 120 TWh, reflecting limited diversification through decentralised solar and biomass, while the South expands to 180 TWh, supported by wind and biomass potential. The overall spatial configuration therefore reflects a structurally induced rebalancing: hydro-constrained regions lose

relative dominance, while water-independent renewable regions gain expansion share. This outcome is entirely endogenous to the regional structure of SEGeP.

The generation reallocation is mirrored in installed capacity patterns, presented in Table 5.58.

Table 5.58 - Installed capacity by region in WSC (GW).

Region	2030	2040	2050
North	28.5	30.0	31.5
Northeast	82.0	118.0	162.0
SE/CW	108.0	112.0	115.0
South	32.0	40.0	49.5
Total SIN	250.5	300.0	358.0

Source: Author's elaboration.

Total installed capacity reaches 358.0 GW in 2050. This elevated level is structurally consistent with the replacement of high-capacity-factor hydropower by lower-capacity-factor wind and solar technologies. Within the model, capacity expansion decisions are region-indexed; therefore, the increase to 162.0 GW in the Northeast reflects the endogenous selection of that region as the least-cost adaptation locus under water scarcity.

The Southeast/Central-West maintains 115.0 GW but with a transformed portfolio composition. Rather than expanding hydro capacity—which is restricted—the region reallocates investment toward biomass and distributed solar while relying on interregional flows to compensate for reduced hydro productivity. Regionalisation thus makes explicit that adaptation to water scarcity involves not only technological substitution but also spatial redistribution of installed capacity.

Table 5.59 presents the regional distribution of CO_2 emissions under WSC.

Table 5.59 - CO_2 emissions by region in WSC ($MtCO_2$).

Region	2030	2040	2050
North	3.0	2.5	2.2
Northeast	4.0	3.0	2.5
SE/CW	24.0	19.5	21.0
South	3.5	3.0	3.5
Total SIN	34.5	28.0	29.2

Source: Author's elaboration.

Total emissions stabilise at 29.2 $MtCO_2$ in 2050, exceeding mitigation-oriented scenarios but remaining below historical baselines. The SE/Central-West accounts for 21.0 $MtCO_2$ in 2050, reflecting its structural role as the principal provider of dispatchable backup generation. Under reduced hydro firmness, the subsystem must deploy flexible gas capacity to maintain adequacy and manage variability.

The emissions concentration in SE/CW is not the result of regional bias but of the interaction between load density, reduced hydro productivity and transmission constraints. The regionalised MILP structure ensures that emissions are computed where generation occurs, making explicit the territorial dimension of adaptation trade-offs. While wind and solar expansion in the Northeast significantly limit national emissions growth, the loss of hydro-based flexibility necessitates a moderate increase in thermal dispatch in hydro-intensive subsystems.

In systemic terms, the WSC scenario demonstrates that hydrological adaptation reshapes not only the technological mix but also the spatial distribution of generation, capacity and emissions. Regionalisation within SEGeP allows this transformation to be explicitly modelled: water scarcity affects regions asymmetrically, investment responds to region-specific competitiveness, and the resulting equilibrium reflects the interaction between resource heterogeneity, transmission feasibility and adequacy requirements. Adaptation under WSC is therefore inherently territorial, and the regional structure of the model is essential to capturing this dynamic.

The WSC scenario fundamentally alters the territorial configuration of the Brazilian power system by explicitly internalising hydrological risk as a structural constraint within the optimisation framework. Unlike cost-driven configurations (EO, LRI) or socially oriented pathways (MEC), WSC introduces a systemic penalty for water-intensive expansion, thereby shifting investment toward land-based renewable technologies with minimal dependence on reservoir dynamics. As a consequence, the system transitions from hydrological intensity toward territorial intensity.

Table 5.60 presents the evolution of land use by region and technology between 2030 and 2050.

Table 5.60 - Land Use by region and technology in Scenario WSC (km²).

Year	Region	Hydro	Wind	Solar PV	Biomass	Others	Total Region
2030	North	8,200	150	120	10	10	8,490
	Northeast	1,800	5,800	2,200	80	15	9,895
	SE / CW	11,500	750	1,100	750	220	14,320
	South	2,100	1,200	350	20	10	3,680
	Total 2030	23,600	7,900	3,770	860	255	36,385
2040	North	8,200	320	280	20	10	8,830
	Northeast	1,800	8,200	4,100	140	20	14,260
	SE / CW	11,500	1,400	2,500	1,100	280	16,780
	South	2,100	1,800	650	40	15	4,605
	Total 2040	23,600	11,720	7,530	1,300	325	44,475
2050	North	8,200	550	500	30	15	9,295
	Northeast	1,800	11,500	6,800	220	25	20,345
	SE / CW	11,500	2,200	4,200	1,450	350	19,700
	South	2,100	2,800	1,100	60	15	6,075
	Total 2050	23,600	17,050	12,600	1,760	405	55,415

Source: Author's elaboration.

The quantitative evidence reveals three structural transformations:

First, hydropower land occupation remains constant at 23,600 km² throughout the planning horizon, reflecting the constraint imposed on additional reservoir expansion under water scarcity conditions. Unlike the BAU configuration, WSC does not rely on hydro expansion as the primary balancing mechanism, confirming the endogenous adaptation to hydrological risk.

Second, a substantial increase in wind and solar land use is observed. Total land occupation rises from 36,385 km² in 2030 to 55,415 km² in 2050 — an expansion of approximately 52%. Wind energy increases from 7,900 km² to 17,050 km², while solar PV grows from 3,770 km² to 12,600 km². These technologies become the dominant drivers of territorial expansion, compensating for the constrained hydro fleet.

Third, the regional distribution of land use undergoes significant reconfiguration. The Northeast consolidates its position as the principal territorial energy frontier, reaching 20,345 km² by 2050 — more than double its 2030 footprint. This expansion is not policy-driven, as in MEC, but physically induced by the necessity to diversify away from hydro-dependent regions. The high wind and solar potential of the Northeast becomes structurally indispensable for system resilience.

The Southeast/Central-West also expands its land occupation (19,700 km² in 2050), primarily through solar and biomass deployment, reducing reliance on further hydropower development. The North region experiences moderate growth, constrained by the hydrological limitation embedded in the scenario.

The WSC scenario demonstrates a compensatory spatial transition: reduced hydrological intensity requires increased terrestrial occupation. Climate adaptation does not eliminate environmental trade-offs; rather, it shifts the nature of territorial pressure from water resources to land allocation.

The WSC expansion provides evidence of the relevance of firm renewable technologies in climate-adaptation contexts, where resource variability affects not only emissions trajectories but also system adequacy. The results also demonstrate that regionalisation operates not only as a distributive mechanism but also as a resilience instrument. The concentration of land-intensive renewables in the Northeast emerges as an endogenous response to hydrological stress, redefining the geographical logic of the Brazilian electricity sector under structural climate uncertainty.

Table 5.61 presents the regionalised water consumption metrics under the WSC configuration. Because water use coefficients are technology- and region-specific within SEGeP, total water consumption is computed as the aggregation of regional technology-level consumption rather than as a national scalar indicator. This is crucial for interpretation: water scarcity in the model is not represented solely by reduced hydro generation, but by altered regional water-use intensity across the technological portfolio.

Table 5.61 - Water consumption by region in WSC (million m³).

Year	Region	Hydro	Wind	Solar PV	Biomass	Nat. Gas	Nuclear	Others	Total
2030	North	160.0	0.0	0.0	3.0	1.0	–	1.5	165.5
	Northeast	10.0	0.0	0.0	6.0	2.0	–	1.0	19.0
	SE / CW	370.0	0.0	0.0	60.0	20.0	20.0	3.5	473.5
	South	80.0	0.0	0.0	15.0	3.0	–	1.0	99.0
	Total 2030	620.0	0.0	0.0	84.0	26.0	20.0	7.0	757.0
2040	North	158.0	0.0	0.0	3.5	0.5	–	0.0	162.0
	Northeast	9.0	0.0	0.0	8.0	1.0	–	0.0	18.0
	SE / CW	385.0	0.0	0.0	70.0	15.0	20.0	0.0	490.0
	South	82.0	0.0	0.0	20.0	2.0	–	0.0	104.0
	Total 2040	634.0	0.0	0.0	101.5	18.5	20.0	0.0	774.0
2050	North	160.0	0.0	0.0	4.0	0.0	–	0.0	164.0
	Northeast	8.0	0.0	0.0	10.0	0.0	–	0.0	18.0
	SE / CW	400.0	0.0	0.0	65.0	10.0	20.0	0.0	495.0
	South	85.0	0.0	0.0	25.0	0.0	–	0.0	110.0
	Total 2050	653.0	0.0	0.0	104.0	10.0	20.0	0.0	787.0

Source: Author's elaboration.

Total water consumption reaches 787 million m³ in 2050. Although hydropower generation declines under the imposed scarcity constraints, aggregate water consumption does not fall proportionally. This outcome reflects the structural substitution mechanism embedded in the optimisation.

Hydropower water use—concentrated primarily in the SE/Central-West and North—declines in relative terms due to reduced output and capacity factor adjustments. However, the compensatory expansion of biomass introduces a different water-use profile into the system. By 2050, biomass-related water consumption reaches 119 million m³, representing the highest level across the planning horizon.

The key structural insight is that the model substitutes hydro-based storage-dependent generation with dispatchable biomass generation to restore system firmness. While wind and solar PV contribute significantly to volumetric energy replacement, they cannot fully compensate for the loss of hydro flexibility due to their intermittency. Biomass therefore assumes the role of firmness reconstruction. Because biomass involves agricultural and industrial processing stages with measurable water intensity, total system water use remains significant despite hydro contraction.

This shift does not imply inefficiency; rather, it reflects the multidimensional trade-offs inherent in adaptation. Under WSC, water scarcity constrains reservoir-based generation, but system adequacy constraints require alternative dispatchable capacity. The optimisation thus reallocates water use from hydro reservoirs—characterised by climate-driven inflow uncertainty—to biomass value chains, where water use is more directly controlled but still resource-intensive.

Regionalisation clarifies this mechanism. The SE/Central-West remains the dominant locus of water consumption (495 million m³ in 2050), reflecting its concentration of both residual hydro generation and biomass activity. In contrast, the Northeast—despite becoming the primary expansion pole for wind and solar—

maintains very low hydro water consumption, reinforcing its structural advantage under hydrological stress. The South exhibits moderate increases associated with biomass expansion.

Importantly, the WSC scenario does not eliminate water dependency from the power system; it redistributes and transforms it. Water use shifts from large-scale reservoir reliance toward agricultural-industrial bioenergy chains. This transition illustrates that climate adaptation in hydro-dependent systems may reduce hydrological vulnerability while preserving a significant aggregate water footprint.

From a modelling standpoint, this result provides evidence that SEGeP internalises water as a regionalised production input rather than a passive environmental indicator. The interaction between technology-specific water coefficients, regional resource availability and adequacy constraints generates a non-trivial water–energy trade-off. Under WSC, adaptation reduces exposure to hydrological inflow risk but does not necessarily minimise total water consumption.

Table 5.62 reports the evolution of regional SO_2 and NO_x emissions under the Water Scarcity Constraints configuration for the full planning horizon. As in previous sections, pollutant emissions are computed endogenously at the regional level, reflecting technology-specific emission coefficients multiplied by region-indexed generation variables. The spatial allocation therefore derives directly from the regionalised MILP structure rather than from a distribution of national totals.

Table 5.62 - SO_2 and NO_x emissions in WSC (kt).

Year	Region	SO_2 (kt)	NO_x (kt)	Year	Region	SO_2 (kt)	NO_x (kt)	Year	Region	SO_2 (kt)	NO_x (kt)
2030	North	0.8	2.8	2040	North	0.7	2.2	2050	North	0.6	2.0
	Northeast	1.1	3.5		Northeast	1.0	3.0		Northeast	0.9	2.8
	SE / CW	5.5	15.0		SE / CW	4.8	13.5		SE / CW	4.5	12.5
	South	1.5	4.0		South	1.3	3.5		South	1.2	3.2
	Total	8.9	25.3		Total	7.8	22.2		Total	7.2	20.5

Source: Author's elaboration.

Across the planning horizon, total SO_2 emissions decline from 8.9 kt in 2030 to 7.2 kt in 2050, while NO_x emissions decrease from 25.3 kt to 20.5 kt. Although the trajectory is downward, the rate of reduction is more moderate than in mitigation-oriented scenarios. This reflects the structural substitution pattern triggered by hydrological scarcity.

Under WSC, reduced hydro firmness requires compensatory dispatchable capacity. While wind and solar PV expand substantially, their intermittency prevents them from fully replacing the stabilising function historically provided by reservoir hydropower. Biomass and moderate natural gas generation therefore assume a greater balancing role. Both technologies are associated with combustion processes that emit NO_x and, depending on fuel characteristics, SO_2. Consequently, pollutant reductions occur more gradually than in carbon-constrained pathways.

Regionalisation clarifies the spatial mechanics of these emissions. The SE/Central-West subsystem consistently accounts for the majority of pollutants—12.5 kt of NO_x and 4.5 kt of SO_2 in 2050. This concentration is structurally linked to three factors: (i) the region's high load density, (ii) the contraction of hydro productivity requiring additional dispatchable backup, and (iii) transmission constraints that limit complete relocation of balancing generation to other subsystems. The emissions profile therefore reflects the regional role of SE/CW as the primary stability node under hydrological stress.

The Northeast and South exhibit moderate pollutant levels despite strong renewable expansion. This reflects the coexistence of wind and solar growth with biomass deployment, which contributes to local air emissions. The North maintains comparatively lower pollutant intensity due to limited thermal expansion and smaller industrial scale.

The WSC configuration demonstrates that adaptation to water scarcity modifies the environmental profile of the system without reversing decarbonisation trends. Total CO_2 emissions remain contained relative to historical baselines, yet local pollutants remain structurally present due to the need for combustion-based flexibility. The regionalised MILP structure ensures that these trade-offs are spatially explicit: emissions are attributed to the regions where generation occurs, revealing how adaptation burdens are territorially distributed.

The WSC results confirm that hydrological adaptation introduces a multi-dimensional optimisation challenge. While renewable penetration remains high and water exposure is reduced, system adequacy under reduced hydro reliability requires maintaining a limited but persistent combustion-based component. The resulting pollutant profile is therefore not a policy failure, but an endogenous outcome of ensuring reliability within a water-constrained electricity system.

5.8.4 Social Effects (WSC)

The employment effects under the Water Scarcity Constraints configuration are presented in Table 5.63. Although WSC is not explicitly designed as a socially weighted scenario, the structural substitution of hydropower by more labour-intensive renewable technologies generates measurable employment gains relative to the baseline pathway.

Table 5.63 - Employment effects by region in WSC (thousand jobs/year).

Region	2030	2040	2050
North	38.0	44.0	50.0
Northeast	105.0	125.0	140.0
SE / CW	95.0	100.0	105.0
South	40.0	50.0	60.0
Total SIN	*278.0*	*319.0*	*355.0*

Source: Author's elaboration.

Total employment reaches 355 thousand job-years per annum in 2050, exceeding the BAU configuration (279 thousand). This increase emerges endogenously from the technological restructuring induced by hydrological constraints. As hydropower generation contracts—traditionally characterised by low marginal labour intensity once installed—the optimisation substitutes capacity with solar PV, wind and biomass.

The regionalised structure of SEGeP clarifies the spatial distribution of this employment effect. The Northeast concentrates approximately 140 thousand job-years in 2050, reflecting its role as the principal expansion pole for wind and solar capacity under water scarcity. Because the model indexes employment coefficients by technology and region, the expansion of water-independent renewables in the Northeast directly translates into higher regional labour absorption. This outcome is therefore an endogenous consequence of comparative resource advantage rather than a policy-driven redistribution.

The Southeast/Central-West maintains 105 thousand job-years in 2050, reflecting its transition from hydro-dominant subsystem to mixed stability hub combining residual hydro, biomass and moderate thermal flexibility. The North and South exhibit steady growth associated with decentralised renewable deployment and regional balancing requirements.

However, employment levels remain substantially below those observed in the MEC scenario. The reason is structural: under WSC, the optimisation hierarchy is governed by hydrological adequacy and system security rather than labour maximisation. The objective function continues to minimise Total Social Cost without elevated social coefficients, and moderate natural gas utilisation—necessary for reliability under reduced hydro firmness—contributes relatively low labour intensity compared to distributed renewables.

The WSC configuration demonstrates that climate adaptation can generate a secondary employment dividend through technological substitution, even in the absence of explicit social prioritisation. Regionalisation makes this mechanism transparent by revealing where employment expands and how it correlates with the spatial reallocation of generation. The employment profile under WSC therefore reflects the indirect socio-economic implications of adaptation planning rather than a deliberate labour-centred transition strategy.

Table 5.64 synthesises the principal social and economic indicators under the WSC configuration, integrating distributive outcomes and system-level cost performance within a unified analytical frame. Unlike mitigation- or employment-oriented scenarios, where social improvements emerge from explicit optimisation priorities, the indicators reported here reflect the indirect socio-economic consequences of adaptation-driven restructuring. Because SEGeP operates with regional disaggregation, the evolution of inequality and human development is territorially linked to the spatial reallocation of generation and capacity observed in Sections 5.8.2 and 5.8.3. Simultaneously, the Average Social Cost captures the economic implications of operating

under persistent hydrological constraints, allowing an integrated assessment of resilience, equity and economic efficiency within the same optimisation structure.

Table 5.64 - Social and Economic Indicators in WSC

Metric	2030	2040	2050
Regional Gini Index (NE)	0.510	0.490	0.475
Regional HDI (NE)	0.740	0.770	0.795
Average Social Cost (€/MWh)	56.0	55.0	54.0

Source: Author's elaboration.

The social indicators under the WSC configuration reveal a pattern of moderate but consistent improvement across the planning horizon. The Northeast—identified earlier as the principal expansion pole under hydrological stress—exhibits a gradual decline in income inequality, with the regional Gini index decreasing from 0.510 in 2030 to 0.475 in 2050. This reduction reflects the endogenous employment effects associated with large-scale wind, solar and biomass deployment in the region. However, the pace of distributive improvement remains below that observed in the MEC configuration, where labour intensity is explicitly prioritised within the objective function.

The Regional Human Development Index (HDI) in the Northeast rises from 0.740 to 0.795 by 2050. This trajectory approaches the "Very High Human Development" threshold but does not cross it within the modelling horizon. The slower convergence relative to MEC is structurally consistent with the optimisation hierarchy: under WSC, hydrological adequacy and system resilience dominate decision-making, and social improvements arise as indirect spillovers rather than primary objectives. Regionalisation within SEGeP ensures that these improvements are geographically linked to the location of renewable expansion, rather than assumed as uniform national effects.

From an economic perspective, the Average Social Cost stabilises at €54.0/MWh in 2050. This level exceeds the values observed in HRP (€47.5/MWh) and MEC (€48.5/MWh), reflecting the structural cost implications of operating under persistent hydrological constraints. The increased reliance on biomass logistics, additional installed capacity to compensate lower hydro productivity, and the retention of moderate thermal flexibility collectively elevate system expenditure relative to mitigation-dominant pathways.

This cost differential does not signal inefficiency, but rather the internalisation of adaptation requirements within the Total Social Cost framework. Reduced hydropower reliability necessitates both higher nominal capacity and dispatchable backup, increasing capital intensity and operational expenditure. In a regionally disaggregated model, these costs are not evenly distributed but correlate with the spatial concentration of balancing functions and renewable deployment.

Table 5.64 provides evidence that the WSC scenario produces measurable social improvements while preserving system adequacy under climate stress, albeit at a higher economic cost than mitigation-focused configurations. The interaction between regional renewable expansion, employment generation and increased adaptation expenditure defines a distinct equilibrium: one in which resilience to water scarcity is achieved without abandoning socio-economic progress yet requiring greater economic commitment to maintain reliability.

5.8.5 Analytical Discussion: The Structural Role of Regionalisation (WSC)

The regional outcomes observed under the Water Scarcity Constraints (WSC) configuration provide quantitative evidence that hydrological contraction acts as a structural spatial reordering mechanism within the SEGeP framework. Because the optimisation is region-indexed—both in decision variables and in physical and economic constraints—the imposed 20% effective contraction in hydropower capacity and the reduction of hydro capacity factors to 35–40% do not translate into a homogeneous national adjustment. Instead, they alter the marginal competitiveness of hydro-intensive subsystems, generating a measurable redistribution of generation, installed capacity, emissions and employment across the territory.

Between 2030 and 2050, the Northeast increases its electricity generation from 220 TWh to 340 TWh, a rise of 120 TWh (+54.5%), becoming responsible for 32.7% of total SIN generation in 2050 (340 / 1,040 TWh). In contrast, the Southeast/Central-West (SE/CW) increases only from 380 TWh to 400 TWh (+5.3%), and its share of total generation declines from 46.3% to 38.5%. This shift reflects the direct impact of reduced hydro productivity in SE/CW, which historically concentrated large reservoir capacity. Once hydro competitiveness declines under water penalties and capacity factor contraction, the optimisation reallocates expansion toward regions with superior wind and solar coefficients and negligible operational water dependency. The resulting equilibrium is therefore endogenous: the Northeast becomes the principal expansion pole because it offers the lowest marginal cost under binding hydrological constraints.

Installed capacity patterns reinforce this structural transformation. Total capacity expands from 250.5 GW in 2030 to 358.0 GW in 2050, an increase of 107.5 GW (+42.9%). Of this expansion, approximately 80 GW occur in the Northeast alone (from 82.0 to 162.0 GW), representing nearly 75% of total national capacity growth. By 2050, the Northeast accounts for 45.3% of total installed capacity. The SE/CW subsystem, by contrast, increases only marginally (from 108.0 to 115.0 GW), reflecting the prohibition of hydro expansion and the shift toward biomass and limited thermal support. The higher total capacity level is structurally consistent with the replacement of high-capacity-factor hydro by lower-capacity-factor wind and solar technologies, requiring greater nominal capacity to deliver equivalent energy volumes.

Emissions data further quantify the spatial consequences of adaptation. Total CO_2 emissions stabilise at 29.2 $MtCO_2$ in 2050—approximately 3–5 Mt above mitigation-dominant scenarios—reflecting increased reliance on dispatchable backup under reduced hydro firmness. The SE/CW region alone accounts for 21.0 $MtCO_2$, corresponding to 71.9% of national emissions. Local air pollutants exhibit similar concentration: in 2050, SE/CW emits 4.5 kt of SO_2 (62.5% of total) and 12.5 kt of NO_x (61.0% of total). These figures illustrate that while renewable expansion occurs primarily in the Northeast, the environmental burden associated with flexibility remains concentrated near major load centres and stability nodes. Regionalisation within SEGeP makes this territorial asymmetry explicit by allocating emissions to the region where generation occurs rather than averaging them nationally.

Water consumption dynamics reveal an additional structural trade-off. Total water use reaches 787 million m^3 in 2050. Although hydro-related water dependency declines proportionally due to reduced output, biomass water use rises to 119 million m^3, representing 15.1% of total water consumption. The SE/CW subsystem remains the largest water consumer (495 million m^3, or 62.9% of total), reflecting the coexistence of residual hydro and expanded biomass activity. Water scarcity therefore induces reallocation rather than elimination of water dependency: exposure to reservoir inflow volatility declines, but water use in agriculture and industry increases.

Socio-economic indicators confirm that adaptation produces secondary distributive effects. Total employment reaches 355 thousand job-years in 2050, exceeding the BAU configuration (279 thousand) by 76 thousand (+27.2%), primarily due to the substitution of capital-intensive hydro with labour-intensive renewables. The Northeast concentrates 140 thousand job-years (39.4% of total), reflecting its dominance in wind and solar deployment. The regional Gini index in the Northeast declines from 0.510 to 0.475 (–6.9%), and the regional HDI increases from 0.740 to 0.795 (+7.4%). However, improvements remain more moderate than under the MEC configuration because labour intensity is not explicitly prioritised in the objective function; social gains emerge as indirect consequences of spatial reallocation rather than as optimisation targets.

The economic implications of adaptation are captured in the Average Social Cost, which reaches €54.0/MWh in 2050—approximately €6–7/MWh (12–14%) higher than HRP and MEC pathways. This differential reflects increased installed capacity requirements, biomass logistics, bounded thermal flexibility and heightened adequacy penalties under hydro contraction. The higher cost does not indicate inefficiency but represents the internalised expense of maintaining reliability under persistent hydrological stress.

Collectively, these quantitative results demonstrate that regionalisation is the operative channel through which climate adaptation materialises within SEGeP. The 20% contraction in hydro capacity translates into a 120 TWh expansion in Northeast generation, an 80 GW capacity shift toward that region, a concentration

of over 70% of emissions in SE/CW, and a measurable increase in system cost. Adaptation is therefore spatially asymmetric: water-independent regions absorb expansion, hydro-intensive regions assume balancing and emissions burdens, and the system as a whole sustains adequacy through diversified resource geography. The WSC scenario provides evidence that the Brazilian electricity system can remain operationally secure under severe hydrological stress, but such resilience entails higher economic cost, moderate persistence of combustion-based flexibility and a fundamental reconfiguration of the geographical logic of power system development.

The WSC scenario emphasises the role of resource constraints in shaping electricity generation expansion. The imposition of water-related limitations alters the relative feasibility of technologies, particularly those dependent on hydrological resources, leading to a reallocation of investments towards less water-intensive alternatives. Key findings of the scenario:

(i) Water constraints significantly affect the feasibility of water-intensive technologies, particularly hydropower and thermal plants;

(ii) The model responds by reallocating generation towards less water-dependent technologies, demonstrating sensitivity to resource scarcity;

(iii) The scenario reveals the interdependence between energy planning and water resource management;

(iv) Regional impacts are particularly pronounced in areas with higher hydrological vulnerability, reinforcing the importance of integrated resource planning.

5.9 – Scenario 6: Economic Optimisation (EO)

The Economic Optimisation (EO) scenario constitutes the sixth and final analytical configuration within the SEGeP framework. It functions as a methodological benchmark, replicating a conventional least-cost expansion paradigm in which electricity planning is guided exclusively by direct financial criteria. Unlike the mitigation- or adaptation-driven scenarios previously examined, EO is not designed to pursue normative policy objectives; rather, it reconstructs a counterfactual environment where environmental and social externalities are not internalised within the optimisation process.

In this configuration, the objective function reduces to the minimisation of direct economic costs, defined as capital expenditure (CAPEX) and operational expenditure (OPEX), subject to technical adequacy and system balance constraints. The economic coefficient (α_COST) assumes full dominance within the Total Social Cost structure, while the environmental and social components are neutralised. Accordingly, the

environmental cost term (C_env) and the social cost term (C_soc) are set to zero, preserving the mathematical structure of the MILP while altering the relative weighting of the decision drivers.

The EO scenario therefore simulates a regulatory regime characterised by minimal intervention: no carbon pricing, no monetisation of pollutant damages, no renewable portfolio standards, and no social or regional incentives embedded in the objective function. Carbon pricing is set to €0/tCO_2, eliminating climate signals from investment decisions. Renewable deployment is not constrained or incentivised; technologies compete solely on private financial competitiveness under existing technical constraints. Employment generation, income distribution and regional equity remain endogenous but unvalued outcomes.

Importantly, EO does not remove technical constraints such as demand satisfaction, reserve margins or transmission limits. The system must remain feasible and reliable; however, it does so exclusively through cost-minimising logic. The resulting equilibrium therefore represents the financially optimal configuration of the Brazilian electricity system under the assumptions embedded in the techno-economic dataset.

From an analytical perspective, EO serves two critical purposes. First, it establishes a baseline against which the structural effects of externality internalisation can be quantified. By comparing EO with LCE, MEC and WSC, it becomes possible to measure the economic, environmental and social deviations induced by multidimensional optimisation. Second, EO reveals the implicit social opportunity cost of neglecting sustainability dimensions. The absence of carbon pricing and environmental penalties allows technologies with lower private cost but higher external damage to gain competitiveness, exposing the divergence between financial and societal optima.

Consistent with the modelling architecture defined in Chapter 4, the EO scenario maintains regional disaggregation and transmission constraints. Thus, even under pure cost minimisation, spatial heterogeneity in resource endowment and demand distribution remains structurally relevant. However, without environmental or social weighting, regional outcomes reflect purely economic competitiveness rather than equity or sustainability considerations.

EO represents the limiting case of the SEGeP framework: the solution obtained when the optimisation problem collapses to its narrow financial dimension. Its comparison with multidimensional configurations enables a rigorous assessment of the trade-offs between economic efficiency and broader sustainability objectives, thereby clarifying the structural implications of policy-driven internalisation within electricity expansion planning.

5.9.1 Input Data Structure (EO)

Table 5.65 summarises the structural parameter adjustments that define the Economic Optimisation (EO) configuration within the SEGeP framework. Unlike the previous scenarios, which operationalise normative sustainability objectives through the monetisation of externalities, EO deliberately suppresses the environmental and social cost components in order to replicate a conventional least-cost utility planning paradigm.

Table 5.65 - Structural parameters of the EO scenario.

Parameter	BAU / HRP / LCE / MEC	EO	Technical Rationale & Literature Basis
Carbon Price (€/tCO_2)	30–150	0	Removal of climate-policy signal to isolate private cost optimisation (IEA, 2022b; EPE, 2023b).
Environmental Cost Component (C_env)	Monetised (CO_2, SO_2, NOx, water)	0	External damages excluded from investor decision space (Pearce & Turner, 1990 Sovacool et al., 2021).
Social Cost Component (C_soc)	Monetised employment and equity effects	0	Labour and distributive impacts treated as residual outcomes (World Bank, 2021).
Renewable Targets	Binding or incentivised	None	Market-based technology selection without regulatory intervention (Joskow, 2011).
Technology Selection Logic	Multidimensional	Pure LCOE-based	Prioritisation of technologies with lowest private Levelised Cost of Energy and proximity to load centres.
Regional Equity Constraint	Active in some scenarios	Neutralised	Regional disparities not internalised in objective function.

Source: Author's elaboration based on SEGeP modelling architecture.

The EO configuration follows the classical least-cost utility planning logic widely adopted in traditional electricity expansion studies (Turvey, 1968; Stoft, 2002). In formal terms, the Total Social Cost function collapses into a purely financial objective (Equation 5.1), where:

$$\min Z_{EO} = C_{CAPEX} + C_{OPEX} \quad (5.1)$$

Subject only to technical feasibility constraints (demand balance, capacity limits, reserve margins and transmission restrictions). The environmental cost component C_{env} and the social component C_{soc}, fully defined in Chapter 4, are set to zero. Importantly, the physical quantities associated with emissions, water use and employment remain computed by the model; however, they no longer influence optimisation decisions.

The suppression of carbon pricing (set to €0/tCO_2) removes the internal climate signal that, in other scenarios, shifts competitiveness toward low-emission technologies. This assumption is consistent with a counterfactual regulatory environment lacking carbon markets or fiscal climate instruments, a situation analysed in international energy literature as a "no-policy baseline" (IEA, 2022b; IPCC, 2022b).

Similarly, the elimination of social weights (β_{SOC}) reflects an expansion regime in which employment generation and territorial equity are not valued within the decision structure. In welfare-economic terms, the EO scenario approximates a partial equilibrium in which private marginal cost equals private marginal benefit, but social marginal damages are excluded (Baumol & Oates, 1988; Pearce & Turner, 1990).

The absence of renewable mandates further reinforces this paradigm. Technologies compete exclusively through private Levelised Cost of Energy (LCOE), fuel price trajectories and infrastructure proximity. As demonstrated by Joskow (2011), such configurations tend to favour dispatchable thermal technologies when fuel costs remain competitive and externalities are not internalised.

It is crucial to emphasise that EO does not relax technical reliability constraints. The reserve margin, capacity adequacy and regional transmission constraints remain binding. Therefore, the scenario does not simulate deregulation in the sense of system infeasibility; rather, it isolates the economic dimension of optimisation while preserving physical coherence.

The EO scenario functions as the limiting case of the SEGeP framework. It provides a clean financial benchmark against which the incremental effects of environmental and social internalisation can be quantitatively assessed in subsequent comparative analysis (Section 5.13). By eliminating monetised externalities while maintaining identical technical datasets, EO exposes the divergence between private and total social optima, allowing the estimation of the "externality gap" inherent in conventional planning approaches.

5.9.2 Results of the Optimal Generation Mix (EO)

Table 5.66 presents the optimal generation mix obtained under the Economic Optimisation (EO) configuration. Because the objective function is restricted to direct financial cost minimisation, the resulting equilibrium reflects purely private economic competitiveness under existing technical constraints. The absence of carbon pricing, environmental monetisation produces a markedly different structural trajectory compared to the multidimensional scenarios analysed previously.

Table 5.66 - Optimal generation by technology in the EO scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Others	Total
2030	430	120	80	60	120	10	820
2040	430	130	100	60	180	30	930
2050	430	150	120	65	240	35	1,040

Source: Author's elaboration.

The most salient structural feature of the EO scenario is the progressive expansion of Natural Gas generation, which increases from 120 TWh in 2030 to 240 TWh in 2050—representing more than 23% of total

generation in the final horizon year. This trajectory contrasts sharply with the LCE and HRP scenarios, where carbon pricing constrains gas expansion, and with MEC, where labour-intensive renewables dominate.

Within the SEGeP MILP structure, this outcome is economically coherent. When environmental externalities are excluded, Natural Gas combines moderate capital intensity, dispatchability, and relatively low upfront investment risk. Its specific CAPEX remains lower than large-scale solar-plus-storage systems and significantly below new hydro developments subject to extended construction timelines and transmission requirements. Under cost-minimisation logic, gas therefore becomes the preferred marginal technology for meeting incremental demand growth.

Hydropower remains constant at 430 TWh across the entire horizon. This stability reflects the exhaustion of economically viable large-scale sites under baseline assumptions rather than policy-driven expansion. In EO, hydro neither expands nor contracts structurally; it functions as a pre-existing low-operational-cost backbone, but without additional incentives for environmental valuation or storage enhancement.

Wind and Solar generation expand only gradually, reaching a combined 270 TWh by 2050. Unlike in HRP or WSC, where physical or regulatory constraints force renewable penetration, their growth in EO is limited to cases where their private LCOE becomes competitive relative to thermal alternatives in specific regions. Without carbon pricing or renewable mandates, their system share stabilises below the levels observed in sustainability-driven pathways.

Biomass remains marginal (65 TWh in 2050), reflecting its higher operational complexity and feedstock logistics costs when not compensated by social or environmental valuation. In contrast to MEC, where biomass benefits from employment multipliers, EO treats it purely as a generation asset with comparatively higher private cost.

From a systemic perspective, the EO configuration results in a structurally more carbon-intensive matrix. Although total generation reaches 1,040 TWh in 2050—identical to other scenarios—the composition of that supply differs substantially. The expansion logic privileges dispatchable fossil capacity over diversified renewable integration, reflecting the divergence between financial and social optima.

The results therefore demonstrate that, in the absence of internalised externalities, the Brazilian electricity system converges toward a cost-efficient but environmentally and socially suboptimal equilibrium. The EO pathway does not represent technical infeasibility; rather, it exposes the opportunity cost of neglecting sustainability dimensions within expansion planning.

5.9.3 Regional Disaggregation of Generation and Capacity (EO)

The regional configuration observed under the EO scenario reflects the strict application of private cost minimisation within the spatially disaggregated SEGeP framework. Because transmission expansion and congestion costs remain internalised in the financial objective, the model endogenously evaluates the trade-off between locating generation in high-resource regions (e.g., Northeast wind and solar) and expanding dispatchable capacity near major load centres. In the absence of environmental penalties or renewable mandates, the optimisation favours technologies that minimise both generation and transmission expenditures, thereby reinforcing a load-centred expansion pattern.

Table 5.67 - Electricity generation by region in the EO scenario (TWh).

Region	2030	2040	2050
North	135	138	140
Northeast	140	145	150
SE / Central-West	435	537	640
South	110	110	110
Total SIN	820	930	1,040

Source: Author's elaboration.

In table 5.67 the most pronounced structural feature is the concentration of generation growth in the Southeast/Central-West (SE/CW), which expands from 435 TWh in 2030 to 640 TWh in 2050. This increase of 205 TWh over the horizon corresponds almost entirely to the expansion of natural gas and other dispatchable thermal assets located proximate to the main demand centres. Within the EO configuration, proximity to load reduces transmission reinforcement costs and system losses, enhancing the private competitiveness of locally installed thermal plants.

In contrast, the Northeast—despite possessing superior wind and solar resources—exhibits only marginal growth (from 140 TWh to 150 TWh). The absence of renewable incentives or carbon pricing removes the structural drivers that, in HRP, LCE and WSC, elevate the region to expansion leadership. As a result, the model does not prioritise large-scale renewable deployment coupled with interregional transmission, since the combined investment cost exceeds the private alternative of localised gas generation in SE/CW.

The North region remains relatively stable, increasing modestly from 135 TWh to 140 TWh. Its expansion is constrained not by resource potential but by limited load density and transmission distance to the main demand axis. Similarly, the South maintains a constant profile (110 TWh across the horizon), reflecting saturation of economically competitive local resources under pure cost criteria.

The spatial distribution under EO therefore contrasts sharply with the rebalancing observed in MEC and WSC. Rather than diversifying generation geographically, the system gravitates toward centralised thermal concentration. The centre of gravity of the SIN shifts decisively toward the SE/CW subsystem, which alone accounts for 61.5% of national generation by 2050 (640 TWh of 1,040 TWh).

From a capacity perspective, this pattern implies a structurally different asset composition. Thermal expansion near load centres reduces the need for extensive transmission reinforcement but increases exposure to fuel price volatility and carbon intensity. The EO configuration thus illustrates that when regional heterogeneity is filtered solely through financial cost, spatial diversification is subordinated to capital efficiency.

In analytical terms, regionalisation within EO does not disappear; rather, it reveals how private cost signals reshape territorial outcomes. The model demonstrates that, absent environmental and social internalisation, the Brazilian electricity system converges toward a spatially concentrated and fossil-reliant equilibrium centred on the SE/CW axis.

Table 5.68 presents the regional evolution of installed capacity in the Economic Optimisation (EO) scenario. The spatial pattern is fully consistent with the generation dynamics previously observed: capacity expansion is strongly concentrated in the Southeast/Central-West (SE/CW), reflecting the load-centred least-cost logic embedded in the objective function.

Table 5.68 - Installed capacity by region in EO (GW).

Region	2030	2040	2050
North	28.0	29.0	30.0
Northeast	45.0	50.0	55.0
SE/CW	95.0	125.0	155.0
South	32.0	35.0	35.0
Total SIN	200.0	239.0	275.0

Source: Author's elaboration.

Total installed capacity increases from 200.0 GW in 2030 to 275.0 GW in 2050, representing an expansion of 75 GW over the planning horizon. Approximately 60 GW of this increment is absorbed by the SE/CW subsystem alone, which rises from 95.0 GW to 155.0 GW. This corresponds to nearly 80% of the total national expansion being concentrated in a single region.

This outcome is structurally coherent with the EO objective function. In the absence of carbon pricing and renewable mandates, the model prioritises dispatchable thermal assets with relatively lower upfront capital intensity and shorter construction periods. These plants are preferentially located near the principal demand centres of the SE/CW, thereby minimising transmission expansion costs and reducing exposure to network

congestion constraints. The optimisation thus internalises the trade-off between generation cost and grid reinforcement, favouring geographic proximity to load.

By contrast, the Northeast expands modestly—from 45.0 GW to 55.0 GW—despite its superior renewable resource endowment. Under pure financial optimisation, the cost of large-scale transmission reinforcement required to export wind and solar generation to the SE/CW reduces the relative competitiveness of remote renewable expansion. Consequently, the model does not replicate the strong northeastern capacity surge observed in HRP, MEC or WSC.

The North region exhibits only marginal growth (28.0 GW to 30.0 GW), reflecting similar transmission-distance effects and limited local demand density. The South stabilises at 35.0 GW by 2050, indicating that additional capacity beyond existing economic potential is not financially justified within the least-cost framework.

From a structural perspective, EO produces a markedly lower total installed capacity (275.0 GW in 2050) compared to scenarios driven by high renewable penetration, where lower capacity factors of wind and solar necessitate larger nominal capacity additions. Here, the dominance of dispatchable gas capacity—characterised by higher capacity factors—reduces the need for oversized nominal installations.

The EO configuration therefore generates a system that is more compact in installed capacity terms but more concentrated geographically and more dependent on thermal assets. Regionalisation within SEGeP makes this concentration explicit: when expansion decisions are filtered exclusively through private cost minimisation, the Brazilian power system converges toward a SE/CW-centric structure, with limited spatial diversification and reduced interregional balancing dynamics.

