

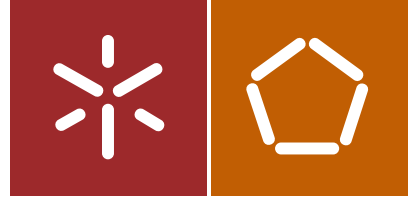
Universidade do Minho
Escola de Engenharia

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Modeling Future Renewable Electricity Scenarios with Demand-Side Management in Brazil

may 2021

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Modeling Future Renewable Electricity Scenarios with Demand-Side Management in Brazil

Doctoral Thesis
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Work performed under the supervision of:
Professor Paula Varandas Ferreira
Professor António Ismael Vaz

may 2021

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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.

Modeling Future Renewable Electricity Scenarios with Demand-Side Management in Brazil

Abstract

The increasing search for energy pathways towards climate change and social wellbeing led to a shift of strategies and policies favoring renewable energy and energy efficiency as the main pillars of the energy transition. Shaping a secure and sustainable energy future may require long-term structural changes in the current energy planning strategies, including actions on the demand-side.

The present study makes several noteworthy contributions to the literature. On the whole, this research provides valuable insights into how the integration between Demand Side Management (DSM) resources and clean energy supply options might affect long-term sustainable energy plans. The relevance and the innovative aspects are related to the proposed modeling approach, which is expected to be unique concerning the proposed enhancements in a co-optimization model for long-term decision-making, recognizing the impact of short-term variability of both demand and RES supply, well suited to systems with a high share of RES and under different demand flexibility conditions. The objectives are explored for the case of the Brazilian sector, which can be justified by the following factors: (i) continental dimensions; (ii) high-RES share; (iii) vulnerability to climate change and (iv) access to data. Therefore, the Integrated Brazilian Electricity System Model (IBESM) is proposed with the main goal of supporting the development of sustainable scenarios for the electricity sector. This approach aims to answer how cost-optimal pathways would change with the inclusion of DSM strategies within the optimization model.

The contribution of this research also lies in the proposition of a step-by-step methodology to estimate the Long-term Average Cost of Saved Electricity (LACoSE). Findings of this study revealed a high Demand Response (DR) potential for delaying future investments in power capacity but a limited contribution for both renewables integration and load balancing purposes. Investments including energy efficiency, are projected to be more economically valuable than investing in DR strategies alone.

The proposed modeling approach would also support the decision-making process in different energy systems. The research offers significant contributions to the scientific community beyond the cases addressed in this study, not only from the possible adaptation and extension of the proposed models but also by showing the importance of the integrated supply-demand management strategy for electricity systems.

Keywords: Brazilian Power Sector; Co-optimization; Demand-side Management (DSM); Generation Expansion Planning (GEP); Renewable Energies.

Modelação de cenários elétricos renováveis com integração da gestão da procura no Brasil

Resumo

A crescente busca por soluções energéticas para as mudanças climáticas e o bem-estar social culminou em alterações significativas nas estratégias e políticas, favorecendo as energias renováveis e a eficiência energética como os principais pilares da transição energética. Um futuro energético sustentável requer mudanças nas estratégias de planeamento incluindo também ações do lado da procura.

No seu conjunto, esta pesquisa fornece informações importantes sobre como a integração entre a gestão da procura e tecnologias de produção de energia elétrica poderão afetar os planos energéticos de longo prazo. A relevância e os aspetos inovadores deste trabalho derivam em grande parte da modelação proposta baseada num novo modelo de co-otimização para tomada de decisão de longo prazo. Este modelo permite reconhecer o impacto da variabilidade de curto prazo da oferta e procura sendo adequado para sistemas com um elevado índice de produção por fontes renováveis e com diferentes condições de flexibilidade da procura. Os objetivos são aplicados ao caso do setor elétrico brasileiro, sendo esta opção justificada, sobretudo, pelos seguintes fatores: (i) dimensão continental; (ii) alto índice de produção renovável; (iii) vulnerabilidade às mudanças climáticas e (iv) acesso aos dados. Desse modo, propõe-se o Modelo Integrado para o Sistema Elétrico Brasileiro (em inglês, IBESM) com o objetivo principal de apoiar o desenvolvimento de cenários sustentáveis para o setor de eletricidade. A abordagem apresentada pretende contribuir para verificar de que modo a inclusão de estratégias de gestão da procura no modelo de otimização poderá impactar os cenários de longo prazo.

Esta pesquisa também propõe uma metodologia para estimar o Custo Médio de Longo Prazo de Energia Economizada (em inglês, LACoSE). Os resultados indicam grande potencial da utilização de estratégias de resposta à procura (em inglês, DR) para adiar futuros investimentos em nova potência instalada. Verifica-se, no entanto, um potencial de contribuição limitado para a integração de energias renováveis e balanceamento de cargas. Os investimentos que incluam também medidas de eficiência energética tendem a ser economicamente mais interessantes do que estratégias apenas baseadas em DR.

A modelação proposta tem como objetivo apoiar a tomada de decisão em diferentes sistemas elétricos. Esta pesquisa oferece contribuições para a comunidade científica que vão para além do caso analisado, não só pelo potencial de adaptação e extensão dos modelos propostos mas também pelos resultados que mostram a importância da estratégia de gestão integrada da procura e oferta nos sistema elétricos.

Palavras-chave: Setor Elétrico Brasileiro; Co-otimização; Gestão da Procura; Planeamento de Expansão da Produção; Energias Renováveis.

Table of Contents

Acknowledgments iii

Statement of Integrity iv

Abstract v

Resumo vi

Table of Contents vii

List of Figures xi

List of Tables xv

List of Acronyms xvi

Chapter 1. Introduction and Thesis Overview 19

1.1 Foreword and problem statement 19

1.2 Research objectives 29

1.3 Research framework 31

1.4 Outline of the manuscript 44

Chapter 2. Literature Review 49

2.1 Introduction 49

2.2 Energy scenarios for high-RES systems 53

2.3 Generation Expansion Planning (GEP) 56

2.4 Co-optimization modeling for long-term power planning 59

2.4.1 Co-optimization in generation-transmission expansion problems 61

2.4.2 Discussion of the findings 67

2.5 The role of Demand-Side Management (DSM) 69

2.5.1 Theoretical background on Demand-Response (DR) 74

2.5.2 A review of the key categories of DR potentials 77

2.5.3 A new conceptual framework to estimate each category of DR potential 87

2.5.4 Discussion of the findings 95

2.6 Concluding remarks 96
Chapter 3. The Brazilian Power Sector 100
3.1 Introduction 100
3.2 Overview of the Brazilian energy sector 102
3.3 Characterization, policy and regulatory framework 108
3.3.1 Tariff Flag System (TFS) 112
3.3.2 White Hourly Tariff (WHT) 114
3.3.3 Electricity prepayment and smart metering 115
3.3.4 Distributed Generation (DG) 117
3.3.5 Storage technologies 119
3.3.6 Electric Vehicles (EVs) 119
3.4 Summarize of the smart grid trends and prospects for the Brazilian electricity sector 123
3.5 Concluding remarks 128
Chapter 4. Integrated Brazilian Electricity System Model (IBESM) 132
4.1 Modeling approach 132
4.2 Objective function 142
4.3 Data collection and case study description 143
4.4 Model validation and reference scenario (BAU) 147
4.5 Concluding remarks 155
Chapter 5. Theoretical DR Potential in the Brazilian Power Sector 156
5.1 Introduction 156
5.2 Data collection and analysis 158
5.3 Estimating the theoretical load flexibility potential 161
5.3.1 DR potential in the industrial sector 161
5.3.2 DR potential in the commercial sector 166
5.3.3 DR potential in the residential sector 168

5.3.4 DR potential across all sectors 174
5.4 Concluding remarks 176
Chapter 6. Cost-Effectiveness of Energy Efficiency Measures (EEMs) 179
6.1 Introduction 179
6.2 Brazilian energy efficiency programs 180
6.3 Evaluation of different levels of Energy Efficiency Measures (EMMs) 181
6.3.1 Data collection 181
6.3.2 Simulation results 182
6.4 Discussion of the findings 185
6.5 Concluding remarks 187
Chapter 7. Integrating Supply and Demand-Side Management 189
7.1 Introduction 189
7.2 Main scenario assumptions 193
7.3 Assessing the technical and economic DR potentials 196
7.3.1 Theoretical background 196
7.3.2 Scenarios with DR 197
7.4 Integrated assessment of DSM strategies (DR and EEMs) 204
7.5 Concluding remarks 210
Chapter 8. Conclusions and Final Remarks 213
8.1 Conclusions & outlook 213
8.2 Implications for policy-makers 218
8.3 Opportunities for further research 221
References 226
Supplementary Material 249
Annex A - IBESM Formulation – List of sets and parameters 249
Annex A.1 - List of model sets [187,413,414]. 249

Annex A.2 - List of model parameters [187,413,414]. 250
Annex A.3 – Translated DR model (GAMS) 254
Annex B – Input data used for the case study 258
Annex B.1 – Techno-economic data for 2018 [311,374–376] 258
Annex B.2 – Other parameters of the model [56,311,374–378]. 258
Annex B.3a – Load profiles for each sector (1 – 12h). 259
Annex B.3b – Load profiles for each sector (12 – 24h). 260
Annex B.4 – Technical and economic scenario assumptions for implementing DR. 261
Annex C – Simulation results 262
Annex C.1 – Simulation results for the new installed capacity (2018-2040) in GW 262
Annex C.2 – Simulation results for the electricity generation share of each power source in 2040 (%) 262

List of Figures

Figure 1.1: Focus areas where policy and decision-makers should act towards a sustainable future. .. 21

Figure 1.2: Planning for the global energy transformation [9]. 22

Figure 1.3: Schematic of the research process for this Ph.D. thesis. 34

Figure 1.4: Methodological approach considered for conducting the systematic review process. 37

Figure 1.5: Overview of the methodological approach for assessing the different types of DR potentials. 38

Figure 1.6: Detailed methodological approach. 39

Figure 1.7: Detailed structure of the model. 42

Figure 1.8: Outline of the manuscript. 46

Figure 2.1: Main drivers of power systems evolution worldwide [68]. 50

Figure 2.2: Classical and future model of the electricity system (Adapted from [81]). 51

Figure 2.3: Emerging energy system archetypes [72]. 52

Figure 2.4: Key Demand-Side Management (DSM) techniques. 71

Figure 2.5: Role of DSM in Electric System Planning and Operations. Source: Adapted from [204]. 72

Figure 2.6: Overview of the main categories of DR potentials. 79

Figure 2.7: Categories of demand response potential versus capacity (GW). Source: Adapted from [200,242,243,246]. 79

Figure 2.8: Key steps of the proposed framework for the estimation of each DR potential category. 88

Figure 3.1: Electricity share from renewable sources in 2009 and 2016 for Brazil and other countries. 103

Figure 3.2: Brazilian power output between 2000 and 2018 (February) (left axis) and water storage level in SE (right axis). 103

Figure 3.3: Brazilian installed power capacity (%)for 2017 and projections for 2026, 2040, and 2050 [2,58,304,305]. 105

Figure 3.4: Brazilian maximum storage capacity in GW (left axis) and the regularization capacity in months (right axis) between 2001 and 2017 ([54]). 106

Figure 3.5: Chronological flowchart of the prospective evolution of the leading Brazilian regulations towards a smart grid power system. 110

Figure 3.6: Concept map of the leading Brazilian regulations toward smarter grids. 112

Figure 3.7: Key features of the Brazilian TFS. 113

Figure 3.8: White Hourly Tariff versus conventional tariff ([332]). 114

Figure 3.9: Distributed Generation (DG) projection for the period 2017 - 2024 [288]. 118

Figure 3.10: Projected light vehicles fleet profile by fuel in Brazil between 2014 and 2050. 120

Figure 4.1: Model enhancements (Part I), model integration (Part II), and model evaluation (Part III). 133

Figure 4.2: Enhancements in the DR code (Part I - Stage 2). 137

Figure 4.3: Methodology for calculating the Long-term Average Cost of Saved Electricity (LACoSE). .. 138

Figure 4.4: A five-step methodological approach to account for the inclusion of EEMs into the long-term power planning model (Part I - Stage 3 in Figure 4.1). 140

Figure 4.5: Comparison between simulated results and real data for the electricity generation in 2018. 147

Figure 4.6: Comparison between simulation results and government projections for scenario BAU... 148

Figure 4.7: Total Installed capacity for each power source for scenario BAU (%). 148

Figure 4.8: Total Installed capacity for the Brazilian power system for scenario BAU (%). 149

Figure 4.9: Total installed capacity by source for scenario BAU (2018-2040). 149

Figure 4.10: Installed capacity by source for scenario BAU. 150

Figure 4.11: Electricity generation by source for scenario BAU. 150

Figure 4.12: Total installed capacity by region for scenario BAU (GW). 153

Figure 4.13: Overall regional installed capacity for scenario BAU in 2018 (%). 154

Figure 4.14: Overall regional installed capacity for scenario BAU in 2040 (%). 154

Figure 4.15: Cost-share by category for scenario BAU (%). 155

Figure 5.1: Regions of the country (Brazil). 163

Figure 5.2: DR potential for each region and energy-intensive industrial process in 2017 (TWh). 164

Figure 5.3: DR potential for each region and energy-intensive industrial process in 2050 (TWh). 164

Figure 5.4: Overall theoretical DR potential by region and year for energy-intensive industrial processes (TWh). 165

Figure 5.5: Maximum DR potential for each energy-intensive industrial process (GW). 165

Figure 5.6: Overall DR potential (energy shifting potential) for commercial processes (TWh). 166

Figure 5.7: Overall DR potential for each commercial process (left axis) and the average daily load curve of the interconnected power system (right axis) (in GW for a typical day of 2017). 168

Figure 5.8: Overall hourly DR potential for each region in the residential sector - 2017 (GW). 169

Figure 5.9: Overall hourly DR potential for each appliance in the residential sector (left axis) and the average daily load curve of the interconnected power system (right axis) (in GW for 2017). 170

Figure 5.10: Overall load profile of the power system for winter and summer (right axis) and DR potential for the residential sector (left axis) for the Southwest (SE) - 2017. 172

Figure 5.11: Overall load profile of the power system for winter and summer (right axis) and DR potential for the residential sector (left axis) for the North (NO) - 2017. 173

Figure 5.12: Overall hourly DR potential for each appliance in the residential sector – 2050 (GW). ... 173

Figure 5.13: Sectoral share for the overall load flexibility potential (%). 174

Figure 5.14: Projected sectoral share in the overall electricity consumption in Brazil (%). Source: Extracted from [90]. 175

Figure 6.1: Installed capacity for scenario BAU and Case 5 (2040). 183

Figure 6.2: Percentage variation for the new installed capacity, CO_2 emissions and costs compared to scenario BAU. 184

Figure 6.3: New installed capacity for each case (2018-2040). 184

Figure 6.4: Comparison between simulation results for scenario BAU and Case 5 for the overall installed capacity (GW). 185

Figure 6.5: Sensitivity analysis for the estimated LACoSE. 186

Figure 7.1: Köppen's climate classification map for Brazil (Ref. [400]). 190

Figure 7.2: Load duration curve for the Brazilian power grid (2017). 192

Figure 7.3. New installed capacity between 2018 and 2040 for each scenario with DR. 198

Figure 7.4. Average regional potential for load shedding for the industrial sector between 2018-2040. 199

Figure 7.5: Contribution shares for each cost category: a) Investment, operating and fuel costs and b) Emissions, DR and imported electricity. 200

Figure 7.6: Exploited and non-exploited load shedding potential compared to the theoretical load flexibility potential. 201

Figure 7.7: Overall level of CO_2 emissions for the period 2018-2040 203

Figure 7.8: Percentage change for the new installed capacity, CO_2 emissions and total system costs for each scenario compared to Scenario 1 (BAU). 205

Figure 7.9: Cost categories for each scenario. 206

Figure 7.10: Percentage variation for the new installed capacity, CO_2 emissions and costs for the most relevant pair of scenarios. 207

Figure 7.11: Carbon emissions for Scenario 1 (BAU) and Scenario 6 (DR^N/EEM_5%). 209

Figure 7.12: Delay in investments for the new installed capacity for selected scenarios. 209

Figure 7.13: Sensitivity analysis over the estimated LACoSE. 210

List of Tables

Table 2.1: A literature review on long-term co-optimization of generation-transmission expansion. 62

Table 2.2: DR classifications usually considered in the literature. 78

Table 2.3: Definition of each category of DR potential. 81

Table 2.4: Overview of each potential DR category. 83

Table 2.5: Representation of the main processes with some degree of DR potential [243,264]. 89

Table 3.1: Brazilian hydro and thermal power installed capacity from 2006 to 2018 [258]. 107

Table 3.2: Summarize of the smart grid trends and prospects for the Brazilian electricity sector 126

Table 5.1: Selected processes/appliances suitable for DR. 160

Table 5.2: Projected number of households (million). 160

Table 5.3: Market penetration rate (%). 161

Table 5.4: Specific energy consumption (kWh/Equipment). 161

Table 5.5: Other input data. 161

Table 5.6: Specific electricity consumption and yearly production for energy-intensive processes. 162

Table 5.7: Commercial DR potential for each process and year (GW). 167

Table 5.8: Residential DR potential (TWh) for each region and year. 168

Table 6.1: Overview of the leading Brazilian EEMs proposals. 181

Table 6.2: Energy efficiency programs in Brazil (based on Ref. [49] and Ref. [392]). 182

Table 7.1: Scenarios description 194

List of Acronyms

ADMS	Advanced Distribution Management System
ANEEL	Brazilian Electricity Regulatory Agency (in Portuguese, ANEEL)
PEE	Energy Efficiency Program (in Portuguese, PEE)
BaU	Business as Usual
BD	Bender's Decomposition
BESS	Battery Energy Storage System
CO	Midwest (in Portuguese, CO)
CoSE	Cost of Saved Electricity
CPP	Critical Peak Pricing
CSP	Concentrated Solar Power
DCOPF	DC-Optimal Power Flow
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution System Operators
EAR	Maximum Hydropower Storage Capacity (in Portuguese, EAR)
EE	Energy Efficiency
EEMs	Energy Efficiency Measures
EMS	Energy Management System
ENSO	El Niño Southern Oscillation
EPE	Brazilian Energy Research Office (in Portuguese, EPE)
EVs	Electric Vehicles
GA	Genetic Algorithm
GAMS	General Algebraic Modeling System
GEP	Generation Expansion Planning
GHG	Greenhouse Gases
GIS	Geographic Information System
GSF	Generation Scaling Factor

HVDC	High Voltage Current Current
IBESM	Integrated Brazilian Electricity System Model
ICT	Information and Communications Technology
IEA	International Energy Agency
IoT	Internet of Things
IRENA	International Renewable Energy Agency
IRSP	Integrated Resource Strategic Planning
LACoSE	Long-term Average Cost of Saved Electricity
LCA	Life Cycle Assessment
LEAP	Long-range Energy Alternatives Planning
LUC	Land-Use Change
MAP	Maximum Achievable Potential
MCoSE	Modified Cost of Saved Electricity
MIBLP	Mixed-Integer Bilevel Linear Programming
MILP	Mixed-Integer Linear Programming
MINLP	Mixed-Integer Nonlinear Programming
MIP	Mixed-Integer Programming
NE	Northeast (in Portuguese, NE)
ONS	National Grid Operator (in Portuguese, ONS)
OPF	Optimal Power Flow
OSeMOSYS	Open Source Energy Modeling System
OMS	Outage Management System
PDE	Decennial Energy Plan (in Portuguese, PDE)
PLC	Power Line Communication
PLD	Difference Settlement Price (in Portuguese, PLD)
PNE	National Energy Plan (in Portuguese, PNE)
PROCEL	National Electrical Energy Conservation Program (in Portuguese, PROCEL)
PtG	Power to Gas
PTR	Peak Time Rebate
PV	Photovoltaic

R&D	Research and Development
RAP	Realistic Achievable Potential
REP	Renewable Energy Projects
RES	Renewable Energy Sources
RN	Normative Resolution (in Portuguese, RN)
RTP	Real-Time Pricing
SCADA	Supervisory Control And Data Acquisition
SDGs	Sustainable Development Goals
SE	Southeast (in Portuguese, SE)
SHP	Small-scale Hydropower Plants
SINPHA	Information System on Possession and Habits of Consumption (in Portuguese, SINPHA)
SMEs	Small- and Medium-sized Enterprises
SO	South (in Portuguese, SO)
SP	Stochastic Programming
SLP	Successive Linear Programming
SSM	Supply Side Management
TEP	Transmission Expansion Planning
TFS	Tariff Flag System
TGEP	Transmission and Generation capacity Expansion Planning
TOU	Time-of-use
TRSP	Traditional Resource Strategic Planning
TSO	Transmission System Operators
VoLL	Value of Lost Load
VPP	Virtual Power Plants
VRE	Variable Renewable Energy
WHT	White Hourly Tariff

Chapter 1. Introduction and Thesis Overview

This chapter contextualizes the topic of this thesis by providing an overview of the recent developments in the field based on both a clear argument and a constructively critical analysis of what has been recently published in the literature (Section 1.1). The research gap is first identified along with Section 1.1, followed by presenting the key accomplishments of this work in Section 1.2. Section 1.3 describes the methods, data collection procedures and the specific research techniques and tools employed along with this research. Chapter 1 ends up presenting the outline of the manuscript, together with the main deliverables originated from this research in Section 1.4.