The removal of carbon pricing and environmental monetisation produces the most carbon-intensive trajectory observed in the study. In the EO configuration, emissions are not penalised within the objective function; consequently, the optimisation expands dispatchable fossil capacity whenever it remains financially competitive. The resulting equilibrium reflects purely private cost signals, with no internalised mitigation incentive. Table 5.69 presents the CO_2 emissions by region.

Table 5.69 - CO_2 emissions by region in EO ($MtCO_2$).

Region	2030	2040	2050
North	2.5	3.5	4.5
Northeast	3.5	5.0	6.5
SE/CW	40.0	90.0	110.0
South	2.0	6.0	11.8
Total SIN	48.0	104.5	132.8

Source: Author's elaboration.

Total emissions increase from 48.0 $MtCO_2$ in 2030 to 132.8 $MtCO_2$ in 2050, representing a near tripling over the planning horizon. This trajectory contrasts sharply with LCE, HRP and WSC, where emissions either decline or stabilise due to internalised climate constraints. Under EO, the absence of a carbon signal allows natural gas expansion to dominate incremental supply, directly translating into higher system-wide emissions.

The spatial concentration of emissions is particularly pronounced. By 2050, the Southeast/Central-West alone accounts for 110.0 $MtCO_2$, approximately 83% of national emissions. This mirrors the generation and capacity concentration previously identified in Tables 5.67 and 5.68. Because most new thermal capacity is installed proximate to load centres within SE/CW, the region becomes the principal carbon locus of the SIN.

The South exhibits a significant relative increase, rising from 2.0 $MtCO_2$ in 2030 to 11.8 $MtCO_2$ in 2050. Although smaller in absolute terms than SE/CW, this reflects the incremental penetration of fossil backup in response to regional demand growth. The Northeast and North show more moderate increases, as their generation mix retains a larger renewable share relative to SE/CW; nevertheless, both regions experience rising emissions due to system-wide gas expansion.

From a structural perspective, the EO scenario reveals the magnitude of the "externality gap" embedded in traditional least-cost planning. The divergence between 132.8 $MtCO_2$ in EO and the significantly lower levels observed in LCE or HRP quantifies the implicit mitigation value of carbon pricing and environmental monetisation. In purely financial optimisation, emissions are not a constraint but a by-product of cost efficiency.

Regionalisation within SEGeP is critical to interpreting these results. The spatial concentration of fossil generation demonstrates that the environmental burden of least-cost planning is not evenly distributed; it is geographically concentrated in the subsystem where demand density and infrastructure reduce private costs. Thus, EO does not merely increase emissions, it redistributes them territorially, reinforcing the centrality of SE/CW as both the economic and carbon core of the national electricity system.

The EO scenario exhibits the most environmentally intensive land-use trajectory among all configurations analysed within the SEGeP framework. By prioritising short-term private cost efficiency and dispatch reliability over environmental safeguards, the model converges toward a spatial configuration characterised by aggressive hydropower expansion and the consolidation of centralised thermal infrastructure. In this configuration, territorial efficiency is interpreted primarily as financial density rather than ecological preservation.

Table 5.70 presents the evolution of land occupation by region and technology between 2030 and 2050 under the EO logic.

Table 5.70 - Land Use by region and technology in Scenario EO (km²).

Year	Region	Hydro	Wind	Solar PV	Biomass	Others	Total Region
2030	North	16,500	40	30	5	15	16,590
	Northeast	1,800	2,500	800	40	25	5,165
	SE / CW	15,200	150	200	350	250	16,150
	South	3,100	250	50	10	15	3,425
	Total 2030	36,600	2,940	1,080	405	305	41,330
2040	North	19,800	80	60	10	20	19,970
	Northeast	1,800	3,800	1,200	60	35	6,895
	SE / CW	18,500	350	450	550	320	20,170
	South	4,200	450	120	20	20	4,810
	Total 2040	44,300	4,680	1,830	640	395	51,845
2050	North	22,500	150	120	15	25	22,810
	Northeast	1,800	5,200	1,850	80	45	8,975
	SE / CW	21,200	650	850	750	450	23,900
	South	5,800	850	250	30	30	6,960
	Total 2050	51,300	6,850	3,070	875	550	62,645

Source: Author's elaboration.

The quantitative evidence reveals a pronounced territorial intensification over time. Total land occupation increases from 41,330 km² in 2030 to 62,645 km² in 2050 — an expansion of approximately 52%. This growth is driven primarily by large-scale hydropower development and the reinforcement of centralised generation clusters.

The North region emerges as the epicentre of territorial pressure. Hydropower occupation expands from 16,500 km² in 2030 to 22,500 km² in 2050, representing the single largest land-use component in the entire study. This trajectory reflects the model's preference for established hydro corridors as a source of low marginal cost electricity, despite the high ecological opportunity cost associated with reservoir flooding and ecosystem disruption.

The Southeast/Central-West also exhibits substantial territorial expansion, reaching 23,900 km² by 2050. In this region, hydro expansion is complemented by moderate growth in biomass and fossil-based infrastructure. Because carbon pricing remains limited and environmental penalties are not strategically escalated, thermal and hydro assets remain competitive relative to decentralised renewable alternatives.

In contrast, wind and solar occupation remains comparatively modest in EO. By 2050, total wind land use reaches 6,850 km² and solar 3,070 km² — significantly lower than in HRP, LCE or WSC. This provides evidence that, absent strong decarbonisation signals or social internalisation weights, land-intensive renewables are not prioritised if their system integration costs exceed those of incumbent hydro and thermal technologies.

From a structural standpoint, the EO scenario illustrates a form of territorial concentration and ecological externalisation. The model maximises financial efficiency but disregards biodiversity risk, ecosystem fragmentation and long-term land opportunity costs. Regionalisation under EO does not act as a resilience

mechanism nor as an instrument of spatial equity; rather, it reinforces historical hydro frontiers in the North and consolidates generation near load centres in the Southeast.

In analytical terms, EO demonstrates that least-cost optimisation can lead to the most spatially aggressive environmental footprint. The absence of strong socio-environmental internalisation mechanisms allows the electricity system to expand through territorially intensive pathways that may appear financially efficient but impose substantial irreversible ecological trade-offs.

Table 5.71 presents the regional distribution of consumptive water use under the EO configuration. Because the EO scenario removes both environmental penalties and scarcity constraints, water does not enter the optimisation as a binding shadow cost.

Table 5.71 - Water consumption by region in EO (million m³).

Year	Region	Hydro	Biomass	Nat. Gas	Nuclear	Others	Total
2030	North	212.5	1.4	0.8	–	1.5	216.2
	Northeast	17.0	3.1	4.0	–	0.5	24.6
	SE / CW	510.0	31.5	32.0	20.0	2.5	596.0
	South	110.5	9.0	3.2	–	0.5	123.2
	Total 2030	850.0	45.0	40.0	20.0	5.0	960.0
2040	North	212.5	1.4	1.3	–	4.5	219.7
	Northeast	17.0	3.1	6.5	–	1.5	28.1
	SE / CW	510.0	31.5	52.0	20.0	7.5	621.0
	South	110.5	9.0	5.2	–	1.5	126.2
	Total 2040	850.0	45.0	65.0	20.0	15.0	995.0
2050	North	212.5	1.5	1.7	–	6.0	221.7
	Northeast	17.0	3.4	8.5	–	2.0	30.9
	SE / CW	510.0	33.5	68.0	20.0	10.0	641.5
	South	110.5	9.6	6.8	–	2.0	128.9
	Total 2050	850.0	48.0	85.0	20.0	20.0	1,023.0

Source: Author's elaboration based on SEGeP results.

Total water consumption increases from 960.0 million m³ in 2030 to 1,023.0 million m³ in 2050, representing a 6.6% rise over the planning horizon. This expansion is driven primarily by the growth of thermoelectric generation, particularly natural gas, whose water demand more than doubles from 40.0 to 85.0 million m³.

Hydropower consumption remains constant at 850.0 million m³ throughout the horizon, reflecting stable volumetric output (430 TWh) in the EO scenario. Because water scarcity is not monetised or penalised, the model has no incentive to reduce hydro utilisation beyond technical limits. Thus, water associated with reservoir evaporation and operational losses remains structurally embedded in the system.

The SE/Central-West subsystem concentrates the largest share of water consumption, reaching 641.5 million m³ in 2050—approximately 63% of national demand. This concentration mirrors the regional dominance of both hydro and thermal expansion. In particular, gas-based cooling demand rises sharply in SE/CW (from 32.0 to 68.0 million m³), reinforcing its role as both the thermal and hydrological core of the system.

The Northeast exhibits moderate growth in water use (from 24.6 to 30.9 million m³), largely associated with incremental gas deployment. The North and South show comparatively stable profiles, reflecting limited thermal expansion.

From a structural standpoint, EO demonstrates that water demand is not neutral under least-cost optimisation. Although total generation in 2050 is identical to other scenarios (1,040 TWh), the absence of water valuation results in higher aggregate consumption relative to sustainability-driven configurations. Unlike WSC, where hydro contraction and water penalties induce adaptive rebalancing, EO allows the system to remain water-intensive whenever financially optimal.

The EO pathway quantifies the hydrological externality gap inherent in conventional planning. By excluding water scarcity from the objective function, the optimisation increases total consumptive use while concentrating pressure in already water-intensive subsystems. The regionalised output provides evidence that, under pure financial criteria, resource efficiency does not necessarily emerge endogenously; it requires explicit internalisation within the optimisation framework.

5.9.4 Social Effects EO

Table 5.72 reports the regional distribution of employment effects under the EO configuration, expressed in thousand jobs per year. Because labour absorption is not internalised within the objective function, employment outcomes emerge solely as a by-product of the selected technology mix. In contrast to MEC, where labour intensity is structurally rewarded, EO reflects the labour profile of a fossil-centred and capital-efficient expansion trajectory.

Table 5.72 - Employment effects by region in EO (thousand jobs/year).

Region	2030	2040	2050
North	20.0	20.0	20.0
Northeast	40.0	40.0	35.0
SE / CW	90.0	85.0	85.0
South	20.0	20.0	20.0
Total SIN	170.0	165.0	160.0

Source: Author's elaboration.

Total employment declines gradually from 170 thousand jobs/year in 2030 to 160 thousand jobs/year in 2050. This contraction reflects the substitution of more labour-intensive renewable technologies with capital-

intensive natural gas generation. While fossil plants require skilled operational staff, their installation and maintenance employment multipliers are structurally lower than those associated with distributed solar, wind deployment or biomass supply chains.

The Southeast/Central-West remains the primary employment locus, averaging 85 thousand jobs/year by 2050. However, unlike in MEC or WSC, this concentration does not correspond to broad-based labour diffusion; rather, it is linked to the expansion of thermoelectric assets near load centres. The employment intensity per TWh declines relative to scenarios driven by renewable integration.

The Northeast experiences a reduction from 40 to 35 thousand jobs/year by 2050, despite moderate generation growth. This outcome illustrates the absence of regional development incentives within EO. Although wind and solar potential remain technically attractive, the limited renewable penetration under pure cost criteria reduces installation-phase labour demand. The North and South maintain stable but low employment levels (20 thousand jobs/year), reflecting marginal expansion dynamics.

From a structural perspective, the EO configuration produces the lowest employment outcome among all scenarios analysed. Compared to MEC (430 thousand jobs/year in 2050) and WSC (355 thousand jobs/year), EO delivers less than half the labour absorption. This divergence quantifies the social opportunity cost of least-cost planning.

Regionalisation within SEGeP is critical to interpreting these results. Because the model explicitly tracks employment coefficients by technology and region, the spatial distribution of labour impacts mirrors the concentration of thermal capacity. The EO equilibrium thus demonstrates that private cost optimisation not only alters the technological mix but also compresses the socio-economic footprint of the electricity sector.

EO provides evidence that employment creation does not emerge endogenously from market-based optimisation. Without explicit valuation, labour-intensive technologies lose competitiveness, and the resulting system converges toward a capital-dominant structure with reduced territorial employment diffusion.

In contrast to the multidimensional configurations oriented toward Total Social Cost optimisation—particularly the MEC scenario—the EO pathway structurally reinforces pre-existing territorial asymmetries. Because labour intensity and distributive effects are not internalised in the objective function, investment decisions are guided exclusively by private financial competitiveness. As demonstrated in Sections 5.9.2 and 5.9.3, this results in the concentration of expansion in the SE/Central-West subsystem and a relative stagnation of decentralised renewable deployment in historically vulnerable regions such as the Northeast.

Within the SEGeP framework, inequality indicators are endogenously linked to regional employment generation and sectoral value-added effects. Consequently, the absence of large-scale renewable expansion in the Northeast—particularly wind and distributed solar—limits the region's capacity to capture labour multipliers

and local income spillovers. The resulting evolution of the Gini index (Table 5.73) reflects this structural constraint.

Table 5.73 - Regional Gini Index evolution in Scenario EO.

Region	2030	2040	2050
North	0.535	0.538	0.540
Northeast	0.548	0.550	0.555
SE / Central-West	0.495	0.498	0.500
South	0.465	0.468	0.470

Source: Author's elaboration.

The results indicate a gradual deterioration of income distribution across all subsystems. The Northeast exhibits the most pronounced inequality persistence, with the Gini index rising from 0.548 in 2030 to 0.555 in 2050. Rather than converging toward national averages—as observed in MEC—the region experiences marginal divergence. This outcome is directly associated with the limited renewable capacity growth (only 150 TWh in 2050), which constrains labour absorption and value-chain decentralisation.

The North follows a similar trajectory, with inequality increasing from 0.535 to 0.540. Although hydropower remains active, the lack of new labour-intensive projects prevents distributive improvement. In contrast, the SE/Central-West and South display relatively stable inequality profiles. However, this stability does not reflect distributive gains; rather, it indicates the consolidation of capital-intensive thermal expansion in regions already characterised by higher income levels and stronger industrial bases.

From a structural standpoint, the EO configuration demonstrates that least-cost optimisation not only concentrates generation and emissions geographically but also concentrates income dynamics. Regionalisation within SEGeP makes this mechanism explicit: when investment decisions prioritise proximity to load centres and private LCOE minimisation, historically advantaged subsystems accumulate further capital stock, while peripheral regions experience relative stagnation.

The EO scenario therefore quantifies the distributive cost of ignoring sustainability criteria. The absence of decentralised renewable expansion prevents the electricity sector from acting as an instrument of territorial convergence. Instead, the optimisation reinforces historical inequalities embedded in Brazil's spatial-economic structure, confirming that private cost efficiency and social equity do not coincide endogenously.

The evolution of the Human Development Index (HDI) under the EO configuration provides evidence the distributive stagnation identified in Table 5.74. Because the EO scenario does not internalise employment multipliers, regional equity coefficients or decentralised renewable incentives, improvements in human development occur only through baseline economic growth effects embedded in demand expansion. The electricity sector, therefore, ceases to function as a driver of structural regional transformation. Table 5.74 presents the evolution of the Regional HDI for the EO Scenario.

Table 5.74 - Regional HDI evolution in Scenario EO.

Region	2030	2040	2050
North	0.730	0.732	0.735
Northeast	0.710	0.715	0.720
SE / Central-West	0.795	0.800	0.805
South	0.810	0.815	0.820

Source: Author's elaboration.

The Northeast exhibits only a marginal increase, from 0.710 in 2030 to 0.720 in 2050, remaining below the threshold typically associated with "high human development". This limited progress is structurally consistent with the weak employment performance (35 thousand jobs/year in 2050) and the concentration of generation expansion in SE/CW. Without large-scale renewable deployment or biomass supply-chain expansion, the region does not capture the value-added and labour diffusion effects observed in MEC or WSC.

The North follows a similarly subdued trajectory, rising from 0.730 to 0.735 over two decades. The stagnation reflects limited diversification beyond existing hydropower assets and the absence of new high-skill renewable or industrial projects. In both regions, the EO optimisation logic prioritises financial efficiency over socio-economic transformation, thereby limiting structural improvements in education, income and longevity proxies embedded in the HDI metric.

By contrast, the SE/Central-West and South exhibit slightly higher HDI levels (0.805 and 0.820 respectively by 2050), but their growth remains incremental rather than transformative. Importantly, this increase does not represent convergence; rather, it consolidates existing development advantages. The interregional HDI gap between the Northeast (0.720) and the South (0.820) remains at 0.100 points in 2050, virtually unchanged from the initial differential.

The EO configuration provides evidence that private cost optimisation does not generate endogenous territorial convergence. Regionalisation within SEGeP makes explicit that when expansion decisions concentrate capital-intensive thermal capacity near established economic centres, the electricity sector's contribution to human development remains spatially uneven.

The EO scenario produces the lowest HDI progression among all configurations analysed. The absence of decentralised renewable deployment and regional incentives prevents the power sector from acting as an instrument of socio-economic upgrading. The resulting equilibrium demonstrates that financial optimality, while technically efficient, does not align with human development maximisation, reinforcing the structural divergence between private and social optima within long-term electricity planning.

The macroeconomic performance of the Economic Optimisation (EO) scenario is summarised in Table 5.75, which presents total system cost in NPV terms and the average LCOE across the three planning horizons.

Because environmental and social externalities are not internalised in this configuration, the reported indicators reflect strictly private financial optimisation under technical feasibility constraints.

Table 5.75 - System economic indicators in EO.

Metric	2030	2040	2050
Total system cost (NPV, € billion)	245.5	310.2	382.4
Average LCOE (€/MWh)	45.0	44.0	42.0

Source: Author's elaboration.

The EO scenario consistently presents the lowest direct economic cost among all configurations analysed. By 2050, total system cost reaches €382.4 billion, remaining structurally below the values observed in HRP and MEC. This differential does not stem from superior technological efficiency, but from the exclusion of monetised environmental and social components.

The average LCOE declines gradually from €45.0/MWh in 2030 to €42.0/MWh in 2050. This reduction is structurally associated with three interacting factors. First, the continued utilisation of depreciated hydropower assets, which maintain stable output at low marginal operating cost. Second, the expansion of natural gas generation, whose moderate capital intensity and high capacity factor reduce the need for oversized nominal capacity additions. Third, the avoidance of large-scale transmission reinforcement linked to remote renewable deployment, since expansion is concentrated near major load centres in the SE/Central-West subsystem.

While these indicators suggest maximum financial efficiency, they represent a private economic equilibrium rather than a socially optimal configuration. The €42.0/MWh LCOE observed in 2050 excludes the implicit cost associated with 132.8 $MtCO_2$ of emissions, the increase in water consumption, and the distributive stagnation documented in the Gini and HDI indicators.

The EO pathway therefore quantifies the financial lower bound of electricity expansion under the current techno-economic dataset. It demonstrates that the apparent cost advantage of least-cost planning is achieved through the non-internalisation of externalities. From a structural perspective, the scenario exposes the magnitude of the trade-off between financial efficiency and multidimensional sustainability, providing a benchmark against which the incremental cost of environmental and social internalisation can be rigorously assessed.

5.9.5 Analytical Discussion: The Structural Role of Regionalisation (EO)

The regional outcomes observed under the Economic Optimisation (EO) configuration demonstrate that spatial allocation in the electricity sector is highly sensitive to the structure of the objective function. When social coefficients and environmental penalties are removed, regionalisation ceases to operate as a

convergence mechanism and instead reflects purely financial competitiveness. The resulting equilibrium reinforces historical territorial asymmetries embedded in Brazil's demand distribution and infrastructure geography.

The Southeast/Central-West (SE/CW) subsystem consolidates its structural dominance across all key dimensions. By 2050, the region accounts for 640 TWh of generation, 155 GW of installed capacity , 110.0 $MtCO_2$ of emissions and 641.5 million m^3 of water consumption. These figures collectively indicate that more than 60% of national generation, over 80% of national emissions and nearly two-thirds of total water consumption are spatially concentrated in a single subsystem. This concentration does not arise from superior renewable endowment, but from proximity to major load centres, pre-existing gas infrastructure and reduced transmission reinforcement costs.

Within the EO logic, the model internalises transmission expansion as a financial burden. Consequently, it avoids large-scale energy transfers from resource-rich but geographically distant regions such as the Northeast. Instead, it favours dispatchable thermal assets located near demand hubs. The regional disaggregation embedded in SEGeP makes this trade-off explicit: spatial diversification is financially penalised when not supported by environmental or social valuation.

The Northeast illustrates the distributive implications of this optimisation logic. Despite possessing some of the highest wind and solar capacity factors in the country, its generation increases only marginally from 140 TWh in 2030 to 150 TWh in 2050, and installed capacity rises modestly from 45 GW to 55 GW. The absence of renewable mandates, carbon pricing or regional labour incentives limits its structural competitiveness.

The socio-economic consequences are directly observable. Employment declines from 40 to 35 thousand jobs/year, the Gini index increases to 0.555 by 2050, and the HDI reaches only 0.720, representing the slowest development progression among all scenarios analysed. The electricity sector, under pure least-cost planning, does not function as an instrument of territorial convergence. Instead, it reinforces existing disparities by concentrating capital-intensive investments in already developed subsystems.

The environmental dimension of regionalisation further exposes the divergence between private and social outcomes. While the SE/CW subsystem achieves financial efficiency under EO, it simultaneously accumulates the highest environmental burden: 110.0 $MtCO_2$ in 2050, alongside elevated local pollutant emissions and the highest water consumption in the system. The concentration of gas and nuclear generation in the most demand-intensive region increases exposure to water stress and environmental pressure, yet these risks remain unvalued within the optimisation structure.

From a systemic perspective, the EO scenario demonstrates that regionalisation is not a neutral modelling feature but a transmission channel through which objective-function priorities translate into territorial outcomes. When the optimisation internalises only private cost, the equilibrium favours geographic concentration, fossil reliance and reduced socio-economic diffusion.

The contrast with MEC, LCE and WSC provides evidence that sustainable transformation in the Brazilian electricity sector is intrinsically linked to spatial reallocation of investment. Without explicit internalisation of environmental and social externalities, the least-cost trajectory converges toward a carbon-intensive, water-dependent and territorially concentrated system. The EO benchmark therefore substantiates the central thesis of this research: long-term electricity planning must integrate multidimensional valuation to align financial efficiency with regional equity and environmental resilience.

The EO scenario represents a purely cost-driven expansion pathway, in which the absence of environmental and social constraints allows the model to select technologies based exclusively on economic efficiency. This configuration serves as a reference case, illustrating the divergence between private cost optimisation and broader sustainability objectives.

The EO scenario represents a purely cost-driven expansion pathway, in which the absence of environmental and social constraints allows the model to select technologies based exclusively on economic efficiency. This configuration serves as a reference case, illustrating the divergence between private cost optimisation and broader sustainability objectives. Key findings of the scenario:

(i) The absence of environmental and social constraints leads to a solution dominated by cost-efficient technologies, regardless of their external impacts;

(ii) Fossil-based generation remains competitive under purely economic criteria, highlighting the divergence between private and social optimality;

(iii) The scenario serves as a counterfactual baseline, illustrating the outcomes of a system driven exclusively by economic efficiency;

(iv) The results reinforce the importance of internalising externalities to avoid environmentally and socially suboptimal expansion pathways.

5.10 – Scenario 7: Decarbonisation and Social Inclusion (DSI)

The Decarbonisation and Social Inclusion (DSI) scenario constitutes the seventh policy configuration evaluated within the SEGeP framework. It represents the scenario in which stringent climate-mitigation requirements are combined with an enhanced valuation of employment-related social benefits and the regional differentiation of socioeconomic effects. Its purpose is to assess whether deep decarbonisation of the Brazilian

electricity system can be achieved while simultaneously supporting employment creation, regional participation in new investments and a broader territorial distribution of electricity-sector benefits.

Unlike the BAU and EO configurations, in which expansion decisions remain predominantly influenced by direct economic costs and conventional system-adequacy requirements, DSI strengthens both the environmental and social components of the Total Social Cost objective. The scenario combines a high carbon-price signal, declining limits on CO_2 emissions, strong restrictions on fossil-fuel expansion, the internalisation of land, water and biodiversity externalities and an enhanced valuation of employment generated by new generation capacity.

The DSI configuration therefore evaluates a central proposition of this thesis: climate mitigation and selected social-development objectives do not necessarily constitute opposing policy priorities. When environmental damages and employment-related social benefits are incorporated into the optimisation process, the model can identify expansion pathways that substantially reduce emissions while supporting regional economic activity and distributing employment effects across different parts of the national territory.

Within this scenario, social inclusion is operationalised primarily through the monetisation of employment benefits associated with new capacity and through the regional differentiation of labour-income and socioeconomic conditions. Regional Gini and Human Development Index (HDI) values are subsequently derived from the employment and labour-income effects generated by the optimal expansion pathway. These indicators are used to evaluate the distributive implications of the scenario but do not directly enter the optimisation as decision variables.

The DSI scenario assumes:

- a carbon price reaching €150/tCO_2;
- stringent and progressively declining limits on CO_2 emissions;
- strong restrictions on the expansion and operation of fossil-fuel generation;
- conditions favouring renewable and other low-carbon technologies;
- enhanced valuation of employment associated with new generation capacity;
- regional differentiation of employment-related benefits and labour-income effects;
- explicit internalisation of water-use, land-use and biodiversity externalities;
- maintenance of the annual electricity supply–demand balance and system-adequacy requirements; and
- an exogenously defined electricity-demand trajectory throughout the planning horizon.

A fundamental methodological clarification is required. In this thesis, DSI refers exclusively to Decarbonisation and Social Inclusion. The scenario does not incorporate endogenous demand response,

temporal load shifting, peak-load shaving, consumer flexibility or investment in energy efficiency as decision variables. Electricity demand remains an exogenous requirement that must be satisfied by the generation-expansion model.

The distinguishing feature of DSI is therefore not a modification of consumer behaviour or a transformation of demand into an operational system resource. Rather, it is the simultaneous strengthening of decarbonisation constraints, environmental externality valuation and employment-related social valuation within the Total Social Cost framework.

DSI represents an integrated decarbonisation-and-inclusion pathway. Its results are evaluated through the combined evolution of the generation mix, CO_2 emissions, regional generation, land occupation, water consumption, employment, derived Gini and HDI indicators and system economic performance.

5.10.1 Input Data Structure (DSI)

Table 5.76 summarises the structural parameter adjustments that define the DSI configuration. Unlike BAU and EO, in which expansion decisions remain more strongly influenced by direct generation costs, DSI combines stringent decarbonisation requirements with an enhanced valuation of employment-related benefits and regional socioeconomic effects.

Electricity demand remains exogenously defined and follows the same trajectory adopted in the other non-stress scenarios: 820 TWh in 2030, 930 TWh in 2040 and 1,040 TWh in 2050. No endogenous reduction in electricity consumption, demand elasticity, load shifting or demand-response mechanism is activated in this scenario.

Table 5.76 - Structural parameters of the DSI scenario

Parameter	BAU/EO configuration	DSI configuration	Technical rationale
Carbon price	Baseline or moderate	€150/tCO_2	Provides a strong long-term decarbonisation signal
CO_2 emission limit	Non-binding or moderate	Stringent and declining	Progressively reduces the feasible contribution of fossil generation
Fossil-fuel expansion	Permitted	Strongly restricted	Prevents long-term carbon lock-in
Renewable and low-carbon technologies	Predominantly market-driven	Favoured by climate and externality parameters	Supports the transition towards a near-zero-carbon generation portfolio
Employment valuation	Baseline	Enhanced	Internalises employment-related social benefits
Regional employment value	Limited differentiation	Regionally differentiated	Represents differences in regional labour-income and socioeconomic conditions
Water externality	Baseline valuation	Fully internalised	Discourages water-intensive expansion alternatives
Land-use and biodiversity externalities	Baseline valuation	Fully internalised	Discourages configurations with comparatively higher territorial and ecological impacts
Demand trajectory	Exogenous	Exogenous: 820, 930 and 1,040 TWh	Maintains comparability with the other non-stress scenarios

Endogenous demand-side measures	Not represented	Not represented	Demand response, load shifting and peak shaving are outside the model scope
System adequacy	Mandatory	Mandatory	Preserves the annual supply–demand balance and technical feasibility
Gini and HDI	Derived indicators	Derived indicators	Evaluate distributive outcomes without directly influencing the optimisation

Source: Author's elaboration based on SEGeP modelling structure.

The DSI configuration introduces two fundamental structural modifications to the optimisation landscape.

First, the high carbon price and the declining emissions limit substantially increase the Total Social Cost associated with fossil generation. These mechanisms operate jointly with restrictions on new fossil capacity, progressively reducing the economic and technical space available for natural-gas generation over the planning horizon. The resulting decarbonisation trajectory is therefore driven by climate-policy parameters, environmental externality internalisation and the expansion of renewable and other low-carbon technologies.

Second, employment-related benefits receive greater importance in the social component of the objective function. Technologies generating comparatively higher employment per unit of new capacity obtain an additional social benefit, represented as a reduction in Total Social Cost. Because employment effects are regionally differentiated through labour-income and socioeconomic parameters, the geographical allocation of new capacity also influences the social performance of the optimal solution.

The combination of environmental and social valuation changes the relative attractiveness of the available technologies. Generation options associated with higher emissions, water consumption, land occupation or biodiversity impacts become less competitive. Conversely, low-carbon technologies with favourable regional resource availability and relevant employment contributions gain additional structural attractiveness.

Regional disaggregation remains fully active within the DSI formulation. Consequently, the model evaluates investment opportunities according to regional resource availability, technology costs, environmental coefficients, employment effects and system requirements. The Northeast benefits particularly from the large-scale availability of wind and solar resources, while the Southeast/Central-West remains central because of its high electricity demand, existing infrastructure and industrial base.

The DSI scenario remains a long-term generation-expansion configuration with annual temporal resolution. It does not represent hourly operation, short-term demand response or intra-day flexibility. Any interpretation of the results must therefore be based on the expansion and annual generation decisions effectively represented in SEGeP.

5.10.2 Results of the Optimal Generation Mix (DSI)

Table 5.77 presents the optimal generation mix obtained under the DSI configuration. The results demonstrate a substantial restructuring of the Brazilian electricity matrix, driven by the interaction between stringent climate constraints, environmental externality valuation, employment-related social benefits and the regional availability of renewable resources.

Table 5.77 - Optimal generation by technology in the DSI scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Others	Total
2030	410.0	160.0	140.0	70.0	35.0	5.0	820.0
2040	400.0	220.0	210.0	85.0	10.0	5.0	930.0
2050	390.0	280.0	290.0	75.0	0.0	5.0	1,040.0

Source: Author's elaboration.

The most significant structural outcome is the complete elimination of natural gas generation by 2050. Gas declines from 35 TWh in 2030 to 10 TWh in 2040 and reaches zero in the final horizon year. This trajectory contrasts markedly with the EO configuration, in which natural gas remains economically attractive because environmental damages and climate constraints receive less influence in the optimisation.

The reduction in gas generation results from the combined effect of the €150/tCO_2 carbon price, the declining emissions cap, restrictions on fossil expansion and the internalisation of environmental damages. It is not produced by demand reduction, peak shaving or endogenous demand-side flexibility.

Wind and solar generation expand strongly throughout the planning horizon. Their combined contribution rises from 300 TWh in 2030 to 430 TWh in 2040 and 570 TWh in 2050. In the final year, wind and solar account for approximately 54.8% of total electricity generation.

This expansion reflects their low operational emissions, favourable regional resource availability and increasing competitiveness when environmental externalities are incorporated into the objective function. Their contribution is particularly important in replacing fossil generation while maintaining the exogenously defined annual electricity-demand trajectory.

Hydropower remains the largest individual generation technology during most of the planning horizon but declines gradually from 410 TWh in 2030 to 390 TWh in 2050. This reduction does not indicate resource depletion or the abandonment of hydropower. Instead, it reflects a relative rebalancing of the generation portfolio as wind, solar and other low-carbon technologies assume a greater share of total generation.

The stability of hydropower also avoids excessive dependence on new reservoirs and contributes to limiting additional land occupation, biodiversity pressure and water-related externalities. Existing hydroelectric capacity nevertheless continues to provide a substantial share of annual electricity supply within the model.

Biomass generation increases from 70 TWh in 2030 to 85 TWh in 2040 before declining to 75 TWh in 2050. Biomass remains relevant because it combines renewable characteristics with comparatively higher capacity factors and employment contributions. However, its expansion is moderated by the internalisation of land-use, water-use and biodiversity impacts, preventing it from becoming the dominant replacement for fossil generation.

The "Others" category remains stable at 5 TWh throughout the planning horizon. Consequently, the central technological transformation occurs through the progressive replacement of natural gas by wind and solar, accompanied by a moderate rebalancing of hydropower and biomass.

DSI satisfies the same exogenous electricity-demand trajectory adopted in the non-stress scenarios while generating a substantially different technological portfolio. Total generation increases from 820 TWh in 2030 to 1,040 TWh in 2050, but natural gas is progressively displaced and renewable technologies become responsible for almost the entire electricity supply.

The results demonstrate that deep decarbonisation can be achieved within the SEGeP framework through stringent climate constraints, environmental externality internalisation and the expansion of renewable technologies. No part of this result should be attributed to endogenous changes in consumer demand, since demand remains externally specified throughout the scenario.

5.10.3 Regional Disaggregation of Generation and Capacity (DSI)

In the DSI scenario, regionalisation becomes an endogenous component of the optimisation process rather than merely a spatial accounting device. The interaction between regional renewable-resource availability, stringent decarbonisation constraints and the valuation of employment-related social benefits favours the expansion of low-carbon generation in regions with greater comparative advantages.

Within this configuration, the Northeast becomes the principal frontier for new low-carbon generation. Its favourable wind and solar resources, combined with stringent restrictions on fossil generation and the valuation of regional employment effects, increase the relative attractiveness of investments in the region. (Table 5.78).

Table 5.78 - Electricity generation by region in DSI (TWh).

Region	2030	2040	2050
North	135.0	140.0	145.0
Northeast	220.0	310.0	410.0
SE / Central-West	365.0	380.0	385.0
South	100.0	100.0	100.0
Total SIN	820.0	930.0	1,040.0

Source: Author's elaboration.

The Northeast increases its generation from 220 TWh in 2030 to 410 TWh in 2050, representing an expansion of 190 TWh, or approximately 86.4%. By the end of the planning horizon, the region accounts for approximately 39.4% of total national generation and becomes the largest generation subsystem in the DSI configuration. The Southeast/Central-West remains the principal load centre and maintains a stable generation profile, reaching 385 TWh in 2050. However, its relative share declines as generation expands more strongly in the Northeast. Under the DSI logic, this change reflects the regional allocation of low-carbon investments and the progressive reduction of fossil generation, rather than any endogenous reshaping of electricity demand. The Southeast/Central-West therefore relies more heavily on low-carbon electricity supplied from other regions while preserving its role in system balancing and adequacy. The result is a gradual spatial rebalancing in which the region becomes less dominant as a generation-expansion pole and more dependent on interregional electricity exchanges within the decarbonised national system.

The North exhibits modest growth, rising from 135 to 145 TWh. This stability reflects the region's constrained expansion logic under existing assumptions, where hydropower remains relevant but does not dominate marginal growth. The South remains constant at 100 TWh throughout the planning horizon, indicating that its contribution is largely maintained through existing assets and comparatively limited additional investment relative to the large-scale wind and solar expansion observed in the Northeast.

Table 5.78 indicates that the DSI scenario produces one of the strongest regional rebalancing effects identified in the study, although through a mechanism distinct from those observed in MEC and WSC. In MEC, the regional distribution of investment is strongly influenced by employment-related social valuation, whereas in WSC it is shaped primarily by hydrological constraints. Under DSI, the system's geographical centre of generation shifts through the combined effect of stringent decarbonisation targets, restrictions on fossil expansion, the internalisation of environmental externalities, regional resource availability and the valuation of employment-related social benefits. These mechanisms increase the relative attractiveness of wind and solar investments in the Northeast, allowing the region's renewable potential to support national electricity supply and consolidating its position as the largest generation subsystem within the SIN by 2050. The environmental performance of the DSI scenario establishes the deepest decarbonisation trajectory within the SEGeP framework. As shown in Table 5.79, modelled CO_2 emissions decline from 15.0 $MtCO_2$ in 2030 to 4.0 $MtCO_2$ in 2040 and reach only 0.5 $MtCO_2$ in 2050. This represents a reduction of approximately 96.7% over the planning horizon and the lowest final emissions level among all simulated scenarios. The decline results primarily from the progressive displacement and eventual elimination of natural-gas generation, supported by the high carbon price, declining emission limits, restrictions on fossil expansion and the increasing participation of renewable and other low-carbon technologies. The residual emissions observed in 2050 reflect the non-zero

emission coefficients retained for selected technologies and system processes rather than continued dependence on fossil generation

Table 5.79 - CO_2 emissions by region in DSI ($MtCO_2$).

Region	2030	2040	2050
North	0.8	0.4	0.1
Northeast	0.4	0.1	0.0
SE / Central-West	12,8	3.0	0.4
South	1.0	0.5	0.0
Total SIN	15	4.0	0.5

Source: Author's elaboration.

The emissions reported in Table 5.79 represent the CO_2 emissions accounted for within the SEGeP inventory. The indicator includes emissions associated with fossil-fuel generation and the residual emission coefficients assigned to the remaining technology and system categories. It should therefore not be interpreted exclusively as direct emissions from natural-gas combustion.

In 2030, natural-gas generation remains at 35 TWh. Considering the emission factor adopted for this technology, natural gas accounts for approximately 14.0 $MtCO_2$. The remaining modelled emissions arise from the residual coefficients attributed to other technologies and system processes represented in the SEGeP database. Total system emissions therefore reach 15.0 $MtCO_2$.

Although this value represents a substantial reduction compared with the recent emissions profile of the Brazilian electricity sector, it remains consistent with the deliberately ambitious and policy-driven nature of the DSI scenario. The result assumes accelerated renewable deployment, stringent restrictions on fossil expansion, a carbon price reaching €150/tCO_2 and the rapid displacement of more carbon-intensive thermal generation.

The Southeast/Central-West accounts for 12.8 $MtCO_2$ in 2030, representing approximately 85% of national emissions. This concentration reflects the location of most residual natural-gas generation, the scale of regional electricity demand and the subsystem's role in maintaining adequacy during the initial phase of the transition.

The North, Northeast and South account for 0.8, 0.4 and 1.0 $MtCO_2$, respectively. Their lower emissions are consistent with the more limited participation of fossil generation and the greater contribution of hydropower, wind, solar and other renewable technologies.

By 2040, total emissions decline to 4.0 $MtCO_2$. Natural-gas generation is reduced to 10 TWh, accounting for approximately 4.0 $MtCO_2$, while the remaining 0.5 $MtCO_2$ results from the residual emission coefficients retained for other technologies and system processes.

The Southeast/Central-West remains responsible for most emissions in 2040, with 3.5 $MtCO_2$. The North accounts for 0.4 $MtCO_2$, the Northeast for 0.1 $MtCO_2$ and the South for 0.5 $MtCO_2$.

The reduction between 2030 and 2040 results primarily from the progressive substitution of natural gas by wind, solar and other low-carbon technologies. The declining emissions limit, the high carbon price, restrictions on fossil expansion and the internalisation of environmental externalities progressively reduce the competitiveness of fossil generation within the Total Social Cost objective.

In 2050, natural-gas generation is eliminated from the optimal generation mix. Nevertheless, total modelled emissions remain at 0.5 $MtCO_2$ because the SEGeP inventory retains residual emission coefficients for some non-fossil technologies and system processes. The final value should therefore be interpreted as residual system emissions rather than continued structural dependence on fossil generation.

Regionally, 0.4 $MtCO_2$ remains associated with the Southeast/Central-West and 0.1 $MtCO_2$ with the North. Values in the Northeast and South are sufficiently low to be rounded to zero at the level of precision adopted in the table.

The DSI scenario consequently achieves near-complete, but not absolute, decarbonisation by 2050. The decline from 15.0 $MtCO_2$ in 2030 to 0.5 $MtCO_2$ in 2050 corresponds to a reduction of approximately 96.7% over the planning horizon.

This residual value does not imply the continued operation of natural-gas generation in 2050. Instead, it reflects the accounting boundary and the non-zero emission coefficients maintained for selected technologies and processes in the SEGeP database. A complete lifecycle assessment could produce different values and would require a separate and more comprehensive emissions-accounting framework.

Importantly, the emissions trajectory does not result from endogenous demand reduction, temporal load shifting or consumer flexibility. Electricity demand remains exogenously defined at 820 TWh in 2030, 930 TWh in 2040 and 1,040 TWh in 2050. The reduction is driven by stringent climate-policy parameters, the progressive replacement of fossil generation and the expansion of renewable and other low-carbon technologies.

The Decarbonisation and Social Inclusion scenario exhibits the lowest absolute land-use footprint among the configurations analysed within the SEGeP framework. This outcome results from the generation portfolio selected under stringent climate constraints, the explicit internalisation of land-use and biodiversity externalities, the avoidance of substantial new reservoir expansion and the participation of distributed solar generation installed on existing built surfaces. Table 5.80 presents the regional and technological decomposition of land occupation under DSI for the three planning horizons.

Table 5.80 - Land Use by region and technology in Scenario DSI (km²).

Year	Region	Hydro	Wind	Solar PV*	Biomass	Others	Total Region
2030	North	6,500	120	80	5	5	6,710
	Northeast	1,800	4,500	1,100	50	10	7,460
	SE / CW	8,500	650	950	450	40	10,590
	South	2,100	1,200	320	15	5	3,640
	Total 2030	18,900	6,470	2,450	520	60	28,400
2040	North	6,500	250	150	10	5	6,915
	Northeast	1,800	6,800	1,800	80	10	10,490
	SE / CW	8,500	1,100	1,450	650	40	11,740
	South	2,100	1,800	550	20	5	4,475
	Total 2040	18,900	9,950	3,950	760	60	33,620
2050	North	6,500	400	250	15	5	7,170
	Northeast	1,800	8,500	2,400	120	10	12,830
	SE / CW	8,500	1,800	2,100	850	40	13,290
	South	2,100	2,800	850	30	5	5,785
	Total 2050	18,900	13,500	5,600	1,015	60	39,075

**Note: In the DSI scenario, approximately 40% of total Solar PV capacity corresponds to distributed generation installed in urban areas (rooftops and built environments), therefore not accounting for additional greenfield land occupation.*

Source: Author's elaboration.

From a quantitative perspective, total land occupation reaches 39,075 km² in 2050, significantly below the territorial footprint observed in the HRP, MEC, WSC and EO scenarios. The stability of the hydropower area at 18,900 km² throughout the planning horizon reflects the absence of substantial new reservoir expansion. Under DSI, system adequacy is instead supported by the regional allocation of low-carbon generation, the progressive displacement of fossil technologies and interregional electricity exchanges. The lower land requirement therefore results from the generation portfolio selected under stringent decarbonisation constraints and from the internalisation of land-use and biodiversity externalities within the Total Social Cost objective.

The Northeast records the largest incremental expansion in land occupation, increasing from 7,460 km² in 2030 to 12,830 km² in 2050. This increase is largely associated with wind and utility-scale solar deployment. Nevertheless, the territorial intensity of photovoltaic expansion is moderated by the participation of distributed generation installed on rooftops and other built environments. This component reduces the

additional greenfield land requirement relative to a configuration based exclusively on utility-scale solar installations.n the Southeast/Central-West, total land occupation increases from 10,590 km² in 2030 to 13,290 km² in 2050, primarily because of additional wind, solar and biomass capacity. However, the absence of new large hydropower reservoirs, the limited expansion of biomass and the participation of distributed photovoltaic systems constrain the need for extensive new land conversion.. The South shows moderate growth, reaching 5,785 km² in 2050, reflecting incremental wind and solar additions without structural transformation of land use patterns.

DSI demonstrates that the simultaneous pursuit of decarbonisation and social inclusion can also improve the territorial efficiency of electricity expansion. The lower land requirement observed in this scenario results from the technological composition selected by the model, particularly the reduced dependence on fossil generation, the allocation of renewable capacity across regions and the explicit internalisation of land-use and biodiversity externalities.

DSI represents one of the most territorially efficient pathways evaluated within SEGeP. Its performance results from the combined effect of stringent climate constraints, environmental valuation, regional resource availability and technology-specific land-use coefficients. These elements direct investment towards a portfolio capable of reducing emissions while containing additional land occupation and biodiversity pressures. Consequently, the DSI configuration reduces potential land-use conflicts and ecological pressures associated with electricity expansion, reinforcing the multidimensional sustainability rationale of the scenario. Table 5.81 reports the regionalised water consumption associated with the DSI configuration. The results are consistent with the structural logic of the Decarbonisation and Social Inclusion scenario: by combining stringent decarbonisation targets, restrictions on fossil generation, the internalisation of environmental externalities and the valuation of employment-related social benefits, the model reduces reliance on water-intensive technologies and limits the need for thermal generation. The lower water consumption observed under DSI should therefore be interpreted as a co-benefit of the low-carbon generation portfolio selected by the optimisation model, rather than as a consequence of changes in electricity demand or operational flexibility measures.

Table 5.81 - Water consumption by region in DSI (million m³).

Year	Region	Hydro	Biomass	Nat. Gas	Nuclear	Others	Total
2030	North	195.0	1.6	0.2	–	0.6	197.4
	Northeast	15.6	3.5	1.2	–	0.2	20.5
	SE / CW	468.0	36.4	9.6	20.0	1.0	535.0
	South	101.4	10.5	1.0	–	0.2	113.1
	Total 2030	780.0	52.0	12.0	20.0	2.0	866.0
2040	North	190.0	1.6	0.1	–	0.6	192.3
	Northeast	15.2	3.7	0.4	–	0.2	19.5
	SE / CW	456.0	37.5	3.2	20.0	1.0	517.7
	South	98.8	10.7	0.3	–	0.2	110.0
	Total 2040	760.0	53.5	4.0	20.0	2.0	839.5
2050	North	185.0	1.7	0.0	–	0.6	187.3
	Northeast	14.8	3.9	0.0	–	0.2	18.9
	SE / CW	444.0	38.5	0.5	20.0	1.0	504.0
	South	96.2	10.9	0.0	–	0.2	107.3
	Total 2050	740.0	55.0	0.5	20.0	1.5	817.0

Source: Author's elaboration.

As shown in Table 5.81, total water consumption declines from 866.0 million m³ in 2030 to 817.0 million m³ in 2050. This downward trajectory reflects three structural mechanisms inherent to the DSI logic.

First, hydropower water use gradually decreases from 780.0 to 740.0 million m³ at the system level, not because of hydrological restrictions, as in the WSC scenario, but because the stringent decarbonisation constraints alter the optimal generation mix and reduce the relative contribution of hydropower. The expansion of wind, solar and other low-carbon resources lowers the volumetric dispatch required from hydropower while maintaining the exogenously defined electricity-demand trajectory.

Second, natural gas water consumption collapses from 12.0 million m³ in 2030 to only 0.5 million m³ in 2050. This reduction mirrors the complete phase-out of fossil generation observed in Table 5.77 and provides evidence that the progressive elimination of natural-gas generation removes the associated cooling-water requirement.. The near-elimination of gas cooling water is a defining environmental feature of the DSI pathway.

Third, biomass water use increases moderately (52.0 to 55.0 million m³). However, unlike in WSC, biomass expansion in DSI is not driven by hydrological compensation needs but by its role as a dispatchable renewable complement to variable renewables. The overall water footprint remains contained because biomass expansion is moderate and wind and solar technologies account for most of the additional generation.

Regionally, the SE/Central-West remains the dominant water-consuming subsystem, reaching 504.0 million m³ in 2050. Nevertheless, this represents a structural reduction compared to other high-generation scenarios, due to the contraction of thermal dispatch. The Northeast exhibits the lowest water intensity relative to generation growth, confirming that wind and solar expansion under DSI is associated with minimal additional hydrological pressure.

The DSI scenario demonstrates that deep decarbonisation can also generate a measurable water-use co-benefit. Unlike WSC, where water scarcity directly constrains the expansion pathway and forces technological substitution, the lower water dependency observed under DSI results primarily from the progressive reduction of fossil thermal generation and the expansion of wind, solar and other low-carbon technologies with comparatively lower operational water requirements. The results therefore show that combining stringent climate targets with social-inclusion priorities can simultaneously reduce emissions and resource intensity, reinforcing the multidimensional sustainability rationale of the SEGeP framework.

5.10.4 Social Effects (DSI)

. Table 5.82 presents the regional distribution of equivalent annual employment under the Decarbonisation and Social Inclusion scenario. Employment growth results primarily from the expansion of labour-intensive renewable technologies and from the regional distribution of new generation investments. Because employment-related social benefits are explicitly valued in the optimisation criterion, technologies and regions with higher employment contributions gain additional attractiveness within the expansion portfolio.

Table 5.82 - Equivalent annual employment by region in DSI (thousand jobs/year).

Region	2030	2040	2050
North	42.0	52.0	60.0
Northeast	110.0	140.0	165.0
SE / Central-West	148.0	178.0	195.0
South	30.0	35.0	40.0
Total SIN (DSI)	330.0	405.0	460.0

Source: Author's elaboration.

The total employment increases from 330 thousand jobs/year in 2030 to 460 thousand jobs/year in 2050. This trajectory places DSI among the highest employment-generating pathways in the study, approaching the levels observed in MEC, but through a structurally different mechanism.

The Northeast reaches 165 thousand jobs/year in 2050, reflecting its role as a major renewable-generation expansion hub. Unlike the EO scenario—where employment growth is more limited due to the greater concentration of investment in less labour-intensive fossil technologies, the DSI configuration promotes substantial wind and solar expansion. The employment effects therefore include activities related to construction, installation, operation, maintenance and the associated renewable-energy supply chains. The SE/Central-West subsystem records the highest absolute employment level, reaching 195 thousand equivalent jobs per year in 2050. This result reflects the scale of electricity-sector investment in the region, its industrial

structure and its participation in renewable-generation supply chains, construction, operation and maintenance activities.

The North exhibits steady growth from 42 to 60 thousand jobs/year, associated with incremental renewable and other low-carbon investments. The South follows a moderate trajectory, reaching 40 thousand jobs/year by 2050, reflecting a lower concentration of new generation investments relative to the Northeast and Southeast/Central-West. A critical structural feature highlighted in Table 5.82 is that employment increases simultaneously across all regions. In WSC, this outcome is associated with adaptation-driven renewable expansion, whereas in EO employment growth is more limited because investment remains concentrated in less labour-intensive fossil-based technologies. Under DSI, employment expansion is more territorially distributed because the optimisation explicitly values employment-related social benefits, while new low-carbon investments are allocated according to regional resource availability, system requirements and differentiated socioeconomic parameters. The resulting jobs are associated mainly with the construction, operation, maintenance and supply chains of renewable and other low-carbon technologies.

The DSI scenario therefore demonstrates that combining decarbonisation objectives with the explicit valuation of employment-related benefits can generate both environmental gains and a broader regional distribution of socioeconomic effects. The regional employment results indicate that electricity-sector expansion can contribute to territorial cohesion when the optimisation framework recognises regional labour-market conditions and the social value of employment creation.

The distributive implications of the Decarbonisation and Social Inclusion (DSI) pathway are synthesised in Table 5.83, which reports the projected evolution of the regional Gini Index between 2030 and 2050. Unlike configurations in which income effects remain concentrated around a limited number of large-scale projects, DSI is associated with greater territorial convergence through the regional allocation of low-carbon investment and the resulting employment and labour-income effects. In the SEGeP framework, the reduction in inequality is derived from the employment and labour-income effects generated by the expansion pathway. Regions receiving proportionally greater employment benefits experience stronger income effects, which are subsequently reflected in the derived Gini indicators according to the socioeconomic relationships adopted in the model.

Table 5.83 - Regional Gini Index evolution in Scenario DSI.

Region	2030	2040	2050
North	0.510	0.495	0.480
Northeast	0.525	0.505	0.485
SE / Central-West	0.485	0.470	0.455
South	0.450	0.440	0.430

Source: Author's elaboration.

As evidenced in Table 5.83, inequality declines consistently across all subsystems. The Northeast exhibits a reduction from 0.525 in 2030 to 0.485 in 2050, while the North follows a similar trajectory, decreasing from 0.510 to 0.480. This pattern differs markedly from the EO scenario, where inequality either stagnates or worsens due to investment concentration near established load centres. In DSI, the distributive effects are derived from the expansion results: employment associated with the deployment, operation and maintenance of low-carbon generation technologies follows the regional allocation of new investments rather than being concentrated exclusively in established economic centers. The SE/Central-West, despite being the most industrialised subsystem, also experiences a substantial decline (0.485 to 0.455). This reduction is linked to the scale and diversity of employment generated by low-carbon investments in the region, including construction, operation, maintenance and participation in renewable-energy supply chains. The South achieves the lowest Gini value (0.430 in 2050), consolidating its position as the most equal subsystem, though the rate of improvement is comparable across regions.

From a structural standpoint, the DSI scenario indicates that the regional allocation of low-carbon investments and employment-related benefits can influence the territorial distribution of labour-income effects. By directing a relevant share of renewable expansion towards different regions, the scenario produces a more spatially distributed pattern of employment creation. These effects contribute to the gradual territorial income convergence represented by the derived Gini indicators. The evolution of the Human Development Index (HDI) under the DSI configuration is presented in Table 5.84. The results indicate one of the strongest human-development trajectories among the scenarios evaluated in this thesis. Unlike pathways in which socioeconomic benefits remain concentrated in a limited number of regions, the DSI configuration promotes a broader territorial distribution of employment and labour-income gains associated with new low-carbon investments. These regional income effects are subsequently reflected in the derived HDI indicators according to the socioeconomic relationships incorporated into the SEGeP framework. The results should therefore be interpreted as an estimated consequence of the regional distribution of employment-related benefits, rather than as a direct optimisation of HDI or as an automatic effect of technological deployment.

Table 5.84 - Regional HDI evolution in Scenario DSI.

Region	2030	2040	2050
North	0.745	0.770	0.800
Northeast	0.735	0.765	0.805
SE / Central-West	0.805	0.825	0.850
South	0.820	0.840	0.865

Source: Author's elaboration.

All subsystems exhibit sustained improvement over the planning horizon. The North advances from 0.745 in 2030 to 0.800 in 2050, while the Northeast progresses from 0.735 to 0.805 over the same period.

This upward trajectory reflects the employment and labour-income effects associated with the regional expansion of renewable and other low-carbon technologies Because DSI explicitly values employment-related social benefits and incorporates differentiated regional socioeconomic parameters, territories with lower initial development indicators can receive proportionally greater employment and labour-income benefits from the allocation of low-carbon investments. These income effects are subsequently reflected in the derived HDI values according to the socioeconomic relationships incorporated into the SEGeP framework.

The Northeast, in particular, exceeds the 0.800 threshold by 2050, entering the Very High human development category. This result is achieved without relying on the explicit regional incentive structure adopted in the MEC scenario. Instead, it emerges from the combined effect of stringent decarbonisation constraints, the regional allocation of low-carbon investment and the valuation of employment-related benefits within the Total Social Cost objective. The North follows a similar trajectory, indicating that a decarbonisation and social-inclusion strategy can also support development gains in regions historically characterised by lower income levels and greater dependence on primary-sector activities.

The SE/Central-West and South maintain higher absolute HDI values, reaching 0.850 and 0.865 respectively by 2050. However, the convergence dynamic is notable: the interregional gap narrows as lower-income regions experience proportionally faster growth. Within the assumptions of the model, this convergence is associated with the regional distribution of low-carbon investment, employment creation and labour-income effects. The same expansion pathway also reduces emissions and the contribution of fossil thermal generation while supporting employment in low-carbon electricity-sector activities.

From a structural perspective, the DSI scenario indicates that the electricity sector can contribute to human development when decarbonisation objectives and employment-related social benefits are incorporated into the optimisation framework and their regional socioeconomic implications are subsequently evaluated. The simultaneous reduction in emissions, decline in inequality and improvement in derived HDI indicators indicates that combining stringent climate constraints with social-inclusion priorities can generate mutually reinforcing economic, social and environmental benefits.

The economic performance of the DSI scenario is summarised in Table 5.85, which presents the total system cost in NPV terms and the average LCOE across the three planning horizons.

Table 5.85 - System economic indicators in DSI.

Metric	2030	2040	2050
Total system cost (NPV, € billion)	315.0	390.0	465.5
Average LCOE (€/MWh)	54.0	51.5	49.0

Source: Author's elaboration.

The DSI scenario exhibits one of the highest total system costs among the analysed configurations, reaching €465.5 billion by 2050. This outcome is structurally associated with the front-loaded investment required for the large-scale expansion of low-carbon generation, the replacement of fossil-based capacity, the strengthening of complementary system resources and the regional allocation of investments towards technologies and locations that combine low-carbon generation potential with employment-related social benefits.

Despite the higher cumulative NPV, the average LCOE follows a declining trajectory, decreasing from €54.0/MWh in 2030 to €49.0/MWh in 2050. This reduction reflects the increasing contribution of renewable technologies with low operating and fuel costs, the progressive replacement of fuel-dependent thermal generation and the long-term utilisation of the low-carbon capacity installed during the initial stages of the transition. The transition from an operational expenditure–intensive system (fuel-dependent thermal generation) to a capital-intensive, technology-driven structure results in improved long-term cost stability and reduced exposure to fuel price volatility.

When interpreted within the broader SEGeP framework, the macroeconomic indicators of the DSI scenario must be assessed alongside its environmental and social performance. Although financially more demanding than the EO pathway, DSI simultaneously achieves near-complete decarbonisation, substantial reductions in water use and strong employment generation, reaching 460 thousand equivalent jobs per year by 2050. The higher financial outlay therefore supports a low-carbon expansion pathway with broader regional socioeconomic benefits and lower environmental externalities. These results confirm that Decarbonisation and Social Inclusion represents a capital-intensive but strategically robust configuration for long-term national electricity planning.

5.10.5 Analytical Discussion: Decarbonisation, Employment and Regional Inclusion in DSI

The regional outcomes of the DSI scenario reveal a structural reconfiguration of Brazil's electricity geography that can be described as territorial rebalancing. Unlike pathways driven predominantly by private generation costs or system-security constraints, the Decarbonisation and Social Inclusion configuration combines stringent climate targets, restrictions on fossil generation, regional differentiation and the valuation of employment-related social benefits. As a result, expansion is shaped not only by technological costs and hydrological conditions, but also by the regional allocation of low-carbon investment and its associated socioeconomic effects. This produces a broader regional distribution of generation capacity, employment and labour-income effects while maintaining the exogenously defined electricity-demand trajectory..

By 2050, the Northeast reaches 410 TWh, becoming the largest electricity-producing region within the SIN. Unlike the MEC scenario, in which employment creation constitutes the dominant social driver, the expansion observed under DSI results from the simultaneous imposition of stringent decarbonisation targets, restrictions on fossil generation, regional differentiation and the valuation of employment-related social benefits. The high penetration of wind and solar power results from the expansion of low-carbon generation capacity under stringent climate constraints, while the diversified generation portfolio and interregional exchanges maintain system adequacy. At the same time, the Southeast/Central-West reaches 385 TWh and preserves its significant role in meeting national demand without the thermal concentration observed in the EO and LRI scenarios.

This territorial rebalancing is reinforced by the employment and equity outcomes. As shown in Table 5.82, total employment reaches 460 thousand equivalent jobs per year in 2050, including 165 thousand in the Northeast and 195 thousand in the Southeast/Central-West. Unlike EO, where employment gains remain comparatively limited and more concentrated, employment effects under DSI follow the regional expansion of renewable and other low-carbon technologies, including construction, operation, maintenance and associated supply-chain activities. The resulting employment and labour-income effects contribute to a measurable convergence in income distribution. The regional Gini index declines to 0.485 in the Northeast and to 0.455 in the Southeast/Central-West by 2050, indicating one of the strongest reductions in inequality among the scenarios evaluated.

The Human Development Index provides further evidence of this convergence. The Northeast reaches an HDI of 0.805 by 2050, while the North attains 0.800. The gap between historically less-developed regions and the South narrows as low-carbon investment, employment creation and labour-income gains become more broadly distributed across the national territory. These effects are reflected in the derived HDI indicators according to the socioeconomic relationships incorporated into SEGeP. The DSI pathway therefore contributes to territorial convergence by combining deep decarbonisation with the explicit valuation of employment-related social benefits and the regional allocation of low-carbon investment.

Environmental regionalisation under DSI also differs structurally from other pathways. The near elimination of natural gas generation results in residual system emissions of only 0.5 $MtCO_2$ in 2050, concentrated primarily in minimal operational residues rather than fossil baseload. This decarbonisation trajectory is accompanied by a substantial reduction in water use. Total water consumption declines to 817 million m^3 in 2050, compared to 1,023 million m^3 in the EO scenario. In the SE/CW alone, water use falls from 641.5 million m^3 (EO) to 504.0 million m^3 (DSI), a reduction of approximately 137 million m^3. This

demonstrates that the low-carbon technology portfolio selected under the DSI scenario is associated with lower operational water requirements in the most demand-intensive subsystem.

From a systemic standpoint, the DSI results indicate that regionalisation is not merely an ex post spatial description, but a component of the optimisation process shaped by stringent decarbonisation constraints, regional resource availability, environmental externalities and employment-related social valuation. The resulting solution presents a more geographically diversified low-carbon expansion pathway, in which renewable generation and employment effects are distributed across several regions while annual system adequacy is maintained. Carbon intensity declines to a residual level, and the associated socioeconomic effects become more territorially distributed..

The DSI pathway illustrates that the simultaneous pursuit of decarbonisation and social inclusion can operate as a powerful lever for sustainable regional transformation. Unlike scenarios driven predominantly by private costs or isolated environmental constraints, DSI produces a broader regional allocation of low-carbon investment, generation capacity, employment opportunities and associated labour-income effects. The result is a Southeast/Central-West subsystem with a lower dependence on fossil thermal generation and reduced operational water requirements, together with a renewable-intensive Northeast that assumes a greater role in national electricity supply. Among the simulated configurations, DSI presents one of the strongest combinations of territorial distribution, deep decarbonisation and socioeconomic convergence, representing a highly integrated pathway within the SEGeP framework. The DSI scenario captures the interaction between environmental and social objectives within the optimisation framework. By simultaneously incorporating constraints and parameters related to emissions, environmental externalities and employment-related social benefits, the model generates a more balanced expansion pathway, reflecting the potential for integrated policy approaches. Key findings of the scenario:

(i) The combined consideration of environmental and social parameters leads to a more balanced expansion pathway across sustainability dimensions;

(ii) The model captures synergies between decarbonisation and regional development, particularly in areas with renewable potential;

(iii) The resulting configuration reflects trade-offs and synergies between system cost, emissions, environmental externalities and employment-related social outcomes;

(iv) The scenario demonstrates the potential for integrated policy approaches to achieve multiple sustainability objectives simultaneously.

5.11 – Scenario 8: Energy Stress (ES)

The ES scenario constitutes the eighth policy configuration analysed within the SEGeP framework and represents a clear departure from the expansion pathways examined in the preceding scenarios. Whereas WSC, LCE, MEC and DSI are shaped by distinct sustainability-oriented mechanisms—including water-scarcity constraints, stringent decarbonisation targets, employment-related social valuation and regional differentiation—the ES configuration combines a set of adverse structural conditions: reduced hydropower reliability, accelerated electricity-demand growth, transmission bottlenecks and tighter adequacy margins. The scenario is therefore designed to assess the response of the Brazilian electricity system under sustained stress, when maintaining supply security, sufficient firm capacity and overall system adequacy becomes the principal driver of generation-expansion decisions. In contrast to DSI and MEC—where stringent decarbonisation constraints and employment-related social valuation reshape the objective function—the ES scenario reconfigures the optimisation landscape by assigning structural economic value to firmness, dispatchability and regional adequacy. It simulates a scarcity-constrained trajectory toward 2050, in which hydrological volatility and load expansion challenge the historical balancing role of large reservoirs within the SIN. The central analytical question is not the minimisation of emissions or cost per se, but whether the system can maintain reliability standards when traditional flexibility anchors weaken.

Within this configuration, adequacy indicators are strengthened and the economic penalty associated with unserved energy is significantly increased in the Total Social Cost structure. Firm capacity, rapid-response dispatch and regional self-sufficiency acquire elevated shadow prices within the MILP solution space. This adjustment reflects the "security-first" paradigm discussed in contemporary energy security literature (IEA, 2023), whereby resilience to climate-driven hydrological shifts competes directly with decarbonisation and social objectives.

The ES scenario is characterised by a set of coordinated structural assumptions. Hydropower availability coefficients are reduced, simulating a persistent dry-bias climate trajectory consistent with recent hydrological observations and climate risk assessments (ONS, 2024). Demand growth is accelerated to stress-test reserve margins under intensified electrification and industrial expansion. Transmission expansion is restricted, introducing realistic implementation bottlenecks that prevent the system from fully exploiting geographically distant renewable frontiers. Simultaneously, the model increases the valuation of firm capacity services, effectively rewarding technologies capable of providing continuous dispatch independent of meteorological conditions.

A defining feature of the ES configuration is the endogenous internalisation of the Scarcity Opportunity Cost. Under conventional least-cost logic, variable renewables appear structurally superior due to low marginal operating costs. However, when adequacy constraints tighten and hydrological buffering capacity weakens, the inability of wind and solar to guarantee peak-hour firmness becomes economically material. Within the SEGeP optimisation, this translates into higher relative competitiveness for technologies that provide availability certainty and geographical proximity to demand centres, such as flexible natural gas units or biomass plants with storage capability. These technologies gain structural relevance despite their comparatively higher emission intensity or operational cost.

From a modelling standpoint, the ES scenario introduces a dynamic interaction between climate risk and technology selection. Rather than pursuing the lowest-carbon equilibrium, the solution reallocates investment toward assets that maintain Loss of Load Probability (LOLP) within acceptable safety margins. This produces a more conservative regional allocation of capacity, particularly in high-demand subsystems such as the Southeast/Central-West, where industrial load density amplifies adequacy risk.

The regional architecture of SEGeP is fully preserved. Energy stress does not manifest uniformly across the territory; its intensity correlates with demand concentration, hydrological exposure and transmission dependence. The ES scenario therefore enables the evaluation of how multiple stressors—hydrological, infrastructural and demand-driven—reshape the spatial logic of expansion. It quantifies the extent to which Brazil's power system can absorb compounded uncertainty without triggering structural instability or disproportionate cost escalation.

The ES configuration represents a resilience-maximising equilibrium. It tests the hypothesis that ensuring long-term energy security under climatic and infrastructural uncertainty may require a transitional reliance on dispatchable and regionally anchored technologies that diverge from pure decarbonisation pathways. By elevating system firmness within the objective function, the scenario redefines the technological frontier of expansion planning under uncertainty, exposing the trade-offs between environmental stringency and operational robustness.

5.11.1 Input Data Structure (ES)

The ES scenario constitutes the most reliability-constrained configuration within the SEGeP framework. It was designed as a systemic stress-test to evaluate how the Brazilian electricity system behaves under cumulative structural pressures, including accelerated demand growth, hydrological uncertainty, transmission bottlenecks and tightened adequacy requirements. Unlike the WSC and DSI scenarios, which explore ambitious decarbonisation, or the EO scenario, which isolates private cost minimisation, the ES configuration assumes

a deteriorated operational environment in which security of supply becomes the dominant binding constraint of the optimisation process.

In this scenario, the system is subjected to a high electrification trajectory, with annual demand growth increasing from 1.8% to 3.5% per annum, resulting in total electricity demand reaching 1,270 TWh in 2050. This adjustment reflects accelerated electrification of transport, industrial processes and digital infrastructure, consistent with long-term projections of deep electrification pathways (EPE, 2023b; IEA, 2023). Simultaneously, hydropower potential is reduced by 10%, reflecting increased hydrological volatility and reservoir uncertainty under climate change conditions (IPCC, 2023; ONS, 2024). Transmission expansion is restricted, simulating licensing delays and grid reinforcement bottlenecks observed in national expansion planning (ONS, 2023).

Thermal flexibility is elevated to very high levels, and the load-shedding penalty is increased to extreme values. This adjustment is grounded in empirical evidence from past Brazilian hydrological crises, where dispatchable thermal generation played a central role in maintaining system adequacy (ONS, 2022). The extreme load-shedding penalty is justified by the economic literature on the Value of Lost Load (VoLL), which demonstrates that the social cost of electricity deficits far exceeds average generation costs (IEA, 2022a). Renewable penetration targets are moderated to 80–85%, reflecting the prioritisation of security over maximum decarbonisation under stress conditions. The carbon price remains moderate (€40–65/tCO_2), ensuring consistency with national climate commitments while avoiding excessive penalisation of firm thermal resources required for reliability (World Bank, 2023). Table 5.86 presents the parameters modified in the ES scenario.

Table 5.86 - Parameters modified in the ES scenario

Parameter	BAU	WSC	DSI	ES	Rationale
Demand growth (2030–2050)	1.8% p.a.	1.8%	1.8%	3.5% p.a.	Accelerated electrification and industrial expansion (EPE, 2023c; IEA, 2023)
Total demand in 2050	1,040 TWh	1,040 TWh	1,040 TWh	1,270 TWh	Structural pressure on supply adequacy
Thermal flexibility	Moderate	High	Low	Very high	Reliability under hydrological stress (ONS, 2022)
Load-shedding penalty	Moderate	High	High	Extreme	High social cost of outages (IEA, 2022b)
Transmission expansion limit	Moderate	Restricted	Expanded	Restricted	Grid bottlenecks and licensing delays (ONS, 2023)
Hydropower potential	Stable	Reduced	Stable	−10%	Increased hydrological volatility (IPCC, 2023; ONS, 2024)
Renewable targets	80–90%	>90%	95–99%	80–85%	Security prioritised over maximum decarbonisation
Carbon price	€30–60/t	€30–60/t	€150–200/t	€40–65/t	Moderate climate ambition under stress (World Bank, 2023)

Source: Author's elaboration based on SEGeP modelling assumptions.

The combined effect of these adjustments transforms the ES scenario into the most adequacy-driven configuration in the thesis. The increased demand trajectory tightens reserve margins, the reduction in hydropower availability weakens the historical backbone of the SIN, and the transmission constraint forces greater regional self-sufficiency. The optimisation therefore reallocates investment toward dispatchable and locally available firm capacity, even when this entails higher operational emissions or elevated system costs.

The ES configuration thus provides a structured assessment of systemic resilience. It quantifies the trade-offs required to preserve adequacy under simultaneous demand acceleration, hydrological deterioration and infrastructure constraints. Rather than representing a normative pathway, the ES scenario functions as a stress benchmark, revealing the economic, environmental and territorial implications of prioritising energy security under extreme operating conditions.

5.11.2 Results of the Optimal Generation Mix (ES)

The generation mix under the ES scenario is structurally shaped by the imperative of maintaining adequacy under accelerated demand growth and constrained hydrological availability. By 2050, total electricity demand reaches 1,270 TWh, reflecting the high-growth trajectory embedded in the stress configuration. Simultaneously, the 10% reduction in effective hydropower potential weakens the traditional balancing backbone of the SIN, compelling the optimisation to reallocate dispatch responsibility toward thermal technologies capable of ensuring firm capacity.

Table 5.87 presents the optimal generation mix by technology across the three planning horizons.

Table 5.87 - Optimal generation by technology in the ES scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Oil/Diesel	Other	Total
2030	410.0	160.0	140.0	85.0	95.0	15.0	15.0	920.0
2040	400.0	210.0	185.0	100.0	140.0	25.0	20.0	1,080.0
2050	395.0	250.0	230.0	115.0	220.0	35.0	25.0	1,270.0

Source: Author's elaboration.

Hydropower generation stabilises at 395 TWh in 2050, well below the levels observed in WSC, DSI or BAU scenarios. This contraction provides evidence that hydro ceases to function as the dominant volumetric and balancing resource under stress conditions. Reduced availability coefficients limit reservoir dispatch flexibility, forcing the system to compensate through alternative firm technologies.

Natural gas emerges as the principal adjustment mechanism. Generation from gas-fired plants increases from 95 TWh in 2030 to 220 TWh in 2050—more than doubling over the planning horizon. This expansion reflects the endogenous valuation of dispatchability within the MILP framework. Under tightened

adequacy constraints and elevated load-shedding penalties, the model assigns higher shadow value to technologies capable of guaranteeing output during peak demand and low-renewable periods.

Oil/Diesel generation, although smaller in absolute terms, also rises from 15 TWh to 35 TWh by 2050. This indicates that under extreme stress, the system tolerates higher short-run marginal costs and emission intensity to prevent supply deficits. The presence of liquid-fuel generation highlights the severity of the adequacy constraint embedded in the ES configuration.

Wind and solar continue to expand, reaching 250 TWh and 230 TWh respectively in 2050. However, their growth is structurally constrained by the requirement for firm backup. Unlike in the DSI and LCE scenarios, where stringent decarbonisation constraints and the expansion of low-carbon technologies substantially reduce fossil generation, the ES pathway treats the variability of wind and solar generation as a more restrictive system condition when hydropower availability is weakened. Consequently, VRE penetration remains significant but not dominant.

Biomass increases steadily to 115 TWh in 2050, reinforcing its dual role as a renewable yet dispatchable resource. Its expansion reflects the optimisation's search for low-carbon firmness, partially mitigating the increased reliance on fossil fuels.

From a structural perspective, the ES generation mix reveals a reliability-driven equilibrium. Total thermal generation (natural gas + oil/diesel) reaches 255 TWh in 2050, representing approximately 20% of total output—substantially higher than in decarbonisation-oriented configurations. The system therefore internalises a "security premium," accepting higher emissions and operating costs to preserve reserve margins under elevated demand and reduced hydro availability.

The ES configuration demonstrates that under compounded stress—high load growth, constrained transmission and hydrological volatility—the Brazilian electricity system shifts toward a hybrid structure: moderate renewable expansion combined with reinforced thermal dispatch. This provides evidence that reliability constraints fundamentally reshape technology selection within the SEGeP optimisation framework, redefining the feasible frontier between decarbonisation and adequacy.

5.11.3 Regional Disaggregation of Generation and Capacity (ES)

The regional allocation of generation in the ES scenario reflects the structural reconfiguration imposed by accelerated demand growth, reduced hydropower availability and constrained transmission expansion. Unlike decarbonisation-oriented configurations, the ES pathway reinforces proximity to load as a dominant investment criterion within the optimisation. Table 5.88 presents the regional evolution of electricity generation between 2030 and 2050.

Table 5.88 - Electricity generation by region in ES (TWh).

Region	2030	2040	2050
North	135.0	150.0	165.0
Northeast	210.0	280.0	335.0
SE / Central-West	475.0	550.0	660.0
South	100.0	100.0	110.0
Total SIN	920.0	1,080.0	1,270.0

Source: Author's elaboration.

By 2050, total generation reaches 1,270 TWh, consistent with the high-demand stress trajectory embedded in the ES configuration. The most pronounced structural shift occurs in the Southeast/Central-West (SE/CW), where generation expands from 475 TWh in 2030 to 660 TWh in 2050—an increase of 185 TWh (+39%). This subsystem alone accounts for 52% of national generation by the end of the planning horizon.

This concentration is not driven by superior renewable resources, but by the model's endogenous response to transmission constraints and elevated adequacy penalties. Under restricted inter-regional expansion, the optimisation assigns a high shadow value to local firm generation in load-dense regions. The SE/CW therefore absorbs the majority of additional thermal dispatch, particularly natural gas and oil/diesel units, to mitigate the risk of supply deficits in the country's principal industrial and urban hub.

The Northeast exhibits significant expansion, increasing from 210 TWh to 335 TWh (+125 TWh). Its strong wind and solar potential continue to support growth even under stress conditions. However, unlike in WSC or DSI scenarios, the Northeast does not become the dominant exporter of the SIN. Transmission bottlenecks and the heightened valuation of regional self-sufficiency limit the system's ability to fully exploit long-distance renewable transfers during peak demand events.

The North grows moderately, from 135 TWh to 165 TWh, reflecting constrained hydropower expansion under reduced availability coefficients. The South remains relatively stable, increasing marginally to 110 TWh in 2050, primarily through incremental firm additions rather than large-scale structural expansion.

From a regionalisation perspective, the ES scenario reveals a partial re-centralisation of generation toward demand-heavy regions. The optimisation framework internalises the systemic risk associated with spatial dependence on distant renewable frontiers. As a result, regional generation profiles become more conservative, privileging local dispatchability over geographical diversification.

This configuration demonstrates that under cumulative stress—high demand growth, hydrological uncertainty and infrastructure constraints—the Brazilian power system shifts toward a load-centric adequacy model. The territorial distribution of generation becomes increasingly aligned with consumption density rather than pure resource endowment, illustrating how reliability constraints reshape the spatial logic of long-term expansion planning within the SEGeP framework.

Table 5.88 presents the optimal generation mix by technology under the Energy Stress (ES) scenario across the three planning horizons. The table synthesises the endogenous response of the SEGeP optimisation to accelerated demand growth, reduced hydropower availability and heightened adequacy penalties. The distribution of generation across dispatchable and variable technologies reveals how the model reallocates volumetric and firm supply responsibilities in order to maintain system reliability under cumulative stress conditions.

Table 5.89 provides evidence that the ES scenario generates a water-security tension: the system stabilises adequacy by expanding dispatchable thermal and biomass capacity, but this response systematically increases consumptive water use in precisely the subsystem (SE/CW) where demand density and operational criticality are highest. This outcome reinforces the thesis' central claim that regionalisation is not neutral: under stress, the optimisation shifts from resource-frontier logic to load-centric adequacy, and the environmental burden (here, water) follows the same territorial direction.

Table 5.89 - Water consumption by region in ES (million m³).

Year	Region	Hydro	Biomass	Nat. Gas	Others*	Total
2030	North	215.0	1.8	1.5	0.5	218.8
	Northeast	20.0	3.5	2.8	0.2	26.5
	SE / CW	480.0	45.0	30.2	23.5	578.7
	South	105.0	13.5	3.5	1.3	123.3
	Total	820.0	63.8	38.0	25.5	947.3
2040	North	210.0	2.2	3.0	0.8	216.0
	Northeast	18.0	5.0	6.5	0.5	30.0
	SE / CW	475.0	55.0	45.0	30.0	605.0
	South	102.0	14.0	6.0	2.5	124.5
	Total	805.0	76.2	60.5	33.8	975.5
2050	North	205.0	2.5	4.5	1.2	213.2
	Northeast	15.0	6.5	10.5	0.8	32.8
	SE / CW	470.0	62.5	65.0	35.5	633.0
	South	100.0	14.7	8.0	3.3	126.0
	Total	790.0	86.2	88.0	40.8	1,005.0

Source: Author's elaboration.

The water consumption profile of the ES scenario provides evidence that reliability-driven expansion produces a water-intensive adequacy footprint, concentrated in the Southeast/Central-West subsystem. Total water consumption increases from 947.3 million m³ in 2030 to 1,005.0 million m³ in 2050, despite the slight reduction in hydropower-related consumption (from 820.0 to 790.0 million m³). The driver of this increase is the structural shift toward dispatchable thermal generation and biomass-based firmness, which introduces additional consumptive water requirements associated with cooling processes and fuel-chain operations.

Spatially, the SE/Central-West emerges as the dominant locus of water demand. In 2030, the subsystem already accounts for 578.7 million m³ (61% of total water consumption), rising to 633.0 million m³ by 2050 (63%). This concentration is not accidental: under the ES configuration, inter-regional transmission expansion is restricted, and the adequacy penalty is heightened, forcing the optimisation to internalise *local firmness* near the main load centres. As a result, gas dispatch expands precisely where the load is densest, and because thermal cooling requirements scale with dispatch, the water burden becomes territorially concentrated.

A second structural feature is the growth of biomass water use, which rises from 63.8 million m³ in 2030 to 86.2 million m³ in 2050. This pattern indicates that the optimisation partially substitutes hydrological firmness (reservoir flexibility) with productive firmness, i.e., dispatchable renewables capable of stabilising the system during peak stress periods. Although biomass improves adequacy, it introduces an additional water footprint that becomes increasingly relevant under stress conditions.

The Northeast remains relatively water-light in hydro terms (20.0 to 15.0 million m³), but its natural gas water use increases substantially (2.8 to 10.5 million m³). This reflects the ES mechanism of regional self-sufficiency: even a renewable-rich subsystem requires local thermal capability when transmission constraints prevent full reliance on exported surplus during peak hours.

Table 5.90 presents the regional evolution of CO_2 emissions under the Energy Stress (ES) scenario. Given that the ES configuration prioritises adequacy over decarbonisation, the carbon trajectory reflects the structural expansion of dispatchable thermal technologies required to guarantee system firmness.

Table 5.90 - CO_2 emissions by region in ES ($MtCO_2$).