1.1 Foreword and problem statement

Driven primarily by economic growth and changes in attitudinal and consumer behavior, the global energy demand accounted for the fastest rise in the last decade, increasing by nearly 2.3% in 2018 [1]. The growing demand for electricity over these past few decades is, therefore, unquestionable, mostly due to the growth of emerging economies, challenges brought about by environmental issues and the constant search for the improvement of the quality of life, provided in particular by the emergence of new technological processes [2]. Together with other infrastructure sectors, energy issues contribute significantly to the economic, technical, and socio-environmental development of a country and present strong synergy and interdependence [3,4].

The increasing search for energy pathways towards climate change and social wellbeing has led to a shift of strategies and policies, favoring Renewable Energy Sources (RES) and Energy Efficiency Measures (EEMs) but also underlying the security of electricity supply as the main pillars of the energy policies in the energy sector. Meanwhile, the effective transition towards a more sustainable, low-carbon, reliable, secure, and affordable energy system has been widely discussed worldwide for economic and social development [5–7]. The challenges and opportunities to achieve a globally sustainable energy future are investigated in Ref. [8], which also highlighted the increasing competitiveness of renewable energy with other energy sources. Ref. [9] supports the idea that the energy transition from carbon-intensive energy systems towards a sustainable energy future is considered environmental, economic and socially more beneficial than the current policies. It is worth mentioning that for systems with a high share of Renewable Energy Sources (RES), potential savings might come out through the decline of air pollution and lower health costs, for instance.

Hence, the need for substituting fossil-based energy fuel with more sustainable sources has been progressively growing due to global concerns about climate change. RES has emerged as a high-priority solution for a sustainable, cost-effective, and environmentally friendly future energy system [10]. The International Energy Agency (IEA) supports that RES is projected to have the fastest growth in the electricity sector and might lead to a sustainable future. This trend is set to continue in the future, primarily aiming to reduce Green House Gas (GHG) emissions – a key driver of climate change – and consequently mitigating climate impacts [11] given the high contribution from the power sector – especially from carbon dioxide (CO_2) emissions. RES development would also contribute to reaching the Paris agreement targets, limiting the average global temperature rise below 2°C in this century [12]. The authors of Ref. [13] support the idea that "*the focus of climate change mitigation must be on the decarbonization of the energy system, given that it accounts for almost two-thirds of greenhouse gas (GHG) emissions worldwide*."

Climate change has been considered one of the most pressing challenges for many countries. Particularly in the past few decades, the long-term effects of global climate change have driven considerable critical attention of researchers and policy-makers. According to the Intergovernmental Panel on Climate Change, "*taken as a whole, the range of published evidence indicates that the net damage costs of climate change are likely to be significant and to increase over time*". A recent paper published in *Nature Sustainability* presented a structured review addressing whether climate change may affect the Sustainable Development Goals (SDGs[1]). Evidence has been found that although combatting climate change may reinforce all the SDGs targets, it may even be a threat to reach part of those targets (i.e., 12 out of 17) [14]. Therefore, the impact on future energy demand due to climate change is predicted to increase. Still, it would depend on a set of interacting sources of uncertainty, and it might vary among regions in the world [15].

Hence, a viable climate solution might be achieved by combining RES and Energy Efficiency Measures (EEMs), which are considered the main pillars of the transition towards a sustainable energy future and for achieving a fully decarbonized global energy system [9,16]. Ref. [9] highlights the potential of both RES and EMMs to support the energy transition in the worldwide effort to mitigate climate change and contribute to reach the SDGs. Recent research has also suggested that EEMs develop a crucial role in reducing electricity consumption and GHG emissions [17]. Improvements due to EEMs, for instance, prevented 12% more GHG emissions in 2017 since 2010 [18]. A new report from the International

[1] The United Nations Member States proposed the SDGs in 2015. The need to develop affordable and clean energy solutions to address future worldwide challenges is one of the SDGs' key goals.

Renewable Energy Agency (IRENA) indicates that renewable energy jobs might reach 42 million by 2050 (out of 100 million) considering the "*energy transition*" scenario. Jobs related to energy efficiency were also reported to increase by 21% compared to the current plans [19]. The importance of gradually shifting the investments to both RES and EEMs to move from carbon-intensive energy systems towards a more sustainable energy future is, therefore, essential [9].

The prospects for achieving a sustainable[2] energy system have been widely addressed in the literature. New studies are published each year, considering different perspectives, such as technological development and climate change issues. Figure 1.1 illustrates the six focus areas proposed by Ref. [9] where policy and decision-makers should act towards a sustainable future.

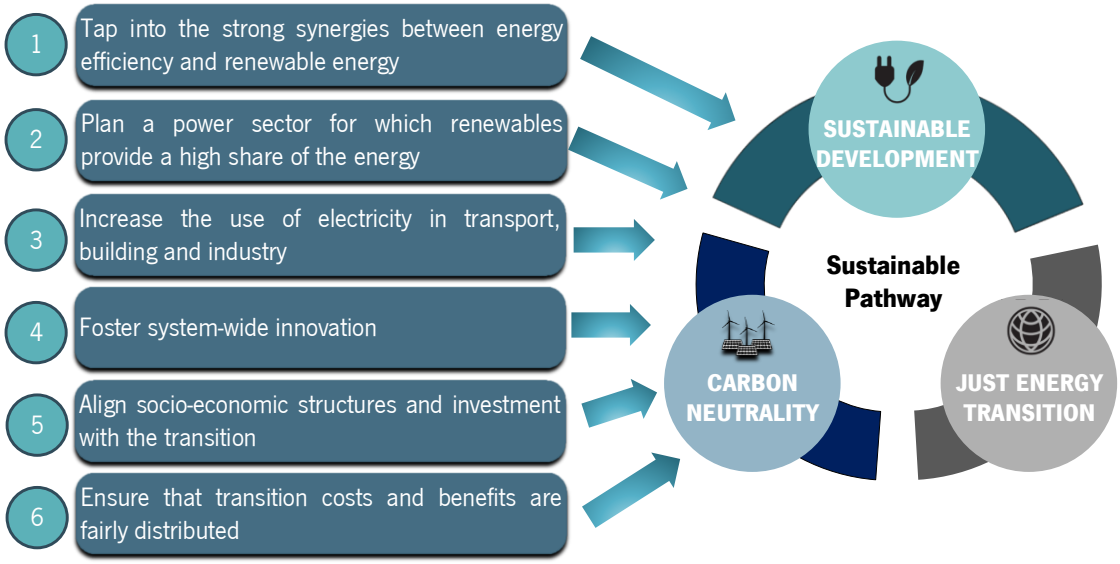


Figure 1.1: Focus areas where policy and decision-makers should act towards a sustainable future.

The first focus area highlighted in Figure 1.1, for instance, suggests the need to tap into the synergies between energy efficiency and RES for achieving a more sustainable and affordable pathway, which is also centered on other two main pillars, i.e., carbon neutrality and the so-called concept of a "*just energy transition* [20] *"*. Several studies have begun to examine the concept of a "*just transition*" which can be split up into energy, climate, and environmental '*justice*' [20]. Ref. [20] emphasizes the importance of this '*justice*' approach to the transition towards a low-carbon economy. However, governments and institutions, in general, have neglected to mention this concept in their current plans.

Although slow and steady changes had characterized the energy system, currently, driven by new technological opportunities, blend of innovation and changes in policies, regulations, and consumer

[2] Previous studies have proposed several definitions to define the concept of "*sustainability*" in the field of energy planning [26]. As stated by Rad (2010, p.1), "*sustainability is a continuous process of balancing the environmental, economic and social aspects related to the living environment (community) and their systematic improvements*". The satisfaction of present needs without compromising the ability of future generations to meet their own need can be defined as Sustainable Development according to the definition proposed by Strantzali & Aravossis (2016).

needs, significant transformations have been experienced in the energy system at local, national, and global levels [6]. Therefore, especially over the past years, fundamental changes have occurred in the global electricity sector. There is a growing body of evidence suggesting that the transformation of the global energy sector into a fully decarbonized energy system strongly depends on the power sector and "*requires long-term energy system planning and a shift to more holistic policy-making and more co-ordinated approaches across sectors and countries* [9]".

At a global level and for the future energy model, a set of changes in the power supply system's structure and operation is projected. New techniques and strategies for the operation and planning would be necessary to address this novel's concerns, including new power planning models, innovative market strategies, and novel public policy and regulation aspects [9,21]. Several challenges for the power sector are also arising, for instance, from the wide range of alternative technologies development. Therefore, substantial shifts in investments[3], policies, and planning strategies are required to accelerate the global energy transition [9]. A set of changes in cognitive (i.e., attitude and behavior) consumer issues should also be considered in the decision-making process [9], such as illustrated in Figure 1.2, which underlines the four key categories to be addressed by governments for planning the global energy transformation.

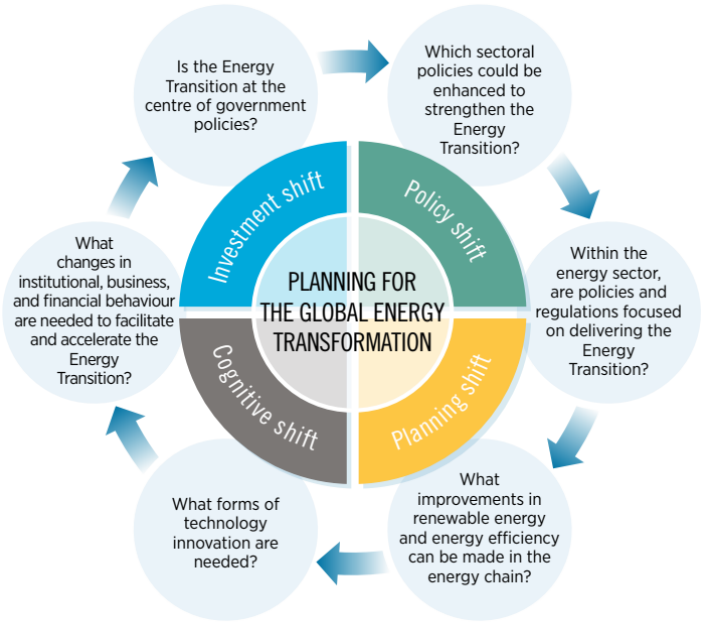


Figure 1.2: Planning for the global energy transformation [9].

The benefits brought about by a fully decarbonized global energy matrix go beyond the reduced environmental impacts, bringing a more comprehensive range of advantages such as human health

[3] The uncertainties associated with renewable energy also require the use of more advanced methodologies for the economic evaluation of Renewable Energy Projects (REP) to increase the investor's perception regarding the main project's risks and account for managerial flexibility [88].

improvement, make universal energy access more affordable, and promoting the diversity of energy supply [9,22,23]. Findings of Ref. [24] supports that a fully decarbonized energy system costs less than business-as-usual portfolios. With regard to the cost of renewable energy technologies (mainly for wind and solar PV systems), it is noteworthy to remember that it is expected to decline steadily in the future years. Therefore, the attractiveness of these types of facilities has substantially increased over the years. Consequently, wind and solar systems are expected to lead the way towards a sustainable future and its worldwide overall installed capacity is projected to increase from 25% in 2017 to 85% by 2050 [9,25].

However, the aforementioned technological advances and opportunities increased the complexity of energy planning tasks mainly because of conflicting factors (e.g., technical, economic, social, environmental, operational, and regulatory) in the energy decision-making process [7,26]. New challenges have also been witnessed in the last couple of years for governments, utilities, and system operators due to the disruptions of the electricity sector. These challenges include, for instance, the need for new techniques to address the intermittent generation from renewables but also new planning strategies to meet global climate goals. Therefore, additional challenges are imposed on the entire electrical power system due to the growing penetration of power generation from intermittent RES (i.e., with limited controllability and predictability), especially from wind and solar power [27,28]. Several studies have appeared over the past few years examining the stochasticity and intermittency characteristic associated with wind and solar systems. These features are expected to become significant concerns related to the uncertainty of future power systems [29]. The high share of RES in power systems may also lead to grid stability problems due to the mismatch between electricity demand and power production.

The implementation of balancing measures has been considered essential to address these challenges associated with flexibility concerns. Examples of balancing measures include the use of energy storage technologies, Demand-Side Management (DSM) strategies, curtailment, and backup power generation, just to name a few. The potential of storage systems (e.g., Battery Energy Storage System – BESS) appears as a possible solution to absorb the excess renewable electricity production from VRE and deliver electricity at a lower price during on-peak times may strongly contribute to the integration of higher shares of VRE into power systems.

The emergence of DSM[4] strategies has also been recognized as one of the main potential contributors to address the challenges mentioned earlier and hold the potential to deliver significant advantages in future

[4]While a variety of definitions of the term 'DSM' have been suggested in the literature, along with this work, the DSM concept will be broadly used to refer to both EEMs and strategies that affect the resources on the demand-side. This last concept is mostly related to Demand-Response (DR) measures. Smart Grids and DSM strategies are interrelated and intrinsically linked. For instance, smart grid technology investments (e.g., smart meters) might enhance the DR potential. In general, if automated control systems (e.g., smart grids) are already implemented, DR programs require little capital expenditure.

electricity supply systems. Therefore, DSM strategies have emerged as a valuable resource flexibility option for balancing supply and demand and consequently enhancing the overall level of power systems' flexibility. Still, it has also been recognized as a new market opportunity for consumers.

In the wake of the climate-change[5] debate [30,31] and the "*just energy transition*" concept [20], the role of Distributed Energy Resources (DER[6]) has also emerged as a potential contributor to address the aforementioned flexibility requirements. The use of DER has become a valuable solution to respond to the several problems brought about by the growth of VRE and thus contribute to enhancing the flexibility in grid operations. The world has been moving towards renewable-based DER mainly because of two key factors (i) the decreasing costs of these technologies and (ii) the increasing need for new energy flexibility requirements in power systems [32]. The introduction of DER also holds the potential to address the three main conflicting variables (i.e., cost, the security of supply, and CO_2 emissions reduction) faced by governments, municipalities, industries, and communities in general for which a holistic and integrated approach is required to meet these goals simultaneously. Regardless of all the benefits related to the development of DER (e.g., the grid losses reduction and the postponing of conventional investments in infrastructure), the growing insertion of these technologies implies more uncertainties on power demand projections by also affecting the optimal future countries' energy mix [33]. The authors of Ref. [34] underline that *"distributed energy resources (DER) are driving the need to change how the grid is managed"*. Therefore, DER represents a high disruptive potential and it can add up significant and systemic benefits to the power system but at the same time, it may significantly increase the power system's complexity.

Short-term power system models such as unit commitment and economic dispatch models have been traditionally used to assess the impact of RES integration on power system operation. These models are usually focused on issues related to power system security or flexibility adequacy [28,35]. In the context of power systems, the term "flexibility" can be broadly defined as "*the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons*" [36]. It is well established the need to enhance the power system flexibility as the stochastic production from VRE increases [37]. The mismatch between production and demand may cause over-voltages, equipment tripping, or even blackouts since

[5] A systematic literature review of the role of energy systems for climate change mitigation is addressed by Ref. [416] highlighting the emergence of both energy-water-land nexus and energy storage areas and the growing interest in waste-to-energy and hydrogen energy production, which have also been in the center focus of much recent research.

[6] One of the main drivers of power system evolution worldwide is related to the use of Distributed Energy Resources (DER), which includes the contribution from Distributed Generation (DG), Demand Response (DR), Energy Efficiency (EE), Electric Vehicles (EVs) and storage systems, just to name a few [68,417–419].

it affects the power system frequency [38]. The load balancing (or net-load balancing) refers to the power system's ability to match demand and supply in a smart grid environment [38]. A novel algorithm has been proposed by Ref. [38] to address the problem of net-load balancing in smart grids with high photovoltaic (PV) penetration. The use of Virtual Power Plants (VPP) can also be considered another possible alternative to provide flexibility to the power system [37] as well as the use of load curtailment techniques [38]. Two potential ways to increase power system flexibility also include (i) the integration of different energy sectors such as heat and electricity and (ii) the interconnection between power systems such as investigated in [39]. The authors of [39] derived broadly applicable conclusions on the benefits and role of the energy system integration emphasizing that this option should be prioritized compared to the transmission system's expansion for the case study evaluated. The scalability of load flexibility strategies, however, has been considered a remarkable challenge worldwide.

The concept of flexibility might be split into short-term (i.e., *flexibility adequacy*[7]) and long-term (i.e., *system adequacy*[8]) [35]. The use of long-term power system models (e.g., Generation Expansion Planning - GEP) has been traditionally employed and best suited to address system adequacy issues and assess the impact of RES integration on power system planning, for instance. Conventionally, GEP models do not include significant temporal and operational detail, which usually leads to an oversimplified representation of short-term system operation and its costs [35]. The high RES integration in power systems in general, concerns related to short-term operating requirements and constraints (i.e., flexibility adequacy) have also attracted strong research interest and should be assessed carefully to ensure a reliable and resilient power system planning [28,35]. The high RES penetration will impact not only the short-term power system operation but also the long-term power system planning [28]. The short-term operation is then becoming increasingly important to be considered in long-term power planning models. The importance of combining short and long-term power planning is addressed by Ref. [40], focusing on the Portuguese electricity system. However, the computational barriers associated with large power systems have usually limited the inclusion of short-term operating requirements in long-term planning models [35].

Particularly for the past couple of years, the link between supply and demand-side has also been at the center of much attention. The need to evaluate the impact of demand-side strategies not only in the short-term but also in the long-term is essential to identify the synergies and potentialities from the demand-side point of view. Findings of the study proposed by [41] indicated that the generation dispatch and

[7] Flexibility adequacy refers to "*the short-term ability to keep the system balanced*" [35].

[8] System adequacy refers to the power system's long-term ability to meet its peak demand [28,35].

investment might be affected by the inclusion of DSM strategies or storage technologies into the co-optimization model.

Co-optimization models are computer-aided decision-support tools that search among possible combinations, the best one in terms of a defined objective subjected to a set of constraints [41]. However, there has been little work in the development of co-optimization models for long-term decision-making, with the objective of recognizing the impact of short-term variability of both demand and RES supply and well suited to systems with a high share of RES and under different demand flexibility conditions. In this context, another question emerges from this thematic: How demand-side management strategies would affect the savings of generation and transmission capacity at the planning stage? Findings of the study proposed by [41] found that the potential benefits from co-optimization planning approaches usually include lowering the overall power system costs. Specifically, the savings might occur due to better decisions regarding retirements, savings of generation investment and operating costs, and efficient integration of other resources such as storage technologies, DR measures, and DERs. Therefore, co-optimization might result in significantly different patterns for investments compared to what traditional planning strategies would suggest.

The integration between supply-side and demand-side options for long-term power system planning using the Long-Range Energy Alternative Planning (LEAP) system was investigated in the work of [42] for a system with high RES penetration (i.e., India) and considering different types and levels of DSM strategies, including both EEMs and peak load shifting. The authors of Ref. [42] argued that cost savings would occur to up to 18% due to the simultaneous implementation of both supply-side and demand-side measures, reducing both the total installed capacity and CO_2 emissions by 10% and 23%, respectively. Energy flexibility measures to manage with high VRE levels (including DSM strategies) were reviewed by Ref. [43], including a detailed sectoral analysis of the DSM potential for Finland and Germany.

The Electric Power Research Institute conducted a research regarding the synergies between energy efficiency and Demand-Response (DR), concluding that "*the combination of demand response and energy efficiency programs has the potential to reduce non-coincident summer peak demand by 157 GW to 218 GW,*" which represents a reduction between 14% and 20% of the projected peak demand in the U.S. by 2030 [44]. To maximize the combined benefits of both energy efficiency and demand-response strategies, the interactions between long-term energy efficiency and daily demand-response at an industrial firm was investigated by Ref. [45]. Ref. [46] assessed the effects of demand-response measures on energy efficiency, concluding that, in general, demand-response yields energy savings. Hence, there is a large number of published studies (e.g., Refs. [47–49]) suggesting that investments in DSM strategies would

avoid investments in the supply-side. The use of DSM strategies has been recognized as one of the primary key drivers towards a sustainable pathway transition and a powerful resource to contribute to the future challenges of the power sector. The benefits brought about by the combination of energy efficiency and Demand Response (DR) strategies may contribute significantly to the power system operation and deferring investments in distribution and transmission systems.

Based on the previous contextualization, it can be seen that much of the attention in previous research has been to consider the technical impacts of RES on power grids [50,51] and most of the previously published works have focused on the short-term impact assessment of DSM strategies. Notwithstanding, there are relatively few studies that attempt to develop a full picture and a comprehensive examination of the role of DSM strategies in the long-term such as the evaluation of changes in the future optimal base power capacity and peak system load in consequence of the implementation of such policies [52,53]. This fact stands out for the specific case of developing countries and, in particular, for systems that deeply rely on renewables. While some countries have a small share of renewable energy, other countries already rely mostly on RES. For instance, this is the case of Brazil, which already generates more than half of its electricity from renewables, relying primarily on hydropower [54]. The country has been witnessing changes in the market and regulatory structure, such as implementing pilot DSM programs that enabled the industrial consumers' to participate in DSM programs [55]. The increasing penetration of VRE from wind and solar systems has also disrupted the current country's planning practices.

The high reliance on hydropower makes the Brazilian power system a particular example of a non-coal-dominated power system, which means that different approaches may be considered to correctly evaluate the long-term impacts of both RES and DSM strategies. Although considered a dispatchable resource, the Brazilian hydropower system's regularization capacity has also witnessed a steady decrease over the past years [54]. This is mainly because of three reasons: (i) the new hydropower projects have been restricted to run-of-river power plants, (ii) the share of hydropower in the electricity mix has been decreasing since new investments are focused on other RES such as wind and solar systems and (iii) due to climate change[9] issues - which has been affecting rainfall and climate conditions in the country [3,56].