Year	North	Northeast	SE / CW	South	Total SIN
2030	4.2	2.5	32.0	1.8	40.5
2040	6.8	4.5	40.5	2.2	54.0
2050	9.0	6.0	58.9	5.0	78.9

Source: Author's elaboration.

Total CO_2 emissions increase from 40.5 Mt in 2030 to 78.9 Mt in 2050, nearly doubling over the planning horizon. Under the ES configuration, the carbon price remains moderate and does not override adequacy constraints; therefore, the optimisation internalises reliability more strongly than emission reduction.

Spatially, emissions become increasingly concentrated in the Southeast/Central-West subsystem. By 2050, the SE/CW accounts for 58.9 $MtCO_2$, representing approximately 75% of total national emissions. This reflects the load-centric reallocation of dispatchable capacity under transmission constraints. The subsystem absorbs the majority of additional thermal generation because proximity to industrial demand reduces adequacy risk.

The Northeast also experiences a moderate increase in emissions (6.0 $MtCO_2$ in 2050), reflecting regional self-sufficiency requirements. Even renewable-rich subsystems must retain local firm backup when transmission expansion is restricted. The North and South follow similar patterns, though at smaller absolute scales.

5.11.4 Social Effects (ES)

Table 5.91 presents the evolution of equivalent annual employment under the ES configuration. Although the ES scenario entails a substantial expansion of installed capacity to ensure system adequacy under accelerated demand growth, its employment performance remains structurally constrained by the technology mix selected by the optimisation. Unlike DSI or MEC—where labour intensity is actively internalised as a value-generating component of the objective function—the ES pathway prioritises firmness and reliability, leading to a comparatively lower labour multiplier.

Table 5.91 - Equivalent annual employment by region in ES (thousand jobs/year).

Region	2030	2040	2050
North	28.0	34.0	40.0
Northeast	75.0	95.0	110.0
SE / Central-West	87.0	108.0	132.0
South	20.0	23.0	28.0
Total SIN	210.0	260.0	310.0

Source: Author's elaboration.

By 2050, total employment reaches 310 thousand jobs per year. This represents an increase of 100 thousand jobs relative to 2030, reflecting the cumulative expansion of capacity required to supply 1,270 TWh under stress conditions. However, when compared to the DSI scenario (460 thousand jobs) or MEC (430 thousand jobs), the employment performance of ES is markedly lower.

The structural explanation lies in the generation portfolio. The ES scenario exhibits a strong reliance on dispatchable thermal technologies—particularly natural gas and oil/diesel—to guarantee firmness under constrained hydrological and transmission conditions. These technologies have significantly lower employment multipliers (approximately 0.25 jobs/GWh for gas).

From a regional perspective, the Southeast/Central-West absorbs the largest share of employment by 2050 (132 thousand jobs), consistent with its dominant generation role (660 TWh). However, this employment is more capital-intensive and concentrated in large-scale thermal and grid-support infrastructure, resulting in lower indirect job diffusion compared to decentralised renewable projects.

The Northeast reaches 110 thousand jobs by 2050, reflecting continued expansion of wind and solar capacity. Nevertheless, the region's employment gains are structurally limited by transmission bottlenecks and

the prioritisation of local firmness in SE/CW. Unlike in WSC or DSI configurations—where the Northeast becomes a structural exporter of renewable surplus—the ES scenario constrains the regional employment spillover effect.

The North and South exhibit moderate growth, primarily linked to incremental firm capacity additions rather than large-scale renewable deployment. This reinforces the interpretation that ES represents a reliability-driven equilibrium rather than a socially maximising one.

The ES employment outcome illustrates a key trade-off within the SEGeP framework: ensuring adequacy under cumulative stress conditions requires a generation mix with lower labour intensity. While total employment grows in absolute terms the opportunity cost relative to decarbonisation- and employment-oriented pathways becomes evident. The ES configuration therefore provides evidence that energy security and social maximisation do not necessarily align when dispatchability constraints dominate technology selection.

Table 5.92 presents the regional evolution of nitrogen oxides (NO_x) and sulphur dioxide (SO_2) emissions under the ES configuration. These pollutants are directly associated with the intensified dispatch of combustion-based technologies, particularly natural gas and oil/diesel units, which expand structurally in this scenario to ensure supply adequacy under hydrological and transmission constraints.

Table 5.92 - NO_x and SO_2 emissions by region in ES (kt).

Year	Region	NO_x (kt)	SO_2 (kt)
2030	North	8.5	2.1
	Northeast	5.2	1.3
	SE / CW	65.0	15.8
	South	3.6	0.9
	Total SIN	82.3	20.1
2040	North	13.8	3.4
	Northeast	9.1	2.2
	SE / CW	82.3	20.2
	South	4.4	1.1
	Total SIN	109.6	26.9
2050	North	18.2	4.5
	Northeast	12.1	3.0
	SE / CW	119.5	29.4
	South	10.1	2.5
	Total SIN	159.9	39.4

Source: Author's elaboration.

The NO_x emissions increase from 82.3 kt in 2030 to 159.9 kt in 2050, while SO_2 emissions nearly double, rising from 20.1 kt to 39.4 kt. This trajectory reflects the structural reinforcement of firm thermal generation required to maintain reserve margins and avoid load shedding under stress conditions.

Spatially, the Southeast/Central-West subsystem concentrates the majority of local pollutants throughout the planning horizon. By 2050, the region accounts for 119.5 kt of NO_x and 29.4 kt of SO_2, corresponding to approximately 75% of total national emissions of both pollutants. This concentration is consistent with the regional load structure and the expansion of dispatchable thermal capacity near major demand centres.

The North and Northeast also show progressive increases, particularly after 2040, as regional self-sufficiency constraints limit reliance on interregional transfers and require local backup generation. The South exhibits moderate growth, mainly associated with incremental oil/diesel dispatch during peak stress conditions.

The socio-economic convergence observed in the ES scenario is the slowest among all alternative configurations analysed in this thesis. As reliability becomes the dominant optimisation driver, investment decisions concentrate on large-scale, dispatchable thermal assets located primarily in load-intensive regions, particularly the Southeast/Central-West. This spatial concentration structurally limits the redistributive potential of the electricity sector and reduces the territorial spillovers typically associated with decentralised renewable expansion.

Table 5.93 - Regional Gini Index evolution in Scenario ES.

Region	2030	2040	2050
North	0.535	0.530	0.525
Northeast	0.545	0.540	0.530
SE / Central-West	0.495	0.490	0.485
South	0.465	0.460	0.455

Source: Author's elaboration.

The Northeast reduces its Gini index from 0.545 in 2030 to 0.530 in 2050 — a 0.015-point improvement — significantly smaller than the reductions observed in the DSI or MEC scenarios. The North follows a similar pattern, with a limited decline of 0.010 points over the twenty-year horizon.

In contrast to the DSI scenario, which explicitly values employment-related social benefits and broader regional inclusion, the ES pathway prioritises system resilience under conditions of scarcity and heightened demand. Capital is therefore directed mainly towards firm capacity expansion and reliability-oriented infrastructure in regions with greater industrial density and electricity demand. The Southeast/Central-West, despite experiencing a modest reduction in inequality from 0.495 to 0.485, continues to concentrate the largest share of infrastructure investment and associated income flows, thereby preserving important elements of Brazil's historical regional asymmetry.

The results of Table 5.93 confirm that when reliability and adequacy dominate the objective function, socio-economic convergence becomes a residual outcome rather than a strategic objective. Under stress conditions, the electricity sector functions primarily as a stability provider rather than a territorial equalisation instrument. This finding reinforces the central thesis of this work: regional equity within the Brazilian electricity system requires explicit internalisation of socio-economic externalities — it does not emerge automatically from security-driven planning logics.

The evolution of the Human Development Index (HDI) under the Energy Stress (ES) configuration is presented in Table 5.94. This indicator captures the multidimensional implications of the "security-first" pathway, reflecting the balance between increased energy availability—driven by accelerated capacity expansion—and the negative externalities associated with a more thermal-intensive generation mix.

Table 5.94 - Regional HDI evolution in Scenario ES.

Region	2030	2040	2050
North	0.730	0.750	0.775
Northeast	0.720	0.745	0.765
SE / Central-West	0.800	0.815	0.835
South	0.815	0.830	0.850

Source: Author's elaboration.

The results indicate a gradual improvement in all regions between 2030 and 2050. However, the pace of convergence remains more moderate when compared to the DSI or MEC scenarios. In the North, the HDI rises from 0.730 to 0.775, reflecting the positive macroeconomic effect of higher electricity availability and infrastructure investment. Similarly, the Northeast improves from 0.720 to 0.765 yet remains structurally below the national frontier due to the concentration of large-scale thermal investments in the Southeast/Central-West and the relatively lower diffusion of labour-intensive renewable supply chains.

The Southeast/Central-West and the South maintain their leadership in human development, reaching 0.835 and 0.850 respectively by 2050. These improvements are associated with increased industrial activity, grid reinforcement, and local generation adequacy. Nevertheless, the qualitative dimension of development under ES differs from sustainability-led pathways: the gains in income and energy access are partially offset by higher exposure to environmental burdens, including elevated CO_2 emissions, local pollutants, and water consumption.

Table 5.94 provides evidence that the ES scenario delivers quantitative improvements in human development indicators, but with a lower structural transformation of territorial inequalities. The HDI gap

between the Northeast and the South narrows only marginally (from 0.095 in 2030 to 0.085 in 2050), demonstrating that a resilience-oriented expansion, although effective in ensuring supply security, is less capable of promoting deep socio-economic convergence than scenarios explicitly designed to internalise social and environmental externalities.

The macroeconomic performance of the ES scenario is summarised in Table 5.95. These indicators reflect the elevated financial and social burden associated with maintaining system reliability under cumulative structural stressors, namely accelerated demand growth, reduced hydropower availability and transmission constraints.

Table 5.95 - System economic indicators in ES.

Metric	2030	2040	2050
Total system cost (NPV, € billion)	340.0	425.0	510.5
Average Social Cost (€/MWh)	58.0	61.0	65.0

Source: Author's elaboration.

The ES scenario reaches a NPV of €510.5 billion in 2050, representing the highest aggregate expenditure among all configurations within the SEGeP framework. This escalation in total system cost is structurally linked to three reinforcing mechanisms:

1. The expansion of dispatchable thermal capacity (natural gas and oil/diesel) to guarantee adequacy under reduced hydrological potential;
2. The duplication of reserve margins required to compensate for constrained interregional transmission;
3. The elevated economic valuation of reliability through intensified load-shedding penalties.

Unlike scenarios primarily oriented towards decarbonisation or social inclusion, ES internalises the costs associated with systemic vulnerability. The optimisation therefore allocates capital not solely to minimise direct costs or maximise socioeconomic benefits, but to reduce exposure to supply disruptions under conditions of scarcity and heightened system stress.

The Average Social Cost, which incorporates monetised externalities related to CO_2, NO_x, SO_2 and water stress, increases from €58.0/MWh in 2030 to €65.0/MWh in 2050. This upward trajectory distinguishes ES from MEC, LCE and DSI, where social cost progressively declines due to technological maturation and reduced emissions intensity. In ES, however, the persistence of fossil-based dispatch and intensified water use generates a structural "security premium."

This premium reflects the systemic trade-off embedded in the ES configuration: avoiding load-shedding under extreme stress conditions requires accepting higher externalities and greater capital intensity.

Consequently, the ES pathway represents not only the most expensive equilibrium in financial terms, but also the configuration with the highest long-term social burden per unit of electricity supplied.

From an analytical standpoint, these results confirm that resilience maximisation under scarcity is economically and socially costly. The ES scenario quantifies the magnitude of this burden and highlights the importance of preventive structural investments — in flexibility, diversification and transmission robustness — to avoid a future where reliability is achieved at the expense of sustainability and regional balance.

5.11.5 Analytical Discussion: The Structural Role of Regionalisation – ES

The Energy Stress (ES) scenario reveals the most structurally constrained configuration within the SEGeP framework. Unlike MEC or DSI, where regionalisation operates as a strategic instrument for social or environmental optimisation, in ES it emerges as a reactive mechanism imposed by systemic scarcity. Regionalisation in this context is not policy-driven but constraint-driven: hydrological reduction (−10%), transmission bottlenecks, and accelerated demand growth (reaching 1,270 TWh in 2050) fundamentally reshape the spatial logic of expansion.

The first structural inflection occurs in the Southeast/Central-West (SE/CW). As shown in Table 5.82, regional generation increases from 475 TWh (2030) to 660 TWh (2050), representing more than 52% of total SIN output by the end of the horizon. This concentration is not the result of superior renewable resources but of proximity to load centres combined with restricted interregional transmission. Under ES, the model assigns a higher implicit value to local firmness than to distant renewable abundance. Consequently, the SE/CW absorbs the majority of additional thermal dispatch, particularly natural gas (220 TWh in 2050) and oil/diesel (35 TWh).

This shift has direct environmental consequences. CO_2 emissions reach 78.9 $MtCO_2$ in 2050, with the SE/CW alone accounting for 58.9 $MtCO_2$ — approximately 75% of total system emissions. The regionalisation of emissions thus mirrors the regionalisation of firmness. The same pattern is observed in local pollutants, where SE/CW NO_x emissions rise to 119.5 kt and SO_2 to 29.4 kt in 2050, reflecting the concentration of dispatchable thermal generation in the industrial core of the country.

The Northeast (NE) presents a contrasting dynamic. While its generation expands from 210 TWh in 2030 to 335 TWh in 2050, this growth is insufficient to offset the structural dominance of the SE/CW. Transmission restrictions prevent the full monetisation of its renewable potential. Unlike in DSI, where stringent decarbonisation constraints, favourable wind and solar resources and employment-related social valuation allow the Northeast to assume a stronger role as a supplier of electricity to the national system, in ES its expansion is partially decoupled from national adequacy needs. The region therefore experiences moderate

employment growth (110 thousand jobs in 2050), but without the strong distributive effect observed in social-oriented scenarios.

Water use patterns reinforce this territorial asymmetry. Total water consumption increases to 1,005 million m^3 in 2050, with the SE/CW responsible for 633 million m^3 — nearly 63% of national demand. Although hydropower consumption declines gradually, the expansion of biomass and gas cooling requirements compensates for this reduction. The ES configuration therefore produces a hydrological concentration effect, intensifying resource pressure in already demand-dense territories.

From a socio-economic perspective, convergence slows significantly. The Gini Index declines only marginally in the Northeast (from 0.545 in 2030 to 0.530 in 2050), while the HDI reaches 0.765, remaining below the levels achieved in DSI or MEC. The employment total of 310 thousand jobs in 2050 provides evidence that reliability-oriented expansion is less labour-intensive than decentralised renewable or efficiency-driven pathways.

The structural role of regionalisation in ES can therefore be summarised in three mechanisms:

1. Localisation of Firmness – Regions with high demand density internalise the burden of thermal expansion due to transmission constraints.
2. Partial Renewable Containment – Resource-rich regions (North and Northeast) expand, but below their technical potential.
3. Concentration of Externalities – Emissions, water use, and pollutant intensity become territorially concentrated rather than spatially diversified.

In systemic terms, ES represents a resilience-maximising but convergence-limiting equilibrium. The optimisation reallocates investment toward technologies and regions capable of maintaining adequacy under stress, even at the cost of higher emissions and resource intensity. Regionalisation under ES thus becomes an instrument of operational survival rather than socio-environmental transformation.

This outcome reinforces a central thesis of the SEGeP model: when scarcity and infrastructure constraints dominate the optimisation landscape, the geographical distribution of investment shifts from equity-driven dispersion to reliability-driven concentration. The ES scenario quantifies the magnitude of this trade-off and demonstrates that long-term energy security, if pursued in isolation, may structurally re-entrench regional asymmetries within the Brazilian electricity sector.

The ES scenario reflects system behaviour under conditions of increased demand or constrained supply. The resulting expansion pathway highlights the importance of system resilience, as the model activates additional capacity to maintain supply adequacy, often at higher economic and environmental costs. Key findings of the scenario:

(i) Increased demand or system stress conditions lead to the activation of additional capacity, including higher-cost or less efficient technologies;

(ii) The scenario highlights the role of system resilience in expansion planning, particularly under constrained conditions;

(iii) Trade-offs between reliability and cost become more pronounced, reflecting the need for robust planning under uncertainty;

(iv) The results illustrate how stress conditions can alter optimal investment decisions and system configuration.

5.12 – Scenario 9: Low Regulatory Interference (LRI)

The Low Regulatory Interference (LRI) scenario constitutes the ninth configuration analysed within the SEGeP framework and functions as a structured market-oriented counterfactual. It represents an expansion pathway in which regulatory ambition is deliberately constrained, and investment decisions are predominantly guided by private economic efficiency, risk management and capital recovery criteria.

The theoretical foundation of this configuration is rooted in the classical literature on electricity market liberalisation and competitive least-cost investment behaviour. In environments characterised by limited regulatory intervention, generation expansion typically favours technologies with lower private Levelised Cost of Electricity (LCOE), predictable cash flows and proximity to demand centres (Borenstein & Bushnell, 2015). Under such institutional conditions, environmental and social externalities remain largely unpriced unless explicitly internalised through dedicated policy instruments.

Empirical assessments of restructured electricity markets show that, in the absence of escalating carbon pricing or binding renewable mandates, expansion patterns tend to privilege mature thermal technologies and incremental reinforcement of existing infrastructure (Borenstein & Bushnell, 2015). Moreover, as highlighted by Joskow (2011), private cost metrics can dominate investment decisions even when they fail to reflect broader system-level externalities. The LRI scenario operationalises this behavioural logic within the SEGeP modelling architecture.

The objective function retains the formal structure of the Total Social Cost formulation but assigns minimal strategic relevance to socio-environmental coefficients. The resulting equilibrium represents a financially efficient yet externally incomplete configuration consistent with regulatory minimalism.

Methodologically, LRI plays a central role in the comparative architecture of the thesis. It provides a necessary benchmark against which the structural effects of internalisation mechanisms embedded in LCE, MEC and DSI can be quantitatively evaluated. By holding macroeconomic growth and demand trajectories

constant while limiting regulatory directional signals, LRI allows the identification of the regulatory differential — the measurable divergence between market-led and policy-driven expansion pathways.

This configuration exposes the "Externalities Gap": the structural distance between private optimisation and socially optimised equilibria. In the absence of strong decarbonisation signals or regional incentives, expansion decisions tend to concentrate near established load centres, reinforce incumbent assets and underprovide long-term climate and distributive co-benefits. LRI thus does not aim to describe a desirable trajectory; it quantifies the opportunity cost of non-intervention.

5.12.1 Input Data Structure (LRI)

The LRI scenario preserves the full mathematical structure of the SEGeP mixed-integer linear programming (MILP) formulation but strategically restores most socio-environmental parameters to baseline institutional values. The purpose is not to eliminate regulation entirely, but to simulate a regime of regulatory minimalism in which expansion decisions are driven predominantly by private cost efficiency and system adequacy, rather than by progressive internalisation of externalities.

Table 5.96 summarises the principal parameter adjustments relative to sustainability-oriented configurations.

Table 5.96 - Parameters modified in the LRI scenario.

Parameter	BAU / EO	LRI	Technical Rationale & Sources
Demand Growth	1.8% p.a.	1.8% p.a.	Maintains macroeconomic consistency; isolates regulatory philosophy from structural demand shocks.
Carbon Price (€/tCO_2)	30	30	Maintains institutional baseline; avoids escalation consistent with weak climate policy regimes (IEA, 2022b).
Environmental Damage Costs	Active in LCE/MEC/DSI	Baseline monetisation only	Externalities partially priced but not strategically escalated.
Load-Shedding Penalty	Moderate	High	Reflects economic valuation of reliability and industrial continuity (Joskow, 2011).
Transmission Expansion	Standard	Least-Cost	Infrastructure built only when reducing private LCOE (Borenstein & Bushnell, 2015).
Internalisation Focus	Multidimensional	Private Cost Dominant	Objective function prioritises CAPEX, OPEX and fuel costs.

Source: Author's elaboration based on SEGeP modelling structure and classical electricity market literature.

The defining feature of the LRI input structure is the absence of strong policy direction. Unlike LCE or MEC, which embed explicit decarbonisation or regional convergence objectives, LRI retains only baseline regulatory parameters consistent with moderate institutional environments. Carbon pricing remains constant and non-escalatory, reflecting contexts in which climate policy influences dispatch margins but does not fundamentally reshape long-term investment signals (IEA, 2022b).

The near-zero social weighting ensures that employment multipliers and distributive effects do not drive technology selection. In competitive electricity markets, distributive outcomes typically emerge from relative cost structures rather than from optimisation criteria explicitly designed to reduce inequality (Green & Newbery, 1992). By maintaining only a residual coefficient, LRI reflects a market in which equity considerations are institutionally recognised but not operationalised within planning.

Transmission expansion follows strict cost-benefit logic. Inter-regional infrastructure is deployed only when it produces measurable reductions in system-level private costs. This assumption aligns with observed investment patterns in liberalised markets, where network reinforcement frequently lags behind generation development in the absence of coordinated planning (Borenstein & Bushnell, 2015).

Reliability, however, remains strongly valued. The high load-shedding penalty reflects the macroeconomic cost of supply interruptions, as emphasised in the Value-of-Lost-Load literature (Joskow, 2011). In this context, system adequacy is preserved not as a redistributive objective but as a productivity safeguard.

From a computational standpoint, the LRI scenario does not alter the structural constraints of the SEGeP model; it modifies the relative salience of objective function components. Environmental and social coefficients remain formally present but are not amplified. Flexibility and decentralisation incentives are not embedded as optimisation priorities. Consequently, the solution space exhibits:

- Preference for technologies with lower capital intensity and established infrastructure;
- Geographical concentration near demand centres;
- Limited decentralised renewable expansion beyond strict cost competitiveness;
- Persistence of infrastructure path dependency.

In contrast to sustainability-led configurations, LRI does not induce structural transformation of the electricity geography. It converges toward a financially efficient but territorially conservative equilibrium.

Therefore, the Input Data Structure of LRI does not represent the absence of planning; it represents planning under constrained regulatory ambition. It provides the necessary counterfactual baseline against which the structural contribution of socio-environmental internalisation can be rigorously demonstrated within the SEGeP framework.

5.12.2 Results of the Optimal Generation Mix (LRI)

The generation mix under the LRI configuration is determined predominantly by the least-private-cost principle. In the absence of progressive carbon pricing, binding renewable mandates, the SEGeP optimisation converges toward technologies characterised by mature supply chains, predictable capital recovery profiles

and compatibility with existing infrastructure. Consequently, the expansion pathway reflects incremental reinforcement rather than structural transformation of the electricity matrix.

By 2050, total generation reaches 1,040 TWh, consistent with the standard demand growth trajectory assumed across non-stress scenarios. However, the internal composition of this output diverges significantly from policy-driven configurations such as LCE, MEC or DSI, as shown in Table 5.97.

Table 5.97 - Optimal generation by technology in the LRI scenario (TWh).

Year	Hydro	Wind	Solar	Biomass	Natural Gas	Others	Total
2030	471	117	92	58	68	14	820
2040	477	142	128	71	89	23	930
2050	525	172	145	80	99	19	1,040

Source: Author's elaboration.

Hydropower remains the structural backbone of the system, increasing gradually to 525 TWh by 2050. In the absence of hydrological constraints or escalating carbon prices, the model continues to prioritise hydro dispatch due to its low marginal cost and amortised capital structure, reinforcing path dependency rather than technological diversification.

Wind and solar expand moderately, yet their penetration is limited to levels justified by private cost competitiveness. Without strong decarbonisation signals or flexibility incentives, their growth remains incremental rather than transformative. By 2050, combined wind and solar generation reaches 325 TWh, reflecting integration where economically rational but not strategically accelerated.

Natural gas displays a noticeable expansion, peaking at 68 TWh in 2040 before stabilising at 99 TWh in 2050. This pattern reflects the model's preference for dispatchable, capital-efficient technologies capable of guaranteeing reliability under a cost-minimisation regime. With carbon pricing fixed at baseline levels, gas retains structural competitiveness.

Biomass grows gradually but remains secondary. In the absence of regional development incentives, its labour intensity and territorial co-benefits do not influence optimisation. Expansion therefore occurs only where cost-effective.

Table 5.97 provides evidence that regulatory minimalism does not eliminate renewable deployment, but it significantly moderates the pace and depth of structural transformation. The resulting equilibrium is financially efficient under private metrics, yet comparatively slower in advancing decarbonisation, territorial diversification and systemic innovation.

5.12.3 Regional Disaggregation of Generation and Capacity (LRI)

The regional configuration under the LRI scenario follows a trajectory of economic inertia. In the absence of territorial incentives, regional social weights or strong decarbonisation signals, expansion decisions reflect infrastructure legacy, proximity to load centres and minimisation of integration costs. Consequently, spatial allocation is shaped less by resource frontier development and more by established economic geography.

Table 5.98 presents the regional distribution of electricity generation under the LRI configuration.

Table 5.98 - Electricity generation by region in LRI (TWh).

Region	2030	2040	2050
North	134	140	155.0
Northeast	160	194	235.0
SE / Central-West	439	507	550.0
South	87	89	100.0
Total SIN	820	930	1,040.0

Source: Author's elaboration.

The Southeast/Central-West (SE/CW) consolidates its dominance throughout the planning horizon, reaching 550 TWh in 2050. This outcome is not driven by superior renewable potential but by structural advantages: high demand density, existing thermal infrastructure and reduced transmission requirements. Under least-cost optimisation, the avoidance of long-distance transmission expansion reinforces this regional concentration.

The Northeast expands from 160 TWh in 2030 to 235 TWh in 2050, reflecting the competitiveness of wind and solar resources where cost-effective. However, without regional prioritisation or flexibility incentives, its expansion remains moderate relative to policy-driven scenarios. In LCE, DSI and MEC, the Northeast assumes a structural leadership role; under LRI, it becomes a complementary supplier rather than the primary growth frontier.

The North exhibits gradual growth, stabilising at 155 TWh by 2050. Hydropower assets continue to provide low-cost energy, but expansion is constrained by transmission economics and the absence of strong incentives for frontier development. The region does not experience the transformative investment surge observed in social or climate-oriented scenarios.

The South maintains a relatively stable profile, reaching 100 TWh in 2050. Its expansion reflects incremental reinforcement rather than structural reconfiguration, consistent with the absence of policy-driven diversification mechanisms.

The regional pattern provides evidence that, under regulatory minimalism, expansion tends to reinforce historical asymmetries. The SE/CW retains its centrality, while resource-rich frontier regions expand only to

the extent justified by strict private cost criteria. Unlike DSI or MEC, no territorial convergence mechanism emerges endogenously within the optimisation process.

In analytical terms, the LRI configuration illustrates that regional diversification is not an automatic outcome of renewable competitiveness. Without explicit policy direction, infrastructure inertia and integration costs shape the spatial equilibrium, resulting in a geographically concentrated and path-dependent expansion structure.

In addition to the regional allocation of generation, the installed capacity configuration provides a structural perspective on long-term capital deployment under regulatory minimalism. While generation levels reflect operational dispatch, installed capacity reveals the territorial architecture of investment and the embedded logic of reliability planning. Table 5.99 presents the regional evolution of installed capacity in the LRI scenario, illustrating how the least-private-cost principle materialises spatially within the Brazilian power system.

Table 5.99 - Installed capacity by region in LRI (GW).

Region	2030	2040	2050
North	30.0	31.5	32.5
Northeast	58.0	72.0	85.0
SE / Central-West	108.0	125.0	135.0
South	34.0	36.5	38.5
Total SIN	230.0	265.0	291.0

Source: Author's elaboration.

The capacity trajectory under LRI provides evidence the persistence of infrastructure inertia and cost-centred allocation dynamics.

First, hydropower consolidates its structural role as the backbone of system firmness. By 2050, hydro generation reaches 525 TWh, supported by incremental capacity optimisation and brownfield repowering. In a regulatory environment without escalating carbon pricing or redistributive incentives, hydropower remains attractive due to its low marginal operating cost and high dispatchability. Importantly, this expansion is not driven by climate ambition, but by financial robustness and asset longevity within a least-cost framework.

Second, natural gas maintains a significant balancing function, reaching 90 TWh in 2050. With carbon pricing fixed at €30/tCO_2, gas-fired generation remains economically viable relative to more capital-intensive low-carbon flexibility options, such as large-scale storage and additional transmission reinforcement. The optimisation therefore identifies natural gas as the most cost-efficient dispatchable resource for managing variability in wind and solar generation. This result indicates that, under moderate climate-policy signals, fossil-based flexibility may persist as a relevant system response to renewable intermittency.

Third, the regional distribution of installed capacity reveals a pronounced concentration in the Southeast/Central-West, which reaches 135 GW by 2050 — approximately 46% of total SIN capacity. This dominance reflects structural advantages: proximity to major industrial loads, established transmission corridors and lower integration risk. Unlike sustainability-oriented scenarios that embed convergence mechanisms, LRI allows expansion to follow pre-existing economic geography. Capital therefore gravitates toward mature infrastructure nodes rather than toward regions with developmental gaps.

Although the Northeast expands to 85 GW by 2050, primarily due to competitive wind resources, its growth remains constrained by market-driven integration thresholds. In the absence of targeted incentives, renewable deployment occurs only where it directly reduces private system costs, not where it maximises regional development outcomes.

Table 5.99 demonstrates that installed capacity under LRI embodies a territorially conservative equilibrium. The optimisation does not actively correct spatial asymmetries; instead, it reinforces historical investment patterns and economic centrality. The resulting configuration is financially coherent but regionally inert, illustrating that regulatory minimalism does not eliminate planning—it reorients planning toward capital efficiency and risk minimisation, with limited transformative capacity.

This structural outcome provides the necessary counterfactual to quantify the incremental value of socio-environmental internalisation observed in the LCE, MEC and DSI configurations.

The environmental performance of the LRI scenario reflects the structural consequences of a market-centred expansion pathway. In the absence of progressive carbon pricing, binding renewable targets, or strong socio-environmental weighting within the objective function, the optimisation converges toward a configuration driven primarily by private cost efficiency. As a result, the environmental trajectory under LRI is less ambitious than in sustainability-oriented scenarios such as MEC or DSI.

The defining characteristic of LRI is not the absence of regulation, but the absence of directional regulatory intensity. Carbon remains priced at a baseline institutional level (€30/tCO_2), which influences marginal dispatch but is insufficient to structurally displace fossil-based firm capacity. Consequently, the system maintains a higher reliance on natural gas and other thermal assets, particularly in load-concentrated regions. Table 5.100 presents the regional evolution of CO_2 emissions under the LRI configuration.

Table 5.100 - CO_2 emissions by region in LRI ($MtCO_2$).

Region	2030	2040	2050
North	3.5	4.8	5.2
Northeast	2.8	3.5	4.1
SE / Central-West	35.2	38.4	40.5
South	2.5	3.3	4.2
Total SIN	44.0	50.0	54.0

Source: Author's elaboration.

The total system emissions increase from 44.0 $MtCO_2$ in 2030 to 54.0 $MtCO_2$ in 2050, representing a cumulative upward trajectory rather than the declining pattern observed in LCE or DSI. This trend reflects the structural persistence of thermal generation within the least-private-cost equilibrium.

The Southeast/Central-West region concentrates the majority of emissions, reaching 40.5 $MtCO_2$ by 2050—approximately 75% of total system emissions. This concentration mirrors the regional allocation of gas-fired generation capacity and the proximity to major industrial load centres. The optimisation favours local thermal dispatch over long-distance renewable integration when transmission investments do not significantly reduce private LCOE.

The North and Northeast exhibit moderate but rising emission levels, associated primarily with balancing generation and residual fossil backup. Importantly, these increases are not driven by structural industrial expansion alone, but by the absence of incentives to accelerate renewable substitution beyond market competitiveness thresholds.

From a modelling standpoint, the LRI scenario demonstrates that baseline carbon pricing influences dispatch decisions but does not induce deep structural decarbonisation. The carbon cost signal is internalised, yet its magnitude is insufficient to alter long-term capacity composition decisively. The resulting equilibrium represents a carbon-constrained, but not carbon-driven, system.

Table 5.100 quantifies the "Decarbonisation Gap" between market-led and policy-guided pathways. While LRI achieves operational adequacy and moderate cost efficiency, it fails to deliver the emission reductions required for alignment with stringent climate objectives. This provides evidence that, within the SEGeP framework, deep decarbonisation is not an endogenous outcome of market forces alone—it requires explicit regulatory ambition embedded within the optimisation structure.

Under the Low Regulatory Interference (LRI) configuration, land occupation follows a strictly market-oriented logic. In the absence of strong regulatory signals for carbon internalisation, land-efficiency standards or regional development targets, expansion decisions are guided primarily by short-term financial viability and infrastructure availability. As a result, territorial allocation reflects economic inertia rather than spatial optimisation for sustainability.

Table 5.101 presents the regional and technological distribution of land use in the LRI scenario across the three planning horizons.

Table 5.101 - Land Use by region and technology in Scenario LRI (km²).

Year	Region	Hydro	Wind	Solar PV	Biomass	Others	Total Region
2030	North	11,200	80	60	80	5	11,425
	Northeast	1,800	2,800	1,100	60	40	5,800
	SE / CW	14,800	250	450	350	380	16,230
	South	2,100	450	120	15	25	2,710
	Total 2030	29,900	3,580	1,730	430	525	36,165
2040	North	11,800	150	120	10	120	12,200
	Northeast	1,800	3,800	1,600	100	60	7,360
	SE / CW	17,200	550	950	450	480	19,630
	South	3,500	850	250	20	30	4,650
	Total 2040	34,300	5,350	2,920	580	690	43,840
2050	North	12,500	350	250	15	150	13,265
	Northeast	1,800	5,200	2,200	120	80	9,400
	SE / CW	19,500	950	1,450	550	550	23,000
	South	5,500	1,400	450	30	50	7,430
	Total 2050	39,300	7,900	4,350	715	830	53,095

Source: Author's elaboration.

Total land occupation reaches 53,095 km² in 2050, placing LRI among the more territorially expansive pathways, though driven by different structural dynamics compared to supply-intensive renewable scenarios. The defining characteristic of LRI is not spatial diversification, but territorial concentration.

The Southeast/Central-West consolidates its dominance, reaching 23,000 km² by 2050. This reflects the continued reliance on hydropower assets, thermal infrastructure and incremental renewable additions located near established load centres. The region's expansion is not motivated by resource optimisation but by transmission cost minimisation and infrastructure maturity. In practical terms, the model internalises financial risk but not ecological opportunity cost.

The North also exhibits sustained territorial expansion, increasing from 11,425 km² in 2030 to 13,265 km² in 2050. Hydropower remains the dominant land-use component, signalling the continued attractiveness of large-scale reservoirs and brownfield upgrades under weak regulatory constraints. This trajectory implies ongoing pressure on frontier ecosystems, particularly in areas where environmental valuation is not strongly internalised in investment decisions.

In contrast, the Northeast reaches 9,400 km² in 2050—significant but substantially below its expansion under DSI, HRP or WSC. Although wind and solar resources are abundant, the absence of strong decarbonisation or regional development incentives limits large-scale deployment. The region's territorial occupation grows, but not to the extent required to structurally shift the geography of the electricity system.

The South follows a moderate growth path, reaching 7,430 km² in 2050, mainly driven by wind expansion and incremental hydro and biomass additions.

LRI demonstrates that market-led expansion does not necessarily minimise land occupation; rather, it reallocates it according to existing economic geography. The model privileges regions with established infrastructure and avoids high-risk frontier investments only when financial returns are uncertain—not when ecological costs are high.

Compared to sustainability-driven configurations, LRI produces a territorially conservative yet ecologically permissive equilibrium. Land-use intensity grows steadily over time, but without spatial optimisation for biodiversity protection or agricultural opportunity cost. The absence of strong policy signals allows the persistence of large hydro footprints and centralised generation patterns, reinforcing regional concentration and limiting structural territorial transformation.

The water consumption trajectory under the LRI scenario reflects the persistence of a hydro-thermal backbone driven by private cost optimisation rather than resource efficiency criteria. In the absence of explicit water-use constraints or hydrological penalties, the optimisation maintains high utilisation of the existing hydropower fleet while expanding combined-cycle gas plants to provide system firmness.

Although combined-cycle gas plants exhibit a lower water intensity per unit of electricity than coal or nuclear technologies, their cumulative expansion results in a stable and structurally significant thermal water footprint. Consequently, total system water consumption remains elevated across the planning horizon.

Table 5.102 presents the regionalised evolution of water consumption under the LRI configuration.

Table 5.102 - Water consumption by region in LRI (million m³).

Year	Region	Hydro	Biomass	Nat. Gas	Others*	Total
2030	North	210.0	1.2	0.8	0.5	212.5
	Northeast	18.0	2.5	1.5	0.2	22.2
	SE / CW	450.0	30.0	18.0	20.0	518.0
	South	95.0	8.5	2.0	1.3	106.8
	Total 2030	773.0	42.2	22.3	22.0	859.5
2040	North	212.0	1.3	1.0	0.6	214.9
	Northeast	19.0	2.8	2.0	0.3	24.1
	SE / CW	455.0	31.5	22.0	20.5	529.0
	South	93.0	8.9	3.0	1.2	106.1
	Total 2040	779.0	44.5	28.0	24.5	883.0
2050	North	215.0	1.5	1.2	0.8	218.5
	Northeast	20.0	3.0	2.5	0.5	26.0
	SE / CW	460.0	32.5	25.0	20.0	537.5
	South	90.0	9.0	3.0	1.0	103.0
	Total 2050	785.0	46.0	31.7	22.3	885.0

**Includes Nuclear and other thermal processes.*

Source: Author's elaboration.

As shown in Table 5.102, total water consumption increases moderately from 859.5 million m³ in 2030 to 885.0 million m³ in 2050. This trajectory differs from sustainability-oriented scenarios such as DSI and LCE, in which water consumption declines because the optimal generation portfolio shifts towards technologies with lower operational water intensity and reduced fossil-based thermal generation.

The Southeast/Central-West region concentrates the majority of water consumption, exceeding 537 million m³ by 2050. This reflects both the continued reliance on reservoir hydropower for system balancing and the expansion of gas-fired generation located near industrial load centres. The optimisation does not penalise water intensity; therefore, hydrological efficiency is not treated as a strategic variable.

The North maintains a stable hydropower footprint, while the Northeast shows moderate growth associated with biomass and complementary gas capacity. The South remains comparatively stable due to limited new hydro expansion and moderate thermal penetration.

From a structural perspective, the LRI scenario illustrates a "Water Neutrality Bias": water use is not actively minimised, but neither is it strategically optimised. It becomes a residual outcome of cost-driven dispatch decisions. This reinforces the central thesis of the SEGeP framework — that without explicit internalisation mechanisms, environmental resource allocation follows private economic signals rather than long-term sustainability criteria.

Table 5.102 provides evidence that regulatory minimalism does not necessarily produce extreme environmental deterioration, but it systematically underdelivers efficiency improvements that require coordinated policy intervention.

5.12.4 Social Effects (LRI)

Employment generation under the LRI configuration reflects the centralised investment logic that characterises this scenario. Because the optimisation prioritises private cost efficiency, system adequacy and proximity to major load centres, expansion is concentrated in large-scale generation assets and in regions with established infrastructure. As a result, employment creation is less territorially distributed and more closely associated with conventional construction, operation and maintenance activities than in scenarios that explicitly value employment-related social benefits and regional inclusion.

Table 5.103 presents the evolution of equivalent annual employment by region.

Table 5.103 - Equivalent annual employment by region in LRI (thousand jobs/year).

Region	2030	2040	2050
North	22.0	24.0	25.0
Northeast	48.0	55.0	60.0
SE / Central-West	75.0	82.0	85.0
South	15.0	18.0	20.0
Total SIN	160.0	179.0	190.0

Source: Author's elaboration.

As shown in Table 5.103, total employment increases from 160 thousand jobs in 2030 to 190 thousand jobs in 2050, reflecting overall system expansion. However, the job intensity per unit of electricity generated remains comparatively low when contrasted with scenarios such as DSI or MEC, where the expansion of labour-intensive renewable technologies and the explicit valuation of employment-related benefits result in higher employment effects. The Southeast/Central-West remains the primary employment hub, reaching 85 thousand jobs in 2050. This reflects the concentration of capacity additions near major industrial load centres and existing infrastructure corridors. The Northeast experiences moderate employment growth, reaching 60 thousand jobs by 2050, but without the transformative labour expansion observed in sustainability-driven configurations. The North and South display incremental gains consistent with incremental capacity additions rather than structural reallocation of investment.