The decrease in the regularization capacity level of reservoirs in the country, however, has put into question the robustness of the current country's planning strategies, and the need for methodological improvements to account for the integrated nature of energy planning tasks is also

[9] The El Niño Southern Oscillation (ENSO), for instance, is considered one of the primary drivers of global climate variability, and therefore, it can affect hydropower production. The ENSO's effects on hydropower production are particularly addressed by Ref. [420], considering historical measured data for both ENSO and electricity production from hydropower at a regional and global scale. For the specific case of the Amazon river basin, which represents the largest unexploited hydropower potential in Brazil, the hydrology is strongly affected by the ENSO, decreasing the rainfall over that region such as better discussed by Ref. [421].

essential in the years to come [56]. Previous research has also shown that currently, there are deficiencies in the treatment of the Brazilian power sector planning, which should be conducted in an integrated, multidisciplinary, and participatory approach to establish an appropriate methodological framework to analyze this non-trivial problem [57]. As reported[10] by EPE (2017), computational tools for energy planning purposes in the country are monthly-based. However, the current planning strategies are getting insufficient to the power system´s operation and planning, primarily due to the future high penetration of wind and solar power. The need for hour-based power planning is essential, and currently, computational tools used in the Brazilian electricity sector have several limitations. Furthermore, those technological alternatives which have some operational flexibility and/or a peak-load capacity, as reversible hydropower or Battery Energy Storage Systems (BESS), have not been well regulated by the electricity market mechanisms and may appear to be less competitive.

Therefore, considering the previous background, the long-term integrated assessment of the role of both RES and DSM for the Brazilian power sector is essential and imperative and it is far from being fully explored in the literature. The developed Integrated[11] Brazilian Electricity System Model - IBESM (hereinafter it will be referred to as IBESM) is, therefore, used along with this research to evaluate the long-term impacts of implementing DSM in the country. IBESM has also been developed to support future research into the assessment of other-related demand-side effects in long-term power planning models.

The relevance and innovative aspects of this study are then strongly related to the integrated assessment of DSM into renewable-based energy systems. The proposed modeling approach is also expected to be unique with respect to the proposed enhancements in the co-optimization model for long-term decision-making, recognizing the impact of short-term variability of both demand and RES supply and well suited to systems with a high share of RES and under different demand flexibility conditions. This combination makes the proposed model unique and challenging to solve and is expected to be a powerful tool to guide and support policy-makers and stakeholders.

The contribution of the present study to the literature is multifold and is strengthened by the following key accomplishments:

- The categorization of the scientific approaches used to estimate the different categories of DR potentials is carried out through a systematic literature review.

[10] EPE highlights in the Decennial Plan [373](PDE 2027) the need for methodological improvements for the integrated (generation, transmission and distributed energy resources) energy planning for the Brazilian power sector. This is needed to account for the new technologies (and its associated complexities) emerging in the energy sector.

[11] Along with this research, the term 'Integrated' refers to the joint implementation of both supply and demand-side resources into the same co-optimization approach.

- Proposal of a user-friendly and step-by-step theoretical framework for the determination of the different categories of DR potentials.
- Comprehensive literature review of the most relevant research into co-optimization in long-term problems within the energy sector.
- Up-to-date assessment of the main prospects, challenges and opportunities towards a smart grid power system in Brazil.
- Establishment of the current and future theoretical load flexibility potential of selected processes and appliances across different sectors (i.e., residential, commercial and industrial) and regions within the Brazilian power sector.
- Evaluate the cost-effectiveness of energy efficiency investments in high renewable electricity systems using the Brazilian power system as the case study.
- Proposal of a novel step-by-step procedure to calculate the newly proposed Long-term Average Cost of Saved Electricity (LACoSE).
- Assessment of the technical and economic impact of DR measures for systems with a high share of RES.
- Evaluation of the effectiveness of the combined use of both energy efficiency and demand-response strategies on a high-RES system.

1.2 Research objectives

The key goal of this Ph.D. thesis is to contribute to the development of sustainable scenarios for the Brazilian electricity system, supported by a co-optimization approach and combining clean energy supply options with DSM strategies. These scenarios are then used to define well-founded pathways for the definition of sustainable energy policies and plans for the country. The scientific contribution of the work is expected to go beyond the Brazilian case, as the proposed modeling approach will support the decision-making process in different systems with both high shares of RES and DSM strategies.
The general research question of this study can be then defined, such as follows:

How can DSM and RES be co-optimized for long-term power planning?

To complement the research question previously defined, we also defined a set of research objectives. The "*research objectives are likely to lead to greater specificity than using investigative questions* - Saunders, Lewis, & Thornhill (2016, p.45)". The most critical criteria to formulate useful research

objectives to operationalize both the research question and the research aim are transparency, specificity, relevance, interconnectivity, answerability and measurability. Therefore, the key goals to be accomplished are the following.

- Identification and critical valuation of the main factors impacting long-term energy planning in the country with a particular focus on the prospects of future demand-side management options. Three main sub-objectives can be established and lay the ground for the research: (i) review of scientific approaches used to estimate different categories of DR potentials; (ii) proposal of a theoretical framework for the determination of the DR potentials categories; (iii) review of co-optimization approaches in long-term planning models.
- Characterization and prospects for policy and regulatory framework in the Brazilian electricity system. The main challenges and opportunities towards a smart grid power system in Brazil will be reviewed.
- Assessment of the theoretical load flexibility potential within the Brazilian power sector. Two central issues will be addressed: (i) a sectoral assessment across the residential, commercial, and industrial sectors and (ii) a regional analysis - splitting the Brazilian power system into four main subsystems.
- Design a co-optimization model for supply and demand coordination, resulting in a new integrated planning model particularly well suited to systems with a high share of RES and under different demand flexibility conditions. This will introduce an innovative approach, using a co-optimization model for long-term decision-making and recognizing the impact of short-term variability of both demand and RES supply.
- Implementation and testing of the proposed model for the particular case of Brazil (IBESM), resulting in new scenarios fully characterized by the technical, economic and environmental perspectives.
- Presentation of strategies and energy policies to support the definition of relevant energy transition pathways towards a sustainable and resilient power system.

The objectives are explored for the case of the Brazilian power system, which can be justified by the following factors: (i) continental dimensions; (ii) high-RES share; (iii) vulnerability to climate change and (iv) access to data. These factors will be described in detail along with this work.

1.3 Research framework

This section aims to present a highly structured methodology to achieve the objectives mentioned above but also to ensure reliability and facilitate research replication. The selection of the research philosophy, research mode, research approach, methodological choice, research nature, research strategy, data collection techniques, and its sources and data analysis procedures will also be described along with this section.

The way to systematically solve a research problem is defined as research methodology [60]. Research is widely referred to as a multi-stage process and should be conducted with rigor by paying attention to the entire research process [59]. The research process is usually described as a rational and straightforward series of linked stages to effectively carry out the research [59,60]. The first step of the research process consists of the formulation of the research topic. After defining the research topic, a systematic literature review should be performed. The systematic literature review conducted in this research has the primary objective of synthesizing a body of evidence of the most recent relevant and significant research and providing a full overview of the current topic in a repeatable, comprehensive, and systematic way [61]. Ref. [62] defines a systematic review as *"a formalized method for synthesizing a body of evidence in a reliable manner that aims to maximize transparency, comprehensiveness and objectivity."*

Designing the research comprises the next step, including the methodological choice, collecting and analysing the relevant data, and writing up [59,63]. The general plan of answering the research question can be defined as research design (or research plan) [59]. As stated by Kothari (2009, p. 31) "*a research design is the arrangement of conditions for collection and analysis of data in a manner that aims to combine relevance to the research purpose with economy in procedure*." Research design should (i) be highly structured, i.e., include the specification of the sources of data collection to increase the levels of research validity and reliability; (ii) how it is expected to collect and analyze the data and (iii) the definition of the methodological choice among a qualitative, quantitative or mixed methods research design [59,63]. Therefore, a comprehensive literature review has been undertaken to establish the theoretical foundation of the research, providing the necessary background knowledge of previously published research in the area, and setting the key research boundaries. This also allowed to identify the level of relevance and novelty of the study. Then, the research gap, the general and the complementary research questions were established (see Figure 1.3 for details). All research questions have been formulated supported by critically reviewing the literature to develop a clear argument based on a constructively critical analysis of

what has been published in the literature. The literature review will include mainly scientific papers and reports for the energy sector at the international level (all stages) and particularly for the case of Brazil.

The definition of both the research question(s) and the research aim(s) are complementary ways of clarifying what the research is about. Nonetheless, neither provides sufficient details concerning the steps to answer the research question and achieve its aim. Therefore, after formulating the research questions, the most appropriate methodological choice should be addressed. After that, the nature of the research, the research strategy, and data collection and analysis techniques should also be selected, followed by identifying the suitable procedures, tools, and techniques [59].

Regarding the type of data, this work will follow mostly a quantitative data collection techniques approach within the research design. However, qualitative analysis is also considered for achieving some specific goals. Data collection techniques include examining multiple-source primary and secondary data, including high-quality academic journals, books, e-books, conference proceedings, official reports produced by all Brazilian government levels such as annual reports and national expansion plans, master dissertations and doctoral thesis. Primary literature sources refer mostly to government, academics, and industry material such as reports, whereas second literature sources are mostly related to published items such as journals and books [59].

This Ph.D. project's research nature may be termed as a combination of the following: exploratory, explanatory, and evaluative purpose, as illustrated in Figure 1.3. The usefulness of exploratory research comprises understanding a problem or phenomenon, and it is usually conducted through a systematic literature review process. The emphasis of explanatory research is to study a situation or problem to explain and establish causal relationships between variables [59]. A theoretical contribution is expected from evaluative investigations through understanding both “how effective” and “why” something works and further comparing this explanation to existing theory.

Within the research design, the use of suitable research strategies should also be addressed. According to Saunders et al. (2016, p. 177) “*a plan of how a researcher will go about answering her or his research question*” can be defined as research strategy. For each task described in Figure 1.3, a different research strategy will be applied to achieve each of the proposed objectives. This research will use archival and documentary analysis and computational modeling (applied to a case study). GAMS modeling language is employed to describe the proposed models and for solving the optimization problems. It is worth mentioning that the research design proposed in this work is expected to be useful to model other countries with both a high share of RES and DSM strategies.

This research will follow the deductive approach to theory development (research approach). The deductive approach consists of developing a theoretical or conceptual framework and subsequently testing it using the available data. For the deductive approach, the research begins with theory, and a suitable research strategy needs to be chosen to test the theory [59].

The research mode can be classified as applied research since the objective is to develop sustainable scenarios for high-RES systemssupported by a co-optimization approach and combine clean energy supply options with DSM. The applied research proposed in this Ph.D. research aims to be academically rigorous, practically useful, and solve specific problems. It may also generate knowledge for practical application, providing essential contributions to international scientific knowledge, energy decision-makers and electricity market companies [59,63,64]. This research also increases the knowledge throughout a set of code enhancements in a previously developed co-optimization model with the objective to support the decision-making process in systems with both high shares of RES and DSM strategies. The proposed enhancements aim to account for the inclusion of energy efficiency measures within the model. Also, improvements related to the DR implementation are presented. The proposition of a novel step-by-step procedure to calculate the newly proposed Long-term Average Cost of Saved Electricity (LACoSE) is also one of the key contributions of this study.

There are several types of research philosophies, including positivism, critical realism, interpretivism, post-modernism, and pragmatism. Positivism is considered the most widely used approach [63]. Typically, quantitative research is generally associated with the positivist paradigm, primarily when used with a highly structured data collection technique. The use of deductive approaches is also often associated with the positivist paradigm [59]. As stated by Saunders et al. (2016, p. 659), "*one feature of positivism is that the researcher is independent of, and neither affects nor is affected by, the subject of the research*." Therefore, the philosophical stance of this research can be termed as positivism.

The schematic of the general research process of this Ph.D. research project is illustrated in Figure 1.3.

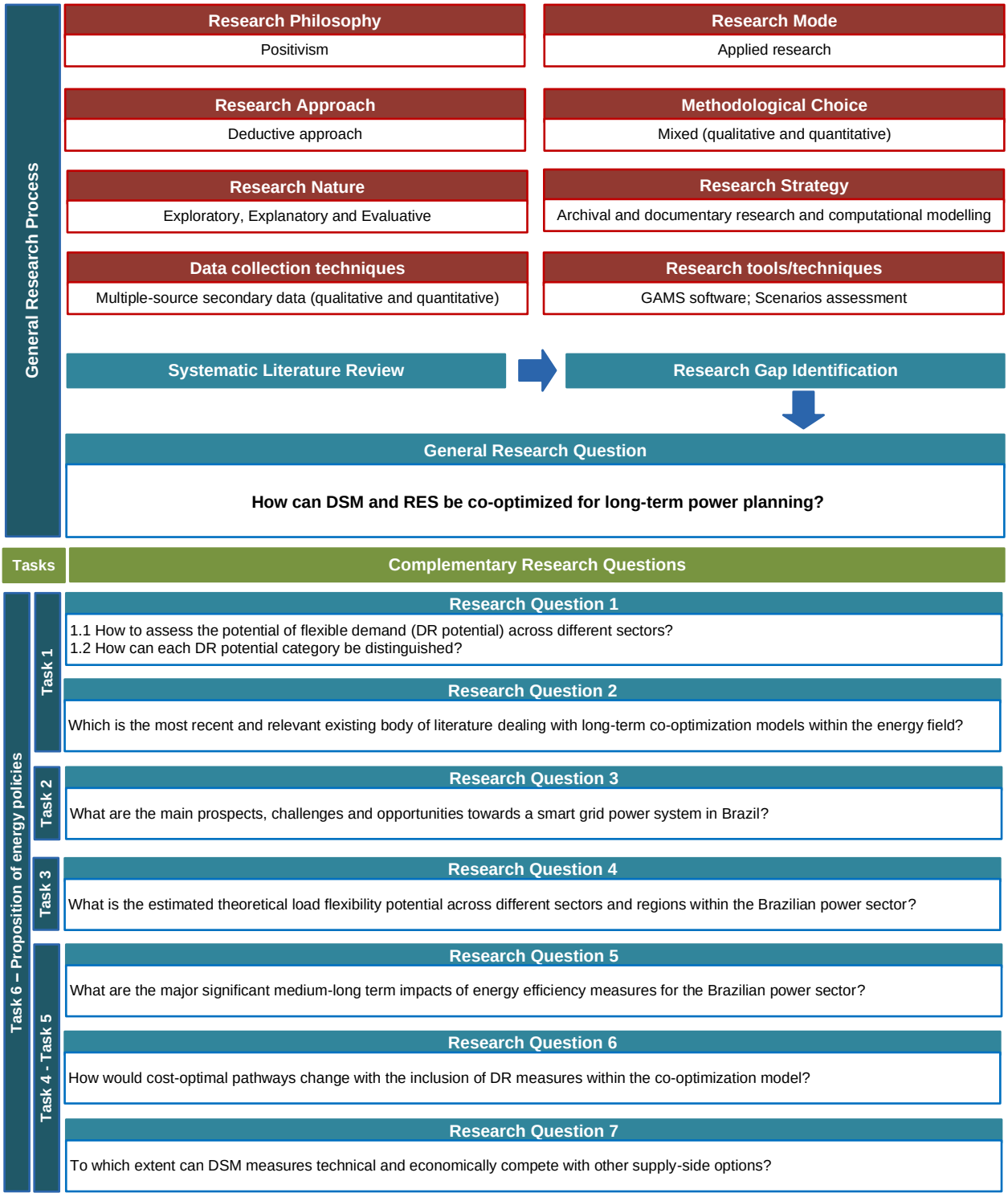


Figure 1.3: Schematic of the research process for this Ph.D. thesis.

Summing up, the five main tasks to be developed in this research can be summarized as follows (see Figure 1.3 for details). **Task 1** provides the theoretical background of the study supported by critically reviewing the literature. This is fundamental to develop a clear argument based on a constructively critical analysis of what has been recent published in the literature. The analysis will include mainly scientific papers from international peer-reviewed journals and reports from the energy sector at national and

international levels. **Task 2** attempts to identify the main challenges and opportunities towards a smart grid power system in Brazil and **Task 3** aims to establish the theoretical load flexibility potential in the country. **Task 4** and **Task 5** are attached to the design, implementation, and testing of the model. **Task 6** draws together the various strands and proposes suitable strategies and energy policies well suited to the case study to support the definition of energy transition pathways towards a sustainable and resilient power system.

The general research question of this study has been previously defined. However, to provide a more straightforward goal for this work, a set of systematic and complementary research questions were determined based on the several identified research gaps. This section proceeds by describing with details each task illustrated in Figure 1.3, which is associated with these driving research questions. Also, it is worth mentioning that each task is linked to each objective described in Section 1.2.

TASKS DESCRIPTION

Task 1 - This task investigates how DR is being considered in planning models and how to incorporate suitable DR options for the Brazilian electricity system. Therefore, Task 1 focuses on categorizing the scientific approaches used to estimate the different categories of DR potentials (**RESEARCH QUESTION 1.1**) followed by the proposal of a novel user-friendly and step-by-step theoretical framework to assess each category of DR potential (**RESEARCH QUESTION 1.2**). Afterward, a comprehensive literature review of the most relevant research into the use of co-optimization approaches in long-term problems within the energy sector is addressed (**RESEARCH QUESTION 2**).

RESEARCH QUESTION 1

1.1 How to assess the potential of flexible demand (DR potential) across different sectors?

1.2 How can each DR potential category be distinguished?

In recent years, there have been a growing number of publications focusing on estimating the different categories of Demand Response (DR) potentials using different methodologies and assumptions in each research study. However, most of the previous reviews have been traditionally centered on specific sectors or power systems and focus on qualitative DR assessments, such as exploring the benefits and challenges of current DR schemes. Additionally, despite a large amount of research on the topic and the best of the authors' knowledge, a general procedure for estimating the different categories of DR potentials is still missing in the available literature.

Therefore, a more comprehensive analysis is necessary for the topic, and the answers to these questions are fundamental to determine not only which are the most relevant factors and parameters to assessing

the potential of each DR category but also to evaluate the extent to which these DR potentials contribute to the transition towards a decarbonized energy system. Therefore, the contribution of **Task 1** to filling these research gaps is twofold. Firstly (i) a review of the different categories of DR potentials is addressed, and (ii) a novel user-friendly and step-by-step theoretical framework is proposed to facilitate the estimation of each category of DR potential. The proposed framework is supported on a small sample of numerical approaches and equations, which results in a structured approach to bringing consensus to the DR potential assessment.

This stage will follow a qualitative data collection technique approach within the research design. The research nature of this study may be termed as an exploratory study [59]. The different categories of DR potentials are assessed based on an in-depth systematic literature review analysis. A four-step process is considered in this research for conducting the systematic review process following the procedure proposed in [59]. Firstly, the formulation of the research questions will be established based on the research gap found by the authors. Subsequent to this, a list of potentially relevant research studies will be selected using the available online databases to generate a list of the most comprehensive research in the field.

The key-word searches that will be used as the selection criteria to locate peer-reviewed journals will include the following search terms: (a) Theoretical, (b) Technical, (c) Economic, (d) Achievable, (e) Practical, (f) Social (g) Market and (h) Realizable, combined with the terms (i) Demand Response Potential, (j) Demand-side Flexibility, (k) Flexible Demand Potential, (l) Flexible Load Potential, (m) Load Flexibility Potential, (n) Potential of Load Reduction and (o) Load Management. A screening process (by title and abstract) will be further conducted in the selection and evaluation phase, excluding the research papers that are not relevant regarding the previously defined research questions [65]. The analysis and synthesis of the results will be then considered, breaking down each study in the year of publication, potential DR category, sectoral coverage, spatial resolution, and special notes. Finally, a novel comprehensive framework will be proposed as a result of this review analysis. Therefore, the methodology can be split into the research question(s) formulation, identification, screening process, and analysis and synthesis of the results for the included papers, as illustrated in Figure 1.4.

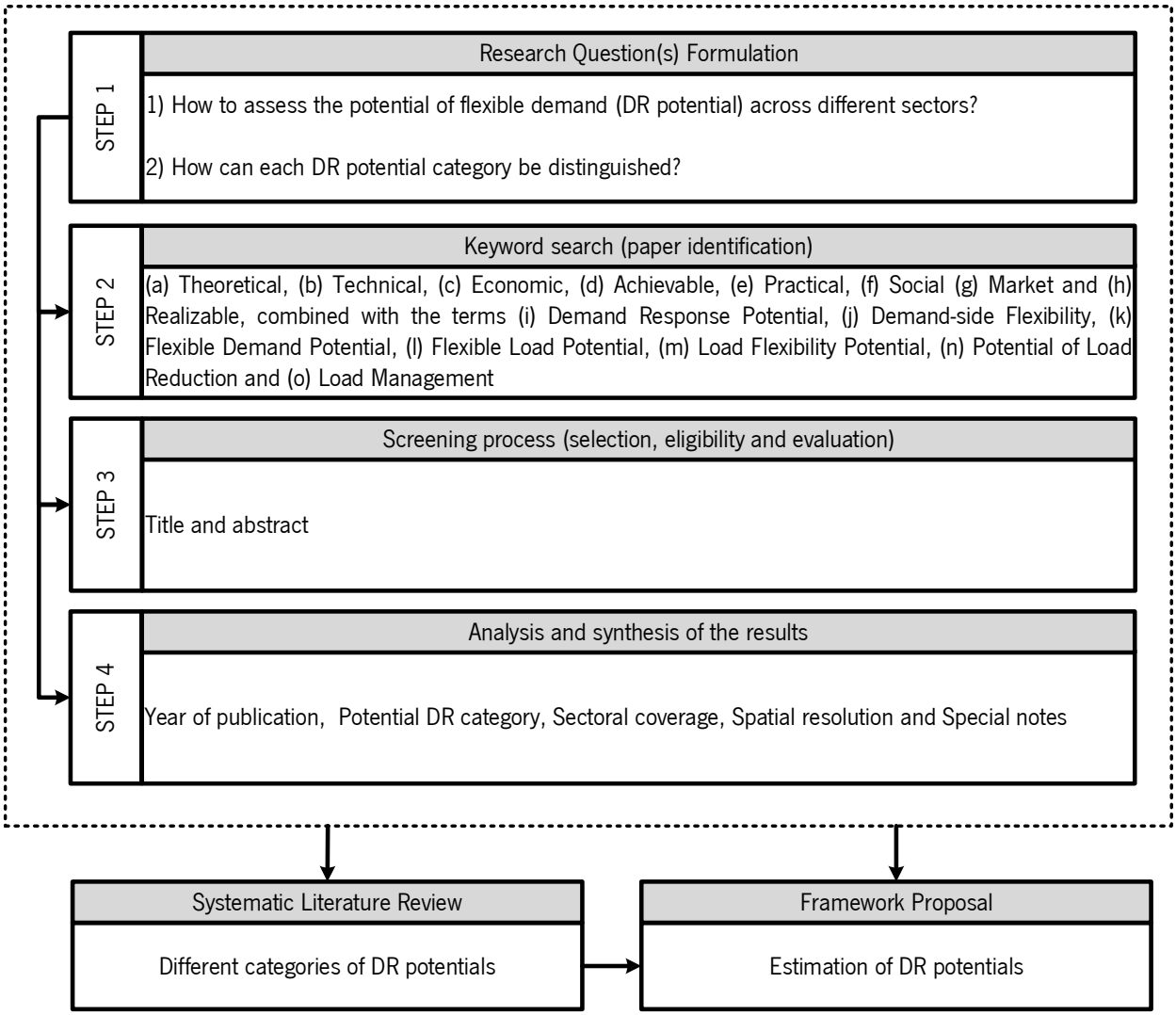


Figure 1.4: Methodological approach considered for conducting the systematic review process.

The novel conceptual framework for estimating the DR potentials will be proposed in a user-friendly manner to provide sufficient methodological detail to allow replication. The general overview of the methodological approach for assessing the different types of DR potentials is illustrated in Figure 1.5. The detailed framework will be presented in Chapter 2.

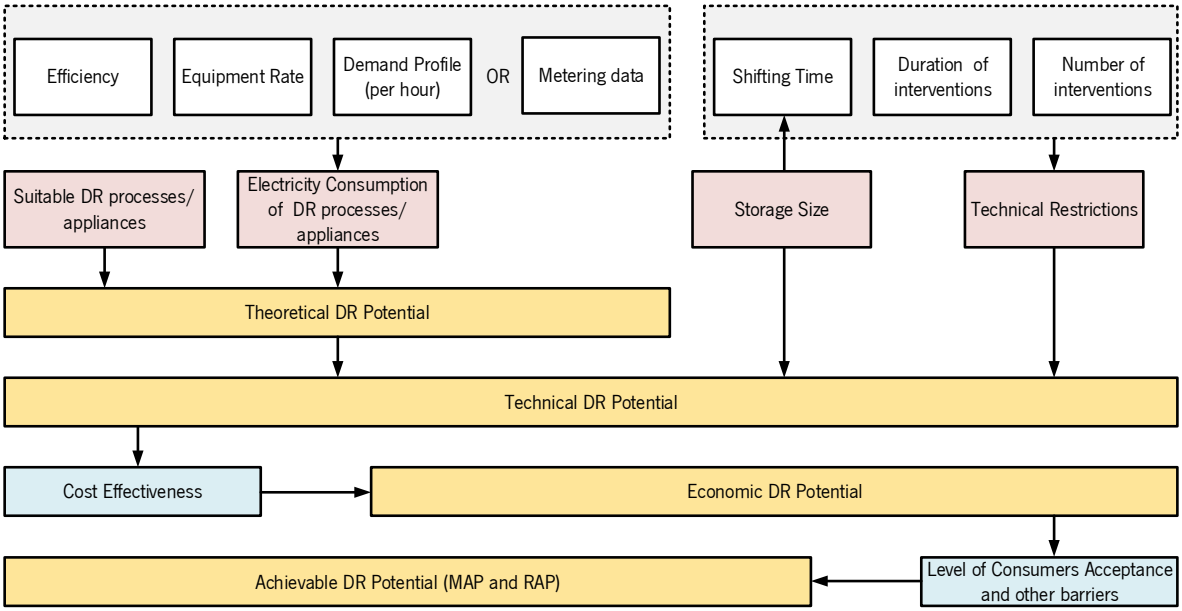


Figure 1.5: Overview of the methodological approach for assessing the different types of DR potentials.

RESEARCH QUESTION 2

Which is the most recent and relevant existing body of literature dealing with long-term co-optimization models within the energy field?

The application of co-optimization within the energy sector has attracted considerable attention in the past few years, mainly because of its potential benefits and synergies that could yield low-cost solutions and improve resource usage compared to traditional decoupled optimization approaches. However, although there is a growing body of literature that recognizes the importance of co-optimization within energy applications, to the best of the authors' knowledge, a comprehensive literature review of the most relevant research into the use of co-optimization in long-term problems is still missing.

The use of co-optimization for expansion planning problems is addressed from a variety of perspectives. This research consisted of an extensive and systematic literature review of the different types of co-optimization approaches used in the energy field, focusing on the long-term (i.e., associated with investment planning problems). Therefore, this investigation will use archival and documentary research data, and it can be classified as an exploratory study regarding its nature. The general methodological approach followed in this research is illustrated in Figure 1.6.

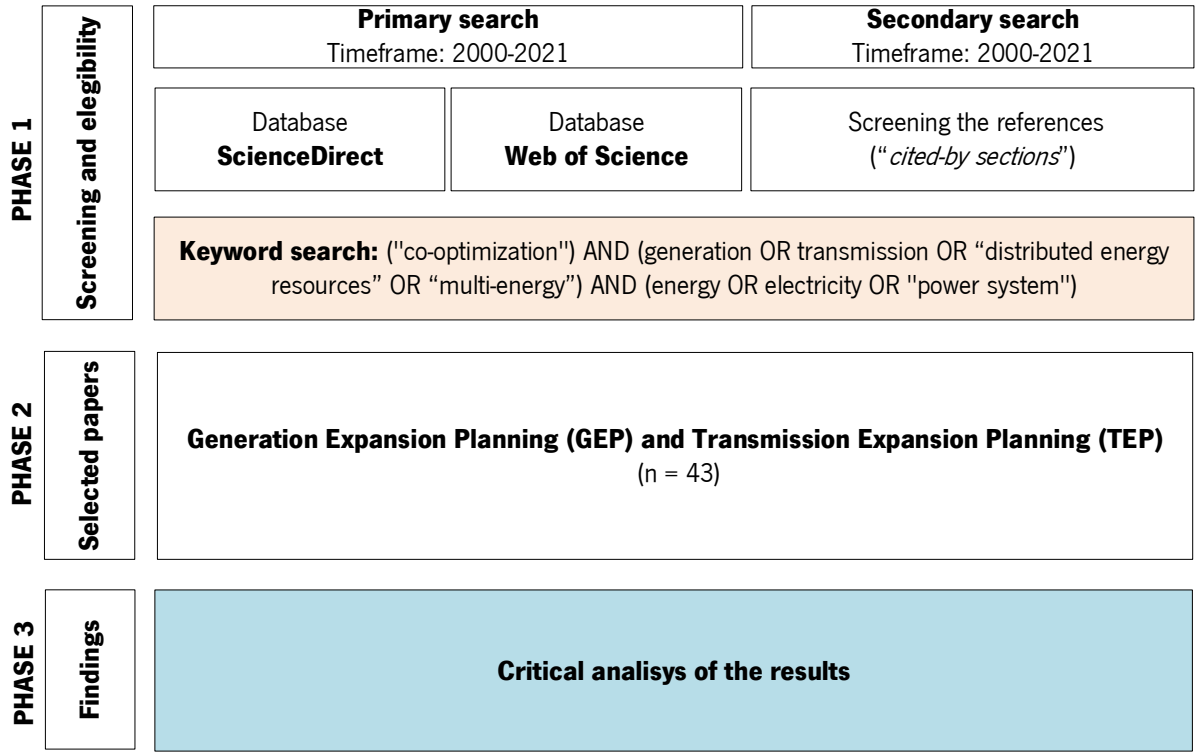


Figure 1.6: Detailed methodological approach.

The primary literature research data will be selected from two central databases: Web of Science and Science Direct (see Phase 1). An additional step will be considered by screening the primary research references (Phase 1 - secondary search). This process is considered essential since previous studies have used different terms to refer to co-optimization. Studies over the past two decades have provided important information on the use of co-optimization approaches in the energy field, and therefore, the chosen timeframe is from 2000 to 2021. The selected keywords that will be considered to locate peer-reviewed journals are also illustrated in the research's detailed methodological approach (Phase 1). The most relevant published research will be identified and thoroughly reviewed (Phase 2). Finally, a critical analysis of the results is undertaken in Phase 3 of the methodological approach.

Task 2 – The purpose of this task is to identify the main challenges and opportunities towards a smart grid power system in Brazil by reviewing the most relevant and significant previous published research. Therefore, given the foreseen application of the proposed model to the Brazilian case study, **Task 2** will also comprise the characterization of the country's electricity system, policy, and regulatory framework.

RESEARCH QUESTION 3

What are the main prospects, challenges, and opportunities towards a smart grid power system in Brazil?

The prospects for a smart power system have been widely discussed in the global electricity sector. Decarbonization, Digitalization, and Decentralization are considered the main drivers for this power system transition, and Brazil is no exception to this universal trend. A search of the literature revealed few studies which attempt to address the main challenges and opportunities towards a smart grid power system in Brazil. The prospects for the electricity sector - including the liberalization of the electricity market, DSM strategies, and technological changes - have intensified the search for advanced planning approaches in the decision-making process. An up-to-date assessment of the present and potential capabilities of existing and future technologies, regulations, and policies will be deeply investigated by also identifying how these elements are interrelated.

A qualitative methodological approach [59] is followed using an archival and documentary research strategy to explore the current and future challenges and the opportunities of the power sector. A three-step research process will be employed, which includes (i) an in-depth systematic literature review analysis[12] followed by the (ii) selection and eligibility and finally by (iii) the evaluation of the included papers.

Task 3 - Although DR is deemed to be highly relevant for the future, based on the literature review, a comprehensive assessment of the theoretical DR potential for the Brazilian power sector is lacking so far, and a detailed analysis which takes into account both a sectoral and regional perspectives is far from being fully explored in the available literature. The assessment of the load flexibility potential across sectors and regions within the Brazilian power system is precisely the main objective of this research stage (**RESEARCH QUESTION 4**).

RESEARCH QUESTION 4

What is the estimated theoretical load flexibility potential across different sectors and regions within the Brazilian power sector?

This study is a first attempt to establish the current (2017) and future (2050) theoretical load flexibility potential for the Brazilian power sector. The theoretical DR potential for future years is estimated based on the data extrapolation and considering a set of technical assumptions. Two central issues are

[12] The systematic literature review includes a comprehensive analysis of the primary papers in the field and considers the last published legal texts (i.e., laws, decrees, and regulations) for the Brazilian power sector.

addressed: (i) a sectoral assessment across the residential, commercial, and industrial sectors and (ii) a regional analysis by broadly splitting up the Brazilian power system into four main subsystems.

A comprehensive literature review is undertaken to establish the boundaries and formulate the research objective of this study. This research might be termed as an explanatory study since its main aim is to establish and explain the relationship between variables [59]. A quantitative methodological choice is considered within the research design. This work uses multiple-source secondary data, mostly based on official data from the National Grid Operator (in Portuguese, ONS), Brazilian Energy Research Office (in Portuguese, EPE), and Brazilian Electricity Regulatory Agency (in Portuguese, ANEEL). The innovative aspects and strengths of this stage rely on applying the methodology to quantitatively evaluate the load flexibility potential across regions and sectors in Brazil.

Task 4 – This task aims to design a new optimization model for supply and demand coordination resulting in a new planning model particularly well suited to systems with a high share of RES and under different demand flexibility conditions. The following decision models will be formulated: (i) an optimization model for long-term power planning and (ii) a co-optimization model that combines the DSM into the long-term model. The last level represents a major step beyond traditional power planning models and extensively contributes to the innovative character of the research, as a co-optimization approach must be followed. This, of course, increases the complexity of traditional models deeply, but it will be particularly useful for a system with a high share of RES for electricity generation and for which DSM can be a valuable option, as is the case of Brazil. It will also allow making long-term defensible decisions and more reliable cost and emissions projections for the future, recognizing the interaction between supply and demand in the electricity system. GAMS modeling language will be used to describe the proposed co-optimization electrical model and to obtain the numerical results.

Task 5 – This task comprises the implementation and testing of the proposed models for the particular case of Brazil. This will result in new scenarios fully characterized by the technical, economic, environmental, and resilience perspectives, aiming to design optimal electricity generation portfolios. The assessment is conducted based on a renewable-based energy system with a particular focus on the potential of DSM to (i) decreasing power generation capacity; (ii) RES integration; (iii) delay in investments; (iv) reduced need for thermal capacity; (v) decrease in the level of CO_2 emissions and (vi) the possibility of enhancing the synergies between power subsystems within the country.

The general description of the model structure is summarized in Figure 1.7. Firstly, the primary input assumptions should be defined, including the use of a set of input parameters and technologies. The

definition of relevant scenarios should be further established, and finally, the definition of suitable energy policies can be proposed.

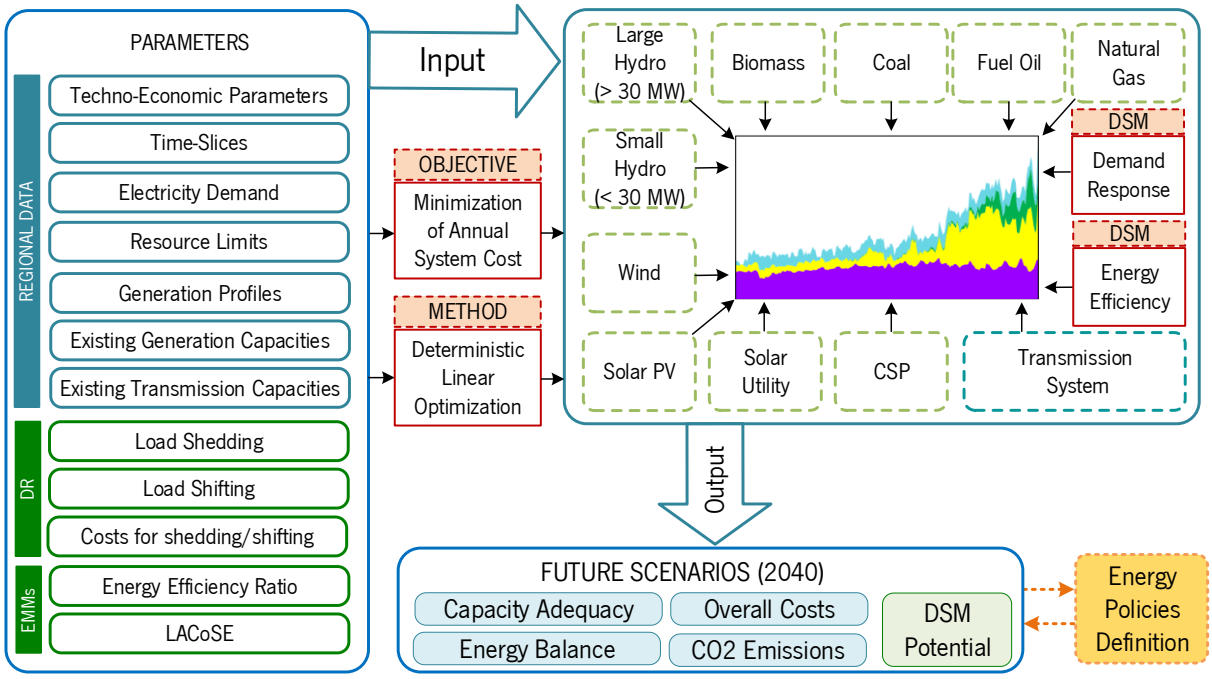


Figure 1.7: Detailed structure of the model.

Task 4 and **Task 5** are reflected into three main research questions (**RESEARCH QUESTION 5, RESEARCH QUESTION 6 and RESEARCH QUESTION 7**), resulting in different scenarios with DSM.

RESEARCH QUESTION 5

What are the major significant medium-long term impacts of energy efficiency measures for the Brazilian power sector?

Although several studies have recognized the challenges brought about by the high integration of RES, research has yet to systematically investigate the effects of different levels of EEMs on power systems with a high share of RES. This stage sought to determine what would be the effects of different percentages of EEMs in systems with a high share of renewable energy, based on the case of Brazil. Our analysis also revealed a lack of understanding of how to calculate the Long-term Average Cost of Saved Electricity (LACoSE). Therefore, this stage will also result in a novel methodological contribution through a step-by-step procedure developed to calculate the newly proposed LACoSE, which extends the traditional average Cost of Saved Electricity (CoSE) model (see Ref. [66]).

A quantitative data collection technique approach is followed in the research design. Data collection techniques include examining multiple-source secondary data, and it will be collected predominantly on online computer databases from official electricity Brazilian institutions. The research nature of this study

may be termed as an explanatory study since the main objective is to explain and establish causal relationships between variables [59]. This study will follow the deductive approach, i.e., the research begins with theory, and a suitable research strategy needs to be chosen to test the theory [59]. Therefore, within the research design, optimization models will be used within the research strategy addressing, in particular, the case of the Brazilian power system to allow a more in-depth insight into the effects of EEMs and to evaluate the effectiveness of these categories of DSM strategies quantitatively. The assessment will be carried out through sensitivity analysis by decreasing the final electricity consumption levels between 1% and 5%. The power scenarios will be built based on the Open Source Energy Modeling System – OSeMOSYS (GAMS version), which considers a large-scale deterministic linear optimization problem.

RESEARCH QUESTION 6

How would cost-optimal pathways change with the inclusion of DR measures within the co-optimization model?

To date and to the best of the author's knowledge, no large-scale studies have been performed to assess the technical and economic impact of DR measures for systems with a high share of RES, such as the case of Brazil. Prior to this study, no clear evidence of the long-term impacts of DR strategies had been reported in the literature based on a holistic assessment (i.e., by using a regional and sectoral analysis) for the country. The assessment efforts of this stage are focused on answering how cost-optimal pathways for the power system would change with the inclusion of DR measures within the co-optimization model. Precisely, the theoretical load flexibility potential estimated in **Task 3** will be included within the long-term co-optimization model to evaluate the scenarios that determine the technical and economic DR potentials.

A broad literature review will be first undertaken to develop a clear argument based on a constructively critical analysis of what has been recently published in the literature. What is not yet fully clear is the extent to which DR may be cost-effective. This task is technically challenging for the particular case of Brazil mostly because of two aspects (i) the data scarcity regarding the potential of DR among sectors and (ii) the lack of infrastructure[13] which makes more difficult the cost estimation for implementing DR (for both investment and operational costs). The first challenge (i) is addressed in Task 3 (see also Ref. [67]), which established the theoretical load flexibility potential in the country, whose results are particularly useful to use within optimization modeling approaches. However, the latter issue (ii) remains still unclear and difficult to predict not only for the case of Brazil but also for other countries worldwide.

[13] Smart Grid is under its initial stage of deployment in the country [88].

Data collection techniques will include examining multiple-source primary and secondary data. It will be collected predominantly on online computer databases from both official electricity Brazilian institutions and expert reports. Specific information for hourly demand of each region within the country will be retrieved from online databases of official Brazilian electricity institutions such as the Energy Research Office (in Portuguese, EPE) and the National Grid Operator [54] (in Portuguese, ONS). Optimization models will be used within the research strategy to assess the long-term effects of DR for systems with a high share of RES and under different demand flexibility conditions. The Brazilian power system will be used as the case study since it is an example of a power system that relies mostly on RES.

RESEARCH QUESTION 7

To which extent can DSM measures technical and economically compete with other supply-side options?

Driven by the recent trends towards a smart power system configuration, there has been a greater focus within the literature placed upon the integration between supply and demand-side resources. It is now well established from a variety of studies that it is more cost-effective to invest in DSM strategies than in the supply-side. However, only a few studies addressed the effects of DSM in the long-term, especially for systems with a high share of RES. The contribution of this research to the literature is multifold since it provides a timely and required study in the field, but it also offers valuable insights into how the integration between DSM resources with clean energy supply options might affect the long-term power planning strategies for high-RES systems. Therefore, this stage investigates whether investing together in energy efficiency and demand response might be economically feasible for the long-term. The relevance and the innovative aspects of this study are strongly related to a framework proposal for assessing the co-benefits between energy efficiency and demand-response on renewable-based energy systems under a long-term perspective. These impacts will be estimated by modeling and analyzing scenarios for Brazil in 2040.

Task 6 – Proposal of strategies and energy policies well suited to the Brazilian electricity system and to the socio-economic characteristics of the country that should support the collective objective of reaching a sustainable and resilient long-term power system is planned to be undertaken in this task. This task is linked with all previous tasks (i.e., Task 1, Task 2, Task 3, Task 4, and Task 5).

1.4 Outline of the manuscript

The overall structure of this Ph.D. thesis takes the form of eight chapters.