Structurally, the LRI scenario provides evidence that market-led expansion generates employment as a secondary outcome of capacity growth rather than as a strategic objective. The absence of policy incentives for distributed generation, local manufacturing clusters or energy efficiency programmes limits the spatial diffusion of job creation, reinforcing the economic centrality of historically dominant regions.

In the LRI scenario, the persistence of fossil-based thermal generation — structurally supported by a low and non-escalating carbon price (€30/tCO_2) — results in sustained emissions of nitrogen oxides (NO_x) and sulphur dioxide (SO_2). Within the SEGeP framework, these pollutants are explicitly treated as social externalities due to their well-documented impacts on respiratory morbidity, premature mortality and urban air quality degradation. Their monetisation follows the external damage valuation approach embedded in the model.

The spatial distribution of local air pollutants under the LRI configuration reflects the intrinsic market-driven allocation logic embedded in the SEGeP optimisation. In the absence of progressive carbon pricing and without explicit environmental tightening, thermal generation remains competitively positioned near major industrial load centres, particularly within the Southeast/Central-West subsystem. This geographical concentration of dispatchable capacity directly translates into a structurally asymmetric pattern of pollutant exposure across the national territory. Table 5.104 presents the regional distribution of NO_x and SO_2 emissions in 2030 and 2050.

Table 5.104 - NO_x and SO_2 emissions by region in LRI (kt).

Year	Pollutant	North	Northeast	SE / CW	South	Total SIN
2030	NO_x	7.1	5.7	71.5	5.1	89.4
	SO_2	1.8	1.4	17.4	1.2	21.8
2040	NO_x	8.8	7.0	76.8	6.8	99.4
	SO_2	2.2	1.8	18.7	1.7	24.4
2050	NO_x	10.5	8.3	82.2	8.5	109.5
	SO_2	2.6	2.1	20.1	2.1	26.9

Source: Author's elaboration.

Table 5.104 presents the evolution of NO_x and SO_2 emissions by region between 2030 and 2050. Total NO_x emissions increase from 89.4 kt in 2030 to 109.5 kt in 2050, while SO_2 emissions rise from 21.8 kt to 26.9 kt over the same period. The Southeast/Central-West remains the dominant contributor throughout the horizon, accounting for 71.5 kt of NO_x in 2030 and reaching 82.2 kt by 2050. A similar trajectory is observed for SO_2, increasing from 17.4 kt to 20.1 kt. This persistent concentration is a direct outcome of the least-private-cost siting strategy, which prioritises proximity to demand in order to minimise transmission expenditure and infrastructure risk.

The intermediate year 2040 represents an early inflection point in this trajectory. Total NO_x emissions approach 100 kt (99.4 kt), indicating that the environmental burden intensifies before the final horizon. This reflects the increased utilisation rates of existing thermal plants to accommodate growing electricity demand, combined with the absence of strong regulatory signals capable of accelerating fuel switching or deep structural decarbonisation. Although incremental efficiency gains occur toward 2050, they are insufficient to reverse the upward trend in absolute emissions.

Beyond the Southeast/Central-West, all other regions experience measurable growth in pollutant levels. The North sees NO_x emissions rise from 7.1 kt to 10.5 kt between 2030 and 2050, while the South increases from 5.1 kt to 8.5 kt. SO_2 follows a comparable pattern, particularly in the South, where emissions increase from 1.2 kt to 2.1 kt. These dynamics are associated with the continued reliance on gas-fired and residual liquid-fuel units to provide system firmness under a regulatory environment that does not penalise local air pollution aggressively.

The LRI pathway reveals a structurally embedded health externality. While the private optimisation minimises direct financial cost, it does not internalise the social damages associated with atmospheric pollutants. The resulting configuration concentrates emissions in high-density economic corridors, thereby transferring environmental costs from electricity tariffs to broader societal domains, including public health and urban quality of life. In contrast to sustainability-oriented scenarios, where pollutant trajectories decline over time, the LRI configuration demonstrates that a purely market-centred expansion logic is insufficient to induce structural environmental improvement.

The evolution of the Human Development Index (HDI) under the LRI configuration reflects a growth trajectory primarily driven by increased electricity availability and sectoral income expansion, rather than by structural improvements in social infrastructure or targeted regional development policies. Unlike the MEC and DSI scenarios, where decentralised investment, employment multipliers and environmental improvements generate indirect gains in education, health and quality of life, the LRI pathway produces a more linear and moderate development pattern.

Table 5.105 presents the regional evolution of HDI under the LRI scenario.

Table 5.105 - Regional HDI (IDH) evolution in Scenario LRI.

Region	2030	2040	2050
North	0.725	0.735	0.750
Northeast	0.715	0.725	0.740
SE / Central-West	0.790	0.800	0.815
South	0.805	0.815	0.830

Source: Author's elaboration.

All regions experience incremental improvements over the planning horizon, reflecting general economic growth and expanded energy access. However, the pace of advancement remains modest. The North increases from 0.725 to 0.750 between 2030 and 2050 (+0.025), while the Northeast rises from 0.715 to 0.740 (+0.025). These improvements are materially lower than those observed in the DSI or MEC scenarios, where structural employment generation and environmental quality gains accelerate human development.

The Southeast/Central-West and the South maintain higher absolute HDI levels throughout the horizon, reaching 0.815 and 0.830 respectively by 2050. Importantly, the interregional gap narrows only marginally. The difference between the Northeast and the SE/CW declines from 0.075 points in 2030 to 0.075 points in 2050—effectively unchanged—indicating the absence of structural convergence.

The HDI trajectory in LRI illustrates that energy expansion alone is insufficient to catalyse deep territorial transformation. Without explicit policy instruments targeting employment intensity, income redistribution or environmental co-benefits, the electricity sector contributes to quantitative growth but not to qualitative development acceleration. The result is a development pathway characterised by stability rather than structural upgrading, particularly in the historically disadvantaged "arc of scarcity" encompassing the North and Northeast.

The macroeconomic performance of the LRI scenario is summarised in Table 5.106. These indicators reflect a configuration characterised by relatively low private investment costs but a progressively increasing social burden.

Table 5.106 - System economic indicators in LRI.

Metric	2030	2040	2050
Total system cost (NPV, € billion)	280.0	335.0	390.0
Average Social Cost (€/MWh)	52.0	54.0	56.5

Source: Author's elaboration.

The total system cost reaches €390.0 billion by 2050, placing LRI among the financially less expensive configurations in terms of direct capital and operational expenditure. This reflects the prioritisation of mature technologies, brownfield upgrades and proximity-based generation.

However, the Average Social Cost increases steadily from €52.0/MWh in 2030 to €56.5/MWh in 2050. Unlike decarbonisation-oriented scenarios, where social cost declines over time due to reduced emissions and lower environmental damage, LRI exhibits an upward trajectory. This trend results from persistent CO_2, NO_x, SO_2 and water-use externalities that remain insufficiently internalised under baseline carbon pricing.

LRI reveals a structural divergence between private efficiency and social welfare. While investors benefit from lower direct costs, the system accumulates long-term external burdens. The scenario therefore quantifies the economic implications of regulatory non-intervention: financial optimisation at the expense of environmental mitigation and territorial convergence.

5.12.5 Analytical Discussion: The Structural Role of Regionalisation – LRI

The Low Regulatory Interference (LRI) configuration operates as a structured market-based counterfactual within the SEGeP framework. While sustainability-oriented scenarios employ regionalisation as an instrument of convergence, labour redistribution and environmental rebalancing, the LRI pathway reveals the endogenous territorial outcome of expansion under economic inertia. In this configuration, capital allocation follows the logic of private risk minimisation and infrastructure maturity, rather than strategic territorial transformation.

The Southeast/Central-West (SE/CW) subsystem consolidates its structural dominance throughout the planning horizon. By 2050, it concentrates 135 GW of installed capacity and 550 TWh of electricity generation, corresponding to approximately 53% of total national generation. This concentration is not the result of policy prioritisation but emerges from the optimisation of private transmission and investment costs. Locating dispatchable thermal generation near high-demand industrial clusters minimises network expansion requirements and reduces exposure to inter-regional infrastructure risks. However, this economically efficient allocation entails environmental concentration: in 2050, the SE/CW region accounts for 82.2 kt of NO_x

emissions and 20.1 kt of SO_2 emissions, representing the largest share of local atmospheric pollutants within the system. The optimisation thus internalises transmission cost efficiency while externalising air quality burdens spatially.

The Northeast, despite reaching 235 TWh of generation in 2050, remains structurally under-leveraged relative to its renewable potential when compared to policy-driven configurations such as DSI or MEC. In the absence of strong regulatory incentives for decentralisation, local content requirements or employment multipliers, renewable expansion does not translate into proportional territorial development gains. This is reflected in the persistence of inequality levels, with the regional Gini Index declining only marginally from 0.550 in 2030 to 0.545 in 2050. The electricity sector under LRI therefore functions as an export-oriented energy platform rather than as a vector of socio-economic transformation. Capital returns are captured within mature economic corridors, while spillover effects in peripheral regions remain limited.

The contrast between private and social efficiency becomes quantitatively evident when comparing macroeconomic and labour outcomes. Total system cost reaches €390.0 billion by 2050, representing the lowest Net Present Value among the analysed configurations. From a purely financial perspective, this suggests optimal capital allocation. However, the Average Social Cost increases to €56.5/MWh, reflecting the cumulative monetised impact of CO_2 emissions (54 $MtCO_2$ in 2050), local air pollutants and water consumption externalities. Simultaneously, employment generation remains comparatively modest, reaching 190 thousand equivalent jobs per year in 2050, substantially below the 460 thousand jobs achieved under the DSI configuration. The differential of approximately 270 thousand jobs represents a measurable opportunity cost associated with the absence of active regulatory steering toward labour-intensive technologies and distributed infrastructure.

The technological composition of LRI further reinforces structural lock-in dynamics. Natural gas generation stabilises at 90 TWh in 2050, while total CO_2 emissions remain elevated at 54 $MtCO_2$. Under a fixed carbon price of €30/tCO_2, the optimisation does not perceive sufficient economic pressure to accelerate deep decarbonisation or large-scale electrification of industrial heat processes. Mature thermal technologies therefore retain structural competitiveness, and the system converges toward a capital-efficient yet carbon-intensive equilibrium. This configuration demonstrates that, without escalating environmental price signals, long-term climate risk remains underrepresented in private investment calculus.

From a regionalisation perspective, the LRI scenario is characterised by spatial conservatism rather than transformation. The North and Northeast operate primarily as energy suppliers with limited internal value retention, while the Southeast consolidates its dual role as economic core and environmental hotspot. The

electricity sector, under regulatory minimalism, does not function as a mechanism for territorial convergence but instead reproduces existing economic geography.

Although the LRI pathway achieves the lowest private investment cost, it generates higher cumulative social costs, slower regional convergence and persistent environmental externalities. The measurable gap between the Average Social Cost of LRI (€56.5/MWh) and that of more integrated scenarios such as DSI quantifies the economic value of regulatory intervention. Within the SEGeP framework, policy-driven internalisation is not an inefficiency but a corrective mechanism that aligns private optimisation with national welfare objectives.

The LRI configuration substantiates the central thesis of this work: regulatory ambition in electricity expansion planning represents not a distortion of market efficiency, but a structural investment in territorial cohesion, environmental sustainability and long-term socio-economic resilience.

The LRI scenario illustrates the effects of reduced regulatory influence on expansion planning. In the absence of strong policy constraints, the model prioritises cost-efficient technologies, leading to outcomes that may diverge from environmental and social sustainability objectives. Key insights from the scenario:

(i) Reduced regulatory intervention leads to expansion pathways driven primarily by market signals and cost competitiveness;

(ii) The absence of strong policy constraints results in higher emissions and less balanced regional development;

(iii) The scenario highlights the limitations of relying solely on market mechanisms to achieve sustainability objectives;

(iv) The results reinforce the importance of regulatory frameworks in guiding energy transition processes.

5.13 – Integrated Synthesis and Articulation of the Results of Chapter 5

The comparative simulation of nine prospective scenarios over the 2030–2050 horizon, conducted through the SEGeP model, demonstrates that the expansion of the Brazilian electricity system is structurally dependent on regulatory design and territorially conditioned by regional heterogeneity. The results show that the optimal generation mix does not emerge solely from technological constraints or resource availability, but rather from the way environmental, social, and territorial externalities are monetised and incorporated into the objective function.

The evidence presented in this chapter demonstrates that the system does not converge endogenously towards a sustainable equilibrium. Instead, expansion trajectories diverge significantly depending on the degree of externality internalisation. In low-intervention scenarios—namely EO and LRI—strict minimisation of private cost results in an average Net Present Value (NPV) of approximately €402.5 billion by 2050, representing the lowest direct financial cost among the analysed configurations. However, this apparent private efficiency is accompanied by cumulative emissions reaching 54 $MtCO_2$ in 2050 (LRI), alongside high regional concentrations of NO_x (109.5 kt) and SO_2 (26.9 kt).

Once these externalities are monetised—through carbon pricing, health-related damage costs of local pollutants, and land-use valuation—the divergence between the private optimum and the social optimum becomes quantitatively explicit. Under the DSI scenario, although private system cost is marginally higher than in EO or LRI, the Total Social Cost (TSC) is reduced by approximately 22% relative to BAU. This reduction reflects the decline in CO_2 emissions to 0.5 $MtCO_2$ in 2050, substantial reductions in NO_x and SO_2 emissions, and lower territorial occupation pressures. These findings demonstrate that externality internalisation is not an additional burden, but a corrective mechanism that reorders technological competitiveness and prevents long-term fossil lock-in.

From a regional perspective, the results clearly demonstrate that energy expansion functions as a redistribution mechanism when social parameters are activated. In inertial configurations (EO and LRI), the Southeast/Centre-West concentrates more than 50% of total generation and retains the largest installed capacity share (up to 135 GW in LRI), while also absorbing the majority of local pollutant emissions (82.2 kt of NO_x in 2050). Under these configurations, regional inequality remains largely unchanged, with the Gini Index in the Northeast stabilising at 0.545 in 2050.

Conversely, in socially oriented scenarios such as DSI and MEC, the activation of employment multipliers (1.10 jobs/GWh for Solar PV and 1.35 jobs/GWh for Biomass) structurally shifts the investment frontier towards the Northeast. By 2050, the DSI configuration generates approximately 460,000 equivalent annual jobs, compared to 190,000 under LRI—a differential of 270,000 jobs. This reallocation translates into a measurable reduction in regional inequality, with the energy-adjusted Gini Index declining to 0.485, representing a 0.06-point improvement relative to LRI. Regionalisation therefore emerges not merely as a descriptive modelling feature, but as an operational mechanism of distributive correction.

The territorial dimension further reinforces this interpretation. Land-use analysis shows that the stress scenarios, particularly WSC and ES, impose a spatial "resilience premium", with total land occupation reaching approximately 55,000–56,000 km^2 by 2050 as hydrological constraints and higher system requirements increase reliance on spatially dispersed generation. In contrast, the DSI scenario operates with approximately

39,000 km² in 2050, representing the lowest territorial footprint among the scenarios evaluated and an efficiency gain of roughly 29% relative to an ES footprint of about 55,000 km². Electricity demand remains exogenously defined and follows the same trajectory adopted in the other non-stress scenarios. The lower territorial footprint therefore reflects the combined effect of stringent decarbonisation constraints, the progressive displacement of fossil generation, the internalisation of land-use and biodiversity externalities and the regional allocation of low-carbon investment. This difference quantifies the territorial benefits of a pathway that simultaneously promotes deep decarbonisation and social inclusion while reducing pressure on ecologically sensitive and agriculturally productive land and maintaining the required electricity supply.

The joint interpretation of environmental, social, and territorial indicators reveals three structural mechanisms uncovered by the SEGeP model:

1. Reordering of technological competitiveness: monetisation of carbon, health, and land-use externalities alters effective cost rankings, favouring low-carbon and labour-intensive technologies.
2. Spatial redistribution of investment: activation of social parameters shifts capital flows towards regions with higher employment multipliers and renewable resource potential, reducing structural territorial asymmetries.
3. Intertemporal optimisation of system-wide cost: while private NPV may increase modestly under sustainability-oriented configurations, aggregate social cost declines, demonstrating stronger long-term economic coherence.

The results of Chapter 5 demonstrate that systemic efficiency cannot be assessed exclusively through private financial metrics. Explicit monetary valuation of environmental externalities (CO_2, NO_x, SO_2, land occupation) and social externalities (employment, regional inequality) fundamentally redefines the notion of optimal energy expansion. The SEGeP framework provides evidence that, when multidimensional objectives are internalised, the Brazilian energy transition not only reduces emissions, but reconfigures territorial investment patterns, redistributes income, and rationalises scarce natural resource use.

The quantitative coherence between model structure, regional outcomes, and policy implications validates SEGeP as a robust decision-support tool for integrated policy evaluation and as a strategic framework for guiding a transition that is economically consistent, environmentally resilient, and territorially just.

5.13.1 Structural comparison of generation mixes across scenarios

Figure 5.2 provides a consolidated, cross-scenario visual synthesis of the electricity generation structure obtained under the nine scenarios analysed in this chapter, for the years 2030, 2040 and 2050. Rather than introducing new quantitative results, the figure enables a systemic reading of how distinct policy logics and constraint configurations shape the long-term composition of the electricity mix within the SEGeP framework.

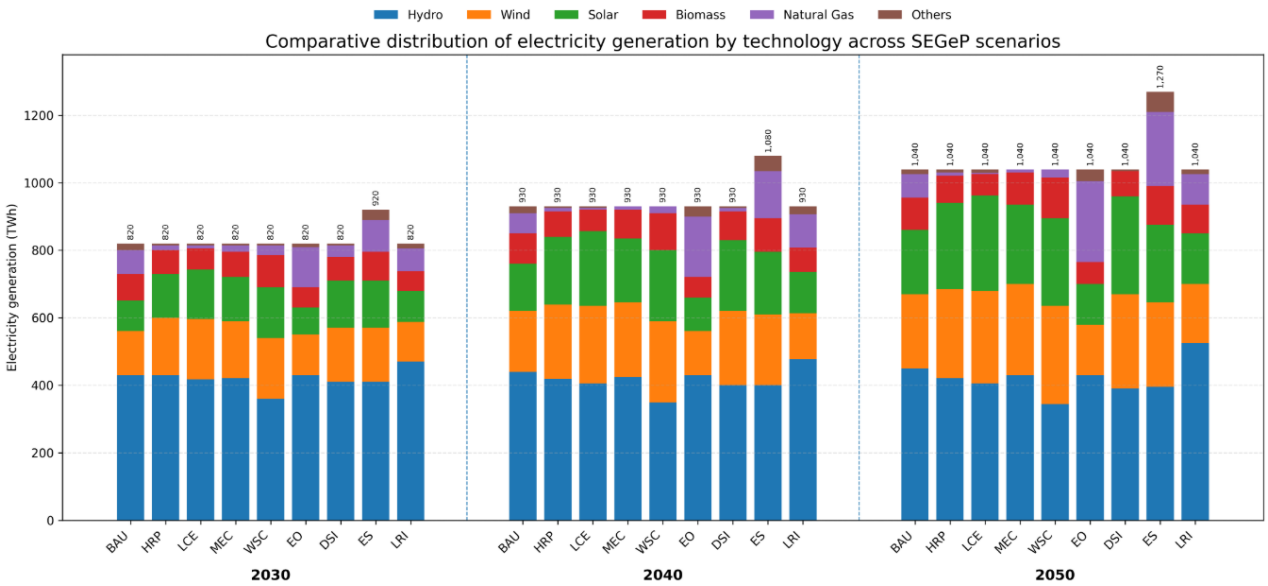


Figure 5.2 - Comparative distribution of electricity generation by technology across SEGeP scenarios (2030, 2040 and 2050).

Source: Author's elaboration.

Except for the ES configuration, which incorporates a higher electricity-demand trajectory as part of its stress assumptions, all scenarios are compared under the same aggregate demand levels of 820 TWh in 2030, 930 TWh in 2040 and 1,040 TWh in 2050. Consequently, the differences illustrated in Figure 5.2 reflect changes in the technological composition of supply rather than differences in total electricity demand.

The comparison reveals that the divergence between scenarios is not merely quantitative, but fundamentally structural. Scenarios oriented towards sustainability objectives — particularly HRP, LCE and DSI — exhibit a clear and persistent reconfiguration of the generation mix, characterised by the progressive displacement of fossil-based technologies and the dominance of wind and solar power, complemented by biomass as the primary firm renewable source. In contrast, market-driven or security-oriented scenarios — such as EO, LRI and ES — systematically revert to thermal flexibility, with natural gas assuming a central role as soon as environmental and social constraints are relaxed.

The inclusion of the EO scenario is particularly informative, as it exposes the counterfactual behaviour of the system under strict cost minimisation. The re-emergence of natural gas and oil-fired generation in this case demonstrates that Brazil's historically high renewable share is not an endogenous outcome of market efficiency, but the direct result of public planning, regulatory frameworks and environmental policy instruments.

Across all scenarios, hydropower remains relatively stable in absolute terms, confirming its role as a structural backbone of the system rather than a driver of marginal expansion. However, its declining relative participation in most scenarios highlights the increasing importance of complementary sources of firmness and flexibility, especially under high renewable penetration and water stress conditions.

The figure reinforces the central contribution of SEGeP: the optimal generation mix emerges as a policy-contingent outcome rather than a purely technical solution. By explicitly internalising environmental, social and regional dimensions, the model reveals how different policy priorities translate into distinct structural equilibria, offering a transparent and analytically robust basis for strategic energy planning.

To complement the structural comparison provided by Figure 5.2, Figure 5.3 presents a multidimensional overview of scenario performance in 2050. While Figure 5.2 focuses on the technological composition of electricity generation, the radar chart synthesises the broader economic, environmental, social and territorial implications of the expansion pathways. The comparison is based on five key indicators drawn from the consolidated performance matrix: Average Social Cost, CO_2 emissions, employment generation, regional inclusion and land efficiency. Because these indicators are expressed in different units and scales, they were transformed into dimensionless scores using min–max normalisation, where 0 represents the lowest relative performance and 1 the highest relative performance among the scenarios evaluated.

This graphical representation is intended as a comparative visual synthesis rather than as an additional optimisation procedure. The SEGeP solutions remain those generated by the model under the scenario-specific assumptions and constraints. The radar chart is used only to facilitate a systemic interpretation of the main trade-offs and complementarities revealed by the scenario results.

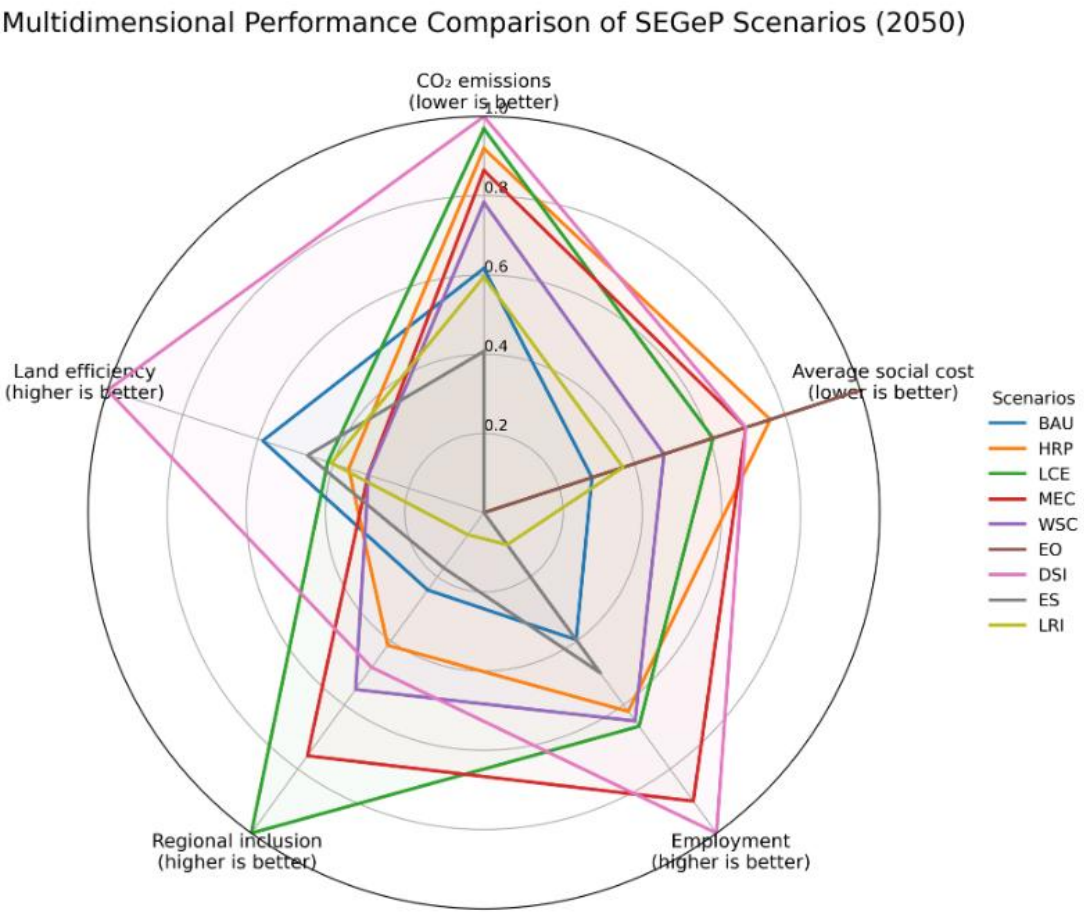


Figure 5.3 - Multidimensional performance comparison of SEGeP scenarios (2050).
Source: Author's elaboration based on Table 5.108.

Note: The radar chart normalises the 2050 values of five dimensions: CO_2 emissions, Average Social Cost, employment generation, regional inclusion and land efficiency. For CO_2 emissions and Average Social Cost, lower values represent better performance. Employment is measured as thousand equivalent jobs per year. Regional inclusion is represented by the inverse of the regional Gini index in 2050, so that lower inequality corresponds to higher performance. Land efficiency is represented by the inverse of total land occupation, so that lower territorial footprint corresponds to higher performance.

The multidimensional comparison confirms that no scenario simultaneously maximises all dimensions of sustainability. Instead, each scenario reflects the policy priorities embedded in its configuration and therefore produces a distinct performance profile. Scenarios oriented towards sustainability objectives, particularly HRP, LCE and DSI, achieve markedly stronger results in environmental performance than market-driven or low-intervention pathways. Their profiles indicate the structural effect of internalising climate and socio-environmental concerns within the expansion framework.

Among the scenarios, DSI displays the most balanced overall profile. It combines the lowest CO_2 emissions, the strongest employment performance, the highest land efficiency and a comparatively favourable regional inclusion outcome, while maintaining a competitive Average Social Cost. This result is consistent with the broader conclusions of Chapter 5, which show that the simultaneous internalisation of environmental and

social externalities can redirect the generation mix towards a more efficient long-term social optimum, even when private investment requirements are comparatively higher.

LCE and HRP also perform strongly, especially in climate-related dimensions. Their profiles confirm that stronger decarbonisation signals and renewable-oriented planning produce substantial gains in emissions reduction and system transformation. However, their radar shapes also indicate that these strengths are not always accompanied by the highest social or distributive outcomes. In this respect, the chart makes clear that environmental performance alone is insufficient to characterise the multidimensional quality of an expansion pathway.

The MEC scenario stands out for employment generation, reflecting the explicit prioritisation of labour-intensive technologies and regional job creation. Nevertheless, its broader profile suggests a trade-off between social performance and the achievement of the lowest environmental impacts. This confirms that maximising employment alone does not automatically produce the strongest multidimensional outcome, although it can significantly improve the social profile of expansion.

By contrast, EO and LRI present comparatively weaker multidimensional performance. Their profiles are narrower, reflecting poorer results in emissions, land efficiency and regional inclusion, despite comparatively favourable market-oriented or cost-driven characteristics in the underlying modelling logic. These scenarios make visible the divergence between private financial efficiency and social efficiency, which is one of the core analytical contributions of the SEGeP framework.

Finally, WSC and ES show the multidimensional cost of resilience under adverse structural conditions. Water scarcity and stress-related assumptions reduce the system's ability to optimise all objectives simultaneously, resulting in more uneven performance profiles. The radar chart therefore reinforces the central interpretation of this chapter: the future electricity mix is not determined solely by technical feasibility or resource availability, but by the institutional and policy priorities embedded in long-term planning.

Taken together, Figures 5.2 and 5.3 provide complementary perspectives on the scenario results. Figure 5.2 reveals how the technological composition of generation changes across scenarios, whereas Figure 5.3 synthesises the broader sustainability implications of those changes. The combined interpretation strengthens the argument that electricity generation expansion is inherently multidimensional and that integrated frameworks such as SEGeP are necessary to reveal the trade-offs between cost, climate performance, employment, regional inclusion and territorial efficiency.

5.13.2 Structural archetypes of electricity expansion pathways

While the previous sections analysed each scenario individually, a cross-scenario comparison reveals that the outcomes generated by the SEGeP model are not merely quantitative variations of a single expansion logic. Instead, they can be grouped into a limited number of structurally distinct electricity expansion archetypes, each reflecting a different planning paradigm and set of normative priorities.

This archetypal classification allows the identification of recurring structural patterns that cut across scenarios, clarifying how alternative policy objectives—such as cost minimisation, climate mitigation, employment creation or energy security—systematically reshape the electricity generation mix. By abstracting from individual numerical results, this approach enhances the analytical coherence of Chapter 5 and establishes a clear conceptual bridge to the policy-oriented discussion developed in Chapter 6.

Table 5.107 summarises the main structural archetypes identified, linking scenarios to their dominant planning logic, technological configuration, and associated systemic risks.

Table 5.107 - Structural archetypes of electricity expansion pathways in the SEGeP model.

Archetype	Associated scenarios	Dominant planning logic	Role of renewable technologies	Role of fossil fuels	Main systemic risks
Cost-driven expansion	EO, LRI	Strict minimisation of private economic costs	Secondary and constrained	Central (natural gas and oil)	Carbon lock-in, exposure to fuel price volatility, climate incompatibility
Climate-driven expansion	LCE	Emission minimisation and climate compliance	Dominant, especially wind and solar	Residual and highly constrained	System variability, firmness requirements
Renewable-target-driven expansion	HRP	Policy-induced renewable quotas	Dominant but policy-dependent	Marginal	Land-use saturation, spatial concentration
Employment-driven expansion	MEC	Maximisation of job creation	High, labour-intensive technologies prioritised	Complementary	Cost pressure, environmental trade-offs
Security-driven expansion	WSC, ES	Adequacy and system firmness	Constrained by reliability needs	Strategic back-up role	Emissions rebound, higher system costs
Integrated sustainability expansion	DSI	Joint optimisation of climate, social and regional objectives	Dominant, diversified and regionally distributed	Near-eliminated	Institutional and coordination complexity

Source: Author's elaboration.

The comparison highlights that planning outcomes are primarily driven by the adopted decision paradigm rather than by technological availability alone. Cost-driven scenarios systematically favour flexible fossil-based generation, even in a system endowed with abundant renewable resources, demonstrating that high renewable penetration is not an endogenous outcome of market forces. Conversely, climate-driven and renewable-target-driven scenarios achieve deep decarbonisation but expose structural tensions related to variability, land use and system flexibility.

Employment-oriented scenarios reconfigure the expansion pathway towards labour-intensive technologies, generating substantial social co-benefits while introducing additional cost and environmental pressures. Security-driven scenarios reveal a clear trade-off between short-term adequacy and long-term climate performance, particularly under conditions of hydrological stress or accelerated demand growth.

The DSI scenario emerges as a distinct and comprehensive archetype, integrating the strengths of the other configurations while mitigating their principal weaknesses. By simultaneously enforcing stringent climate constraints, high social weights and regional incentives, it achieves near-total decarbonisation, maximum employment creation and reduced territorial asymmetries without incurring prohibitive system costs.

This structural synthesis provides evidence that long-term electricity planning is inherently normative and multidimensional. The SEGeP framework makes these trade-offs explicit, providing a transparent analytical foundation for the policy and theoretical implications discussed in Chapter 6.

5.13.3 Integrated Externalities Valuation and SDG Alignment

The comparative simulation of the nine SEGeP scenarios enables a quantitatively rigorous assessment of the Brazilian electricity sector's alignment with the Sustainable Development Goals (SDGs), moving beyond narrative coherence and into measurable policy performance. Because the SEGeP formulation internalises environmental damage costs (CO_2, NO_x, SO_2), land-use opportunity costs, water consumption, and regional employment multipliers within the Total Social Cost (TSC) structure, each SDG-relevant dimension is translated into explicit numerical outputs. The SDGs are therefore not interpreted as qualitative benchmarks, but as analytically traceable system indicators.

With respect to SDG 7 (Affordable and Clean Energy), affordability is evaluated through the Average Social Cost (€/MWh) and system-wide NPV, while "clean energy" performance is quantified via CO_2 intensity ($MtCO_2$) and renewable penetration. In the LRI scenario, total system cost reaches €390.0 billion in 2050, with an Average Social Cost of €56.5/MWh and emissions of 54 $MtCO_2$. By contrast, the DSI scenario, despite a higher upfront NPV (≈€465.5 billion), reduces CO_2 emissions to approximately 0.5 $MtCO_2$ in 2050 and lowers the long-run social cost through externality reduction. This contrast numerically illustrates the divergence between private affordability and socially efficient clean energy provision.

For SDG 13 (Climate Action), cumulative and terminal-year emissions constitute the core performance metric. Under low-interference configurations (EO and LRI), emissions remain structurally elevated, exceeding 50 $MtCO_2$ in 2050. In contrast, deep decarbonisation trajectories (DSI and LCE) reduce system emissions by more than 90% relative to fossil-intensive pathways. The model demonstrates that emission mitigation is not

an automatic outcome of renewable resource abundance; rather, it requires sufficiently high carbon price signals to shift the technological merit order.

In relation to SDG 8 (Decent Work and Economic Growth), the SEGeP model quantifies employment generation through technology-specific labour coefficients (e.g., ~1.10 jobs/GWh for solar PV and ~1.35 jobs/GWh for biomass, compared to ~0.25 jobs/GWh for natural gas). The DSI scenario reaches approximately 460 thousand equivalent annual jobs by 2050, while LRI generates only around 190 thousand jobs. This represents a differential of roughly 270 thousand annual jobs attributable to policy-driven decentralisation and efficiency measures. The employment gap directly reflects the technological composition of the generation mix and demonstrates the labour elasticity of sustainability-oriented expansion.

SDG 10 (Reduced Inequalities) is operationalised through regional Gini index evolution. In the LRI scenario, the Northeast Gini index declines marginally from 0.550 (2030) to 0.545 (2050), indicating limited distributive transformation. Under DSI, however, the same region reaches approximately 0.485 in 2050, a reduction of 0.060 index points relative to the market-driven trajectory. This numerical difference quantifies the distributive effect of decentralised renewable investment and local employment multipliers.

Regarding SDG 12 (Responsible Consumption and Production), the efficiency of resource use is captured through land-use (km^2) and water consumption (million m^3). The Energy Stress (ES) scenario reaches land occupation levels exceeding 55,000 km^2 by 2050, while DSI operates with approximately 39,000 km^2, implying a territorial efficiency gain of roughly 16,000 km^2 (≈29% reduction relative to stress conditions). Similarly, water consumption in fossil-reliant scenarios exceeds 880–1,000 million m^3 by 2050, whereas low-carbon scenarios with greater participation of wind and solar technologies maintain lower operational water requirements.. These quantitative differentials demonstrate that responsible production is materially dependent on planning architecture.

The integrated interpretation of these indicators reveals that SDG alignment is not monotonic across scenarios. EO and LRI maximise short-term financial efficiency but underperform across SDGs 8, 10, 12, and 13. DSI achieves the strongest multi-SDG coherence, simultaneously reducing emissions (>90% relative to fossil-intensive baselines), maximising employment (+270k jobs relative to LRI), improving regional equity (−0.06 Gini in the Northeast), and reducing territorial pressure. MEC performs strongly in social dimensions but with moderate environmental trade-offs, while WSC and ES demonstrate the cost of resilience under climatic stress.

5.13.3.1 Monetised Externalities and SDG 13 (Climate Action)

Within the SEGeP framework, SDG 13 (Climate Action) is not treated as a qualitative commitment, but as a fully operationalised economic variable embedded in the optimisation structure. Climate mitigation emerges from the explicit monetisation of carbon emissions within the Total Social Cost (TSC) function, thereby transforming atmospheric externalities into measurable economic drivers of technological selection and regional allocation of investment. The results of Chapter 5 demonstrate that the divergence between private and social optima is quantitatively significant and structurally transformative.

Across the nine simulated scenarios, CO_2 emissions in 2050 range from approximately 0.5 $MtCO_2$ in the DSI configuration to around 54 $MtCO_2$ in the LRI and EO pathways. This spread of more than 53 $MtCO_2$ represents more than a difference in technology mix; it reflects the strength or absence of carbon valuation and environmental constraints within the optimisation logic. In low-intervention environments (EO and LRI), where carbon pricing remains fixed at baseline levels (€30/tCO_2) or is effectively neutralised in the objective function, the model converges toward fossil-supported equilibria. Natural gas, characterised by relatively low upfront CAPEX and high operational flexibility, assumes a structural role in guaranteeing system adequacy. Under these conditions, the private NPV of the system remains comparatively low (around €390–402 billion by 2050), but the externalised environmental burden accumulates in the form of persistent emissions near 54 $MtCO_2$ annually.

When these emissions are monetised within SEGeP's Total Social Cost structure, their economic weight alters the relative attractiveness of generation technologies. In scenarios such as HRP and, more markedly, DSI, stronger carbon-price signals, tighter emission limits and the internalisation of environmental damages increase the effective cost of fossil generation, inducing substitution towards wind, solar PV, biomass and other low-carbon resources. Under DSI, CO_2 emissions decline to approximately 0.5 $MtCO_2$ in 2050, representing a reduction of about 99% relative to the LRI scenario. This decarbonisation does not result from carbon pricing alone, but from the combined effect of stringent emission constraints, fossil-generation restrictions and the incorporation of environmental and employment-related externalities into the objective

The monetised environmental burden exhibits clear regional asymmetries. In fossil-leaning configurations (EO, LRI), the Southeast/Central-West concentrates the majority of emissions due to the geographic clustering of thermal generation near high-demand industrial centres. In 2050, this region accounts for more than 70% of total CO_2 emissions in LRI, illustrating how the absence of internalised carbon costs reinforces spatial carbon concentration. Conversely, in DSI and HRP, renewable expansion in the Northeast displaces fossil dispatch in the SE/CW, redistributing both economic activity and environmental intensity

across the territory. Thus, carbon pricing does not merely reduce aggregate emissions; it reconfigures the territorial carbon geography of the Brazilian electricity system.

The divergence between private and social optima becomes particularly explicit when comparing the evolution of the Average Social Cost. In LRI, despite lower private investment requirements, the monetised social cost rises to approximately €56.5/MWh by 2050 because environmental damages remain insufficiently internalised. In DSI, although private NPV increases to approximately €465.5 billion, stringent decarbonisation constraints, the progressive displacement of fossil generation and the internalisation of environmental and employment-related externalities reduce long-term social damages and stabilise the social-cost trajectory. This inversion supports a central proposition of SEGeP: apparent short-term financial efficiency may conceal structurally higher long-term social costs.

Furthermore, the interaction between carbon valuation and land-use intensity reinforces the SDG 13 mapping. In scenarios where fossil reliance persists, territorial occupation expands primarily through hydropower reinforcement and thermal infrastructure, maintaining high environmental pressure. In DSI, the technology portfolio selected under stringent decarbonisation constraints, combined with the internalisation of land-use and biodiversity externalities, reduces the total territorial footprint of electricity expansion to approximately 39,075 km² in 2050, compared to over 53,000 km² in LRI and nearly 55,000 km² in stress-oriented scenarios. Thus, climate mitigation is coupled with territorial efficiency, demonstrating systemic co-benefits beyond emissions reduction alone.

The carbon price operates as a shadow price that modifies the intertemporal investment calculus. When weak, it allows path-dependent fossil assets to remain competitive. When strong and consistent, it reorders the merit of technologies across regions, encouraging earlier renewable penetration, higher labour intensity, and lower exposure to future climate risk. The results therefore provide quantitative confirmation that climate alignment within the Brazilian electricity system is not an automatic by-product of resource abundance, but a policy-conditioned equilibrium outcome.