Chapter 1 begins by laying out the theoretical dimensions of the research. The identification of the research gap is illustrated, followed by the leading research objectives. **Chapter 1** also attempts to

describe the research framework by describing the main procedures and methods used along with this investigation.

Chapter 2 presents the key theoretical concepts in the energy planning field, starting with the importance of energy scenarios for long-term power planning models followed by reviewing GEP problems. The use of co-optimization approaches in energy planning is further examined, particularly addressing the role of co-optimization in long-term power planning models. **Chapter 2** proceeds by introducing the role of Demand-Side Management (DSM) in the context of the energy transition. The chapter follows by providing an in-depth systematic review analysis regarding the different categories of DR potentials (i.e., theoretical, technical, economic, and achievable). **Chapter 2** ends up proposing a well-founded and user-friendly framework for the quantification of the DR flexibility across different sectors and applications.

Chapter 3 contextualize the case study used along with this research – the Brazilian power sector. The literature review includes a brief overview of the sector's recent developments followed by the characterization, policy, and current regulatory framework. The main challenges and opportunities towards a smart power system are finally addressed by identifying relevant policy implications for the country.

Chapter 4 moves on to describe the formulation of the co-optimization model used along with this research. The co-optimization modeling approach is based on the Open Source Energy Modeling System (OSeMOSYS) but implemented in the General Algebraic Modeling System (GAMS) software. A methodology is further presented to calculate the newly proposed LACoSE, which allows for a fair comparison with the obtained results from traditional long-term power planning models. **Chapter 4** proceeds by presenting the objective function of the model, followed by the full characterization of the electricity system under analysis. **Chapter 4** ends up by validating the model and establishing the reference scenario (Scenario BAU).

The purpose of **Chapter 5** is to assess the theoretical load flexibility potential for the Brazilian power system. The methodological approach followed for quantifying the flexible load potential in the residential, industrial and commercial sectors comes from **Chapter 2**. **Chapter 5** proceeds by underlining the critical findings obtained for the case study under analysis, including a discussion on the implication of the results to future research into the field.

Chapter 6 focuses on evaluating the long-term effects of using EEMs for high-RES systems using the Brazilian power system as the case study. The chapter provides a brief overview of the main historical Brazilian EEMs proposals to promote electricity's rational use. **Chapter 6** proceeds by comparing

scenario BAU with scenarios that consider different levels of EEMs varying from 1% to 5%. The chapter ends up by discussing the key findings from the implementation of EEMs in high-RES systems.

Chapter 7 attempts to simulate the scenarios with (i) only DR strategies and (ii) with both DR strategies and EEMs. Therefore, this chapter explores the proposed key modeling enhancements by strengthening the key findings from the co-optimization model for each scenario with DSM. **Chapter 7** ends up providing in-depth critical analysis and assessment of the research findings.

Chapter 8 draws together the various strands and the main conclusions of the thesis. A set of policy-related recommendations are then proposed bringing together the key lessons from the research findings. This final chapter ends by underlining the possible future research pathways.

The **References** are finally presented with relevant **Annexes** with useful information regarding the data used, GAMS codes, and results from the different scenarios evaluated.

Figure 1.8 illustrates an overview of the manuscript, including the interactions among chapters and achievements.

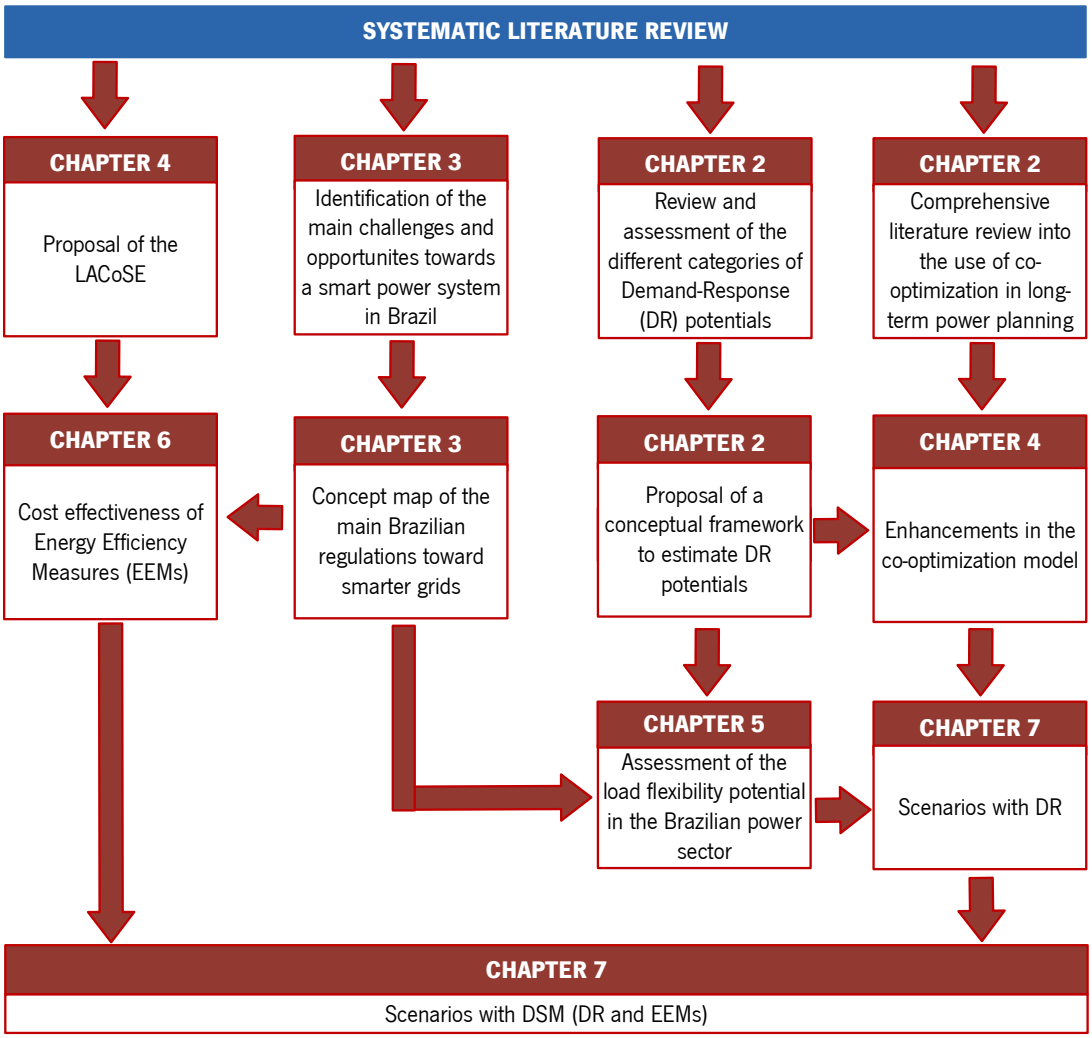


Figure 1.8: Outline of the manuscript.

This Ph.D. thesis resulted in new scientific developments. Therefore, the deliverables originated from this research include presentations in international conferences and scientific publications in international peer-reviewed journals such as follows.

International peer-reviewed journals

- (1) Dranka, Géremi Gilson; Ferreira, Paula (2018) **Planning for a renewable future in the Brazilian power system**. Energy 2018; 164:496–511. https://doi.org/10.1016/j.energy.2018.08.164.
- (2) Dranka, Géremi Gilson; Ferreira, Paula (2019) **Review and assessment of the different categories of demand response potentials**. Energy 2019; 179:280–94. https://doi.org/10.1016/j.energy.2019.05.009.
- (3) Dranka, Géremi Gilson; Ferreira, Paula (2020) "**Electric Vehicles and Biofuels Synergies in the Brazilian Energy System**." Energies 13(17), 4423 https://doi.org/10.3390/en13174423.
- (4) Dranka, Géremi Gilson; Ferreira, Paula (2020) "**Towards a smart grid power system in Brazil: Challenges and opportunities**." Energy Policy 136: 111033 https://doi.org/10.1016/j.enpol.2019.111033.
- (5) Dranka, Géremi Gilson; Ferreira, Paula; Vaz, A. Ismael F. (2020) "**Cost-effectiveness of energy efficiency investments for high renewable electricity systems**." Energy, Vol. 198: 117198. http://dx.doi.org/10.1016/j.energy.2020.117198.
- (6) Dranka, Géremi Gilson; Ferreira, Paula (2020) "**Load flexibility potential across residential, commercial and industrial sectors in Brazil**." Energy, Vol. 201: 117483. https://doi.org/10.1016/j.energy.2020.117483.
- (7) Dranka, Géremi Gilson; Cunha, Jorge; Lima, José Donizetti de; Ferreira, Paula (2020) "**Economic evaluation methodologies for renewable energy projects**." AIMS Energy, Vol. 8(2): 339–364. http://www.aimspress.com/article/10.3934/energy.2020.2.339.

International Conferences

- (1) Dranka, G. G., Ferreira, P., 2018. **Analysis of the Future Electricity System in Brazil**, in: ECOS 2018 - Proceedings of the 31st International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems. ISBN: 978-972-99596-4-6. University of Minho, Guimarães.
- (2) Dranka, G. G., Cunha, J., Ferreira, P., Lima, J. D., 2018. **Real Options Theory Applied to the Evaluation of Small Hydropower Investments in Brazil**, in: ECOS 2018 - Proceedings of the 31st International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems. ISBN: 978-972-99596-4-6. University of Minho, Guimarães.
- (3) Dranka, G. G., Ferreira, P., 2018. **Prospects for a smart power system in Brazil**, in: 4nd International Conference on Project Evaluation. ISBN: 978-989-97050-8-1 University of Minho, Guimarães, pp. 13–18.

- (4) Dranka, G. G., Ferreira, P., 2019. **Cost-effectiveness of energy efficiency measures for systems with a large share of renewables**, in: World Energy Sustainable Days – Young Energy Researchers Conference, Wels - Austria.
- (5) Dranka, G. G., Ferreira, P., Vaz, A. I., 2019. **Economic Analysis of Energy Efficiency Measures for the Brazilian Power System,** in: ICEE 2019 **-** 4rd International Conference on Energy and Environment - Bringing Together Economics and Engineering, University of Minho, Guimarães.
- (6) Dranka, G. G., Ferreira, P., 2019. **Demand Response Potential in Brazil: Theoretical Assessment**, in: 5th International Conference on Smart Energy Systems, Alborg University, Copenhagen - Denmark.
- (7) Dranka, G. G., Ferreira, P., Vaz, A. I., 2019. **Technical demand response potential for the Brazilian power system**, in: 4th Annual APEEN Conference – Energy Demand-Side Management and Electricity Markets, University of Beira Interior, Covilhã.

Chapter 2. Literature Review

This chapter provides the theoretical background of this Ph.D. research. A brief overview of the recent trends and developments in the energy planning field, together with the main drivers of power system evolution worldwide, is presented in Section 2.1. Section 2.2 addresses the importance of energy scenarios in the context of high-RES systems. The problem of Generation Expansion Planning (GEP) is further described in Section 2.3. The most relevant published research on co-optimization approaches in long-term energy planning models is then reviewed in Section 2.4. The chapter proceeds by introducing the role of Demand-Side Management (DSM) strategies towards the transformation of the global energy sector from fossil-based to low carbon systems in Section 2.5. Section 2.5 attempts to review, in particular, the key theoretical concepts related to the current DR strategies and the different categories of DR potentials. A well-founded and user-friendly framework is also proposed along with Section 2.5 to quantify the DR flexibility potential across different sectors and applications. Chapter II closes with Section 2.6, which draws together the main findings and address possible avenues for further research.

2.1 Introduction

The global energy sector has been witnessing rapid changes, mainly due to the fast-paced technological advances. The new technological advances - coupled with the recent environmental and social challenges - have also heightened the need for using more holistic and integrated approaches to meet these goals simultaneously. The past few years have witnessed, in particular, rapid advances in the field of smart grids technologies, which enable the integrated operation among a set of different resources [68,69]. These new conflicting aspects surrounding energy systems increased the search for solutions that consider the trade-offs between climate neutrality goals and envisage a "*just energy transition*" [20,70]. Several studies suggest that the growing interest in RES has become a reality over the last years worldwide, mainly due to climate change concerns and sustainability aspects. Decarbonization, Digitalization, and Decentralization have been considered the three main drivers of power systems evolution worldwide, which may strongly impact the demand and supply of electricity at a remarkable and unprecedented pace [71,72]. Figure 2.1 illustrates these main drivers and their associated elements based on Refs. [9,71,73–77]. The concepts illustrated in Figure 2.1 may be interrelated to each other. For example, the renewable energy integration of DG is strongly associated with the concept of Decentralization. However, at the same time, it is still related to Digitalization (e.g., the deployment of smart meters) and low-carbon systems (i.e., Decarbonization).

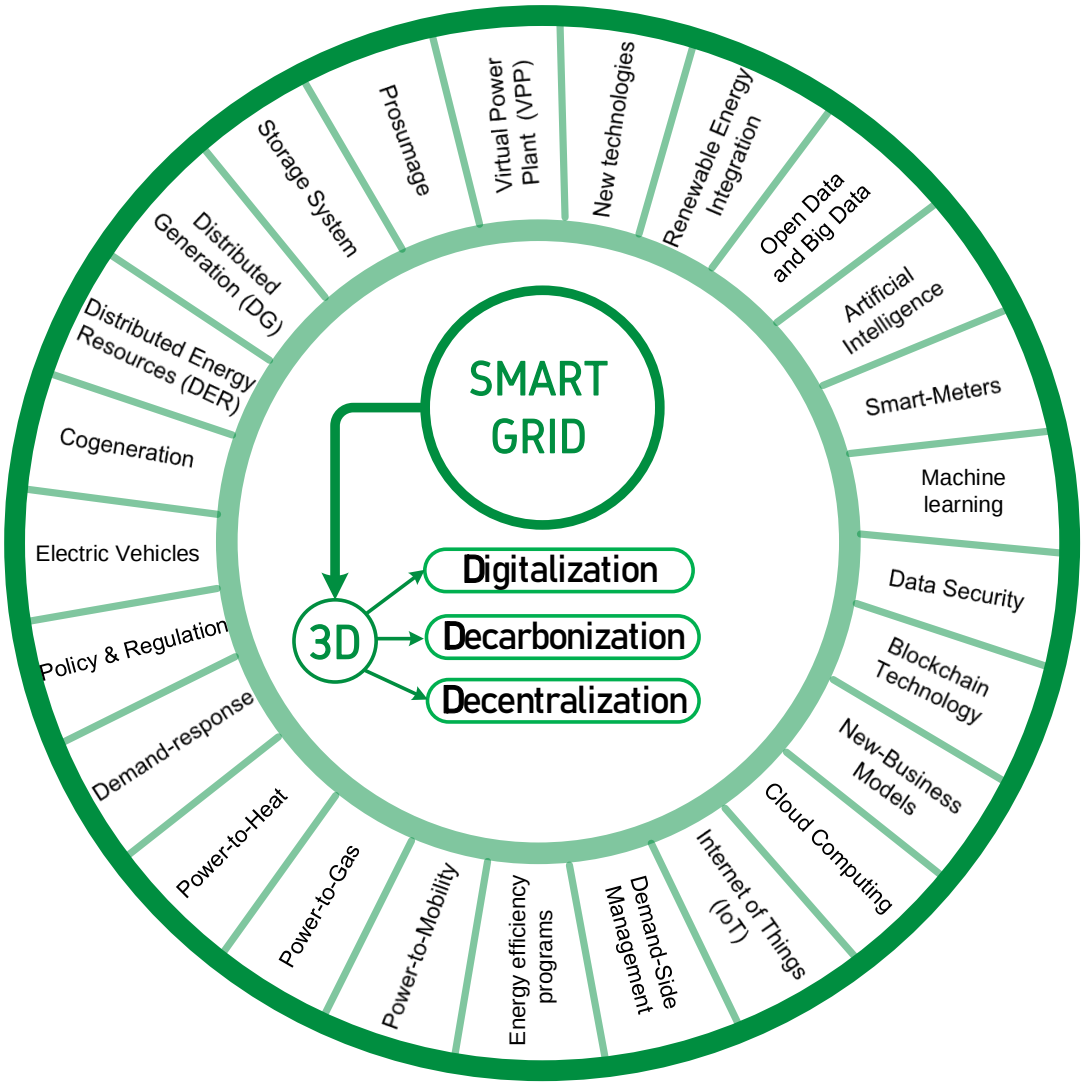


Figure 2.1: Main drivers of power systems evolution worldwide [68].

Additionally, the entire world has been experiencing new opportunities through the 4th industrial revolution, thanks to digitalization [71]. This latter concept would strongly impact the utilities through the latest market models emerging for the sector, such as the blockchain-based energy market models [75]. Blockchain technology in the energy field has recently emerged as a new market and business model, as discussed in [78]. Last, but not least, decentralization of energy systems appears as a growing need primarily given the increasing growth of electricity demand. The concept of decentralization [71] is strongly "*linked to decarbonization and digitalization since the most of the generation units are RES-based plants that must be coordinated in order to achieve security and efficiency.*" The importance of decentralization and decarbonization of the power sector is also highlighted in [79].

Smart grids are fundamental for the energy transition as it can be used to support different policy goals. As reported by [74], "*smart grids are among the most significant evolutionary developments in energy management systems because they enable integrated systems, including decentralized energy systems,*

the use of large-scale renewable energy and major improvements in demand-side-management." Therefore, smart grid deployment is at the heart of the power system evolution as this concept is inherently related to new technologies and intelligent energy management through the entire value chain from the generation to the consumers. The most significant impacts of a digitalized industry 4.0 on renewable energy systems were addressed in Ref. [80], focused on a German case study. The concept of Energy 4.0 has recently appeared in the literature referring to the energy sector's digitalization, which includes advanced energy management systems and control algorithms. The transition to Energy 4.0 is considered a challenge for energy companies and the government worldwide.

Figure 2.2 illustrates, respectively, the classical (centralized and unidirectional power system structure) and the future model (distributed and bidirectional power system structure) of the electricity system [81]. For the future model, there is a major paradigm change towards customer-centricity. This concept focused on consumer protagonism has been changed recently from "*prosumer*" (**pro**ducer + con**sumer**) to "*prosumage*" (**pro**ducer + con**sum**er + stor**age**), representing a consumer with both energy generating capacity and energy storage capacity [82–84]. This new consumer has some economic choices among self-supply, utility supply or partial utility and self-supply. According to [71], "*the end-users will play a crucial role as prosumers and as a provider of regulation services also through new business models empowered by digitalization*."

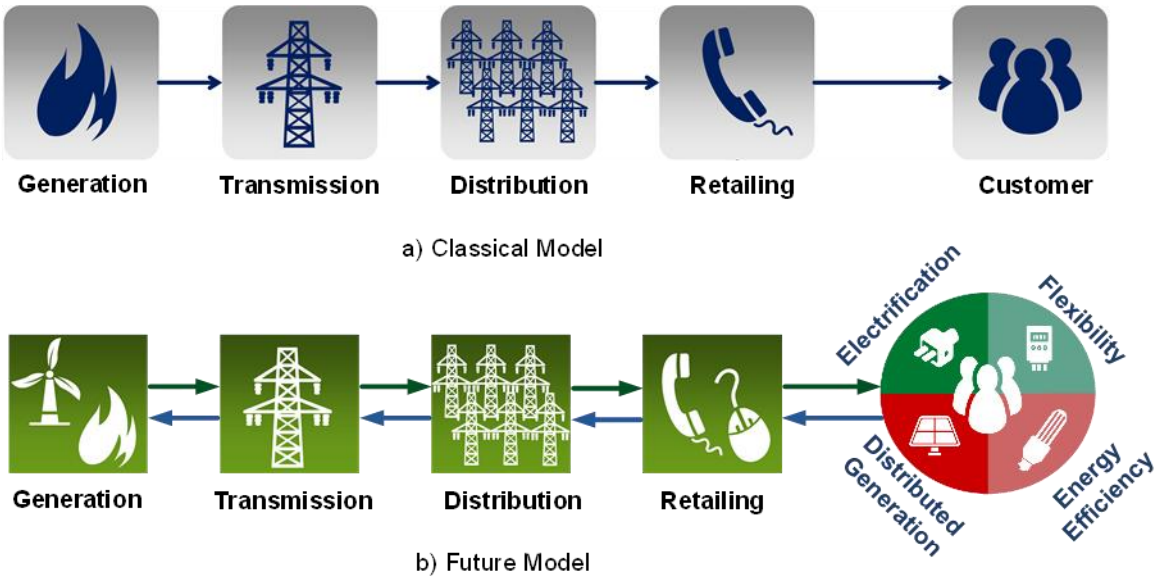


Figure 2.2: Classical and future model of the electricity system (Adapted from [81]).

For the next two decades (2020 – 2040), two central potential trajectories for network development would appear, namely, larger networks (bulk) and smaller networks (micro) [76]. The need to interconnect large centralized renewable energy sources and connect different countries and energy markets is related to

the bulk power system model. In contrast, the distributed generation and storage (i.e., prosumage) and active customer participation are considered the main characteristics of the micropower system model. A mix of large and small networks (referred to as hybrid power systems) is considered by literature [71,76] a more promising future regarding the development of power systems.

In light with this, Ref. [72] highlight that the transition from predominantly centralized to hybrid power systems is envisaged for many countries in the years to come. The authors argued that "*fundamental to the transition of the energy system from a centralised model to a hybrid model will be revisions in policy design, where policymakers and regulators need to define who can participate in the energy market, how they can participate, and how they can charge for services provided*" [72]. Thereby, a more generic approach to represent the power system configuration has been proposed by Ref. [72], which reflected it into four emerging system archetypes corresponding to different combinations between centralized and decentralized power systems, such as illustrated in Figure 2.3. These four emerging system archetypes include (1) centralized systems; (2) hybrid systems with minimal DG; (3) hybrid systems with significant DG and (4) decentralized systems. It is worth noting that *prosumers* come out in all the proposed systems archetypes. The three main characteristics which are expected to strongly affect each system archetype can be summarized as follows [72]: (i) technology (e.g., DG type, grid development stage, and the current percentage of DG capacity); (ii) market structure (e.g., degree of market liberalization, separation of generation and distribution and the relationship between market players); and, last but not least, (iii) regulation (e.g., permits and import duties, technical standards, and financing policies and charges).

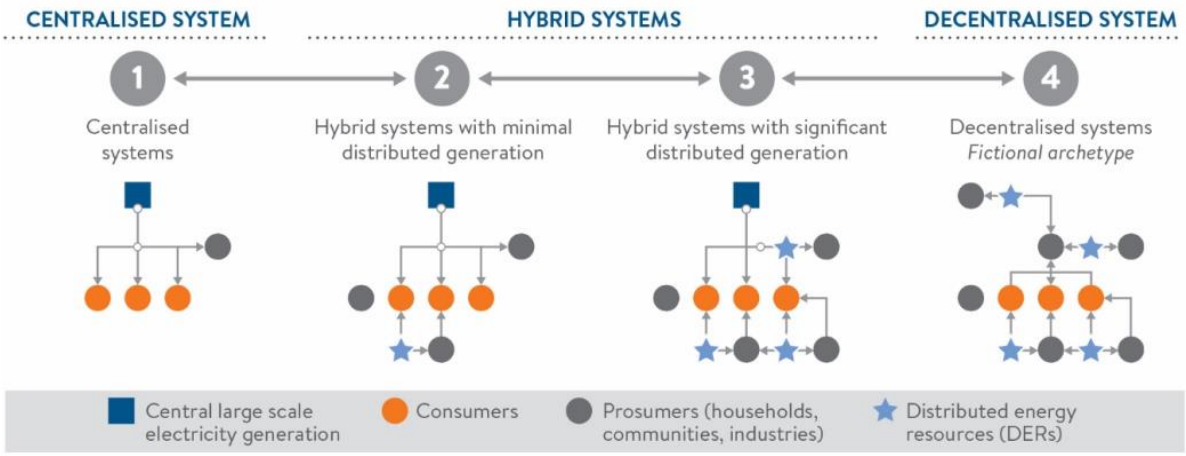


Figure 2.3: Emerging energy system archetypes [72].

2.2 Energy scenarios for high-RES systems

The energy planning process[14] describes a procedure with a high complexity level due to many conflicting aspects that should be considered in the energy decision-making process, including environmental, technological, social, and economic [85–87]. Specifically, the electricity planning has become more complicated due to a set of factors, namely the growing share of RES[15], specifically those RES with variable output [88]; the need for reliability and security of supply; fuel-increasing prices and fuel supply security; regional job creation; climate concerns; among others. Several uncertainties are also involved in the long-term energy planning process, such as economic growth, government policies, technological development, energy efficiency, and demand-side concerns. These features together might define the pathways in which the energy mix will be deployed in the future. The combination of methods and tools which have been generally employed for the integrated energy planning of cities and territories was reviewed by [89], concluding that they have not yet been combined to manage all the required integrated energy planning tasks.

Therefore, energy planning is considered a complex issue that involves many factors, and there can be no one size fits all solution, given the different challenges facing each country. The proper construction of future scenarios for the electricity sector appears as a fundamental tool to subsidize the government decision-making process. The energy planning exercise will then result in a large discrepancy of scenarios, which depend on a multitude of factors such as cultural, economic, and political ones [4]. However, regardless of this diversity of options and difficulties, scenario planning is fundamental for both policy-making and the development of business strategies, mainly those relating to investments.

Additionally, the risks and uncertainties had increased in the short, medium, and mainly in the long-term [3]. Specifically, for the long-term generation expansion planning, the challenges are even more significant, primarily due to the characteristics inherent to the sector in which such decisions need to be made in advance [90]. There are several challenges in the scenario's construction, especially for long-term planning. One of the main difficulties is to predict the behavior over time of energy technologies that currently may not be feasible on a large scale or are not yet available. The definition of consistent hypotheses and the proper problem delimitation are also essential to achieve real and relevant scenarios.

[14] The energy planning process can be split into three main levels [89]: (i) The participatory level is composed of the participants of the planning process, and they can be members of the steering committee (e.g., the investors), which typically have the most significant decision-making influence; the interested parties (e.g., the end-user or affected groups) and the planner or other experts such as the utility companies or local energy agencies; (ii) The process level which comprises the planning steps and activities; (iii) Last but not least, the methodical level encompasses the methods and tools used to support the quantitative analysis and the impact assessment (analytical tools), but it also includes the procedure tools that assist in the participatory, interactive planning process and to the decision-making process.

[15] Ref. [87] mention that the inclusion of RES in energy planning is a complicated task and has to surpass economic, social, technical, environmental, and institutional barriers.

Furthermore, the design of a few future trajectories is desirable and demonstrates the relevance of the scenario-building technique for a well-informed decision-making process [91]. Scenario analysis techniques are then well suited for evaluating the impacts of RES technologies such as wind and solar power in the electricity system.

Comparing different strategies to transform the Denmark heating sector into a 100% renewable energy system is addressed in [92] resourcing the advanced energy system analysis tool EnergyPLAN. The authors of [93] proposed a methodology to link local and national planning, evaluating how much each energy system can exchange excess electricity. Ref. [94] compares two 100% RES systems. The first scenario proposed by [94] considers a non-integrated renewable energy system. In contrast, the second scenario is based on the smart energy system[16] concept in which the synergies between other sectors are considered using Zabreg as the case study. A 100% local RES for the year 2050 is proposed by [95] focused on the electricity, heating, and transport sectors for Croatia. This previous research work also analyzes the local energy system's integration with the rest of the country. How increasing operating reserve requirements impact generation capacity investments has been addressed in [28] for a power system with high-RES integration. Findings of [28] revealed that operating reserve requirements might represent considerable additional costs for integrating higher shares of renewable generation. The integration of RES, storage technologies, and flexible loads into the German power grid was addressed in Schwarz & Cai (2017).

A large and growing body of literature has also focused on constructing future RES-based scenarios, particularly for the Brazilian power system. The work proposed by [97], for example, considered a 100% RES for Brazil in the year 2030 considering the set of technologies available, mix of capacities, operation modes, and the least cost energy supply. This research simulated the Brazilian electricity system's operation on an hourly basis and used a multi-node approach. The model was based on a linear optimization problem aiming to minimize the total annual energy system cost and takes DG and self-consumption from residential, commercial, and industrial electricity consumers into account. The results obtained by [97] showed that the required overall installed power capacity by 2030 would reach 165 GW from solar PV, hydroelectric dams (85 GW), run-of-river hydropower (12 GW), biomass (12 GW), biogas (12 GW) and 8 GW of wind power.

[16] A systematic literature review regarding the smart energy systems concept is undertaken by Ref. [422]. Ref. [423] addressed the role of smart energy systems and the 4th district heating generation. The concept of DSM in district heating systems has also been recently taken into account by Ref. [424]. Based on a statistical approach and considering an urban district level, the waste heating potential for sewage systems is assessed by Ref. [425]. The coupling between district heating and electrical distribution grids is considered by Ref. [426] in which the authors highlight the potential of the proposed methodology to address the coupling between heat and power networks technically.

The simulation of a fully decarbonized system for 2030 has also been addressed in [97], using an hourly resolution model considering the use of storage technologies, Power-to-Grid (PtG) technologies, and water desalination for sector's integration. A linear optimization model has been considered to minimize the total annual energy system costs using a multi-node approach to represent Brazilian subsystems interconnections. The model also included DG and self-consumption from prosumers. The need for a small storage capacity using Power-to-grid (PtG) technology is highlighted for the year 2030. This is because the existing hydropower system is expected to develop a vital role in complementing electricity storage in the country. Also, the small projected storage capacity is due to the low seasonal variability of RES. The authors of [97] also concluded that the Brazilian system's PtG capacity is expected to be much lower than forecasted in previously published research. The LCOE decreased from 61 €/MWh to 53 €/MWh when considering the sector's integration [97].

In the same vein, Ref. [98] proposed a least-cost power system for a 100% RES-based system for the year 2050 focused on the Brazilian case. The authors appraise the effect of sector coupling on the Brazilian power system through a high-resolution model called REMix (linear programming). The model considers the use of storage technologies, DR contribution, electric mobility, and hydrogen production. Findings of this research also revealed that the expansion of wind and solar power might be more cost-efficient than the construction of new hydropower plants since the hydropower system might provide enough storage capacity to compensate for the high integration of RES in the country (even considering that only run-of-river power plants are being projected for the future). The authors of [98] also concluded that neither varying the share of wind and solar power nor the spatial distribution of power generation would significantly impact the overall supply costs. Therefore, other criteria could be used to promote the renewable energy transition towards a 100% RES system, such as public acceptance, so that this would have only a small influence on system costs.

Likewise, a long-term GEP optimization model has also been proposed in [99] focused on the Brazilian sector. However, the primary purpose of this paper was to evaluate how to maintain a high share of RES in the country and reduce, at the same time, the future hydrological risks. The long-term optimization model is used to evaluate how high shares of wind and solar PV would technically impact the power system taking each power source's regional potential into account. This research has also shown that the expansion of wind power and solar PV would reduce the future needs of thermal resources. From the technical point of view (i.e., decreasing supply risks), the second significant finding revealed that solar PV expansion would be better than wind power growth.

2.3 Generation Expansion Planning (GEP)

The planning of a power system is considered a complex optimization problem [100]. Power system expansion planning models are usually divided into three main categories: Generation Expansion Planning (GEP), Transmission Expansion Planning (TEP), and generation-transmission co-expansion [29]. As stated by [101], GEP is a very complex problem and it is usually defined as "*the problem of determining when, what and where the generation plants are required so that the loads are adequately supplied for a foreseen future*." There are many challenges associated with GEP and TEP problems because of their long-term, large-scale, and nonlinear nature. Several models and tools have been proposed in the literature to help decision-makers in this process. For the past three decades, studies on expansion planning problems have been mostly restricted to the independently planning of generation and transmission. However, these conventional planning approaches can lead to sub-optimal results [7].

Several studies have appeared over the past few years addressing different optimization schemes considering a wide range of objectives for the power system (see [66,102], for example). Hence, there are many studies and optimization models available in the literature to support GEP problems. Generation expansion planning also plays a crucial role in constructing future energy scenarios [103]. On the other hand, a model usually fits best to a particular case, such as a specific country, and needs to be adapted to address other power systems' specific characteristics considering multiple technical, economic, political, environmental, and social restrictions. As reported by [85], different solutions can be obtained at different times, considering the decision-maker's priority. Traditionally, energy planning solutions are in charge of each country, presenting a significant discrepancy of scenarios, depending on cultural, economic, and political factors [4].

Long-term power GEP models (typically for two or more decades) usually aim to determine the power system's capacity expansion over a determined planning horizon. Traditionally, the goal of long-term generation expansion planning models is to find an optimal generation capacity expansion plan that meets the future increase of power and peak demand for electricity with the minimum cost solution, ensuring at the same time the power grid's stability and security [52,104,105]. Conventionally, the objective function of GEP problems comprises the minimization of the total system costs, although multi-objective frameworks have been proposed for solving typical expansion planning problems. Consequently, long-term generation expansion-planning models are usually multi-objective problems in which a set of objectives are optimized simultaneously. These objectives are sometimes conflicting and a compromise should be found considering the different perspectives involved in the decision-making process. Future long-term generation expansion models would probably focus on seeking the minimization of not only

financial costs but also the environmental and social costs of electricity, for example. This multiplex task and the establishment of new power market structures such as deregulated electricity markets, together with the inclusion of other criteria such as environmental impacts, quality, the security of supply, and reliability, have added more complexity to the long-term power GEP problem [52,104].

A considerable amount of literature has been published addressing different long-term GEP problems. Power GEP models have been applied to guide decision makers' policies worldwide, focusing mainly on optimal investment strategies [105]. Over the past few decades, however, new features appeared, and planning models have to adapt to address these new concerns. The inclusion of intermittent renewable resources, for instance, turned the planning activity into a more challenging task. Questions related to climate neutrality, DSM strategies (including energy efficiency and DR), changes in policies and regulations are some of the new features that future energy planning models are expected to include. The expansion of integrated long-term energy plans for regional or local places is not trivial because the plans take into account various aspects (e.g., economic, social, environmental, technological and institutional); consider different energy sources such as oil, gas, and electricity; and multiple sectors are involved such as the residential and transportation ones [89]. Moreover, the generation, conversion, transportation, and energy distribution processes require a set of different technologies, enhancing the complexity of such energy plans [89,106].

A comprehensive review study has been recently performed by Ref. [7] addressing the multi-dimensionality associated with GEP problems. The authors emphasized the importance placed upon the integration between generation and transmission expansion planning problems. Ref. [107] presented a state-of-the-art review study concerning the GEP problem over the past three decades from climate change and environmental perspectives, regulatory policies, new techniques for optimization and modeling and liberalization of the electricity market. Findings of Ref. [107] revealed that the main concerns among the papers analyzed are the emission-related technologies, short-term features, alterations due to smart grid employment and the recent shifts in the electricity sector, which occurred primarily in developing countries.

GEP and TEP planning problems have been extensively addressed over the literature considering national and regional-scale power systems [29]. These studies can be categorized into three main modes, i.e., (i) single-stage (or static) [108] or multiple-stage [109] problems; (ii) conventional mathematical programming or meta-heuristic optimization methods [29]; and (iii) transmission expansion only (subject to a static scenario of generation investment); generation expansion only (generation investment subject to a static transmission system) or even both generation and transmission expansion plan [29,41].

Traditionally, GEP and TEP models have been modeled separately [110], i.e., these planning models have typically applied single-stage models to address power system expansion by firstly planning the generation and then the transmission planning is designed to meet this supply such as in Refs. [110–114]. These separately modeling approaches have been performed mostly because the investment decisions are made independently [110], typically from non-vertically electricity markets.

A long-term GEP optimization model has been proposed in the work of [28] focused on the Belgian power system. The study focused on how increasing operating reserve requirements impact generation capacity investments of a power system with high-RES integration. The cost of curtailment and load shedding was also included in the optimization model. Findings of [28] revealed that operating reserve requirements might represent considerable additional costs for integrating high shares of renewable generation.

The work proposed by [100] compared the use of different optimization models to be employed in power systems dominated by wind and solar sources with storage facilities and simultaneously designing a High-Voltage Direct-Current (HVDC) transmission system. The modeling of the HVDC transmission system is considered one of the biggest challenges of the proposed model.

An optimization model has also been proposed by Ref. [115] with a particular focus on large-scale systems that are subject to a highly uncertain and volatile electricity market. The authors of Ref. [115] proposed a multi-period Mixed-Integer Linear Programming (MILP) optimization technique for the minimization of the total discounted cost (2014-2030) combined with the Monte-Carlo simulation and including a DR mechanism. Findings of [115] pointed out the importance of incorporating stochasticity and DR into deterministic optimization models to evaluate the influence of specific parameters and policies.

A new integrated binary mixed-integer non-linear cost optimization model is proposed by Ref. [116], incorporating the effects of high-RES of variable output on thermal power plants output based on the Portuguese case. The model is focused on power systems with high shares of wind, hydropower, and thermal plants. The unit commitment problem has also been included in the optimization model. The authors derived broadly applicable conclusions on the benefits of the integrated proposed model, ensuring the best GEP without disregarding the technical constraints from thermal plants. The limitations of the model include the high computational effort needed for running the model.

The impact of operating reserve requirements on the installed generation mix of a power system with high-RES integration is addressed by Ref. [28]. However, this latter work does not considered the use of DR strategies and storage technologies in the problem formulation. Findings of the study proposed by Ref. [41] indicated that generation dispatch and investments might be affected by the inclusion of

demand-side strategies or storage technologies within the optimization model. The procedure carried out by Ref. [35] addressed the role of storage in future RES-based systems using a long-term generation expansion planning model. The role of storage for the integration of RES in future power systems is also discussed in Ref. [117]. Ref. [118] analyzed the main institutional challenges caused by the integration of VRE in the European electricity sector. The integration of RES, storage technologies, and flexible load into the German power grid has also been investigated in the work of [96].

2.4 Co-optimization modeling for long-term power planning

Along with the past years, new studies have been published addressing the different faces surrounding operational and planning aspects within the energy field by using different modeling approaches. The particular use of optimization models has been extensively discussed over the literature addressing operational and planning problems to support the decision-making process of electricity supply, transmission investments and policy designs [100,119]. Several studies in the energy field have been carried out using optimization approaches for modeling both short (e.g., [120,121]) and long-term (e.g., [110,111,122,123]) problems. Extensive research has been conducted, for example, in economic dispatch [120] and unit commitment problems [121], Generation Expansion Planning (GEP) [66,102,110], Transmission Expansion Planning (TEP) [111,124], integrating RES into GEP problems [122] and modeling and simulation of energy systems [123] which are among the most commonly exploited research topics in the field. Thus, traditional planning models have been traditionally addressed operational and expansion planning problems individually.

The goal of traditional optimization models is to find in a set of solutions the best one which minimizes or maximizes the value of an objective function [125]. Long-term optimization models have been widely addressed by previous research works considering several solutions and modeling approaches, objective functions, geographical scope, temporal resolution and considering centralized and decentralized systems (see Section 2.3 for details). The complexity of optimization problems with the inclusion of Variable Renewable Energy (VRE) resources has been highlighted in the work of [100], for instance.

There is also a growing body of recent literature focused on using co-optimization approaches within the energy field. Co-optimization models are computer-aided decision-support tools that search among possible combinations, the best one in terms of a defined objective subjected to a set of constraints [41]. The term "*co-optimization*" has been also commonly referred to as "*co-planning*" [126–134], "*joint optimization*" [135–137], "*simultaneous optimization*" [135,138], "*combined optimization*" [100,139]. We also highlight that many research works have been using the term "*optimization*" to refer to "*co-*

optimization" problems. This means that these terms have been often used interchangeably and without high precision within the energy sector.

Since the definition of co-optimization varies among researchers, it is essential to clarify how this concept has been traditionally used within the energy field. According to the definition proposed by Ref. [41], "*co-optimization is the optimization of two or more different yet related resources within one planning framework".* The main aim of co-optimization approaches is to find the best solution in terms of cost or other objectives while satisfying a set of economic, technical and environmental constraints [41,119]. Ref. [41] also provides a more general definition focused on power system planning. This broader definition refers to co-optimization as "*the simultaneous identification of two or more classes of investment decisions within one optimization strategy".* The authors point out that:

> *"Classes of investment decisions, in the context of electric systems planning, almost always include decisions to build generation and transmission. But they may include other types of decisions as well, such as demand-side solutions, decisions to install storage, or building of natural gas pipelines. "One optimization strategy" may consist of a formulation to solve a single optimization problem (e.g., minimize cost subject to constraints) or it may consist of a formulation to solve an iterative series of optimization problems (i.e., sequential yet coordinated generation and transmission planning)* [41]".

Although the established practice has been to design generation planning first and further to plan transmission, generally, both generation and transmission are assessed simultaneously to identify integrated solutions in a co-optimization approach. Co-optimization might also involve other types of decisions such as supply and demand-side integration, the coupling of the power grid and Natural Gas (NG) networks, and multi-energy carriers (e.g., electricity, gas, and district heating systems), just to name a few. The existing literature on co-optimization approaches might also be broadly divided into (i) short-term (i.e., associated with operational planning problems) and (ii) long-term (i.e., associated with expansion planning problems). In a comprehensive literature review of the models for integrated power and natural gas network coordination, the authors of [140] highlighted the cumulative synergies in power and gas systems coupling. Along the same lines, significant analysis and discussion on the use of co-optimization of transmission and generation resources for long-term planning purposes have been addressed by Ref. [119] through a comprehensive review of concepts and modeling approaches. Ref. [119] focused its review efforts on the existing and emerging co-optimization models for the joint optimization of generation and transmission with a particular focus on the optimizers, data, modeling fidelity, and computational requirements.

Therefore, co-optimization may play a central role in the development of integrated approaches for operational and planning energy-related strategies. Nevertheless, although there is a growing body of literature that recognises the importance of co-optimization in the energy field, to the best of the authors' knowledge, a comprehensive literature review of the most recent and relevant literature which deals with co-optimization in long-term planning models within the energy field is still missing. Therefore, this study makes a step further by providing a state-of-the-art review of co-optimization approaches in the energy field, addressing the most relevant scientific methods addressed by previous high-quality research works. The next subsection will synthesize the most relevant body of recent research regarding the use of co-optimization approaches in long-term co-optimization models. The key selected studies will be divided into the year of publication, sector, spatial resolution, planning horizon, objective, programming/tool and whether or not the term '*co-optimization*' is explicitly mentioned in each study. Although far from being exhaustive, this literature review aims to illustrate the diversity of approaches and models used by recent research and demonstrate their potential application to different planning problems.

2.4.1 Co-optimization in generation-transmission expansion problems

Although GEP and TEP have been usually characterized by sequential optimization [141], the benefits brought about by the simultaneous co-optimization between generation and transmission resources have been highlighted by recent research works [141]. Therefore, there is a large number of recently published studies that deal with generation-transmission co-optimization problems, such as illustrated in Table 2.1.