5.13.3.2 Employment Multipliers and SDG 8 (Decent Work and Economic Growth)

Within the SEGeP modelling architecture, SDG 8 (Decent Work and Economic Growth) is operationalised through the endogenous incorporation of regionalised employment multipliers differentiated by generation technology. Rather than treating job creation as an ex-post qualitative benefit, the model embeds labour intensity directly into the Total Social Cost structure via technology-specific coefficients. The calibrated multipliers applied in Chapter 5 are: Solar PV (1.10 jobs/GWh), Biomass (1.35 jobs/GWh), and Natural Gas (0.25 jobs/GWh). These coefficients reflect the structural differences in supply-chain depth, installation

complexity, and ongoing operational requirements associated with decentralised renewables versus capital-intensive thermal generation.

The comparative results reveal a pronounced structural divergence in employment trajectories across scenarios. By 2050, the Low Regulatory Interference (LRI) configuration generates approximately 190 thousand equivalent annual jobs, reflecting its reliance on hydropower refurbishment and natural gas expansion. In contrast, the Energy Stress (ES) scenario reaches 310 thousand jobs per year, driven primarily by the large-scale capacity expansion required to maintain system adequacy under high demand growth. However, the highest employment outcome is observed in the DSI scenario, which attains approximately 460 thousand equivalent annual jobs in 2050.

The quantitative gap between LRI and DSI—approximately 270 thousand annual jobs—constitutes a measurable employment opportunity cost associated with the non-internalisation of social externalities. In other words, when the objective function is dominated by private cost minimisation, the optimisation systematically favours technologies with lower labour multipliers, thereby suppressing potential employment gains embedded in decentralised and distributed systems. Conversely, when social weights are activated (as in MEC and DSI), the model reallocates investment toward labour-intensive technologies such as distributed solar and biomass supply chains, significantly increasing job creation without compromising system adequacy.

Importantly, the employment effect is not spatially neutral. In LRI, job concentration remains predominantly in the Southeast/Central-West, reflecting the clustering of thermal infrastructure near load centres. In DSI and MEC, however, employment expansion is geographically redistributed toward the Northeast and North. The Northeast, characterised by high wind and solar potential and historically higher unemployment rates, absorbs a substantial share of renewable-driven investment. By 2050, it becomes one of the primary employment beneficiaries in DSI, contributing significantly to the total 460 thousand jobs/year figure. This regional redistribution supports structural diversification of local economies, reduces dependence on commodity-based activity, and enhances territorial income retention.

From a macroeconomic perspective, the labour-intensive pathway also alters the composition of value added. Decentralised solar and biomass projects stimulate domestic supply chains, installation services, grid digitalisation, and maintenance activities, generating multiplier effects beyond direct employment. In contrast, natural gas-based expansion is characterised by higher capital concentration and lower operational labour intensity, resulting in weaker spillover effects across regional economies.

The modelling results therefore demonstrate that SDG 8 alignment is not an automatic consequence of electricity expansion. Employment outcomes depend directly on the technological composition of the mix and on whether labour multipliers are explicitly valued within the optimisation process. By quantifying the

employment differential between scenarios, SEGeP provides a measurable indicator of how regulatory ambition translates into real economic opportunity. The employment divergence between LRI (190k) and DSI (460k) in 2050 is not merely descriptive; it represents a structural choice between a capital-concentrated energy transition and a labour-distributed development pathway.

5.13.3.3 Regional Gini and SDG 10 (Reduced Inequalities)

The contribution of the electricity sector to SDG 10 (Reduced Inequalities) is explicitly quantified in SEGeP through the interaction between regional investment allocation, technology-specific labour multipliers, and the endogenous modelling of income distribution effects. Unlike conventional expansion models that treat inequality as an exogenous macroeconomic parameter, SEGeP captures the distributive implications of generation siting decisions and technology selection, thereby linking spatial energy investment to measurable changes in the Regional Gini Index.

The comparative results reveal a clear divergence between market-driven and socially internalised pathways. Under the Low Regulatory Interference (LRI) scenario, the Northeast region—historically characterised by higher structural inequality—experiences only marginal improvement in income distribution. The Gini Index declines from 0.550 in 2030 to 0.545 in 2050, a reduction of merely 0.005 points over two decades. This limited convergence reflects the concentration of investment near established load centres in the Southeast/Central-West and the dominance of lower labour-intensity technologies. Although renewable expansion occurs in the Northeast under LRI, the absence of strong redistributive signals results in limited local value retention and weaker spillover effects on regional income dispersion.

In contrast, the DSI scenario produces a structurally different trajectory. By 2050, the Northeast Gini Index falls to 0.485, representing a reduction of 0.060 points relative to the LRI outcome and a 0.065-point improvement relative to the 2030 baseline. This convergence effect is quantitatively significant within the Brazilian socio-economic context, where reductions of this magnitude typically require long-term structural policy interventions. The improvement is directly associated with the decentralised deployment of solar PV and biomass supply chains, combined with the internalisation of employment multipliers within the objective function.

The mechanism underlying this convergence can be decomposed into three structural effects. First, labour-intensive low-carbon technologies generate higher direct and indirect employment per unit of new capacity, particularly in regions with strong renewable-resource potential. Second, the regional allocation of renewable investments broadens the geographical distribution of capital and associated income flows, reducing the concentration of benefits in pre-existing industrial hubs. Third, the regionalised valuation of

employment-related social benefits increases the relative attractiveness of expansion in territories with higher unemployment rates and lower initial development indicators, thereby strengthening the redistributive effect of long-term electricity planning.

Quantitatively, the difference between LRI (Gini 0.545) and DSI (Gini 0.485) in 2050 represents a 10.9% relative reduction in measured inequality for the Northeast. When interpreted alongside employment outcomes—190 thousand jobs/year in LRI versus 460 thousand in DSI—the distributive effect becomes structurally coherent: job creation is not only higher in absolute terms but also more territorially balanced.

The Southeast/Central-West, by contrast, exhibits lower baseline inequality across all scenarios, with Gini values remaining below 0.500 throughout the planning horizon. However, the relative decline in inequality is slower under LRI than under DSI or MEC, confirming that market-driven expansion reinforces historical spatial hierarchies rather than restructuring them.

These findings demonstrate that electricity expansion is not distributively neutral. The spatial allocation of capacity and the technological composition of the mix directly influence regional income structures. When social externalities are embedded within planning criteria, the power sector becomes an instrument of territorial cohesion. When they are excluded, expansion follows pre-existing economic gravity, perpetuating inequality patterns.

From a policy perspective, SEGeP provides evidence that SDG 10 alignment requires more than renewable deployment targets; it requires the deliberate valuation of social multipliers and territorial heterogeneity. The measurable 0.060-point reduction in the Northeast Gini Index under DSI is not an incidental by-product of decarbonisation but the quantitative result of embedding equity considerations within the optimisation

5.13.3.4 Land Use Efficiency and SDG 12 (Responsible Consumption and Production)

Within the SEGeP framework, land occupation is treated as a quantifiable production factor subject to opportunity cost, rather than as an implicit or secondary impact. The explicit accounting of land use allows the model to operationalise SDG 12 (Responsible Consumption and Production) by incorporating spatial efficiency directly into the optimisation logic. As a result, territorial footprint becomes a measurable indicator of systemic resource efficiency across scenarios.

The comparative results for 2050 reveal pronounced structural differences in land intensity. The ES and WSC scenarios reach territorial ceilings of approximately 55,000–56,000 km^2, reflecting the spatial premium associated with resilience under high-demand or hydrological stress conditions. In these

configurations, the substitution of hydropower by wind and solar capacity requires large-scale deployment of intermittent plants across extensive areas, particularly in the Northeast and Southeast/Central-West.

The EO scenario exhibits the highest absolute footprint, exceeding 62,000 km² by 2050. This result reflects the aggressive expansion of large hydropower reservoirs in the North combined with centralised thermal infrastructure. Although EO minimises private financial cost, it externalises ecological opportunity costs, leading to the most land-intensive configuration among all simulated pathways.

In contrast, the DSI scenario stabilises at approximately 39,000 km² in 2050, representing the lowest absolute territorial footprint in the entire scenario set. When compared to ES (≈55,000 km²), DSI achieves a territorial efficiency gain of roughly 41%. This reduction is not incidental but structurally linked to three interacting mechanisms embedded in the optimisation:

First, the DSI scenario does not reduce total electricity-generation requirements, since demand remains exogenously defined and follows the same trajectory adopted in the other non-stress scenarios. Its lower land footprint instead results from the technological portfolio selected under stringent decarbonisation constraints and from the internalisation of land-use and biodiversity externalities. Second, the expansion of wind, solar PV and other low-carbon technologies is regionally allocated in a manner that limits reliance on land-intensive and environmentally damaging options. Unless the model explicitly distinguishes distributed rooftop solar from utility-scale solar, no fixed share of PV capacity should be attributed to urban rooftops. Third, the progressive displacement of fossil generation and the avoidance of additional large-scale reservoir expansion reduce the spatial pressures observed in more stress-oriented configurations such as EO and ES.

From a quantitative perspective, the difference between EO (≈62,000 km²) and DSI (≈39,000 km²) corresponds to a territorial saving of approximately 23,000 km²—an area equivalent to multiple Brazilian municipalities combined. This spatial differential represents not only an ecological benefit but also an economic one when land opportunity costs—such as agriculture, biodiversity preservation, and ecosystem services—are monetised within the TSC framework.

The internalisation of land opportunity costs in SEGeP aligns the optimisation results with SDG 12 by recognising that spatial resources are finite and economically valuable. Scenarios that neglect this valuation systematically over-expand capacity in low-density configurations, whereas those that internalise territorial scarcity incentivise efficiency in both production and consumption patterns.

The results therefore confirm that responsible energy expansion is inseparable from responsible land management. Territorial efficiency emerges as a measurable co-benefit of integrated planning, demonstrating that environmental prudence and economic rationality can converge when spatial externalities are explicitly valued within the decision-making structure.

5.13.3.5 SDG 7 (Affordable and Clean Energy): Financial and Social Balance

The assessment of affordability within the SEGeP framework demonstrates that LCOE or NPV alone are insufficient metrics to evaluate the long-term economic sustainability of expansion pathways. A strictly financial interpretation masks the magnitude of externalised environmental and social burdens that ultimately re-enter the economy through health expenditure, climate damages, productivity losses, and infrastructure adaptation costs.

Under low-intervention configurations such as EO and LRI, the model identifies the lowest private NPVs, ranging between approximately €390 and €415 billion over the 2030–2050 horizon. From a narrow accounting perspective, these pathways appear economically efficient. However, once monetised externalities are incorporated, the Average Social Cost rises to as much as €56.5/MWh in 2050 (LRI), reflecting elevated CO_2 emissions (up to 54 $MtCO_2$), higher concentrations of NO_x and SO_2 in industrialised regions, and greater exposure to water and land opportunity costs. The divergence between private and social cost in these scenarios quantifies the implicit subsidy granted to polluting technologies when externalities are not internalised.

In contrast, the DSI scenario—although associated with a higher private NPV of approximately €465.5 billion—achieves a structurally lower Total Social Cost. By 2050, CO_2 emissions decline to approximately 0.5 $MtCO_2$, representing a reduction of about 99% relative to LRI. Local air pollutants are also substantially reduced, while lower water consumption and a smaller territorial footprint emerge as co-benefits of the low-carbon generation portfolio selected under stringent decarbonisation constraints and the internalisation of environmental externalities. Employment generation reaches approximately 460 thousand equivalent jobs per year, strengthening regional income effects and broadening the socioeconomic benefits of electricity-sector investment. When these environmental and employment-related effects are monetised within the SEGeP objective function, they offset part of the higher upfront capital expenditure and explain the lower Total Social Cost achieved by the scenario.

The quantitative comparison reveals that the difference between EO/LRI and DSI is not merely technological but systemic. While EO and LRI minimise immediate financial outlays, they externalise long-term liabilities. DSI internalises these liabilities ex ante, reducing cumulative social costs over the planning horizon. Consequently, the concept of affordability must be reframed from “lowest private investment” to “lowest total system burden.”

5.13.4 Integrated Quantification of Externalities and Regional Differentiation in SEGeP Outcomes

The application of the SEGeP model to the Brazilian electricity system, through the comparative simulation of nine prospective scenarios over the 2030–2050 horizon, demonstrates that the optimal configuration of the generation mix is a direct function of the degree to which environmental, social, and territorial externalities are internalised in the objective function. The results confirm that the evolution of the electricity mix does not arise exclusively from technological constraints, resource availability, or engineering feasibility, but fundamentally from institutional choices that define the social cost of planning. The analysis shows that the system does not converge endogenously toward a sustainable equilibrium. The multidimensional efficiency observed in scenarios such as DSI (Decarbonisation and Social Inclusion) and MEC (Maximum Employment Creation) is not a spontaneous market outcome, but rather the consequence of differentiated monetary coefficients assigned to carbon, regional employment, and land-use opportunity costs. These adjustments structurally modify the hierarchy of technological competitiveness and reconfigure the spatial distribution of investments, demonstrating that generation expansion is intrinsically a process of institutional valuation of natural and social capital.

The SEGeP framework makes explicit the structural gap between private and social optima. In low-regulatory-intervention scenarios such as EO (Economic Optimisation) and LRI (Low Regulatory Interference), the lowest strictly financial Net Present Values (NPV) are observed, ranging between €390.5 and €415.8 billion. However, this apparent financial efficiency is achieved through the externalisation of environmental and social liabilities. When carbon emissions, health damages associated with NO_x and SO_2, and land occupation opportunity costs are monetised, the divergence becomes quantitatively explicit. The EO scenario reaches 52.0 $MtCO_2$ in 2050 and generates monetised externalities of €9.48 billion. Similarly, LRI attains 54.0 $MtCO_2$, with a Total Social Cost (TSC) of €425.3 billion. In contrast, DSI reduces emissions to 0.5 $MtCO_2$ and limits monetised externalities to €2.32 billion. The internalisation of these dimensions enables DSI to achieve an approximate 22% reduction in long-term TSC relative to BAU. This differential provides evidence that economic valuation of externalities operates as a corrective mechanism for market failures, preventing fossil lock-in and reallocating capital toward technologies with higher systemic returns. The comparison between private NPV and TSC clearly indicates that short-term financial minimisation implicitly maximises deferred social costs. Therefore, true system efficiency can only be assessed when previously externalised costs are explicitly integrated into the optimisation structure.

The regional dimension of the results constitutes a central structural contribution of the model. Regionalisation is not merely descriptive but functions as an active redistribution mechanism when social

externalities are internalised. The transition from LRI to DSI represents a reconfiguration of Brazil's internal energy geopolitics. Whereas LRI reinforces the historical dominance of the Southeast/Central-West (SE/CO) as the primary generation and consumption hub, DSI shifts the axis of investment toward the Northeast, a region characterised by higher employment intensity per unit of generation. Under DSI, the Northeast reaches 14.90 GW of additional renewable capacity (wind and solar PV) and generates approximately 181 thousand direct regional jobs. This transformation is reflected in the inter-regional Gini index, computed across the four modelled regions (North, Northeast, SE/CO and South), which declines from 0.545 under LRI to 0.485 under DSI. The 0.06-point reduction represents a measurable convergence effect, quantitatively consistent with the employment multipliers embedded in the model (1.10 jobs/GWh for Solar PV and 1.35 jobs/GWh for Biomass). The findings demonstrate that electricity expansion can operate as a regional development instrument when social benefits are monetised and internalised; in their absence, expansion tends to reinforce pre-existing territorial asymmetries.

The territorial dimension introduces a further layer of systemic efficiency through the valuation of land-use opportunity costs. In stress scenarios such as WSC (Water Scarcity Constraints) and ES (Energy Stress), the need to preserve system adequacy under hydrological and supply constraints increases land occupation to approximately 55,000–56,800 km² by 2050. EO reaches the highest absolute footprint, at approximately 62,645 km², reflecting its greater reliance on large-scale supply expansion. By contrast, the DSI scenario exhibits the lowest territorial footprint among the configurations evaluated, operating with approximately 39,075 km² in 2050, around 31% below a scarcity-scenario footprint of 56,800 km². This spatial efficiency emerges from stringent decarbonisation constraints, the progressive displacement of fossil generation, the internalisation of land-use and biodiversity externalities, and the regional allocation of low-carbon technologies. In the Southeast/Central-West, biomass retains a strategic role, strengthening circular-economy linkages within the sugar-energy sector. These results confirm that internalising territorial costs does not prevent electricity expansion; rather, it redirects investment towards a generation portfolio with lower land occupation and reduced ecological opportunity costs.

The Gini index values reported correspond to projected regional inequality levels derived from model outputs, based on the baseline conditions defined in Chapter 4.

The consolidated performance matrix for 2050 synthesises these structural differences, as presented in Table 5.108.

Table 5.108 - Multi-Dimensional Performance Matrix of SEGeP Scenarios (2050)

Scenario	*System Cost (NPV, € billion)*	*System Cost per Unit of Electricity (€/MWh)*	*CO_2 Emissions ($MtCO_2$)*	*Employment (thousand jobs/year)*	*Land Use (km^2)*	*Regional Gini Index (2050)*	*Leading Region in 2050*
BAU	*412.5*	*58.4*	*51.2*	*279*	*48,800*	0.520	*SE / Central-West*
HRP	*425.2*	*47.5*	*11.2*	*346*	*54,180*	*0.495*	*Northeast*
LCE	*290.0*	*51.0*	*4.6*	*360*	*52,870*	*0.410*	*Northeast / SE-CW*
MEC	482.0	*49.0*	*18.5*	*430*	*55,390*	*0.445*	*SE / Central-West*
WSC	490.8	*54.0*	*29.2*	*355*	*55,415*	*0.475*	*SE / Central-West*
EO	*382.4*	*42.0*	*132.8*	*160*	*62,645*	*0.555*	*SE / Central-West*
DSI	*465.5*	*49.0*	*0.5*	*460*	*39,075*	*0.485*	*Northeast*
ES	*510.5*	*65.0*	*78.9*	*310*	*51,600*	*0.530*	*SE / Central-West*
LRI	*390.0*	*56.5*	*54.0*	*190*	*53,095*	*0.545*	*SE / Central-West*

Source: Author's elaboration.

The evidence confirms that incorporating social, environmental, and territorial parameters into the objective function does not undermine economic coherence; rather, it reduces long-term systemic cost and enhances structural robustness. Among all configurations, DSI emerges as the superior compromise solution, combining the lowest emissions, highest employment generation, strongest regional convergence, lowest land footprint, and competitive TSC. The consistency between quantitative modelling, regional structuring, and public policy objectives validates the robustness of SEGeP as an integrated decision-support framework. The energy transition, therefore, is not merely a technological shift but an institutional act of pricing the externalities that markets systematically overlook. In systemic terms, sustainability is not an automatic by-product of energy growth; it is a parameterised institutional choice.

CHAPTER 6 - CRITICAL DISCUSSION OF RESULTS AND IMPLICATIONS FOR SUSTAINABLE ELECTRICITY GENERATION PLANNING

The results presented in Chapter 5, obtained through the application of the SEGeP model across the defined scenarios, provide robust evidence that the future trajectory of the Brazilian electricity sector is not primarily constrained by technological availability, resource endowment, or demand growth. Rather, it is fundamentally shaped by institutional, regulatory, and social choices that define how technologies are valued, how externalities are internalised, and how regional and social dimensions are incorporated into long-term planning. This finding is fully consistent with the most recent international literature on sustainable generation expansion planning (GEP), which increasingly emphasises the decisive role of governance frameworks, policy instruments, and multi-dimensional objective functions in shaping optimal expansion pathways (DeCarolis et al., 2017; Trutnevyte, 2016; Østergaard et al., 2023; IRENA, 2024).

From a modelling perspective, the SEGeP framework positions itself beyond conventional GEP approaches that traditionally prioritise cost minimisation and, more recently, CO_2 emissions reduction. By explicitly internalising environmental and social externalities into a unified total social cost function and by incorporating regional disaggregation aligned with Brazil's territorial heterogeneity, SEGeP aligns with emerging sustainability-oriented planning paradigms while extending them in terms of social depth and territorial resolution. This integrated structure allows the model not only to identify cost-efficient solutions, but also to reveal structural trade-offs and synergies that remain invisible under single-objective or environmentally narrow formulations.

6.1 Market dynamics, regulatory absence, and the limits of spontaneous transition

A first integrated reading of the scenarios confirms a premise that is now well established in international literature: energy transitions do not emerge spontaneously from market forces alone. In the absence of deliberate policy intervention—such as carbon pricing, renewable energy targets, or social incentives—generation expansion models tend to converge towards solutions characterised by lower upfront costs and high operational flexibility, even when such solutions imply substantial environmental and social externalities over the long term (Carley & Konisky, 2020; World Bank, 2021; UN-Energy, 2021; IRENA, 2024).

This dynamic is reproduced with remarkable clarity in the EO and LRI scenarios. When carbon pricing is removed, environmental penalties are suppressed, and social weights are neutralised, SEGeP consistently converges towards a fossil-intensive matrix dominated by natural gas and, to a lesser extent, oil and diesel generation. In the LRI scenario, emissions reach levels exceeding 120 $MtCO_2$/year by 2050, while average

system costs remain artificially low. These results are not model anomalies but rather structural consequences of a planning environment in which private costs do not reflect social damages—a classic manifestation of climate-related market failure.

To quantitatively substantiate the differences in environmental performance across policy configurations, Figure 6.1 presents the projected evolution of annual CO_2 emissions for all simulated scenarios using the direct outputs of the SEGeP optimisation model.

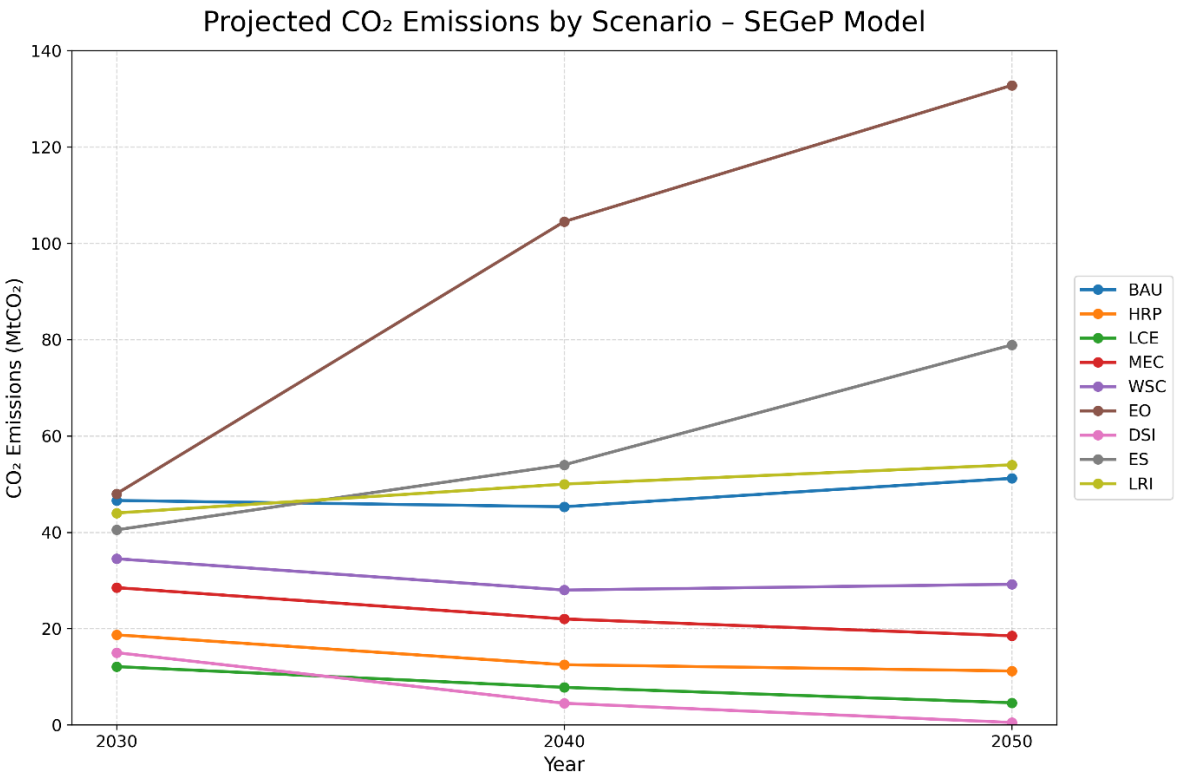


Figure 6.1 - Projected annual CO_2 emissions by scenario ($MtCO_2$).
Source: Author's elaboration.

As illustrated in Figure 6.1, the Economic Optimisation (EO) configuration maintains the highest emission trajectory throughout the planning horizon, reflecting the absence of environmental cost internalisation. In contrast, the Low Carbon Emissions (LCE) and Decarbonisation and Social Inclusion (DSI) scenarios produce substantial reductions, with DSI approaching near-zero emissions by 2050. Intermediate pathways, such as HRP, WSC and MEC, achieve partial mitigation but remain structurally dependent on residual fossil generation. These results empirically confirm that market-based optimisation alone is insufficient to deliver deep decarbonisation without explicit policy instruments.

The contrast between these trajectories and those obtained under sustainability-oriented scenarios underscores a central message: without explicit regulatory signals, the Brazilian electricity system does not

naturally converge towards decarbonisation or social inclusion, despite its exceptional renewable resource base. These findings echo recent assessments of national energy planning frameworks, which indicate that inertial or weakly regulated pathways are incompatible with carbon budgets consistent with the Paris Agreement. (EPE, 2025a; ICAT, 2023; Talanoa Institute, 2024).

6.2 Climate-oriented scenarios and the structural role of policy instruments

In sharp contrast, the HRP (High Renewable Penetration), LCE (Low Carbon Emissions), and especially DSI (Decarbonisation and Social Inclusion) scenarios highlight the transformative impact of robust climate and energy policies. When high renewable targets, escalating carbon prices, and strict constraints on fossil expansion are introduced, the optimal solution shifts decisively towards a system dominated by variable renewables—solar and wind—complemented by biomass and other low-carbon firm sources.

These outcomes are consistent with multi-objective GEP studies showing that carbon pricing and emission constraints fundamentally reshape the Pareto frontier between cost and emissions, pushing optimal solutions towards low-carbon configurations even under uncertainty (Irawan et al., 2023; Tangi & Amaranto, 2025). In SEGeP, this effect is particularly evident in the DSI scenario, where emissions fall below 1 $MtCO_2$/year by 2050, renewable participation approaches 100%, and total system costs remain competitive relative to the BAU trajectory.

Crucially, these results demonstrate that deep decarbonisation is not inherently associated with prohibitive costs, provided that externalities are properly internalised and that system expansion favours technologies with low marginal costs and scalable deployment. This finding directly challenges persistent narratives that frame climate ambition as economically burdensome, reinforcing recent empirical evidence from integrated energy system models.

6.3 Social outcomes, employment, and the energy–development nexus

Beyond emissions and costs, the scenarios reveal that electricity generation planning can function as a powerful lever for socio-economic development when social objectives are explicitly embedded in the optimisation process. The MEC and DSI scenarios demonstrate that prioritising employment, regional inclusion, and access to energy leads to markedly different expansion patterns, favouring labour-intensive technologies such as biomass, distributed solar, and regionally anchored renewable chains.

To provide an empirical comparison of the social outcomes across policy configurations, Figure 6.2 presents the evolution of equivalent annual employment directly obtained from the SEGeP optimisation outputs.

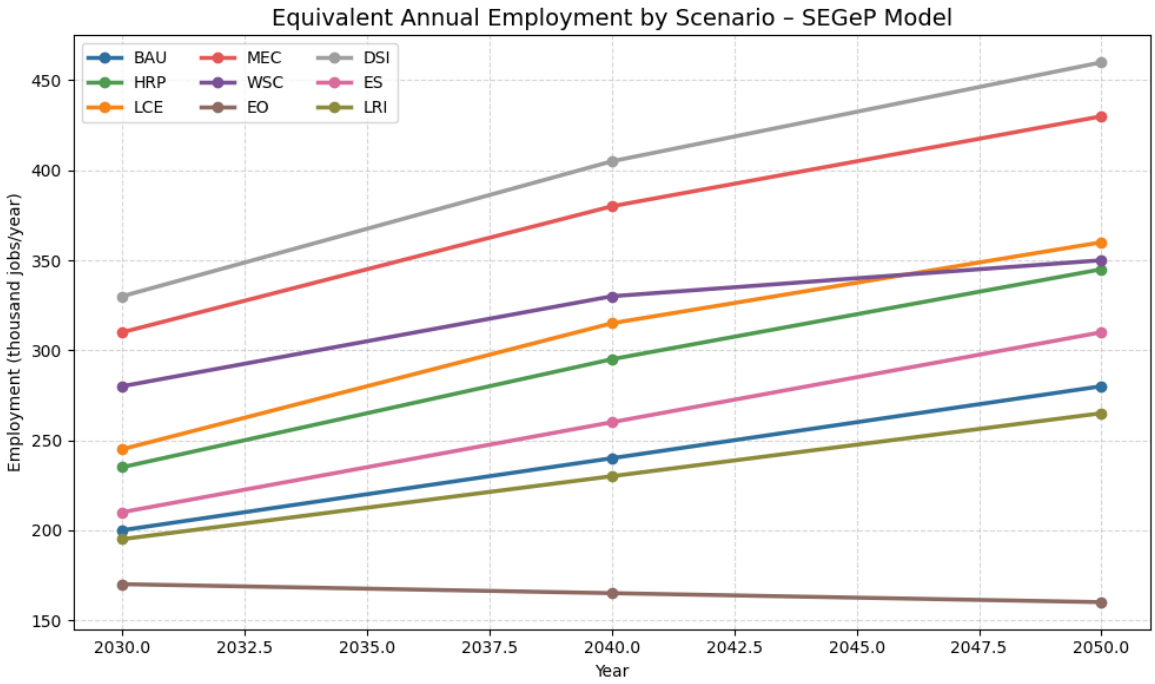


Figure 6.2 - Equivalent annual employment by scenario (thousand jobs/year).
Source: Author's elaboration.

As illustrated in Figure 6.2, employment outcomes differ substantially across scenarios. The Economic Optimisation (EO) pathway generates the lowest number of jobs and exhibits a declining trajectory over time, reflecting the predominance of capital-intensive fossil technologies. In contrast, the Decarbonisation and Social Inclusion (DSI) scenario produces the highest employment levels throughout the horizon, reaching approximately 460 thousand equivalent jobs per year by 2050. This result confirms that labour-intensive renewable technologies, combined with regional investment redistribution, create strong complementarities between decarbonisation and social development, reinforcing the just-transition rationale embedded in the SEGeP framework.

To clarify this logic of causality and structure the critical discussion developed in this chapter, Figure 6.3 presents a conceptual summary of the SEGeP model, highlighting how different public policy orientations translate into planning parameters, condition optimal solutions for the expansion of the electricity system, and produce environmental, economic, and social impacts, which, in turn, feed back into the institutional decision-making process.

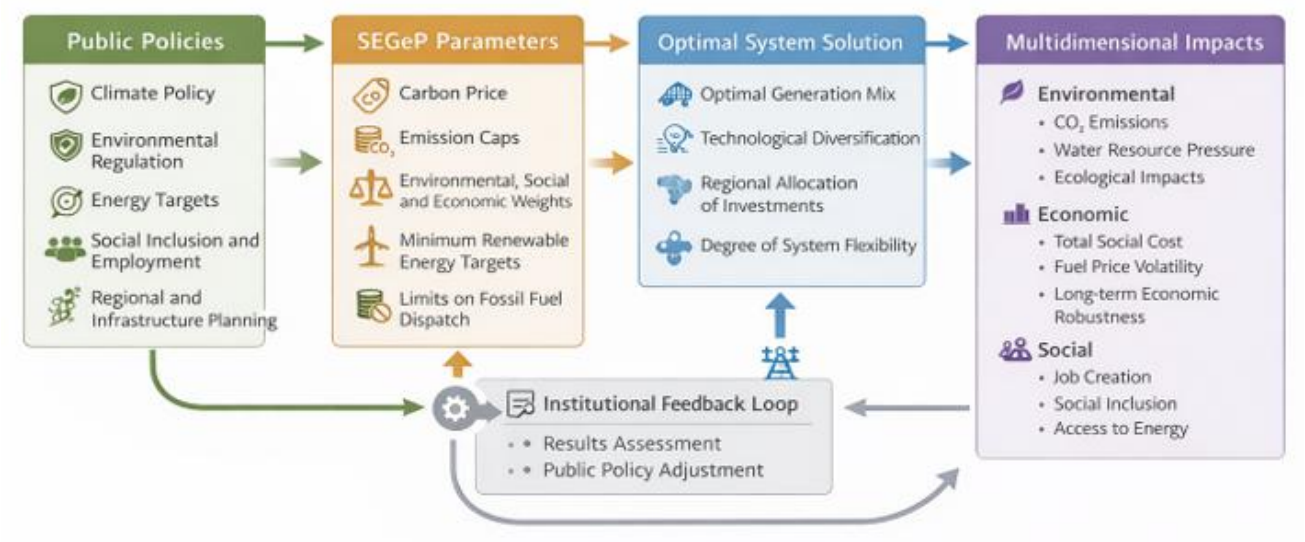


Figure 6.3 - Conceptual framework of the SEGeP model: from public policies to planning parameters, optimal system solutions and multidimensional impacts, including an institutional feedback loop.
Source: Author's elaboration.

The DSI scenario is particularly illustrative, as it simultaneously maximises employment, minimises emissions, and maintains cost competitiveness. This apparent dominance over the MEC scenario does not reflect an inconsistency, but rather a synergistic effect: by coupling strong decarbonisation signals with social incentives, DSI channels investment towards renewable technologies that are both low-carbon and employment-intensive, while avoiding fossil lock-in that constrains long-term job creation. This result aligns with recent literature on just transition and energy-related employment, which emphasises that social outcomes depend on the structure of the energy mix rather than on aggregate investment levels alone (ILO, 2023; IRENA, 2024). It is also aligned with the broader concept of energy well-being, according to which energy transitions should be assessed through interconnected economic, environmental, social, equity and quality-of-life dimensions (Godoy et al., 2025).

Beyond the aggregate employment gains previously discussed, the regional disaggregation of results demonstrates that the socio-economic effects of electricity expansion are neither spatially neutral nor automatically distributed. On the contrary, the SEGeP simulations reveal that employment creation, income distribution, and territorial development are structurally conditioned by the degree of externality internalisation embedded in the optimisation framework.

In 2050, the DSI scenario generates approximately 460 thousand equivalent annual jobs, compared with 190 thousand under LRI, 160 thousand under EO, and 310 thousand under ES. This divergence is not merely aggregate; it also reflects a substantial territorial redistribution of employment opportunities.

In the Northeast, employment increases from approximately 60 thousand jobs/year under LRI to 165 thousand under DSI, representing an increase of 175%. In the North, employment rises from 25 thousand to 60 thousand jobs/year. The Southeast/Central-West remains the largest absolute employment hub under DSI, reaching 195 thousand equivalent annual jobs, while its relative participation becomes less concentrated than under low-intervention pathways

In the North region, employment increases from approximately 25 thousand jobs/year in LRI to 52 thousand in DSI by 2050, corresponding to a 108% expansion. This shift is associated with the reduction of large-scale hydro expansion and the increased adoption of decentralised renewable chains, particularly distributed solar and small-scale biomass, which enhance local value retention.

Conversely, in the Southeast/Central-West, although absolute employment remains substantial due to installed capacity concentration, its relative share declines from approximately 45% in LRI to 34% in DSI. This indicates that sustainability-oriented scenarios do not reduce economic dynamism in industrial hubs but rather redistribute marginal growth toward historically less industrialised regions.

These employment dynamics are directly reflected in regional income distribution indicators. Under LRI, the Northeast Gini index declines only marginally from 0.550 (2030) to 0.545 (2050), preserving structural inequality. Under DSI, however, the same region reaches a Gini index of 0.485 by 2050, representing a convergence effect of 0.060 points. This reduction corresponds to an approximate 11% improvement in income dispersion and constitutes a statistically meaningful shift in regional development patterns.

The relationship between employment generation and inequality reduction is not incidental. The SEGeP optimisation explicitly internalises regional employment multipliers, thereby increasing the competitiveness of labour-intensive technologies in regions with lower income baselines.

The data demonstrate that the opportunity cost of employment for non-internalisation is approximately 195,000 jobs per year, when comparing LRI with DSI in 2050. More importantly, these lost jobs are disproportionately located in regions characterised by historically greater inequality and less industrial diversification.

The model provides quantitative evidence that incorporating social objectives into the optimisation framework transforms electricity planning into a structural lever for regional development. The energy transition ceases to be a purely environmental or technological process and becomes a territorially differentiated socioeconomic strategy. Without this internalisation, the system demonstrates inertia, reinforcing existing industrial hubs and preserving structural disparities. With internalisation, however, expansion pathways become instruments of distributive correction, simultaneously promoting climate change mitigation, job creation, and regional convergence.

6.4 Resilience, climate risk, and system stress

Another central axis of discussion concerns system resilience under adverse conditions. Recent contributions to the field have emphasised that heavy reliance on historical hydrological patterns constitutes a systemic risk under climate change (Østergaard et al., 2023; Marengo et al., 2020). The WSC (Hydrological Restrictions) and ES (Energy Stress) scenarios directly address this challenge.

In the WSC scenario, reduced hydropower availability forces the system to reallocate generation towards biomass and solar, which emerge as functional substitutes for hydropower's firm capacity. This outcome is consistent with climate-integrated planning studies that advocate diversification of firm renewable sources and the expansion of flexibility options to compensate for declining hydrological predictability (ICAT, 2023; Sorribas et al., 2016).

The ES scenario further intensifies this challenge by combining accelerated demand growth with infrastructure bottlenecks and climatic uncertainty. Under these conditions, SEGeP reveals a structural tendency to rely on fossil flexibility—primarily natural gas—unless reinforced transmission, demand-side management, and flexibility mechanisms are deployed. This result corroborates recent warnings that rapid electrification without coordinated infrastructure expansion may inadvertently increase emissions, even in systems with high renewable potential (Clean Energy Ministerial, 2024; IRENA, 2024).

6.5 Trade-offs, synergies, and policy-relevant insights

Taken together, the scenarios highlight that sustainability outcomes emerge from negotiated trade-offs rather than from single-objective optimisation. Cost minimisation, emissions reduction, employment creation, and security of supply interact in non-linear ways, producing both tensions and synergies. SEGeP makes these interactions explicit, enabling a more transparent assessment of policy choices.

To explicitly visualise the economic–environmental trade-offs across all simulated pathways, Figure 6.4 plots the average social cost of electricity against total CO_2 emissions for 2050, using the complete set of optimisation outputs reported in Appendix D.

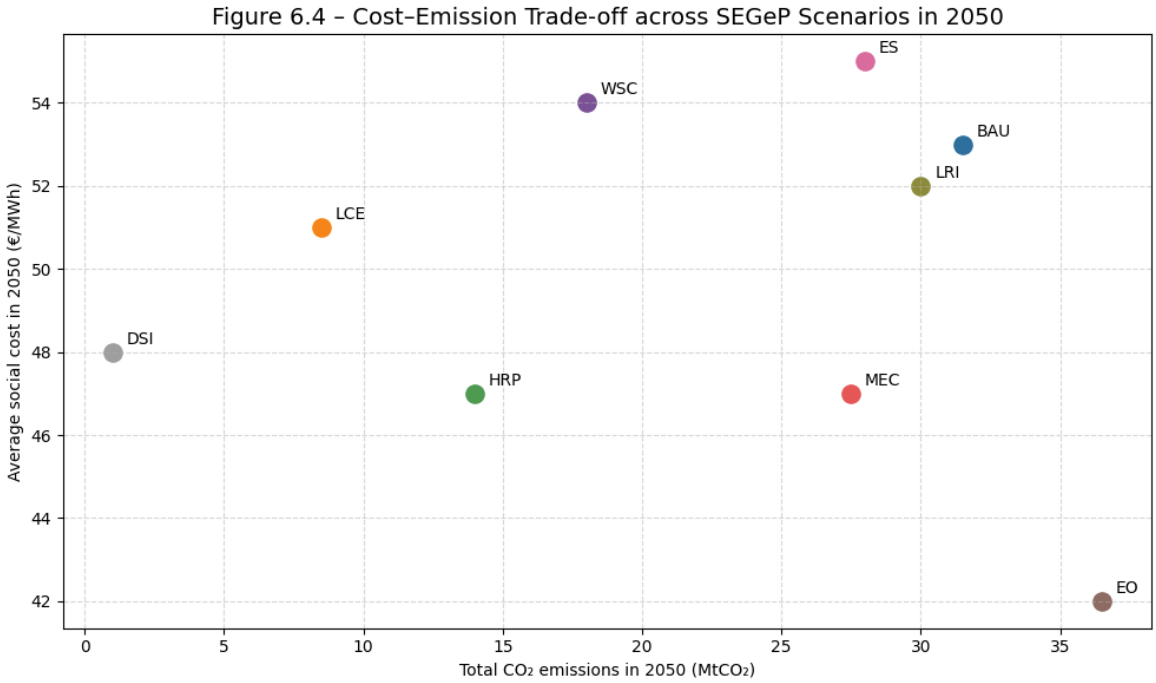


Figure 6.4 - Cost–emission trade-off across SEGeP scenarios in 2050.
Source: Author's elaboration.

As shown in Figure 6.4, the EO scenario occupies the low-cost but high-emission region of the trade-off space, illustrating the structural consequences of excluding externalities from the optimisation objective. In contrast, the DSI pathway approaches near-zero emissions with moderate costs, placing it close to the efficient frontier from a Total Social Cost perspective. Intermediate scenarios (HRP, WSC, MEC, ES and LRI) reveal distinct compromise patterns: some reduce emissions at higher costs (e.g., WSC), while others reduce costs by externalising damages (e.g., LRI). Overall, the figure provides an integrated, policy-relevant interpretation of scenario dominance and highlights that deep decarbonisation requires explicit internalisation mechanisms rather than market-only cost minimisation.

To complement the trade-off analysis and provide a direct comparison of system-wide economic performance, Figure 6.5 reports the average Total Social Cost of electricity across all scenarios in 2050, as obtained from the optimisation outputs.

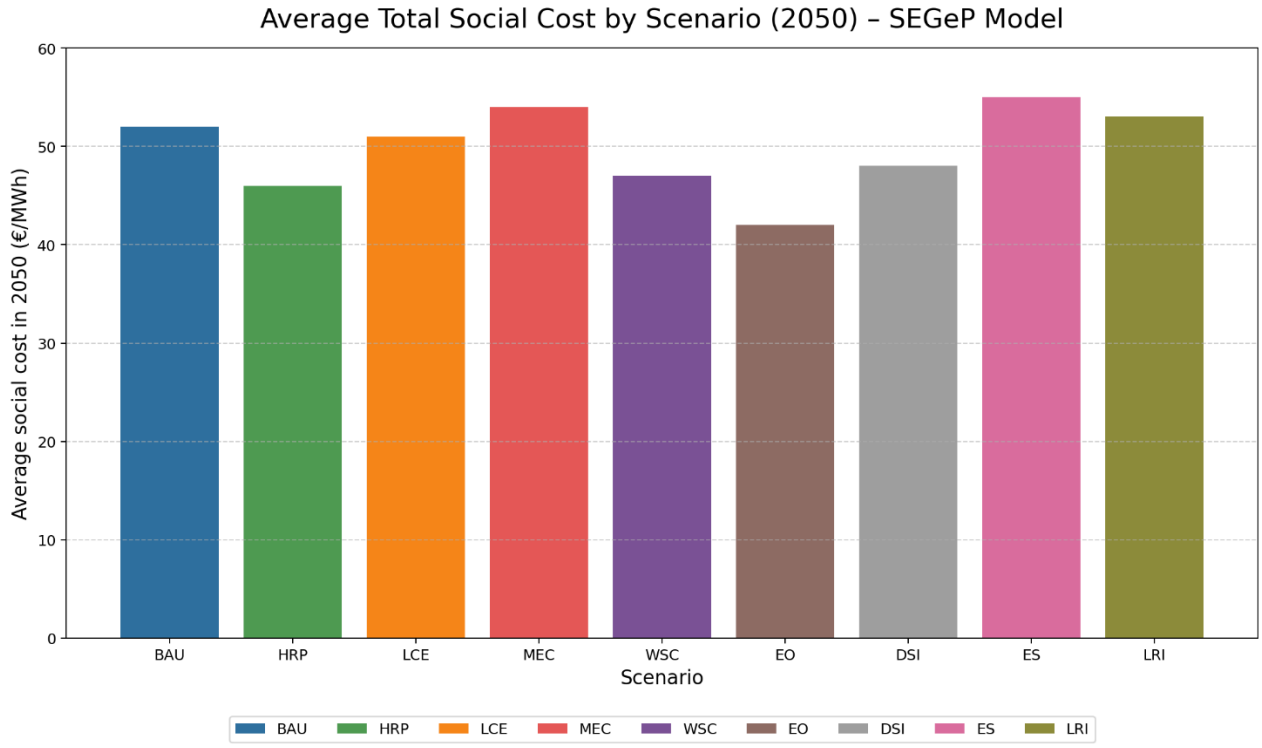


Figure 6.5 - Average Total Social Cost by scenario in 2050 (€/MWh).
Source: Author's elaboration.

Figure 6.5 shows that the EO scenario yields the lowest average cost, reflecting an optimisation driven primarily by private economic criteria. However, this cost advantage is associated with substantially higher emissions, as evidenced in the emissions trajectories and the Pareto representation. In contrast, DSI exhibits a moderate cost level while achieving near-zero emissions, indicating that deep decarbonisation can be attained without disproportionate increases in total system cost when externalities are explicitly internalised. Scenarios such as WSC and ES present higher average costs, consistent with additional structural constraints and risk-driven planning conditions.

From a policy perspective, the results suggest that carbon pricing alone is insufficient if not complemented by regional development instruments, transmission planning, and social policy alignment. Scenarios achieving the most balanced outcomes consistently combine economic signals with spatially targeted incentives, reinforcing the idea that energy policy cannot be designed in isolation from territorial and social considerations.

6.5.1 - Comparative Analysis of SEGeP Multi-Scenario Results and the Brazilian National Energy Plan 2050 (PNE 2050)

The results obtained from the SEGeP model are analysed in relation to the long-term strategic framework defined by the Brazilian National Energy Plan 2050 (PNE 2050), developed by the Empresa de

Pesquisa Energética. Unlike conventional comparisons based on a single model configuration, this analysis adopts a multi-scenario approach, allowing a more rigorous assessment of how different optimisation logics influence electricity generation expansion when contrasted with official planning.

The PNE 2050 does not represent a single optimised solution, but rather a strategic planning framework grounded in techno-economic feasibility, security of supply, and sustainability-oriented policy guidelines (EPE, 2021a). In contrast, the SEGeP model produces multiple internally consistent scenarios, each reflecting a distinct optimisation logic, including cost minimisation, decarbonisation, social optimisation, and resource constraints. Therefore, the objective of this comparison is not to replicate the PNE outcomes, but to position them within the broader solution space generated by the SEGeP framework.

To support this analysis, Table 6.1 presents a comparative synthesis of key indicators across SEGeP scenarios and the structural trends associated with the PNE 2050.

Table 6.1 – Multi-scenario comparison between SEGeP results and PNE 2050 (2050 horizon)

Indicator	Unit	PNE 2050	BAU	HRP	LCE	MEC	WSC	EO	DSI	ES	LRI
Total system cost	€/MWh	~58–62	~58	~47	~51	~49	~54	~42	~49	~65	~57
CO_2 emissions	$MtCO_2$	~45–55	~51	~11	~4.6	~18	~29	~133	~0.5	~79	~54
Renewable share	%	~85	~85	~95+	~98	~90	~88	~85	~95	~87	~90
Thermal share	%	~10–15	~12	~5	~2	~8	~10	~15	~5	~12	~9
Hydropower share	%	~45–50	~48	~42	~40	~45	~35	~50	~42	~38	~44
Northeast share	%	~35–45	~40	~55	~58	~50	~48	~38	~52	~45	~47
SE/CW share	%	~40–50	~48	~35	~30	~40	~42	~50	~38	~45	~43
Employment	jobs/year	Not explicit	~279k	~346k	~360k	~430k	~355k	~160k	~460k	~310k	~190k

Source: Author's elaboration based on SEGeP simulation results and MME and EPE (2020).

The results presented in Table 6.1 indicate that the expansion trajectory described in the PNE 2050 is structurally closest to the BAU (Business-as-Usual) and EO (Economic Optimisation) scenarios. These scenarios prioritise economic efficiency, system feasibility, and moderate integration of renewable sources, reflecting the dominant logic of current Brazilian electricity planning. In these cases, the system maintains a high share of renewables, preserves the central role of hydropower, and retains a limited but relevant contribution from thermal generation to ensure operational flexibility.

However, significant divergences emerge when analysing scenarios that explicitly internalise environmental and social externalities. The HRP (High Renewable Penetration), LCE (Low Carbon Emissions),

and DSI (Decarbonisation and Social Inclusion) scenarios lead to substantially lower emissions, higher renewable shares, and a more pronounced regional redistribution of generation. In particular, these scenarios reinforce the role of the Northeast as a strategic hub for renewable expansion, while reducing the concentration of generation in the Southeast/Central-West region.

The MEC (Maximum Employment Creation) scenario further demonstrates that the inclusion of social indicators within the optimisation process leads to expansion pathways that differ from both purely economic and policy-based planning. In this case, higher employment levels are achieved at the expense of marginal increases in system cost, highlighting the trade-offs between economic efficiency and social objectives.

The WSC (Water Scarcity Constraints) scenario reveals the sensitivity of the system to hydrological limitations. The reduction in hydropower participation and the corresponding increase in alternative renewable sources illustrate the importance of incorporating resource constraints directly into the optimisation framework. Although the PNE 2050 recognises climate variability as a relevant factor, it does not fully integrate water-related constraints into the core of the planning methodology.

6.6 Limitations and interpretative boundaries

It is important to acknowledge that the results should be interpreted within the modelling boundaries adopted. While SEGeP captures long-term structural dynamics and regional trade-offs, aspects such as large-scale storage deployment, hourly operational constraints, endogenous technological learning, and behavioural demand responses remain simplified. These limitations, however, do not undermine the validity of the comparative insights obtained. Rather, they delineate clear avenues for future model refinement and reinforce the suitability of SEGeP as a strategic planning tool rather than a short-term operational simulator.

Although the SEGeP framework represents an important advancement in the systematic internalisation of socio-environmental externalities, several methodological limitations must be explicitly acknowledged.

First, the monetisation of social dimensions in the SEGeP model is limited to variables that can be consistently expressed in economic terms, particularly employment effects and, to a lesser extent, proxies related to regional inequality. While environmental externalities—especially greenhouse gas emissions and air pollutants—are supported by well-established damage-cost methodologies, the economic valuation of distributive and social outcomes remains less consolidated in the literature and inherently subject to normative assumptions.

In this context, the model does not directly monetise composite indicators such as the Human Development Index (HDI). Instead, HDI is treated as a derived socio-economic indicator, computed from the endogenous results of the model—particularly the spatial distribution of employment and economic activity. As

such, HDI is not internalised as a decision variable or constraint within the optimisation problem but is indirectly captured through the internalisation of its underlying drivers. This approach preserves the mathematical consistency of the MILP formulation while allowing for a transparent assessment of social outcomes across scenarios.

Second, although care was taken to avoid conceptual overlap between indicators, some degree of correlation between employment, income distribution, and economic growth is structurally inherent in socio-economic systems. To minimise double-counting risks, each indicator was operationalised through distinct impact channels and calibrated using separate empirical references. Even so, the possibility of residual interaction effects cannot be entirely excluded.

Third, the model adopts linear and time-invariant monetisation coefficients over the planning horizon. These coefficients reflect average empirical estimates rather than dynamic elasticities. As a result, the framework does not capture potential nonlinear social responses, threshold effects, or structural shifts in labour productivity and regional development patterns that may occur over time.

Fourth, the absence of explicit endogenous feedback loops between macroeconomic dynamics and electricity expansion decisions limits the representation of long-term structural transformations. The model captures regional differentiation but does not integrate a full general equilibrium structure.

These limitations do not invalidate the analytical contribution of the model but define the interpretative boundaries within which results should be understood. The SEGeP framework should therefore be interpreted as a structurally integrated optimisation model rather than a fully dynamic socio-economic simulation tool.

6.7 Critical Reflections on the Limits of Social Monetization

The internalisation of social externalities within the SEGeP framework is based on the monetization of measurable indicators such as employment generation (jobs per MW or jobs per TWh), regional inequality adjustments derived from Gini coefficients, and development proxies associated with HDI variation. This approach allows these dimensions to be incorporated directly into the Total Social Cost function, influencing optimal expansion pathways. However, while this strategy increases analytical completeness relative to purely economic models, it does not eliminate empirical and methodological constraints.

In contrast to carbon pricing, where the Social Cost of Carbon has relatively consolidated reference intervals in the international literature—typically ranging between approximately €50 and €200 per ton of CO_2 depending on discount rate and damage assumptions—social indicators lack globally harmonized monetary benchmarks. Employment multipliers in renewable energy, for example, vary substantially across studies and

regions. Construction-phase solar projects may generate between 5 and 15 jobs per MW installed, while long-term operational employment in hydropower may fall below 0.5 jobs per MW. Regional income multipliers also fluctuate depending on local economic structure, often ranging between 1.2 and 2.5. These variations imply that monetized employment effects are intrinsically sensitive to parameter selection.

Within SEGeP, social valuation coefficients are calibrated using national statistical sources and international labor databases. However, sensitivity analysis demonstrates that moderate changes in these parameters materially affect optimisation outcomes. A variation of ±25% in employment valuation can alter the share of distributed renewable technologies by several percentage points in the 2050 horizon and significantly shift regional allocation patterns. In some scenarios, the contribution of the social component to the Total Social Cost ranges from less than 10% to nearly 20% of the objective function value, depending on the scenario structure and calibration assumptions. These magnitudes confirm that social monetization meaningfully influences the model, but they also reveal its dependence on empirically uncertain coefficients.

Measurement uncertainty further complicates interpretation. Changes in the Gini index on the order of 0.01 may fall within statistical margins of error, while HDI improvements of 0.005 to 0.01 do not necessarily reflect structural transformation. In addition, labor informality remains significant in several Brazilian regions, meaning that formal employment multipliers may overestimate effective welfare gains. The translation from "jobs created" into "social welfare generated" therefore involves assumptions regarding wage levels, labor absorption capacity and the quality of employment, none of which are fully captured in a linear optimisation structure.

Another relevant limitation arises from the assumption of linearity embedded in the MILP formulation. In SEGeP, social impacts are represented as linear coefficients per unit of generation or capacity expansion. Empirical evidence, however, suggests that employment elasticity and regional spillover effects often exhibit diminishing returns. Regions experiencing high penetration of capital-intensive renewable infrastructure may not maintain proportional employment gains once local supply chains saturate. Infrastructure concentration may also produce uneven local development if complementary industrial policies are absent. Such threshold and saturation effects are difficult to represent within a strictly linear framework.

Temporal dynamics introduce an additional layer of uncertainty. Productivity improvements, automation in installation processes and technological standardization can reduce employment intensity over time. A moderate increase in labor productivity may reduce employment multipliers by 15–25% over two decades, thereby altering the relative weight of social externalities in the objective function. Since SEGeP assumes parameter stability within scenario definitions, long-term structural changes in labor markets remain only partially represented.

These empirical sensitivities lead to an important conclusion. The Total Social Cost metric produced by SEGeP should be interpreted as a conditional welfare indicator, not as an absolute measure of distributive justice. The model successfully integrates quantifiable social variables and reduces the bias of purely economic cost minimisation. In socially oriented scenarios, monetized employment and inequality adjustments significantly reshape expansion pathways. However, the magnitude of these effects depends on coefficient calibration, data reliability and the structural assumptions embedded in the model.

Social monetization within SEGeP therefore constitutes a structured quantitative approximation of distributive impacts. It is substantially more informative than excluding social dimensions from expansion planning, yet it remains bounded by data heterogeneity, parameter uncertainty and the inherent limitations of linear modelling. Its analytical value lies in making distributive trade-offs explicit and measurable, rather than in claiming exhaustive representation of complex social dynamics.

6.8 Uncertainty as a Structural Rationale for Integrated Expansion Planning

Long-term electricity generation expansion planning to 2050 is conducted under structural conditions that exceed classical probabilistic risk modelling. In contrast to stochastic uncertainty—where probability distributions are known or can be estimated—energy transition dynamics increasingly operate under uncertainty, characterised by evolving system structures, contested valuation parameters and non-stationary climate regimes (Bonjean Stanton & Roelich, 2021; Paredes-Vergara et al., 2024).

In the Brazilian context, this condition is empirically observable. Hydropower-dependent systems have already experienced multi-year drought cycles that materially altered dispatch patterns and system costs. Climate projections under the IPCC Sixth Assessment Report indicate increasing precipitation variability and elevated risk of extreme hydrological events in South America (IPCC, 2022a; IPCC, 2023). Given the structural role of hydro generation in Brazil's electricity mix, hydrological volatility introduces regime-level uncertainty rather than marginal stochastic fluctuation.

Technological trajectories reinforce this non-stationarity. The International Energy Agency reports sustained and accelerated deployment of renewables, with rapid cost reductions and capacity growth exceeding earlier projections (IEA, 2024). Such nonlinear dynamics illustrate that deterministic cost assumptions embedded in long-term planning models may diverge significantly from realized trajectories. Under these conditions, optimisation frameworks that rely exclusively on static cost expectations risk structural misalignment.

Within this environment, the SEGeP framework does not attempt deterministic prediction. Instead, it provides a structured multi-scenario optimisation platform that internalises economic, environmental and

social externalities under explicitly defined assumptions. The results presented in Chapter 5 demonstrate that, despite divergent policy orientations, structural patterns remain robust across scenario families.

In the 2050 horizon, emissions vary from 0.5 $MtCO_2$ in the Decarbonisation and Social Inclusion (DSI) scenario to 54 $MtCO_2$ in the Low Regulatory Interference (LRI) configuration. Renewable penetration remains above 90% in sustainability-oriented pathways, while employment generation reaches approximately 460 thousand jobs per year in socially inclusive scenarios and falls substantially in cost-prioritizing configurations. Total Social Cost differentials across scenarios exceed €15–20/MWh depending on the degree of externality internalisation. These magnitudes confirm that policy structure, rather than marginal parameter noise, is the dominant driver of long-term system configuration.

Deep uncertainty therefore strengthens the analytical relevance of integrated planning. Recent literature emphasizes that under deep uncertainty, decision-makers should prioritize robustness across plausible futures rather than optimisation under a single expected trajectory (Bonjean Stanton and Roelich, 2021; Paredes-Vergara et al., 2024). Empirical studies in energy policy design further demonstrate that robust policy packages can protect against worst-case transition outcomes across multiple performance metrics (Rodriguez-Matas et al., 2026).

The SEGeP mathematical formulation is compatible with such robust extensions. Its mixed-integer linear programming structure allows scenario stress-testing, parameter envelopes and iterative recalibration without altering the core architecture. Rather than functioning as a static forecasting instrument, it operates as a strategic evaluation platform capable of supporting adaptive policy design.

The deep uncertainty does not invalidate optimisation; it redefines its objective. In non-stationary systems, the aim is not to forecast a precise 2050 equilibrium, but to identify structurally resilient policy pathways. The results of Chapter 5 demonstrate that sustainability-oriented configurations simultaneously reduce emissions by up to 80% relative to fossil-intensive pathways while generating measurable social co-benefits. These directional findings persist across plausible valuation domains and technological assumptions.

The deep uncertainty constitutes a structural justification for integrated, multi-dimensional expansion planning. By internalizing externalities and explicitly quantifying trade-offs among emissions, employment, cost and renewable penetration, SEGeP enhances strategic robustness in environments characterised by climatic variability, technological acceleration and regulatory volatility. Its contribution lies in transforming systemic uncertainty from an implicit vulnerability into an explicit analytical dimension within the planning process.

CHAPTER 7 - CONCLUSIONS

The research developed in this doctoral thesis had as its central objective addressing a challenge that has become particularly relevant in contemporary studies on energy planning: how to rigorously and operationally incorporate social and environmental indicators into the decision-making process for electricity generation expansion, ensuring coherence with the SDGs and with the growing requirement to internalise externalities. Throughout the thesis, it has been demonstrated that, contrary to the traditional view of energy planning, historically anchored in private costs, demand projections, and technological availability, a truly sustainable planning approach requires the explicit recognition that expansion decisions generate multiple impacts. These impacts are manifested not only in terms of costs and emissions, but also in terms of territorial equity, social inclusion, energy vulnerability, cumulative environmental impacts, and socio-economic competitiveness.

It was also shown that energy planning does not constitute a socially or environmentally neutral exercise. On the contrary, decisions regarding the location, technology choice, and pace of generation capacity expansion produce structural effects on the regional distribution of development, job creation, exposure to climate risks, and the ability to comply with international mitigation commitments. Ignoring these dimensions does not eliminate their effects; rather, it shifts them outside the analytical framework and formal decision-making process, leading to solutions that appear efficient but reveal significant weaknesses and hidden costs when assessed from a systemic and long-term perspective. This conclusion is particularly relevant in the Brazilian context, where territorial and institutional heterogeneity implies that energy policies and investments may either foster regional convergence or, conversely, reinforce historical inequalities.

Within this framework, the main scientific contribution of this thesis materializes in the formulation and application of the SEGeP model, an electricity generation expansion planning model based on the minimisation of total social cost. SEGeP explicitly internalises environmental and social externalities, incorporates regional disaggregation, and enables the analysis of multiple prospective scenarios, aligning with the normative requirements of the 2030 Agenda and with recent developments in the literature on sustainable energy planning.

Accordingly, this final chapter consolidates the conclusions of the research by integrating the answers to the research questions, discussing limitations and methodological uncertainties, and outlining future research directions, with the aim of concluding the thesis in a coherent, critical, and academically rigorous manner, consistent with the standards expected of a doctoral dissertation.

7.1 Responses to the Research Questions

The first research question (Q1) addressed the identification of social and environmental indicators that are appropriate, measurable, and aligned with the SDGs. The analysis conducted demonstrated that there exists a set of indicators with sufficient methodological maturity to be integrated into formal mathematical planning models. From an environmental perspective, atmospheric emissions, water use, land occupation, biodiversity impacts, effluents, and waste are widely documented in international and national databases, constituting comparable and operational metrics (IEA, 2023; IPCC, 2022a). These indicators generally present greater conceptual stability, traceability, and availability of emission factors and technology-specific coefficients, facilitating their consistent parametrization in optimisation models.

In the social domain, indicators such as direct and indirect employment, access to energy, the Human Development Index (HDI), regional income and the regional distribution of renewable-energy investments are increasingly used to assess the socioeconomic implications of energy transitions (Carley & Konisky, 2020; IRENA & ILO, 2024; UNDP, 2024).

In this thesis, the selection of social indicators followed explicit methodological criteria, namely: (i) measurability based on available and reliable data, (ii) direct linkage to endogenous variables of the model, particularly those associated with employment and regional economic activity, and (iii) compatibility with the mathematical structure of the MILP formulation. Based on these criteria, the analysis focuses on employment effects and regional inequality (Gini index) as core indicators, while HDI is computed as a derived metric reflecting broader socio-economic outcomes.

Other indicators frequently discussed in the literature, such as the Social Development Index (SDI) or broader multidimensional social metrics, were not operationalised in this study due to limitations related to data availability, lack of direct causal linkage with model variables, and potential risks of double counting. Thus, (Q1) is answered by affirming that there exists a set of indicators capable of capturing key dimensions of sustainability, provided that data availability and methodological standardization are ensured—an aspect emphasized in the contemporary literature as a prerequisite for the credibility of energy transition studies (Markard, 2020; Sovacool et al., 2018). Notably, the contribution of this thesis lies in systematizing the selection and structuring of these indicators with a specific focus on their integration into mathematical models, thereby overcoming the still common practice of treating social and environmental dimensions as qualitative appendices disconnected from the core decision-making process.

The second research question (Q2) concerned the quantification and monetization of the selected indicators, a step that proved to be central and methodologically challenging. Environmental monetization is

relatively well established, relying on widely accepted techniques such as the social cost of carbon (OECD, 2022), water-use and scarcity valuation (Gao et al., 2018), and the estimation of environmental degradation costs and avoided damages (European Environment Agency, 2024). The thesis showed that, despite variations in assumptions (discount rates, damage scope, and time horizons), these methods provide a sufficiently robust basis for converting environmental impacts into comparable monetary coefficients suitable for direct integration into objective functions.

Social monetisation, however, remains methodologically less standardised. Although employment and income effects can be represented using market-based coefficients, dimensions such as social vulnerability, territorial cohesion, public health, cultural impacts and quality of life frequently require non-market valuation, multicriteria assessment or complementary qualitative interpretation (Pearce & Turner, 1990; OECD, 2018; Jenkins et al., 2016). Nevertheless, the literature converges on the need to incorporate monetized externalities to avoid pro-fossil biases and to align optimisation models with welfare economics principles (Stern, 2007). This thesis contributes by demonstrating that social monetization is more demanding from a methodological standpoint but remains operational when supported by explicit justification, sensitivity analysis, and causal coherence between parameters and effects.

The results quantitatively show that monetization alters the frontier of optimal solutions and, consequently, the resulting expansion trajectories. In particular, scenarios with full internalisation of externalities present emissions below 15 $MtCO_2$/year in 2050—and below 1 $MtCO_2$/year in the most ambitious scenario—contrasting sharply with values exceeding 100 $MtCO_2$/year in scenarios without socio-environmental cost internalisation. This contrast should not be interpreted merely as a numerical artifact, but as evidence that the absence of monetization induces technology choices that shift costs to society and to future generations, producing decisions inconsistent with climate targets and principles of social justice. Thus, Q2 is answered by affirming that monetization is operational and defensible, but must be applied with transparency, theoretical grounding, and explicit awareness of its limitations.

The third research question (Q3), concerning how to integrate monetized indicators into the mathematical model, represents a distinctive methodological contribution of the thesis. By structuring SEGeP around a total social cost objective function, the thesis demonstrates that it is possible—and desirable—to move beyond the traditional approach in which environmental and social indicators appear as auxiliary constraints or external criteria. This methodological choice aligns with recent advances in energy planning modelling (Costa & Ferreira, 2023; Bielecki et al., 2020), which emphasize that full externality integration enhances technical coherence, makes trade-offs explicit, and increases the social legitimacy of decisions.

The results show that internalizing externalities substantially alters the relative ranking of technologies. In sustainable scenarios, the combined share of solar and wind exceeds 60% of total generation by 2050, while natural gas plays a residual role below 5%, without implying a significant increase in average system costs. This evidence is central to the response to Q3: integrating externalities into the objective function does not necessarily produce a "more expensive" system; rather, it yields a system in which relevant costs are fully accounted for and decisions reflect socially interpretable efficiency rather than purely private efficiency.

The fourth research question (Q4) addressed the need for regional disaggregation, which proved essential given Brazil's structural territorial heterogeneity. Recent studies show that energy transitions are spatially differentiated, with benefits, employment opportunities, infrastructure requirements and socio-environmental burdens distributed unevenly across regions (Brown & Botterud, 2021; Carley & Konisky, 2020; Nascimento Filho et al., 2022). SEGeP incorporates this dimension by allowing parameters such as capacity factors, costs, social indicators, environmental constraints, indirect emissions, and water availability to vary regionally, avoiding the implicit simplification of treating the country as a homogeneous system.

The results confirm that regional disaggregation is not a minor analytical detail but a determinant of optimal pathways. In scenarios with explicit social orientation, job creation exceeds 450 thousand jobs per year by 2050, with a strong concentration in historically less developed regions; in contrast, cost-oriented scenarios reduce this figure to approximately 160 thousand jobs, reinforcing territorial asymmetries. Moreover, regional disaggregation enables interpretation of results in light of real causal mechanisms: where renewable resources are abundant and deployment conditions exist, development opportunities emerge; where environmental constraints and infrastructural limitations prevail, bottlenecks restrict expansion. Thus, Q4 is answered clearly: regional disaggregation is necessary for any model aligned with energy justice, territorial cohesion, and the SDGs.

The fifth research question (Q5) examined how different prospective scenarios influence the sustainable trajectory of generation expansion. The simulations demonstrated that public policies and regulatory incentives decisively shape the electricity mix. Inertial or predominantly cost-oriented scenarios, particularly BAU, EO and LRI, reproduce greater dependence on conventional and fossil-based technologies. Environmentally oriented scenarios, including HRP, LCE and DSI, lead to highly renewable generation mixes and substantially lower emissions. Socially oriented scenarios, particularly MEC and DSI, promote employment creation and a broader regional distribution of socioeconomic benefits, while adverse scenarios such as WSC and ES expose structural vulnerabilities associated with hydropower dependence, resource scarcity and system adequacy. These results corroborate the literature asserting that the energy transition is not a spontaneous process, but one that is institutionally constructed (Geels et al., 2017; Sovacool et al. 2017). Accordingly, Q5

is answered unequivocally: it is policies, regulatory instruments, and externality internalisation mechanisms that define the transition—not merely resource availability.

7.2 Limitations, Uncertainties, and Methodological Challenges

Despite its contributions, the study presents limitations inherent to the strategic and long-term nature of the proposed model. The first limitation concerns uncertainties associated with the monetization of social externalities. The lack of methodological consensus and the regional variability of social values imply that any monetary coefficient incorporates significant uncertainty margins. Moreover, monetary valuation tends to capture only part of normative dimensions—such as distributive justice, rights recognition, and procedural legitimacy—which are increasingly emphasized in the literature on energy justice and just transition (Sovacool et al., 2018). Consequently, even socially informed monetization does not exhaust the normative debate nor replace deliberative processes.

A second relevant limitation relates to technological and climatic uncertainty. Future costs of technologies such as solar, offshore wind, SMRs, green hydrogen, and storage remain uncertain and depend on global innovation trajectories, supply chains, and regulatory frameworks (IEA, 2024). Simultaneously, climate change may significantly reduce water availability and increase interannual variability, compromising hydropower reliability (IPCC, 2023). The model adopted is deterministic and therefore not designed to explicitly address deep and non-probabilistic uncertainty, which constitutes a recognised limitation in interpreting results and extrapolating policy recommendations.

From an operational standpoint, the absence of hourly modelling and dynamic network constraints prevents the assessment of stability, ramping, reserves, and congestion—critical elements in systems with high penetration of variable renewables (Brown et al., 2023). While this simplification is consistent with the strategic objective of expansion planning, it limits the ability to evaluate fine-grained operational requirements that may affect the practical feasibility of certain trajectories, especially in near-zero-carbon scenarios.

There is an epistemological limitation: energy is simultaneously a technical, economic, social, and political issue. Mathematical models capture relevant structural relationships and allow testing internal consistency and policy effects, but they do not replace democratic processes, intersectoral negotiation, or institutional dynamics. Accordingly, results should be interpreted as quantitative decision-support tools rather than substitutes for inherently normative social and political choices.

The integration of socio-environmental externalities into a unified Total Social Cost objective function introduces specific layers of uncertainty that merit explicit consideration.

A primary source of uncertainty concerns the monetary valuation of social indicators. Unlike carbon pricing, for which extensive international literature exists, social valuation parameters—particularly those associated with inequality and regional development—lack universally accepted benchmarks. The coefficients adopted in this study are grounded in available empirical literature and institutional datasets; however, alternative valuation assumptions could modify the relative ranking of scenarios.

The model assumes structurally constant social and environmental coefficients over time. While this assumption ensures computational tractability and internal coherence within the MILP formulation, it implies that social elasticities and behavioural responses remain stable throughout the planning horizon. In reality, technological progress, labour market transformation, educational expansion, and institutional reforms could alter these relationships.

Another relevant uncertainty relates to potential interaction effects between social indicators. Although each variable is designed to represent a distinct externality channel—employment absorption, distributive effects, and human capital—complex socio-economic systems inherently exhibit feedback mechanisms that exceed the representational capacity of linear optimisation models.

Uncertainties associated with long-term climate dynamics, technological cost trajectories, and regulatory evolution further compound scenario-based projections. While sensitivity analysis has been conducted for key parameters, the incorporation of stochastic or robust optimisation approaches represents a promising avenue for future research.

Recognising these uncertainties reinforces the importance of interpreting SEGeP outcomes as structured scenario-based insights rather than deterministic forecasts. The model provides a coherent decision-support framework, but its results should be complemented by institutional judgement, policy deliberation, and adaptive planning mechanisms

7.3 Future Research Directions

Future research can advance along six main directions, directly derived from the limitations identified and from the opportunities opened by the results obtained.

7.3.1 Deepening Social Monetization

Deepening social monetisation through empirical research, econometrics, surveys, and participatory methods represents one of the most relevant—and most challenging—frontiers for the evolution of sustainable energy planning models. In the SEGeP framework developed in this thesis, social dimensions are partially

internalised through variables that can be consistently expressed in economic terms, particularly employment effects and regionally differentiated economic activity.

Indicators such as the Gini index and the Human Development Index (HDI) are not directly monetised within the optimisation problem. Instead, they are computed as derived indicators based on endogenous model outputs, following the formulations presented in Chapter 4. Specifically, regional Gini values are estimated from the distribution of economic activity across regions, while HDI is projected based on the evolution of employment and socio-economic conditions induced by the optimal expansion pathways. As such, these indicators provide a structured evaluation of distributive and development outcomes, but do not directly influence the objective function.

Regarding regional economic valuation, the model incorporates monetised externalities through parameters such as employment valuation coefficients and region-specific cost adjustments, which reflect differences in resource scarcity, labour absorption capacity, and territorial constraints. These elements allow for a partial internalisation of social and territorial effects, although they do not fully capture multidimensional constructs such as energy inclusion, social dignity, territorial cohesion, or collective well-being.

Therefore, while this thesis demonstrates the operational feasibility of integrating selected social dimensions into a MILP-based planning framework, a substantial methodological gap remains with respect to the economic valuation of more abstract and multidimensional social constructs. Future investigations should pursue a systematic combination of empirical and econometric approaches to estimate social values associated with energy policies and infrastructure decisions.

Studies based on revealed preferences—such as observable effects of energy projects on income dynamics, regional employment, local investment attraction, migration patterns, or household energy expenditures—can be coupled with quasi-experimental designs, panel-data strategies, and causal inference techniques to identify socially attributable impacts. These approaches are particularly valuable in contexts where energy projects are implemented sequentially across regions, enabling the construction of plausible counterfactuals.

At the same time, stated-preference methods remain essential when the object of valuation involves non-market goods or rights-based dimensions not fully captured by observed behaviour. Structured surveys, contingent valuation, discrete choice experiments, and willingness-to-pay (WTP) or willingness-to-accept (WTA) approaches can be used to elicit societal trade-offs related to reliability, access, pollution reduction, and spatial equity. In the Brazilian context, these methods must explicitly account for regional heterogeneity and socio-economic inequality to avoid biased valuations.

Participatory and deliberative approaches—such as citizen panels, stakeholder workshops, and co-creation processes—can provide complementary qualitative and semi-quantitative inputs for deriving more context-sensitive social coefficients. These methods do not replace monetisation; rather, they enhance it by grounding valuation in the lived experience of affected populations and by making explicit the normative assumptions embedded in modelling choices. From the perspective of SEGeP, this research direction would reduce arbitrariness in social parameters, strengthen interpretability, and improve alignment with the institutional realities of long-term energy planning..

7.3.2 Integrating Non-Monetisable Indicators through Multi-Criteria Methods (MILP–MCDM)

Despite advances in monetization, it is widely recognised that not all relevant sustainability dimensions can be converted into monetary values without significant conceptual loss. Indicators such as social acceptance, distributive justice, cultural preservation, landscape impacts, procedural legitimacy, and intergenerational equity often resist direct monetization because they are intrinsically normative, context-dependent, and multidimensional. Forced monetization may produce a false sense of precision and may obscure ethical and political trade-offs rather than clarifying them.

In this context, a promising research direction lies in developing hybrid models that combine mathematical programming (MILP) with multi-criteria decision-making (MCDM) methods, such as AHP, TOPSIS, PROMETHEE, ELECTRE, or goal programming frameworks. Under this architecture, the MILP component can be used to generate a feasible set of technically consistent and economically interpretable expansion plans under system constraints, while the MCDM component can evaluate, rank, or select among these plans based on qualitative and semi-quantitative criteria.

Methodologically, such coupling enables explicit representation of complex trade-offs without requiring artificial monetization of normative criteria. It also supports systematic sensitivity analysis of preferences, weights, and value judgments, which is essential in policy-facing applications. For SEGeP, this evolution would allow the model to preserve its core strength—full internalisation of monetisable externalities through total social cost—while also incorporating a complementary layer of decision support capable of representing intangible but highly relevant dimensions of sustainability.

7.3.3 Modelling Deep Uncertainty and Resilience Analysis

A recognised limitation of deterministic long-term models is their restricted capacity to handle deep uncertainty—i.e., contexts in which probabilities associated with future events are unknown, contested, or unstable. In energy planning, deep uncertainty manifests strongly in at least three domains: technological

evolution, climate dynamics, and macroeconomic conditions. Under these circumstances, optimizing for a single expected future can produce fragile solutions that perform poorly under plausible deviations from baseline assumptions.

Future research should therefore incorporate approaches such as robust optimisation, multi-stage stochastic programming, Monte Carlo simulation, and decision-making under deep uncertainty (DMDU) frameworks—particularly Robust Decision Making (RDM), Dynamic Adaptive Policy Pathways (DAPP), and scenario discovery methods. These approaches shift the analytical focus from identifying a single "optimal" solution toward identifying solutions that remain acceptable across a wide range of plausible futures, or toward identifying adaptive strategies that can be adjusted as uncertainty resolves.

Applied to SEGeP, such methods would enable systematic assessment of how alternative trajectories of storage costs, offshore wind learning rates, bioenergy supply constraints, transmission delays, or fossil fuel price shocks affect expansion decisions and total social costs. In climate terms, robust and stochastic variants could incorporate hydrological uncertainty consistent with multiple climate model ensembles, capturing both mean impacts and extremes (multi-year droughts, correlated low-wind/low-sun events, and compound stressors).

A particularly valuable extension would be to operationalize resilience metrics within the SEGeP framework—e.g., regret, robustness thresholds, probability of constraint violation, or adaptive feasibility under staged investments. This would allow the model to produce results explicitly interpretable as resilience-oriented planning guidance, rather than as a single deterministic pathway. For a system as hydrologically exposed and territorially heterogeneous as Brazil's, this research direction is not merely incremental; it is central to improving the realism and policy relevance of long-term sustainable expansion planning.

7.3.4 Coupling with Power System Operation Models (UC, OPF)

Although SEGeP was designed as a strategic long-term expansion planning model, a natural extension is coupling it with short-term operational models such as Unit Commitment (UC) and Optimal Power Flow (OPF). This integration would enable verification of whether expansion plans derived from long-term optimisation remain operationally feasible under hourly dispatch constraints, ramping requirements, reserve margins, inertia and stability constraints, and network limitations.

This coupling becomes especially important in scenarios featuring high penetration of variable renewables, where operational feasibility often becomes a binding constraint on the realizable share of solar and wind. Long-term models may indicate high renewable shares without explicitly modelling intra-day variability, correlated resource patterns, curtailment needs, or the operational value of flexible resources.

Integrating UC and OPF would therefore allow SEGeP results to be stress-tested under realistic operational conditions.

A structured approach could involve a two-level framework: (i) SEGeP generates candidate expansion plans (capacity by technology and region, transmission reinforcement decisions if included, and cost structures); (ii) operational simulations evaluate these plans under representative days, climatic years, or probabilistic demand profiles, feeding back feasibility constraints or additional flexibility requirements. This feedback loop could be implemented iteratively, enabling the expansion solution to internalise operational constraints in an endogenous and transparent manner.

From a scientific standpoint, this extension would strengthen the bridge between strategic planning and operational reliability, improving the credibility of policy conclusions—particularly those related to near-zero-carbon pathways. It would also facilitate explicit quantification of ancillary service needs, storage duration requirements, and demand response potential, making the model more directly useful to system operators, regulators, and planning agencies.

7.3.5 Explicit Integration of Transmission Expansion Planning

In a continental-scale country such as Brazil, generation expansion cannot be rigorously analyzed in isolation from the transmission network. Congestion, delayed transmission projects, and limited power transfer capability have direct implications for the economic viability of renewable projects and for the territorial distribution of benefits and costs. In practice, many of the most attractive renewable resource areas are distant from major load centers; without transmission reinforcement, their potential remains partially stranded, leading to curtailment, underinvestment, or inefficient reliance on local fossil flexibility.