Such problems have been also referred to as (i) Transmission and Generation capacity Expansion Planning (TGEP) [142]; (ii) GEPTEP co-optimization models [143]; (iii) proactive expansion planning [142] or even (iv) anticipative transmission expansion planning [142]. The simultaneous co-optimization of generation and transmission expansion plans might provide long-term co-optimized expansion planning [144–146]. Typically, these models aim to find the least-cost power system configuration for a given period. In the proactive approach, both systems (i.e., GEP and TEP) are co-optimized simultaneously, whereas, in the reactive approach, the GEP problem is firstly solved, followed by the TEP problem [147,148]. Ref. [142] highlight that "*in centralized TGEP problems, generation and transmission capacity expansions are simultaneously optimized by a single entity that maximizes social welfare or minimizes the total investment and operation cost*".

Table 2.1: A literature review on long-term co-optimization of generation-transmission expansion.

Ref.	Year	Spatial Resolution	Planning horizon	Objective	Tool[17]	Co-opt[18]
[149]	2010	Chilean power system	Planning for 2030	Minimization of the total system costs	MILP	Yes
[150]	2010	Portuguese power system	10-year planning horizon	n/a	OPF	Yes
[151]	2012	Multi-area power system	20-year planning horizon	Minimization of the total system costs	MIP	No
[152]	2013	Chilean power system	A single period (one-year horizon)	Minimization of the total system costs	MILP	No
[108]	2014	Modified 6-bus test system and IEEE 24-bus RTS	Static (single period)	Minimization of the total system costs	MILP	No
[100]	2015	Power system with solar PV, onshore wind, and natural gas	Half-year planning period	Load-matching procedure and cost-minimizing techniques	LP	No
[153]	2015	Garver's six-bus system and IEEE 30-bus system	10-year planning horizon	Minimization of the total system costs	BD	No
[154]	2015	6-bus test system and IEEE 30-bus system	20-year planning horizon	Minimization of the total system costs	MILP and MINLP	No
[155]	2015	4-bus and 7-bus test system, and a modified IEEE 30-bus and 118-bus test system	Static (single period)	Minimization of the total system costs	MILP	Yes
[156]	2015	240-bus network	50-year planning horizon	Minimization of the total system costs	MILP	Yes
[157]	2015	Association of East Asian Nations region	Planning for 2050	Minimization of the total system costs	LP	Yes
[158]	2016	European electricity market (33 countries)	Static and multi-year representation	Maximization of total market surplus	SLP	Yes
[159]	2016	IEEE 30-bus system	10-year planning horizon	Minimization of the total system costs	MINLP	No
[160]	2016	IEEE 24-bus RTS system	n/a	Minimization of the total system costs	MILP	Yes
[161]	2016	Colombian power system	15-year planning horizon	Minimization of the total system costs	MILP	No
[29]	2016	U.S. Eastern Interconnection system	16-year planning horizon	Minimization of the total system costs	MIP	Yes
[162]	2016	IEEE 30-bus system	5-year planning horizon	Minimization of the total system costs	MINLP	No
[163]	2017	Chinese power system	15-year planning horizon	Minimization of the total system costs	MINLP	No
[142]	2017	3-node system and modified IEEE 24-bus RTS system	Single-level problem	Minimization of the total system costs	MILP	Yes

[17] The programming/tool employed for each study can be split into the following categories: Linear Programming (LP), Mixed-Integer Programming (MIP), Mixed-Integer Linear Programming (MILP), Mixed-Integer Nonlinear Programming (MINLP), Mixed-Integer Bilevel Linear Programming (MIBLP), Optimal Power Flow (OPF), DC-Optimal Power Flow (DCOPF), Bender's Decomposition (BD), Stochastic Programming (SP), Successive Linear programming (SLP) and Genetic Algorithm (GA).

[18] If co-optimization is explicitly mentioned, then 'Yes', otherwise 'No'.

[164]	2017	5-bus test system, IEEE 118-bus test system, and Chilean power system	Static (single period)	Minimization of the total system costs	MILP	Yes
[165]	2017	3-bus and 6-bus test systems and modified IEEE 96-bus and 118-bus test systems	Static (single period)	Minimization of the total social costs	MIBLP	No
[146]	2017	Case study of the U.S. Eastern interconnection	20-year planning horizon	Minimization of the total system costs	MILP	Yes
[166]	2017	WECC 240-bus system	Static (single period)	Minimization of the weighted average of expected transmission and generation costs and their conditional value at risk (CVaR)	SP	Yes
[129]	2018	IEEE 24-bus RTS	Static model (monthly)	Minimization of the total system costs	MILP	No
[167]	2018	IEEE 118-bus test system	Static (single period)	Minimization of the total system costs	MINLP	No
[130]	2018	Australian National Electricity Market	12-year planning horizon (hourly resolution)	Minimization of the total system costs	GA	Yes
[168]	2018	Case of Queensland (Australia)	14-year planning horizon	Minimization of the expected cost	MILP	Yes
[169]	2018	Two cases (Garver IEEE system and IEEE 118-bus system)	25-year planning horizon	Three-level problem (i.e., with three objectives)	MILP	No
[170]	2018	IEEE 24-bus test case	20-year planning horizon	Minimization of the total social costs	Non-linear	Yes
[171]	2018	Canadian power sector	Static (single period)	Minimization of the total system costs	LP	Yes
[172]	2019	IEEE 24-bus RTS and IEEE 118-bus test systems	15-year planning horizon	Minimization of the total system costs	MILP	No
[141]	2019	312-bus network representing the U.S. Western interconnection	50-year planning horizon	Minimization of the total system costs	MIP	Yes
[173]	2019	Regional Energy Deployment System (ReEDS) model (U.S.)	Planning for 2050	Minimization of the total system costs	LP	Yes
[148]	2019	IEEE 24-bus test system	10-year planning horizon	Minimization of the total system costs	DCOPF	Yes
[174]	2019	Chinese power system	38-year planning horizon	Minimization of the total system costs	LP	Yes
[175]	2019	German power system	Planning for 2030 and 2050	Minimization of the total system costs	LP	Yes
[176]	2019	28 countries of the European Union	Planning for 2050	Minimization of the total system costs	LP	Yes
[177]	2020	Case study of Liberia (sub-Saharan Africa)	n/a	Benefit maximization approach (maximize the stakeholder's utility)	MILP	Yes
[178]	2020	13 U.S. regions	34-year planning horizon	Minimization of the total system costs	LP	No
[179]	2020	6-bus test and IEEE 118-bus system	10-year planning horizon	Minimization of the total system costs	MILP	Yes
[145]	2020	169-bus system (representing the North American power grid	20-year planning horizon	Minimization of the total system costs	LP	Yes

[180]	2020	CAISO 17-bus data set	10-year planning horizon	Minimization of the total system costs	MINLP	Yes
[181]	2021	European power system	1-year planning horizon	Minimization of the total annual system costs	LP	Yes

The advantages of co-optimizing generation and transmission have been pointed out by [141]. The authors of [141] compared the sequential versus co-optimized generation and transmission expansion planning approaches and concluded that economic benefits might be achieved through the integrated planning between generation and transmission systems. Refs. [143,146] also underlined that cost savings would be achieved through generation-transmission co-optimized approaches. A broadly similar point has also been considered by Ref. [119], which reviewed the co-optimization between transmission and generation resources for planning purposes highlighting that planning generation and transmission independently might be sub-optimal.

Other studies, however, hold the view that "*proactive transmission expansion decisions may lead to suboptimal solutions when the generation expansion equilibrium problem have multiple solutions (i.e., leading to higher total costs and lower social welfare)* [142]". Ref. [142] proposed a methodology addressing the problem of proactive expansion planning over generation expansion decisions focused on deregulated electricity markets. The benefits of co-optimizing transmission and generation investments under a proactive approach and RES integration into the generation mix is addressed in [146] for the U.S. Eastern interconnection. A further study [29] used a Mixed-Integer Programming (MIP) generation and transmission expansion co-optimization model considering a high wind power penetration rate for the U.S. Eastern system. The future of the U.S. electricity system is also evaluated in [178] for the year 2050 by splitting the country into 13 regions and using an extended version of the Open Source Energy Modeling System (OSeMOSYS) model. The impact of RES integration on transmission expansion planning was assessed in Ref. [148] through a 10-years co-optimization model based on an hourly resolution approach for supply and demand (IEEE 24-bus test system). The authors employed the multivariate interpolation method to estimate the operational costs to reduce the high computational time associated with the hourly resolution model [148]. The authors of [154] also proposed a new dynamic model for the simultaneous expansion of generation-transmission planning based on two case studies, i.e., a 6-bus and the IEEE 30-bus systems. Ref. [154] converted the original Mixed-Integer Nonlinear Programming (MINLP) model into a MILP model through the Benders decomposition technique.

There is also a growing body of recent research addressing the problem of generation and transmission expansion planning, considering the high integration of RES in multi-region power systems [29]. The co-optimization between generation and transmission planning for maximizing large-scale solar PV

integration is addressed in [179], for instance. Ref. [130] explored the role of Concentrating Solar Power (CSP) for the Australian National Electricity Market based on a scenario-based approach. The authors of Ref. [130] also underlined that most of the previous co-planning models between generation and transmission expansion planning do not use high temporal resolution. Therefore, the hourly temporal resolution model is considered one of the main advantages of the proposed model. The procedure carried out by [29] is based upon a generation and transmission expansion co-optimization problem using a MIP formulation considering wind power and load variations on a large-scale power system. A co-optimization expansion planning model is developed for the Chilean power system by assessing the impact of electric vehicle penetration in the country for 2030 [149].

The importance of co-optimization between generation and transmission for the Chinese power system has been investigated in [174] through a linear programming approach. The authors highlighted the importance of using a co-planning approach, particularly because the best wind and solar resources are located far from the country's load centers. Two linear optimization models (a load-matching and a cost-minimizing procedure) were compared in the work of [100] for power systems with high shares of wind and solar power. The first model is a load-matching optimization and the second model minimizes the annual overall system costs. The benefits and disadvantages of both approaches are discussed and the most efficient method is shown. The authors concluded that the cost-minimization optimization technique seems to have the most real-world application, although the computational effort largely increases. Findings of Ref. [100] also revealed that linear optimization techniques are well suited to represent an electrical power system from a high-level without the complexity brought about by mixed-integer or nonlinear programming. Shorter solution times can also be achieved through the use of linear optimization models.

Several models have also been proposed addressing the integration between GEP and TEP problems with the presence of storage under co-optimization approaches. Co-optimization between generation and transmission with the inclusion of storage has been handled by [100,157,160,171,175,176], for instance. A least-cost co-optimization model has been developed by Ref. [175], dealing with the capacity expansion problem focused on the European energy system. The hourly model also includes transmission and storage constraints into the formulation. Cost-optimal pathways are also evaluated in [279] for the Association of East Asian Nations region, taking the generation, transmission, and storage technologies into account. The main advantage of the proposed model lies in high temporal and spatial resolutions. The results from modeling (i) only generation and transmission compared to the case in which (ii) the ESS devices are included in the co-optimization model has been assessed by Ref. [160]. The authors

compared the results with the traditional sequential investment model in which generation and transmission are first made and then the ESS decisions are defined. Findings of [160] revealed that co-optimizing ESS investments might be a cost-effective option for the power system evaluated. The results also showed lower curtailment and investment deferrals when the co-optimization approach is followed. The least-cost pathways to decarbonize the Canadian electricity system is addressed by [171] through a long-term co-optimization of GEP and TEP with the presence of storage. The authors employed a new linear programming-based cost-minimization model that minimizes the overall annual electricity system costs in new generation, transmission and storage facilities [171]. Findings of this study demonstrated that new transmission systems and the expansion of wind power in high wind locations would allow Canada to reduce GHG emissions [171].

A review of co-optimization models for GEP, TEP and traditional DSM programs (including DR) is addressed in [119], which also reviewed the main available co-optimization tools. Therefore, the integration between GEP and TEP models and DR strategies to seek optimal expansion plans for the long-term under co-optimization approaches has also received attention from recent research works. A source-grid-load coordinated optimization planning model is proposed by [162] using a MINLP model to seek a general optimal expansion solution for minimizing the overall power system costs, including the cost of DR employment and social costs for an IEEE 30-bus system case study. The regulation constraints are also included in the co-optimization model developed by [162]. Outcomes from this previous research also revealed that integrating DR measures into the modeling approach might provide a low-cost pathway for integrating wind resources for the power system evaluated. Also, the source-grid-load coordinated planning model might reduce the overall system costs. The computational effort seems to largely increase when simultaneously taking supply and demand-side resources into account. A source-grid-load planning model has also been proposed by [163], focused on the Chinese power sector. In addition to the generation and transmission expansion planning, the model also considers the demand-side resources.

A model for the integrated planning of generation and transmission expansion for the interconnected Colombian power system with the inclusion of DSM into the modeling framework has been proposed by Ref. [161]. The authors concluded that reconfiguring the existing power generating technologies would significantly reduce CO_2 emissions in the country. Ref. [158] included DR resources into their modeling framework for the generation and transmission expansion planning problem. Findings of [158] revealed DR as a valuable resource that might change the location, economics and the required investments in generation and transmission. A bi-level planning model is proposed by [159], addressing the simultaneous expansion of generation and transmission (GTEP) by also incorporating the DR effects. The

upper-level model addresses the GTEP problem whose output data is used in the lower level, simulating the system's operation during a peak load day in the target year.

Ref. [170] dealt with the generation-transmission co-optimization problem in cases with a pay-as-bid auction in place. In a further research study, Ref. [166] addressed whether risk aversion might affect the optimal transmission and generation expansion planning. In contrast, Ref. [129] proposed a generation-transmission expansion planning model for mitigating the power's system vulnerability to deliberate physical attacks.

2.4.2 Discussion of the findings

This section summarizes the main findings from the systematic literature review on co-optimization in the generation-transmission expansion problems. A great deal of previous studies remains narrow in focus, dealing purely with optimization approaches. These studies have been generally linked to GEP and TEP problems, although co-optimization practices in this field have been at the center of much attention in recent years. Overall, over the past few years, a considerable amount of literature has been published on co-optimization models focused on long-term decision making and addressing different facets of the problem.

The majority of studies in generation-transmission co-optimization have been based on least costly approaches. However, Ref. [177] underlined the weaknesses of such least-cost approaches and proposed a benefit maximization methodology that allows planners to allocate the available resources optimally. The incorporation of stakeholders' equality preferences into the generation-transmission planning model has also been proposed in the methodology approach of Ref. [177]. The authors also highlight the advantages of their proposed modeling approach, particularly for assessing the possibility of rebuilding a power system to maximize social welfare once their proposal is highly commendable for rebuilding power systems after natural disasters.

Overall, the reviewed studies on GEPTEP expansion clearly indicate the importance of including short-term operation requirements and storage technologies within long-term planning models. These results are also in agreement with those obtained by Ref. [182], which reviewed GEP optimization problems coupled with renewable energy integration. This review focused on identifying the impact of smart grid technologies, the treatment of uncertainties and the increasing need for operational flexibility on GEP problems. The authors of [35] also underlined the importance of considering the short-term operation constraints and long-term planning model requirements. One of the more significant findings to emerge from this study [35] is that storage resources' availability might lower the total system cost. Ref. [183] further support the importance of representing short-term operation for long-term decisions, especially

for storage technologies that might be used in both short (e.g., batteries) and long-term (e.g., hydro). To give a well-known example for the sake of clarity, a framework has been developed in [184], which accounts for the inclusion of both short and long-term storage constraints for a two-level proactive transmission expansion model. In a comprehensive literature review of optimization models, Ref. [185] also identified four significant short-term operation issues that literature has recently included into planning models, which includes (i) integration of VRE; (ii) demand-response; (iii) interregional transmission and (iv) energy storage.

As a rule, over the past decades, generation and transmission planning models had been addressed as independent problems, mainly due to computational limitations. The majority of previous planning studies focused on generation and transmission expansion models have been conducted to minimize the total system costs (i.e., based on least cost-based pathways) once a vertically integrated approach is usually assumed to be responsible for planning activities. However, a large and growing body of literature has also pointed out the need for future models to seek for the minimization of not only financial costs but also environmental and social ones, for example.

Long-term co-optimization between generation and transmission is usually best suited for centralized vertically-integrated electricity markets [119,143,186], i.e., the same entity is responsible for both generation and transmission resources planning. However, the recent liberalization of electricity markets has questioned the usefulness of such approaches since new dynamics have been introduced by this novel market model, leading to conflicting interests among stakeholders and decision-makers. Notwithstanding, Ref. [41] highlights that generation-transmission co-optimization approaches may also be useful for unbundled environments since it can identify possible grid reinforcements that would support more optimal generation investment decisions and consequently decrease the costs of the overall system.

A state-of-the-art review is addressed by Ref. [143], exploring how equilibrium[19] co-planning generation and transmission expansion models have been developed under a market-based environment. Although the terms "*co-optimization*" and "*co-planning*" have been used interchangeably by previous research to refer to the joint optimization of generation and transmission, Ref. [143] argue that the term "*co-planning*" might be more accurate for the co-planning problem in market-based environments. In contrast, the term "*co-optimization*" is best suited for centralized environments (i.e., vertically-integrated electricity markets) in which a single entity makes the investment decisions. Ref. [119] also called the attention that for unbundled market structures - in which different entities perform the expansion planning of transmission

[19] Ref. [160] called the attention to the new category of planning tools referred as equilibrium models. It is important to highlight that for perfectly-competitive markets the solution found by optimization models should be equivalent to the ones obtained from equilibrium models [160].

and generation - the "*simultaneous optimization*" between these two classes of investments will become into a different co-optimization paradigm called "*anticipatory transmission planning*[20]" which requires an iterative approach until achieving coordination between generation and transmission planning.

Although most studies that deal with the integration between GEP and TEP models under co-optimization approaches have focused on generation and transmission integration only, a considerable amount of literature has been published on the joint planning of GEP and TEP in the presence of DERs. This finding corroborates with Ref. [33], which pointed out that the large-scale diffusion of DER "*requires a stronger integration of transmission and generation planning with the distribution networks, demanding several advances in the existing tools and methodologies*." Therefore, the studies that couple supply and demand-side planning issues have been emerging in recent years. The potential benefits of using co-optimization in generation and transmission planning models are also considered essential in the context of high renewable integration into power systems [119]. Lower curtailment and investment deferrals have also been reported when co-optimization approaches are followed in generation-transmission expansion studies.

2.5 The role of Demand-Side Management (DSM)

To meet the future electricity demand, public policy-makers should also ensure that supply would be sufficient to satisfy both the energy and the power capacity over a forecast planning period [47]. However, only the supply-side resources are used in the Traditional Resource Strategic Planning (TRSP) [48]. On the other hand, for the Integrated Resource Strategic Planning (IRSP), the DSM strategies and other resources are considered in the planning model [48]. Integrating higher shares of VRE into the energy system requires an integrated energy planning approach since it may increasingly affect the power systems' voltage and frequency control. Therefore, the stability and reliability analyzes may strongly contribute to addressing these concerns [187].

Traditionally, the balance between supply and demand has been achieved focusing on the supply-side, mainly through the building or upgrading of new power plants, transmission and distribution systems [47]. Over the past years, however, we have witnessed a significant trend towards exploring not only the supply-side options, but a strong growth has been placed on exploring the flexibility potential from the demand-side, which has also been disrupting traditional energy planning models. Over the past years, recent changes have also occurred in the electricity sector, such as the consumers' participation in DR

[20] "A proactive or anticipative transmission planner makes transmission investments taking into account the effect of these upgrades on generation investments and, ultimately, on total system cost or social welfare [160]".

initiatives, affecting the load and electricity price [105]. DR initiatives are getting popular among utilities to match generation and demand more effectively [188], and it has a vast potential to improve the reliability of power systems [189]. The International Energy Agency (IEA) highlights the fundamental contribution of DR measures for integrating VRE and projected that nearly 185 GW of flexible demand would be reached cost-effectively by 2040 [190].

The integration between the Supply Side Management (SSM) and DSM strategies is essential to achieve a more accurate model for power system planning purposes but also to support energy management, especially in future smart grid models [42]. Therefore, the deployment of DSM strategies[21] has been seen as an alternative[22] to traditional generation and transmission expansion models. DSM strategies have also been developing overtime to deal with the economic and environmental challenges brought about by the expansion of supply-side energy resources [42]. DSM may also play a central role in integrating renewables, poverty alleviation, and employment [191]. The use of DSM measures has also been considered a powerful tool to contribute to the future challenges of integrating VRE resources into the power grid and can even partially release the energy network stress. DSM may also support supply shortages and load growth control [192], decrease the maximum interconnection capacity but also optimize resource allocation [193]. DSM can increase the flexibility of power systems by reshaping the load profile and reducing the peak load [194,195]. The employment of demand-side techniques might provide a significant number of benefits, including the reduced need for thermal capacity, deferring investments in distribution and transmission systems, and contributing to reducing the overall level of GHG emissions and thus increasing the grid sustainability [47,52,191,194,196,197]. Therefore, DSM has also been considered a major driver to achieve the ambitious goal set out by the Paris agreement once the power sector has a central role in the transition towards carbon neutrality. This also means that the environmental impacts brought about by implementing both EEMs and DR programs (both are examples of DSM strategies) are essential to account for climate change mitigation issues. However, according to Ref. [198], the environmental benefits brought about by the DR implementation are not well-recognized mostly because of two factors: *"(1) the effects are specific to the time and place where energy use was avoided and (2) the effects depend on whether the electricity use was offset to another time - and if so, what power sources were used to generate that electricity"*.

[21] Literature has been using different terms to refer to "DSM measures" [427,428], which includes for instance: (1) DSM techniques [429,430], (2) DSM strategies [66,234], (3) DSM initiatives [206,431], (4) DSM schemes [231,432], (5) DSM programs [431,433], (6) DSM approaches [194,197] and (7) DSM procedures [206]). Therefore, these different terms have been employed interchangeably across different research papers within the literature.