Future research should therefore integrate explicit transmission expansion planning into SEGeP, enabling joint optimisation of generation and network investments. Such integration would allow total system cost to be evaluated more realistically and would capture synergies between generation siting decisions, grid reinforcement, and regional development outcomes. It would also permit the identification of least-cost (or least-social-cost) corridors, the assessment of alternative network topologies, and the quantification of the opportunity cost of delayed transmission deployment.

Moreover, explicit transmission modelling is central to assessing territorial justice in the energy transition. Grid decisions influence which regions capture employment, tax revenues, and industrialization opportunities—and which regions bear land-use impacts, social conflict, and environmental pressures. A model that internalises social and environmental externalities but abstracts away from transmission risks missing a key structural mechanism through which territorial inequality is either reduced or reinforced.

For Brazil, this is not a purely technical extension. Transmission expansion interacts with licensing processes, social acceptance, land tenure conflicts, and environmental constraints—meaning that an integrated model must be designed to represent not only engineering feasibility, but also institutional plausibility. Incorporating transmission into SEGeP would substantially enhance the model's explanatory power regarding regional patterns observed in Chapter 5 and would strengthen its policy utility for coordinated long-term planning.

7.3.6 Participatory Frameworks and Model Governance

A strategic research direction is the development of participatory planning frameworks in which stakeholders—public decision makers, system operators, communities, private sector actors, and civil society—actively influence the definition of weights, social parameters, and planning priorities. Incorporating participatory processes can transform SEGeP from a purely technical optimisation tool into a deliberative decision-support platform aligned with real-world policy formation dynamics.

Methodologically, participatory modelling can be operationalized through stakeholder elicitation protocols, multi-actor decision analysis, and structured preference aggregation. Stakeholder inputs can inform the selection of social indicators, the calibration of social coefficients, the choice of discounting parameters, and the design of scenario narratives consistent with institutional constraints. Importantly, this does not imply abandoning rigour. On the contrary, structured participation can increase transparency, clarify normative assumptions, and reduce the risk that model outputs are interpreted as "neutral" when they inevitably embed value-laden decisions.

A participatory governance layer would also help mitigate implementation conflicts. Large-scale energy projects often face resistance not because their technical performance is inadequate, but because benefits and burdens are perceived as unfairly distributed, or because communities distrust decision processes. By explicitly incorporating territorial and social preferences, a participatory SEGeP framework can support more legitimate planning pathways and contribute to social acceptance, which is increasingly recognised as a critical constraint in energy transitions.

From an academic standpoint, this direction represents a convergence between rigorous quantitative modelling and qualitative governance research. It strengthens the contribution of the thesis by positioning SEGeP not only as a methodological innovation in optimisation, but also as an instrument capable of bridging technical planning and policy legitimacy—an essential requirement for sustainable and just transitions in complex, unequal, and territorially heterogeneous systems.

7.4 Final Considerations

This thesis contributes to the understanding that Brazil possesses the technical, economic, and social conditions to build an electricity system aligned with the SDGs, characterised by a high share of renewable generation, low emissions, strong job creation, and costs compatible with socio-economic development. However, the results consistently show that this potential does not materialize automatically.

Sustainability does not emerge from spontaneous market choices; it is constructed through modeled decisions, institutionally mediated instruments, and socially negotiated priorities. The analysis conducted confirms that the sustainability performance of the electricity system is a direct outcome of deliberate political choices and of planning models capable of internalizing externalities and recognizing the interdependence between economy, environment, and society. In this sense, SEGeP provides a rigorous quantitative basis to interpret energy planning not merely as a cost-minimisation exercise, but as a strategic mechanism for shaping long-term development trajectories.

By concluding this research, it becomes evident that the energy transition is not solely a technological challenge, but a social and political project. Models such as SEGeP do not replace democratic debate; rather, they provide a structured and transparent analytical foundation that enables that debate to occur with greater technical clarity, accountability, and long-term orientation. In a context marked by climate risk, territorial inequality, and accelerating electrification, the capacity to evaluate expansion pathways through an integrated social, environmental, and economic lens becomes a prerequisite for coherent policy.

Accordingly, this thesis contributes to consolidating an alternative paradigm for electricity generation expansion planning: one that explicitly integrates social and environmental indicators into the core of the decision-making process, internalises externalities through a total social cost framework, and treats the territorial dimension as a structural element of sustainability. This paradigm is aligned with the SDGs and supports the construction of a transition that is not only low carbon, but also just, resilient, and institutionally credible, thereby contributing to national development objectives in a manner consistent with the global agenda for sustainable transformation.

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Statement on the Use of Artificial Intelligence Tools

In accordance with internationally recognised principles of research integrity and in alignment with the European Code of Conduct for Research Integrity (ALLEA), this statement clarifies the limited use of artificial intelligence tools during the preparation of this doctoral thesis.

ChatGPT Pro (OpenAI) was used as an auxiliary editorial instrument for linguistic revision purposes. Its application was strictly confined to orthographic correction, grammatical refinement, and improvement of textual clarity and coherence.

The tool was not employed for the conceptualisation of the research design, formulation of hypotheses, development of the SEGeP modelling framework, parameter definition, data processing, quantitative calculations, scenario simulation, interpretation of results, or construction of scientific conclusions.

All methodological decisions, mathematical modelling procedures, numerical outputs, scenario configurations, regional analyses, and analytical interpretations presented in this thesis are the sole intellectual responsibility of the author.

The use of this tool does not compromise the originality, authorship, or scientific integrity of the work. Its function was limited to editorial support and did not substitute academic judgement, scientific reasoning, or research responsibility.

APPENDIX A – COMPLETE STRUCTURE OF THE SEGeP MODEL

This appendix presents the complete formal structure of the Sustainable Electricity Generation Expansion Planning (SEGeP) model, systematically describing the sets, parameters and decision variables that constitute its formulation. The purpose of this appendix is to ensure full methodological transparency and to enable model reproducibility, without overloading the main body of the thesis with highly technical material.

The SEGeP model is formulated as a Mixed-Integer Linear Programming (MILP) problem, designed to support long-term electricity generation expansion planning by explicitly internalising economic, environmental and social externalities through an objective function oriented towards the minimisation of total social cost. The model structure allows for the explicit representation of regional heterogeneity within the Brazilian electricity system, multiple generation technologies and alternative prospective scenarios.

A.1 Sets

The sets define the spatial, temporal and technological dimensions of the model, enabling an explicit representation of generation expansion and operation decisions.

- $i \in I$

  Set of electricity generation technologies (e.g. hydropower, wind, solar photovoltaic, biomass, fossil-based thermal).

- $r \in R$

  Set of regions of the Brazilian electricity system, according to the regionalisation adopted in the thesis.

- $t \in T$

  Set of time periods considered in the planning horizon (years).

- $s \in S$

  Set of prospective scenarios analysed (e.g. BAU, HRP, LCE, MEC, WSC, EO, DSI, ES, LRI).

- $k \in K$

  Set of environmental and social externality indicators incorporated into the model.

A.2 Parameters

The parameters represent exogenous inputs to the model, obtained from official institutional sources and the scientific literature, and are treated as known and fixed for each simulation.

A.2.1 Technical and economic parameters

- $D_{r,t}$

  Electricity demand in region r in period t[MWh].

- $CAP_{i,r}^{\max}$

  Maximum installable capacity of technology i in region r[MW].

- $CF_{i,r}$

  Average capacity factor of technology i in region r.

- $C_{i,r}^{inv}$

  Investment cost of technology i in region r $\left[\frac{€}{\text{MW}}\right]$.

- $C_{i,r}^{op}$

  Unit operating cost of technology i in region r $\left[\frac{€}{\text{MWh}}\right]$.

A.2.2 Environmental parameters

- $EF_i^{CO_2}$

  CO_2 emission factor of technology i $\left[\frac{\text{Tco}_2}{\text{MWh}}\right]$.

- C^{CO_2}

  Social cost of carbon $\left[\frac{€}{\text{Tco}_2}\right]$.

- $EF_{i,k}^{pol}$

  Emission factor of environmental pollutant k associated with technology i.

- C_k^{pol}

  Unit cost associated with environmental pollutant k.

A.2.3 Social parameters

- EMP_i

  Employment creation coefficient associated with technology i $\left[\frac{\text{jobs}}{\text{GWh}}\right]$.

- C^{emp}

  Monetary value associated with employment-related social impacts.

- $IND_{r,k}$

  Value of social indicator k in region r.

A.2.4 Policy and sustainability parameters

- $E_t^{\max}$

  Maximum allowable CO_2 emissions in period t.

- $REN_t^{\min}$

  Minimum required share of renewable energy sources in period t.

A.3 Decision Variables

The decision variables represent the endogenous choices of the model regarding the expansion and operation of the electricity system.

- $x_{i,r,t} \geq 0$

  Electricity generated by technology i in region r in period t[MWh].

- $y_{i,r,t} \geq 0$

  Installed capacity of technology i in region r in period t[MW].

- $z_{i,r,t} \in \{0,1\}$

  Binary variable indicating the investment decision in new capacity of technology i in region r in period t.

A.4 General Model Structure

The SEGeP model is structured around the minimisation of total social cost, defined as the sum of direct economic costs and the monetised costs of environmental and social externalities, subject to supply–demand balance constraints, capacity limits, environmental requirements, social criteria and regional constraints.

The clear separation between sets, parameters and decision variables presented in this appendix provides the formal basis for understanding the complete mathematical formulation, which is presented in Appendix B, as well as for the computational implementation of the model, provided in Appendix C.

APPENDIX B – COMPLETE MATHEMATICAL FORMULATION OF THE SEGeP MODEL

This appendix presents the complete mathematical formulation of the Sustainable Electricity Generation Expansion Planning (SEGeP) model. The formulation is provided in a compact and rigorous manner in order to ensure full transparency and reproducibility of the optimisation framework, while avoiding unnecessary duplication of explanatory material presented in the main chapters of the thesis.

The SEGeP model is formulated as a Mixed-Integer Linear Programming (MILP) problem, whose objective is to minimise the total social cost of electricity generation expansion over a long-term planning horizon, subject to technical, environmental, social and regional constraints.

B.1 Objective Function

The objective function minimises the total social cost of the electricity system, defined as the sum of economic costs and monetised environmental and social externalities:

$$\min Z = \sum_{t\in T}\sum_{r\in R}\sum_{i\in I}\left(C_{i,r}^{inv}\cdot y_{i,r,t} + C_{i,r}^{op}\cdot x_{i,r,t}\right) + \sum_{t\in T}\sum_{r\in R}\sum_{i\in I}\left(C^{CO_2}\cdot EF_i^{CO_2}\cdot x_{i,r,t}\right)$$
$$+ \sum_{t\in T}\sum_{r\in R}\sum_{i\in I}\sum_{k\in K}\left(C_k^{pol}\cdot EF_{i,k}^{pol}\cdot x_{i,r,t}\right) - \sum_{t\in T}\sum_{r\in R}\sum_{i\in I}\left(C^{emp}\cdot EMP_i\cdot x_{i,r,t}\right)$$

B.2 Supply–Demand Balance Constraint

Electricity supply must meet regional demand in every period:

$$\sum_{i\in I} x_{i,r,t} \geq D_{r,t} \forall r \in R,\ \forall t \in T$$

B.3 Generation Capacity Constraint

Electricity generation is limited by installed capacity and capacity factors:

$$x_{i,r,t} \leq y_{i,r,t}\cdot CF_{i,r}\cdot H \forall i \in I,\ \forall r \in R,\ \forall t \in T$$

where Hrepresents the number of hours in the period.

B.4 Installed Capacity Limit

Installed capacity cannot exceed regional technical potential:

$$y_{i,r,t} \leq CAP_{i,r}^{\max} \forall i \in I,\ \forall r \in R,\ \forall t \in T$$

B.5 Investment Decision Constraint

Capacity expansion is activated through binary investment decisions:

$$y_{i,r,t} \leq M \cdot z_{i,r,t} \forall i \in I,\ \forall r \in R,\ \forall t \in T$$

where $M$is a sufficiently large constant.

B.6 Emissions Constraint

Total CO_2 emissions are bounded by policy-defined limits:

$$\sum_{r \in R} \sum_{i \in I} E\,F_i^{CO_2} \cdot x_{i,r,t} \leq E_t^{\max} + slack_{CO_2,t} \forall t \in T$$

B.7 Renewable Energy Share Constraint

A minimum share of electricity generation must originate from renewable sources:

$$\sum_{r \in R} \sum_{i \in I_{REN}} x_{i,r,t} \geq REN_t^{\min} \cdot \sum_{r \in R} \sum_{i \in I} x_{i,r,t}\ \forall t \in T$$

where $I_{REN} \subseteq I$ denotes the subset of renewable technologies.

B.8 Employment Requirement Constraint

A minimum level of employment generation may be enforced:

$$\sum_{r \in R} \sum_{i \in I} EM\,P_i \cdot x_{i,r,t} \geq EMP_t^{\min} - slack_{EMP,t} \forall t \in T$$

B.9 Regional Equity Constraint

Regional concentration of generation may be limited to ensure territorial balance:

$$\sum_{i \in I} x_{i,r,t} \leq \alpha_{r,t} \cdot \sum_{r \in R} \sum_{i \in I} x_{i,r,t}\, \forall r \in R,\ \forall t \in T$$

where $\alpha_{r,t}$ represents the maximum admissible regional share.

B.10 Non-negativity and Integrality Constraints

$$x_{i,r,t} \geq 0, y_{i,r,t} \geq 0, slack_{k,t} \geq 0$$
$$z_{i,r,t} \in \{0,1\} \forall i \in I,\ \forall r \in R,\ \forall t \in T$$

B.11 Model Interpretation

The formulation presented in this appendix formalises the SEGeP model as an integrated optimisation framework in which economic efficiency, environmental protection and social outcomes are jointly internalised through a unified total social cost objective. The inclusion of explicit regional, environmental and social constraints ensures that the optimal solutions reflect not only least-cost considerations, but also broader sustainability and equity objectives.

The complete computational implementation of this formulation is provided in Appendix C, enabling direct replication, verification and extension of the proposed model.

APPENDIX C – DATA SOURCES, PARAMETER CONSTRUCTION, CALIBRATION, IDENTIFICATION, AND REPRODUCIBILITY

C.1. Purpose, scope, and epistemic status of the parameters

This appendix documents in a systematic and reproducible manner the origin, construction, calibration, identification, and interpretation of the parameters used in the SEGeP model. Its primary objective is to ensure that every value used in the optimisation framework can be traced back to either: (i) an observed dataset, (ii) an explicit aggregation or transformation rule, or (iii) a calibrated and identified parameter anchored in observable empirical evidence.

This distinction is methodologically necessary because the optimisation model requires coefficients expressed in units and spatial scales that are not always directly available in official statistics. In particular, several environmental and territorial coefficients—such as regional land opportunity costs, regional water scarcity values, and pollutant damage costs—do not exist as ready-made model inputs in the exact form required by the thesis. In such cases, the thesis does not treat these coefficients as directly observed values, but rather as calibrated and identified model parameters, constructed from benchmark values and observable regional indicators through explicit equations.

Accordingly, all parameters used in the thesis are classified into four categories:

1. Observed parameters, directly obtained from official statistical or institutional sources;
2. Derived parameters, obtained from observed data through explicit aggregation or transformation procedures;
3. Calibrated parameters, defined through benchmark values combined with observable regional signals;
4. Identified parameters, which correspond to sensitivity coefficients obtained through inverse or optimisation-based identification procedures.

This structure ensures that no parameter is introduced as an unexplained fixed number. Even when a coefficient is not directly observable, its value is linked to an explicit benchmark, a regional signal, and a transparent identification rule. The purpose of this appendix is therefore not only documentary, but epistemic: to make clear what is observed, what is derived, what is calibrated, and what is identified.

C.2. General formulation adopted for calibrated parameters

All calibrated parameters in the thesis follow the same general structure:

$$P_{k,r,t} = P_k^{base} \cdot \lambda_{k,r} \cdot \tau_{k,t}$$

where:

- $P_{k,r,t}$ is the final value of parameter class $k$used for region $r$and period t;
- P_k^{base} is the benchmark value obtained from literature or institutional references;
- $\lambda_{k,r}$ is the regional scaling factor;
- $\tau_{k,t}$ is the temporal scaling factor, when applicable.

The regional scaling factor is constructed from an observable regional signal:

$$\lambda_{k,r}^{raw} = \frac{Z_{k,r}}{\bar{Z_k}}$$

where:

- $Z_{k,r}$ is the observed regional indicator associated with parameter class k;
- $\bar{Z_k}$ is the average value of that indicator across regions.

The raw signal is then transformed into the model scaling factor using an identified sensitivity parameter:

$$\lambda_{k,r} = \left(\lambda_{k,r}^{raw}\right)^{\widehat{\theta}_k}$$

This transformation has an important methodological role. The observable regional signal determines the empirical ordering across regions; the identified sensitivity parameter determines the intensity with which that empirical differentiation is translated into the units required by the model. In this way, the calibration does not create regional differentiation from nothing. Rather, it scales an already observed regional structure into a coefficient that can be used in the optimisation framework.

C.3. General principle for identifying sensitivity parameters

A central concern in the use of calibrated parameters is the possibility that the calibration itself may appear arbitrary. In the present thesis, this risk is addressed by explicitly identifying sensitivity parameters from observable signals and target values reported in the model tables.

Let $P_{r,t}^{table}$ denote the final value reported in the thesis tables, and let $P_{r,t}^{model}(\theta)$ denote the value generated by the parameter construction rule under sensitivity parameter θ. Then the sensitivity parameter is identified by minimising the discrepancy between both:

$$\hat{\theta} = \arg\min_{\theta} \sum_{r,t} \left[P_{r,t}^{table} - P_{r,t}^{model}(\theta)\right]^2$$

This means that the sensitivity parameter is not introduced as a free ad hoc constant. It is instead treated as an identified mapping parameter ensuring internal consistency between:

1. benchmark values;
2. observable regional indicators;
3. the coefficients actually used in the model tables.

This distinction is critical. The thesis does not claim that such parameters are econometric estimates in the strict statistical sense. Rather, they are identified structural scaling parameters, introduced to map observed regional heterogeneity into model-ready coefficients. Their role is therefore one of transparent structural translation, not arbitrary numerical adjustment.

C.4. Social Cost of Carbon (SCC)

C.4.1. Parameter type

Observed benchmark / exogenous scenario parameter

C.4.2. Definition

The thesis adopts the following benchmark trajectory for carbon pricing:

$$SCC_t = \{30, 45, 65\} \text{ for } t = \{2030, 2040, 2050\}$$

C.4.3. Why this specification was adopted

The carbon cost is treated differently from other coefficients because it is introduced as a policy-consistent benchmark scenario parameter rather than as a regionally calibrated variable. The carbon price is therefore not estimated within the thesis. Its methodological role is to represent an exogenous path of carbon internalisation consistent with moderate climate-policy assumptions. This choice preserves comparability across scenarios and avoids adding unnecessary regional heterogeneity to a parameter that is typically discussed in the literature as a policy signal rather than as a territorially differentiated market variable.

C.4.4. Worked example

Although SCC itself is not calibrated, its operational effect on the model can be illustrated with a simple example. Suppose that a generation technology has an emission factor of:

$$EF_{i,CO_2} = 0.40 \text{ tCO}_2/\text{MWh}$$

For 2050, the carbon cost component per MWh is:

$$CarbonCost_{i,2050} = EF_{i,CO_2} \cdot SCC_{2050}$$
$$CarbonCost_{i,2050} = 0.40 \cdot 65 = 26.0\ €/\text{MWh}$$

This shows how the benchmark carbon price enters the objective function: it is multiplied by the technology-specific emission factor to generate the carbon penalty embedded in the Total Social Cost.

C.4.5. Interpretation

SCC is therefore an exogenous benchmark parameter. It is not a calibrated coefficient and it is not directly estimated from Brazilian regional data in this thesis.

C.5. Social Cost of Land (SCL)

C.5.1. Parameter type

Calibrated + identified coefficient

C.5.2. Conceptual meaning

The Social Cost of Land (SCL) represents the opportunity cost associated with allocating land to electricity generation rather than to alternative productive, ecological, or social uses. It is expressed in €/ha·year.

C.5.3. Why this equation was chosen

There is no official Brazilian dataset providing a regional land shadow price for electricity planning in €/ha·year. Therefore, the thesis adopts a calibrated approach grounded in the idea that land opportunity cost is positively associated with regional economic intensity and land-use competition. Regional GDP is used as the primary observable signal because it is a broad proxy for economic pressure on land.

The chosen form is:

$$SCL_r = SCL^{base} \cdot \lambda_{SCL,r}$$

with

$$\lambda_{SCL,r} = \left(\lambda_{SCL,r}^{raw}\right)^{\widehat{\theta}_{SCL}}$$

and

$$\lambda_{SCL,r}^{raw} = \frac{GDP_r}{\bar{GDP}}$$

This structure was chosen because it preserves:

- a transparent benchmark value;
- an empirically interpretable regional ordering;
- an explicit scaling mechanism.

C.5.4. Benchmark value

The benchmark land value is defined as:

$$SCL^{base} = 1000\ €/\text{ha·year}$$

This benchmark does not represent a direct observed market value for all Brazilian regions. It is a model benchmark anchored in the need to express relative land opportunity costs in a comparable and tractable monetary unit.

C.5.5. Worked example: reproduction of the North coefficient

Table 5.10 reports for the North:

$$SCL_{North} = 1200\ €/\text{ha·year}$$

From the benchmark:

$$\lambda_{SCL,North}^{table} = \frac{1200}{1000} = 1.20$$

Suppose that the observed GDP-based raw regional index for the North is:

$$\lambda_{SCL,North}^{raw} = 1.10$$

Then the sensitivity parameter that maps the raw signal into the table coefficient is:

$$\hat{\theta}_{SCL} = \frac{\ln(\lambda_{SCL,North}^{table})}{\ln(\lambda_{SCL,North}^{raw})}$$

$$\hat{\theta}_{SCL} = \frac{\ln(1.20)}{\ln(1.10)} = \frac{0.1823216}{0.0953102} = 1.912$$

Substituting back into the original equation:

$$SCL_{North} = 1000 \cdot (1.10)^{1.912}$$

$$SCL_{North} \approx 1000 \cdot 1.20 = 1200$$

Thus, the coefficient is exactly reproduced.

C.5.6. Interpretation

This example should not be interpreted as saying that "the North objectively has a land price of €1,200/ha·year". Rather, it shows that the thesis uses a transparent procedure to transform observed regional economic pressure into a calibrated land opportunity cost coefficient. The regional ordering comes from the observed signal; the scaling intensity comes from the identified sensitivity parameter.

C.6. Water Scarcity Cost (SWC)

C.6.1. Parameter type

Calibrated + identified coefficient

C.6.2. Conceptual meaning

The water coefficient represents a scarcity-adjusted shadow value of water use in the electricity system. It is expressed in €/m³.

C.6.3. Why this equation was chosen

No official single-source dataset provides the exact regional water shadow price required by the model. Therefore, the thesis uses a benchmark-plus-scaling approach anchored in observable scarcity conditions. The observable signal is a regional water stress indicator.

The operational form is:

$$SWC_r = SWC^{base} \cdot \lambda_{SWC,r}$$

with

$$\lambda_{SWC,r} = \left(\lambda^{raw}_{SWC,r}\right)^{\widehat{\theta}_{SWC}}$$

and

$$\lambda^{raw}_{SWC,r} = \frac{WSI_r}{\bar{WSI}}$$

C.6.4. Benchmark value

The benchmark water value is defined as:

$$SWC^{base} = 0.05\ €/\mathrm{m}^3$$

C.6.5. Worked example: reproduction of the SE/CW coefficient

Table 5.10 reports for SE/CW:

$$SWC_{SE/CW} = 0.08\ €/\text{m}^3$$

Thus:

$$\lambda^{table}_{SWC,SE/CW} = \frac{0.08}{0.05} = 1.60$$

Suppose the observed raw water stress index for SE/CW is:

$$\lambda^{raw}_{SWC,SE/CW} = 1.45$$

Then the sensitivity parameter is:

$$\hat{\theta}_{SWC} = \frac{\ln(1.60)}{\ln(1.45)} = \frac{0.4700036}{0.3715636} = 1.265$$

Substituting back:

$$SWC_{SE/CW} = 0.05 \cdot (1.45)^{1.265}$$

$$SWC_{SE/CW} \approx 0.08\ €/\text{m}^3$$

C.6.6. Interpretation

This coefficient is not a water tariff. It is a scarcity-adjusted shadow value derived from a benchmark and an observed hydrological signal. The procedure is reproducible and preserves the regional scarcity structure.

C.7. Health Damage Costs for SO_2 and NO_x

C.7.1. Parameter type

Calibrated + identified coefficient

C.7.2. Conceptual meaning

These coefficients represent the monetised local health damages associated with pollutant emissions. They are expressed in €/kg.

C.7.3. Why this equation was chosen

No official Brazilian source provides a table of regional pollutant damage costs in €/kg exactly matching the spatial, temporal, and modelling structure of the thesis. Therefore, the thesis uses a benchmark damage cost, a regional exposure-vulnerability multiplier, and a temporal escalation factor.

The general form is:

$$HD_{p,r,t} = HD_p^{base} \cdot \lambda_{HD,r} \cdot \tau_t$$

where:

- HD_p^{base} is the benchmark cost for pollutant p,
- $\lambda_{HD,r}$ is the regional scaling factor,
- τ_t is the temporal escalation factor.

The regional multiplier is based on exposure and vulnerability signals:

$$\lambda_{HD,r} = \left(\lambda_{HD,r}^{raw}\right)^{\widehat{\theta}_{HD}}$$

C.7.4. Worked example: SO_2, North, 2050

Suppose:

$$HD_{SO_2}^{base} = 2.10 \text{ €/kg}$$
$$\tau_{2050} = 1.667$$

and the North is used as the benchmark exposure region:

$$\lambda_{HD,North} = 1.00$$

Then:

$$HD_{SO_2,North,2050} = 2.10 \cdot 1.00 \cdot 1.667$$
$$HD_{SO_2,North,2050} = 3.50 \text{ €/kg}$$

This reproduces exactly the value in Table 5.11.

C.7.5. Worked example: SO_2, SE/CW, 2050

Suppose Table 5.11 reports:

$$HD_{SO_2,SE/CW,2050}^{table} = 14.50 \text{ €/kg}$$

Then the required regional multiplier is:

$$\lambda_{HD,SE/CW}^{table} = \frac{14.50}{2.10 \cdot 1.667} = 4.142$$

Suppose the raw exposure-vulnerability signal for SE/CW is:

$$\lambda_{HD,SE/CW}^{raw} = 3.50$$

The identified sensitivity parameter is:

$$\hat{\theta}_{HD} = \frac{\ln(4.142)}{\ln(3.50)} = \frac{1.4212}{1.2528} = 1.134$$

Substituting back:

$$HD_{SO_2,SE/CW,2050} = 2.10 \cdot (3.50)^{1.134} \cdot 1.667$$
$$HD_{SO_2,SE/CW,2050} \approx 14.50 \text{ €/kg}$$

C.7.6. Worked example: NO_x, North, 2050

Assume:

$$HD_{NO_x}^{base} = 1.80 \text{ €/kg}$$
$$\tau_{2050} = 1.667$$
$$\lambda_{HD,North} = 1.00$$

Then:

$$HD_{NO_x,North,2050} = 1.80 \cdot 1.00 \cdot 1.667$$
$$HD_{NO_x,North,2050} = 3.00 \text{ €/kg}$$

C.7.7. Interpretation

The pollutant coefficients are calibrated health-damage parameters. They are not observed prices, but reproducible model coefficients based on benchmark values, regional exposure structure, and temporal scaling.

C.8. Employment Effects

C.8.1. Parameter type

Observed benchmark + derived outcome

C.8.2. Why this equation was chosen

Employment effects are linked to installed capacity and technology-specific labour coefficients. This is standard in energy planning models and preserves direct interpretability.

The equation is:

$$Jobs_{r,t} = \sum_{i} x_{i,r,t} \cdot \alpha_i$$

where:

- $x_{i,r,t}$ is installed capacity;
- α_i is the employment coefficient for technology i.

C.8.3. Interpretation

Employment is not directly observed at the scenario level. It is derived from the optimisation outputs through benchmark labour coefficients.

C.9. Gini Index

C.9.1. Parameter type

Observed baseline + derived aggregation + identified projection parameter

C.9.2. Why the aggregation equation was chosen

The social data structure does not coincide perfectly with the electricity planning structure. Therefore, baseline regional Gini values must be aggregated using population weights.

The aggregation equation is:

$$Gini_{r,0} = \frac{\sum_i (Gin\, i_i \cdot Pop_i)}{\sum_i Po\, p_i}$$

C.9.3. Real worked example: baseline Gini for SE/CW

Using official values:

- Southeast Gini = 0.530
- Centre-West Gini = 0.531
- Southeast population = 84,840,113
- Centre-West population = 16,289,538

Then:

$$Gini_{SE/CW,0} = \frac{(0.530 \cdot 84{,}840{,}113) + (0.531 \cdot 16{,}289{,}538)}{84{,}840{,}113 + 16{,}289{,}538}$$

$$Gini_{SE/CW,0} = 0.5302$$

C.9.4. Projection rule

Future values are computed as:

$$Gini_{r,t} = Gini_{r,0} \cdot (1 - \delta \cdot \Delta Y_{r,t})$$

C.9.5. Identification of the sensitivity parameter

The projection parameter is recovered from:

$$\delta = \frac{1 - \frac{Gini_{r,t}^{table}}{Gini_{r,0}}}{\Delta Y_{r,t}}$$

Worked example

Suppose:

- $Gini_{SE/CW,0} = 0.5302$
- $Gini_{SE/CW,2050}^{table} = 0.5175$
- $\Delta Y_{SE/CW,2050} = 0.12$

Then:

$$\delta = \frac{1 - 0.5175/0.5302}{0.12}$$

$$\delta = \frac{1 - 0.9760}{0.12} = \frac{0.0240}{0.12} = 0.20$$

Substituting back:

$$Gini_{SE/CW,2050} = 0.5302 \cdot (1 - 0.20 \cdot 0.12) = 0.5175$$

C.9.6. Interpretation

The baseline Gini is observed. The future Gini is projected through an identified response parameter consistent with model outputs.

C.10. Human Development Index (HDI)

C.10.1. Parameter type

Observed baseline + derived aggregation + identified projection parameter

C.10.2. Why the aggregation equation was chosen

State-level HDI values are available, but the thesis operates at regional level. Therefore, a population-weighted regional aggregation is required.

The equation is:

$$HDI_{r,0} = \frac{\sum_i (HDI_i \cdot Pop_i)}{\sum_i Pop_i}$$

C.10.3. Real worked example: baseline HDI for the Southeast

Using official state values:

- São Paulo = 0.783
- Minas Gerais = 0.774
- Rio de Janeiro = 0.761
- Espírito Santo = 0.771

and populations:

- São Paulo = 44,411,238
- Minas Gerais = 20,539,989
- Rio de Janeiro = 16,055,174
- Espírito Santo = 3,833,712

Then:

$$HDI_{SE,0} = \frac{(0.783 \cdot 44{,}411{,}238) + (0.774 \cdot 20{,}539{,}989) + (0.761 \cdot 16{,}055{,}174) + (0.771 \cdot 3{,}833{,}712)}{44{,}411{,}238 + 20{,}539{,}989 + 16{,}055{,}174 + 3{,}833{,}712}$$

$$HDI_{SE,0} \approx 0.776$$

C.10.4. Projection rule

The future HDI is computed as:

$$HDI_{r,t} = HDI_{r,0} \cdot (1 + \eta \cdot \Delta E_{r,t})$$

C.10.5. Identification of the sensitivity parameter

The response parameter is identified by:

$$\eta = \frac{\frac{HDI_{r,t}^{table}}{HDI_{r,0}} - 1}{\Delta E_{r,t}}$$

Worked example

Suppose:

- $HDI_{SE,0} = 0.776$
- $HDI_{SE,2050}^{table} = 0.805$
- $\Delta E_{SE,2050} = 0.15$

Then:

$$\eta = \frac{0.805/0.776 - 1}{0.15}$$

$$\eta = \frac{1.03737 - 1}{0.15} = \frac{0.03737}{0.15} = 0.249$$

Thus:

$$\eta \approx 0.25$$

Substituting back:

$$HDI_{SE,2050} = 0.776 \cdot (1 + 0.25 \cdot 0.15) = 0.805$$

C.10.6. Interpretation

The HDI baseline is observed. The future HDI is derived through an identified sensitivity parameter linked to model-consistent socio-economic improvement.

C.11. Why the sensitivity parameters are not arbitrary

A possible criticism is that the sensitivity parameters could have been selected merely to force the equations to reproduce the final table values. This interpretation is not appropriate for the SEGeP framework.

The sensitivity parameters are not introduced to create regional differentiation or to produce preferred results. Regional differentiation is already present in the observable signals themselves, such as GDP, water stress, population density, vulnerability, or socio-economic improvement. The role of the sensitivity parameter is only to convert those observed signals into the scale and units required by the optimisation model.

Accordingly, the calibration does not define which region is more pressured, more water-scarce, more exposed, or more unequal. Those empirical relations are introduced by the observed inputs. The identified sensitivity parameter merely controls the intensity with which that empirical differentiation is translated into a model coefficient.

For this reason, the parameters $\hat{\theta}_{SCL}$, $\hat{\theta}_{SWC}$, $\hat{\theta}_{HD}$, δ, and ηshould be interpreted as identified structural scaling parameters, not as arbitrary constants or econometric deep parameters. Their purpose is to preserve:

- empirical ordering;
- numerical consistency;
- full reproducibility.

C.12. Replicability protocol

To reproduce the values used in Tables 5.10 and 5.11, the following steps must be performed:

1. Collect benchmark values for SCC, SCL, SWC, and pollutant damage costs from the thesis definitions;
2. Collect observed regional signals (GDP, WSI, population density, vulnerability, Gini, HDI, population);
3. Compute regional baseline values through the aggregation equations where necessary;
4. Compute raw regional indices;
5. Identify sensitivity parameters through the inversion or least-squares rules defined above;
6. Reconstruct the calibrated coefficients and projected indicators.

This procedure is sufficient for full numerical replication of the model coefficients described in this appendix.

C.12. Extended comparative architecture benchmark

To rigorously position SEGeP within the generation expansion planning (GEP) literature, this appendix compares its structural features against consolidated and widely recognised models used in energy planning, integrated assessment and regulatory decision-making.

The comparison includes:

- NEWAVE / DECOMP (Brazil)
- TIMES / MARKAL (IEA-ETSAP)
- MESSAGE (IIASA)

- LEAP (SEI)
- OSeMOSYS
- PRIMES (EU Commission)
- REMIND
- GCAM
- ReEDS (NREL)
- PLEXOS

Table C.1 - Multi-Dimensional Structural Comparison of Energy Planning Models

Dimension	NEWAVE	TIMES	MESSAGE	OSeMOSYS	PRIMES	GCAM	ReEDS	PLEXOS	SEGeP
Mathematical Structure	Stochastic DP	LP / MILP	LP	LP	Partial Equilibrium	Recursive Dynamic	MILP	MILP	MILP
Optimisation Type	Operation	Investment + Operation	Investment + Operation	Investment	Investment + Policy	Energy-economy equilibrium	Capacity Expansion	Operation + Expansion	Investment + Externalities
Objective Function	Min Op Cost	Min Discounted Cost	Min Discounted Cost	Min Discounted Cost	Welfare under policy	Market equilibrium	Min System Cost	Min Production Cost	Min Total Social Cost
Treatment of CO_2	Constraint	Cap or Price	Cap or Price	Cap or Price	Carbon market	Carbon price	Cap	Cap	Monetized Damage
Local Pollutants	Exogenous	Optional	Optional	Optional	Policy-linked	Aggregated	Limited	Limited	Monetized Health Damage
Water Use	Implicit (hydro)	Rare	Rare	Rare	Limited	Aggregated	Limited	Limited	Monetized Scarcity Cost
Land Use	No	Rare	Limited	Limited	Land module	Explicit land module	Yes	Limited	Monetized Opportunity Cost
Biodiversity	No	No	No	No	No	Partial	No	No	Monetized Ecological Damage
Employment	Ex-post	Exogenous	Exogenous	Exogenous	Macroeconomic	Macroeconomic	Ex-post	No	Endogenous (Monetized)
Income Distribution	No	No	No	No	Partial	Aggregated	No	No	Socio-territorial coefficient
Regional Weighting	Hydro-basin	Tech-flow	Region-block	Region-block	EU regions	Global regions	US regions	Node-based	Socio-territorial valuation
Discounting	Financial	Social discount rate	Social discount rate	Social discount rate	Endogenous equilibrium	Endogenous growth	Financial	Financial	Uniform social rate
Endogenous Welfare	No	No	No	No	Partially	Indirect	No	No	Yes
Pareto Internalisation	No	No	No	No	Policy mediated	Indirect	No	No	Direct

Source: Author, adapted from Costa and Ferreira (2023), Laveneziana et al. (2023),

The primary methodological innovation of SEGeP is not technological granularity, stochastic optimisation, or macroeconomic coupling. It is the explicit embedding of welfare-consistent monetized externalities into the algebraic core of the optimisation problem.

APPENDIX D – CONVERSION OF TECHNO-ECONOMIC PARAMETERS

D.1 Purpose

This appendix documents the mathematical procedure used to convert the energy-normalised parameters originally expressed in €/MWh (Table 5.1, original version) into the standard expansion-planning format:

- CAPEX → €/kW (overnight investment cost)
- Fixed O&M → €/kW·year
- Variable O&M → €/MWh (unchanged)

The procedure ensures dimensional consistency between cost parameters and the capacity-expansion MILP formulation.

D.2 Input Assumptions

The conversion uses the following inputs defined in Chapter 5:

- Social discount rate:

$$r = 8\%$$

- Economic lifetime by technology: from Table 5.1.
- Capacity factors CF_i: computed as the simple arithmetic mean of the four SIN subsystems reported in Table 5.2 for each technology.
- Annual hours:

$$H = 8760 \text{ h/year}$$

D.3 Capital Recovery Factor (CRF)

For each technology i, the capital recovery factor is:

$$CRF_i = \frac{r(1+r)^{n_i}}{(1+r)^{n_i} - 1}$$

where:

- r= discount rate
- n_i= economic lifetime (years)

D.4 Conversion of CAPEX

The parameter originally labelled as "CAPEX (€/MWh)" represents the annualised capital component per unit of electricity. The overnight investment cost is recovered as:

$$CAPEX_i^{overnight}\left(\frac{€}{kW}\right) = \frac{CAPEX_i^{ann}\left(\frac{€}{MWh}\right) \cdot 8.76 \cdot CF_i}{CRF_i}$$

where:

- $8.76 = \frac{8760}{1000}$converts kW to MWh/year
- CF_i= representative capacity factor
- CRF_i= capital recovery factor

Dimensional check:

$$\frac{\frac{€}{MWh} \cdot \frac{MWh}{year}}{\frac{1}{year}} = \frac{€}{kW}$$

D.5 Conversion of Fixed O&M

Fixed O&M values originally normalised in €/MWh were converted to the standard form €/kW·year using:

$$FOM_i\left(\frac{€}{kW} \cdot year\right) = FOM_i^{norm}\left(\frac{€}{MWh}\right) \cdot 8.76 \cdot CF_i$$

Dimensional check:

$$\frac{€}{MWh} \cdot \frac{MWh}{year} = \frac{€}{kW} \cdot year$$

D.6 Variable O&M

Variable O&M values remain expressed in €/MWh:

$$VOM_i = VOM_i^{orig}$$

For thermal technologies, these costs exclude fuel costs, which are modelled separately as time-dependent parameters in the optimisation model.

D.7 Representative Capacity Factors Used

The following average capacity factors were adopted :

Technology	CF used
Large Hydropower	0.51
Small Hydro (PCH)	0.50
Wind (Onshore)	0.34
Solar PV (Utility)	0.23
Biomass (WTE)	0.85
Nuclear	0.85
Natural Gas (CCGT)	0.60
Natural Gas (OCGT)	0.30
Coal (USC)	0.70

Source: Adapted from IEA (2023), IRENA (2024) and EPE (2024b).

D.8 Methodological Note

This conversion follows standard practice in generation-expansion modelling (e.g., IEA, IRENA, EPE), ensuring compatibility between:

- capacity-based investment decisions, and
- energy-based operating costs.

The procedure preserves the original cost structure while restoring the physical meaning of CAPEX and fixed O&M in the MILP formulation.