[22] It is worth mentioning that from the power system's perspective, a reduction in demand has the same effect as an increase in supply.

The term 'DSM' embodies a multitude of concepts and several definitions have been proposed by previous research works. "*The implementing of managerial measures to produce the resources on the demand-side by influencing the load demand"* can be defined as DSM - following the definition proposed by [197]. Ref. [47] defines DSM as "*the practice of shaping the demand patterns and energy use*." A systematic review of DSM architecture, approaches, optimization models, and methods was addressed by Ref. [194]. The authors of [194] classified DSM measures regarding the optimization approach (deterministic versus stochastic), the time-scale (day-ahead versus real-time), and user interactions (individual users versus cooperative users). A novel theoretical framework was proposed in [197] to unify the methodologies, terminologies, and concepts associated with DSM initiatives.

DSM can be broadly divided into two key categories, i.e., Energy Efficiency Measures (EEMs) and Demand Response (DR) strategies, such as illustrated in Figure 2.4. EEMs might be roughly considered permanent load reductions, whereas DR is more focused on load flexibility [199]. Consequently, DR strategies can be broadly classified as temporary load reductions (e.g., load shedding or load shifting) [200]. The leading indicators used to evaluate the success of DSM programs are energy savings (MWh/year), peak demand savings (MW), and environmental savings (expressed in units of weight for SO_2, NO_x, and CO_2 emissions, for example) [47].

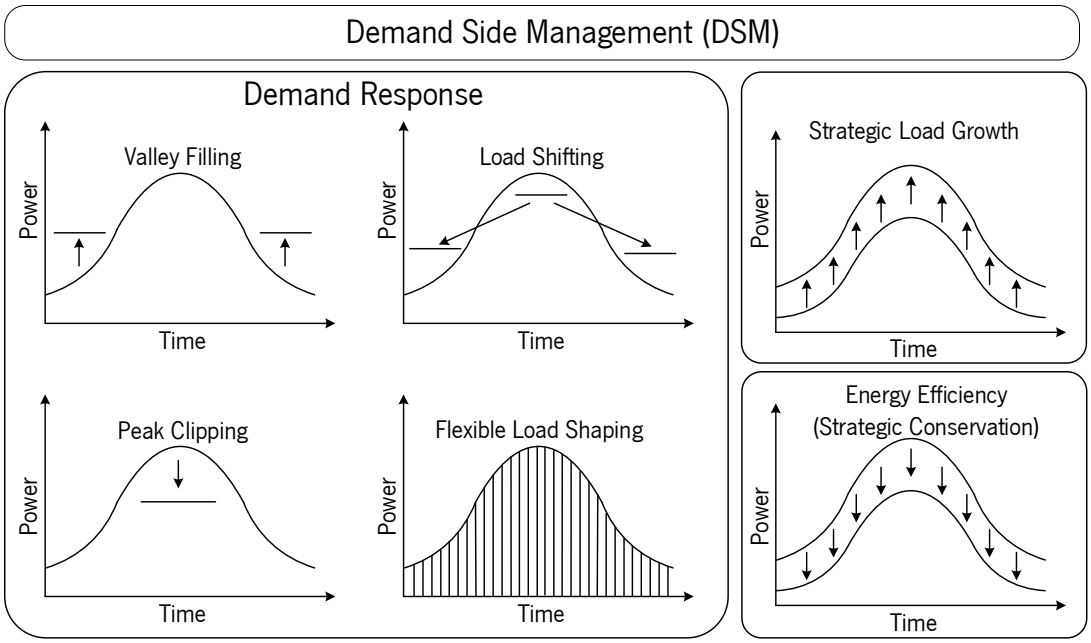


Figure 2.4: Key Demand-Side Management (DSM) techniques.

The main goals of DSM techniques are valley filling, load shifting, peak clipping[23], flexible load shaping, strategic load growth[24] and strategic conservation (also referred to as energy efficiency) [201]. Load shifting and valley filling strategies clearly can improve the grid load factor and avoid capacity costs, for example [48]. Load shifting is considered one of the most prominent DSM strategies since this technique may shift the load from peak to off-peak times [194]. Peak clipping might greatly assist the power system, particularly during peak times [202].

DR programs can be divided into two main categories (i) price-based programs and (ii) incentive-based[25] programs [203]. Price-based programs use time-varying electricity rates, i.e., Time-of-use (TOU); Critical Peak Pricing (CPP) and Real-Time Pricing (RTP). For this category, when the electricity prices are high, customers are intended to reduce their electricity consumption. However, for incentive-based programs, customers receive money from the utility to reduce their loads at requested times (e.g., when electricity prices are high or due to reliability problems). Detailed information on each category can be found in [204]. Figure 2.5 presents a brief overview of different DSM programs, which can be valuable according to different timescales.

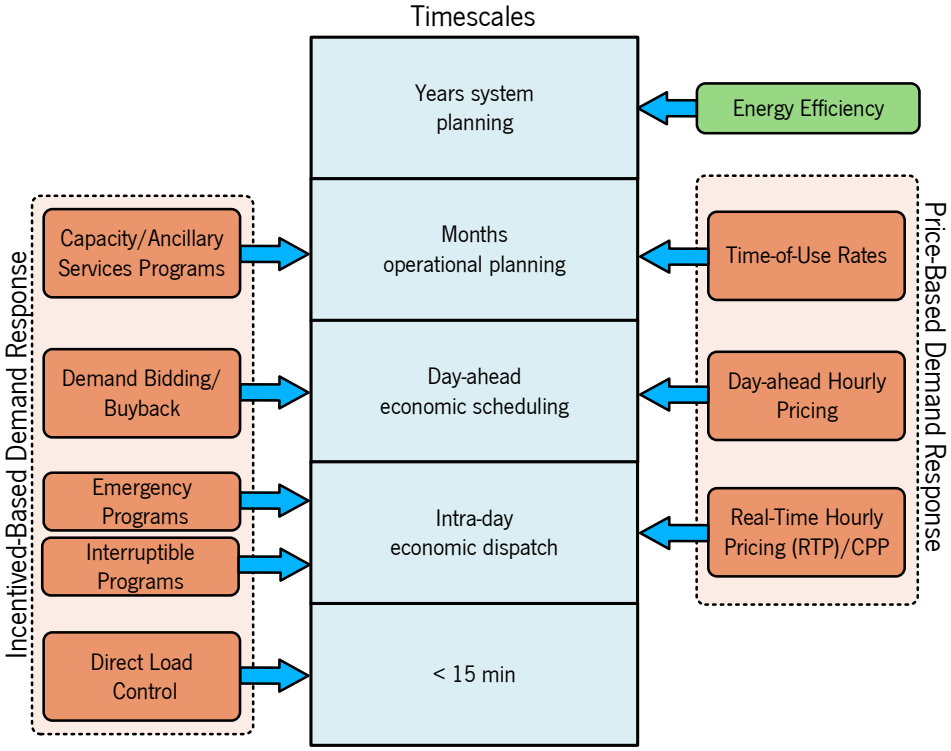


Figure 2.5: Role of DSM in Electric System Planning and Operations. Source: Adapted from [204].

[23] Also referred to as load shedding or curtailment.

[24] The strategic load growth is considered a particular category of DSM strategy.

[25] This category is also referred in the literature as controllable DR programs in which the consumer accepts load curtailment promoted by an external entity under specific conditions [361].

The smart meter is the equipment that interfaces the consumer and the energy provider for implementing DR initiatives. Load control techniques[26] can be reflected into three main categories (i) Direct Load Control, (ii) Local Load Control (LLC), and (iii) Distributed Load Control.

(i) **Direct Load Control:** The consumer allows the utility to remotely switch selected smart appliances (e.g., air-conditioning systems, refrigerators, water heaters, and heat pumps [205]) in or out of service and thus helping to release the stress on the grid [206]. The utility counterpart is paying a fair remuneration for interrupting the consumer's load [207]. Ref. [208] highlighted the potential offered by the direct load control scheme to provide regulation and spinning reserves time-scales.

(ii) **Local Load Control:** The local load control scheme is set up by the consumer. By analyzing the information provided by the smart meter, the consumer has the capability to make more informed decisions [206]. Circuit breakers can be employed for local load control by switching the supply off if the load exceeds a predetermined value [206,209].

(iii) **Distributed Load Control:** Both utilities and consumers implement the distributed load control strategy. The distributed control is commonly implemented for large industrial consumers, which establish a bilateral contract agreement with the utility, allowing it to switch out non-essential loads during a specific period [206,209]. As a reward for providing flexibility to the grid, the consumer receives a compensation payment value [206].

As stated previously, EEMs are not dispatchable resources, but they can also be classified as demand-side resources that provide permanent demand reductions. Energy efficiency is usually valued during the energy system planning process, and its impacts are mostly related to the long-term horizon [204]. The authors of Ref. [17] developed a conceptual framework to characterize EMMs to support decision- and policy-makers to build the most effective energy efficiency policies.

The co-benefits (also referred to as multiple benefits) from investing in EEMs have also become increasingly important in the past years. There is extensive evidence that energy efficiency plays a crucial role in benefiting the environment since it reduces the overall electricity generated and, consequently, can decrease the overall level of carbon emissions, water, and land use, for example. Although EEMs and DR are considered strictly related concepts and present strong synergy, in general, each approach has

[26] Ref. [206] highlighted the importance in the order that the controlling strategies are selected during the energy network stress which ideally should follow the sequence: local load control, distributed load control and the use of direct control should be implemented as the last resource to not deeply affect customer satisfaction levels.

been traditionally designed and evaluated independently [45,210]. However, with only a few exceptions - what is not yet clear and research has not extensively addressed - is related to the interactions and co-benefits between DR and EEMs [45]. Ref. [191], for instance, demonstrates the contribution of EEMs for economic and social development, environmental sustainability and increasing prosperity.

Although DR primarily aims to promote reductions in demand (i.e., kW) during the most expensive times and EEMs yield energy savings (i.e., kWh) at all times, overlapping effects of DR and EEMs can also be observed since DR may indirectly[27] promote the reduction of the total electricity consumption while EEMs would reduce the demand permanently. Therefore, both EEMs and DR might deliver benefits across the electricity system, reducing the overall generation costs and peak demand [45,198]. The co-benefits of using EEMs and DR together also include applying the consumer's revenue stream originated from the energy savings resulted from DR implementing in more efficient appliances. Consequently, deeper electricity savings would occur, which in turn would represent a new revenue stream.

On the other hand, the presence of multiple rebound effects linked to EEMs would partially break down this so-called "Virtuous Cycle" since energy efficiency improvements might save less energy than expected. The rebound effect (also known as load kickback effect) can be described as *"the sudden rise in demand during the non-peak hours that is caused by the overuse of power by the consumers after their reduction of power during peak hours* [211]". More recently, researchers have also investigated the interactions between the rebound effect with DR [211,212]. Therefore, this is a vital issue when implementing DR measures since it can also jeopardize the power system operation through congestion problems, for example [212]. Traditionally the load kickback effect has been controlled using direct load control of electronic devices or incentive reward systems that pay for consumers to minimize their consumption during specific periods [211].

2.5.1 Theoretical background on Demand-Response (DR)

The high level of VRE and the growing penetration of power generation from intermittent RES [27,28,213] (i.e., with limited controllability and predictability [214]), especially from wind and solar power [28], led to the development of intermittency mitigation techniques [215]. There are two primary methods to tackle this problem [215]. The first method requires the use of energy storage technologies (e.g., batteries and capacitors) to smooth the power output variability. In contrast, the second main alternative comprises the use of DR strategies.

[27] It is worth mentioning that DR implementation does not necessarily result in the reduction of the electricity consumption [337].

Demand Response (DR) is a well-known concept that has been recognized as an increasingly valuable tool (i) to provide flexibility to the power system; (ii) to support the integration of Variable Renewable Energy (VRE) resources and (iii) to manage the grid more efficiently. DR aims primarily to encourage end-users to reduce electricity usage by specific incentive schemes, especially when electricity prices are high [162]. According to the U.S. Department of Energy, DR can be defined as *"changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."*

The benefits brought about by the use of DR strategies cover a broader scope [196]. DR can contribute, for example, to defer or even avoid transmission and distribution system expansion; promote reductions in production costs by preventing operation of peak-power supply units; reduce the need of reserve margin[28] capacity; promote lower transmission system utilization; increase the share of renewable energy in the power system, as well as promoting the optimal operation of base power units [52,196]. Economic outcomes are considered the primary objective of traditional DR strategies. The environmental benefits can also be achieved through the implementation of DR by reducing the overall level of emissions related to electricity production from fossil fuel power plants, for instance [196]. In this last case, the amount of savings varies directly with the number of hours that fossil fuel power plants did not operate [47].

According to Krishnan et al. (2016, p. 316):

> "*Demand response competes against generation and transmission projects for addressing peak system needs, and also is capable of providing ancillary services. The modeling of demand response can be thought of as modeling a dispatchable load (or a dispatchable generator with negative generation), in some cases with storage-like characteristics (for instance, deferrable or schedule-able loads). Demand-side services can be provided from loads that are price sensitive or emergency interruptible, and from certain kind of storage systems such as ice-storage. Both storage and demand response can provide very significant benefits in terms of flexible response to changing operating conditions as well as fuel and capacity cost savings, in part because they can help defer or replace any generation or transmission expansion plans. Hence their consideration within the overall co-optimization tool provides a wider set of potential solutions to the long-term planning problem, and thus has potential to significantly lower costs.*"

In this context, as reported by [216], the deployment of DR programs has been seen as an alternative to generation and transmission expansion. Beyond the high capability of reducing the peak load on the

[28] Reserve Margin (RM) is defined as the difference between the installed capacity and load. The installed generation capacity should be higher than the peak load to achieve the required generation adequacy target. In general, the higher the need for reliability, the higher the reserve margin.

power system [52], DR might be used to contribute to power system regulation capacity to promote wind power integration, for example [162]. Peak-demand reductions might result in deferring or avoiding new generation capacities and/or new transmission and distribution systems, in addition to other benefits such as possible reductions in production costs, the need for lower reserve margin capacity, an increase of the security of supply [217] as well as lower transmission system utilization [52]. This last aspect is particularly important for power systems in which the transmission congestion problem is even more critical than the generation capacity. For this case, the use of DR strategies would reduce the load requirements primarily during peak times and therefore improving the transmission constraints [218].

DR might also provide more reliable power system services than conventional generation systems such as spinning reserve [219] and peak load shaving [220]. DR may also help integrate higher shares of intermittent renewable energy [221] by shifting and shaping electricity demand more cost-effectively than traditional options [118]. Therefore, implementing DR strategies might reduce customers' utility bills, such as verified in [222], improve electricity generation's resource-efficiency and promote social and environmental benefits [52]. Thus, regardless of all the benefits related to the development of smart grids [223], DR is expected to become a valuable energy solution [162], being able to mitigate the variability of RES [224]. The fast DR deployment and the little additional infrastructure are likely to be the most relevant advantages regarding the use of this source of flexibility [225].

Literature review about DR has been extensively performed along with the last years addressing different aspects [226]. In the work of [227], the authors selected 117 papers addressing different DR issues. They concluded that *"all major aspects of DR are relatively well covered by model developments (DR pricing schemes, the impact of DR on electricity systems and markets and the participation of selected end-users in DR schemes)".* Aspects regarding the different market approaches (i.e., incentive-based or price-based DR mechanisms) have also been addressed by a significant number of works such as by [228] and [229]. Time-sensitive pricing can be classified as non-dispatchable resources [230] and are traditionally split up into Time-Of-Use (TOU), Critical Peak Pricing (CPP), Real-Time Pricing (RTP), and Peak Time Rebate (PTR) [231]. For dispatchable resources, the decision to dispatch can be broadly divided into reliability (capacity, reserve, energy, or regulation) and economic (demand bidding & buy-back) categories.

The flexibility requirements of VRE systems were categorized in the work of [232] into technical, economic, and market potentials with a focus on Europe and particularly addressing the case of the German power system. The literature review presented in [232] attempted to address the following topics: flexibility requirements, resource potential in future energy systems and storage demand. Studies

comparing specifically the technical with the economic DR potential can be found in [233]. Ref. [234] reviewed the different categories of DR potentials and concluded a lack of understanding among literature regarding these different categories and proposed unifying these different classifications. The authors of [235] investigated the DR flexibility potential on office buildings. It has been reported that the estimation of DR potentials may be further restricted by the variation of thermal comfort performance within the buildings. A literature review regarding the different methodologies used to assess the potential for flexible use in buildings energy systems is presented by [236].

Further, the assessment of the building's flexibility potential was addressed by [237]. To better understand the mechanisms of different DR programs, Ref. [238] classified the various DR programs in the U.S. electricity markets. Ref. [239] evaluated the economic load management potential with a particular focus on specific buildings of the industrial and commercial sectors (e.g., offices and schools) for the state of Texas in the United States. A methodology to evaluate the load-shifting potential in Small- and Medium-sized Enterprises (SMEs) was assessed in [240] based on a case study of four companies in Germany.

The following subsection attempts to address a review of the categories of DR potentials. Also, a new conceptual framework to assess the theoretical, technical, economic, and achievable load flexibility potentials will be presented (see Ref. [234] for details).

2.5.2 A review of the key categories of DR potentials

In recent years, there have been a growing number of publications focusing on the estimation of different categories of Demand Response (DR) potentials using different methodologies and assumptions in each research study. Existing literature usually distinguishes the various types of DR potentials into the following categories: Theoretical, Technical, Economic, and Achievable. A simplified classification is considered by Ref. [241], which broadly divides the DR potentials into only three key categories: technical, economic, and achievable. Ref. [44] also considers the same classification as proposed by Ref. [241]. However, in this last case, the achievable potential is divided into the Maximum Achievable Potential (MAP) and the Realistic Achievable Potential (RAP). The attitudinal (e.g., consumers' resistance), societal, and market barriers that limit customer participation is considered for the MAP definition. The RAP discounts MAP, considering additional constraints related to DR implementation impediments (e.g., regulatory, political, and financial barriers) [44]. Table 2.2 presents a diverse number of classifications regarding the different categories of DR potentials proposed by different research studies.

Table 2.2: DR classifications usually considered in the literature.

Reference	Year	DR Categories
[44]	2009	Technical, Economic and Achievable (MAP and RAP)
[241]	2010	Technical, Economic and Achievable
[217]	2010	Technical, Economic and Realizable
[242]	2011	Theoretical, Technical, Economic and Achievable (or Market)
[243]	2015	Theoretical, Technical, Economic, Practical and Social
[244]	2015	Technical and Market (also referred to as Achievable)
[240]	2017	Theoretical, Technical, Economic, Acceptable and Realizable
[245]	2017	Technical, Economic and Achievable
[246]	2018	Theoretical, Technical, Economic and Realizable
[247]	2018	Theoretical, Technical, Economic and Practical

Significant differences can be identified when distinguishing the so-called "achievable" DR potential, which has been treated differently within the literature. Some authors split this last concept (i.e., achievable DR potential) into two: MAP and RAP [44], Acceptable and Realizable [240], or even Practical[29] and Social [44] DR potentials. Other authors do not divide the "achievable" DR potential but refer to it with different terminologies such as practical [247], realizable [217], feasible [240], or even market [242] DR potential. Therefore, these terms have been used interchangeably across different research papers within the literature. In fact, for all cases, the "Achievable" [242] (or "Practical" [243], "Social"[243], "Realizable" [217], "Feasible" [240] or even "Market" [242]) DR potential would represent a set of one or more barriers to the DR implementation [217] such as summarized in the proposed framework which will be further presented in Figure 2.8. This might suggest the need to standardize this term definition to avoid the undue use of these words. This would simultaneously contribute to overcoming the barriers mentioned above by making easier future reviewing pathways, for example. Therefore, after a systematic literature review, the different classifications regarding the different DR potentials categories were unified in a standard classification, such as illustrated in Figure 2.6.

[29] For the authors of [243], the practical DR potential corresponds to the intersection between the economic and social potential.

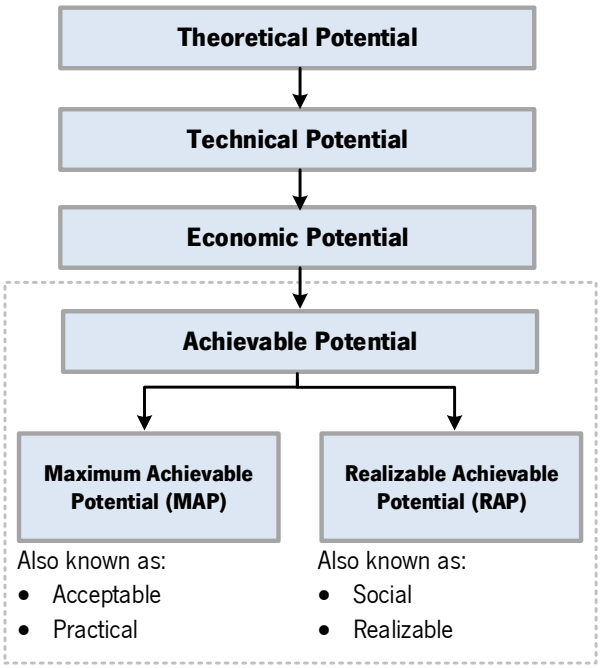


Figure 2.6: Overview of the main categories of DR potentials.

The different categories of DR potentials *versus* capacity (GW) and a brief description of each potential are illustrated in Figure 2.7. Along with this paper, for the sake of clarity, the term that will be most used to describe the last DR potential is "Achievable."

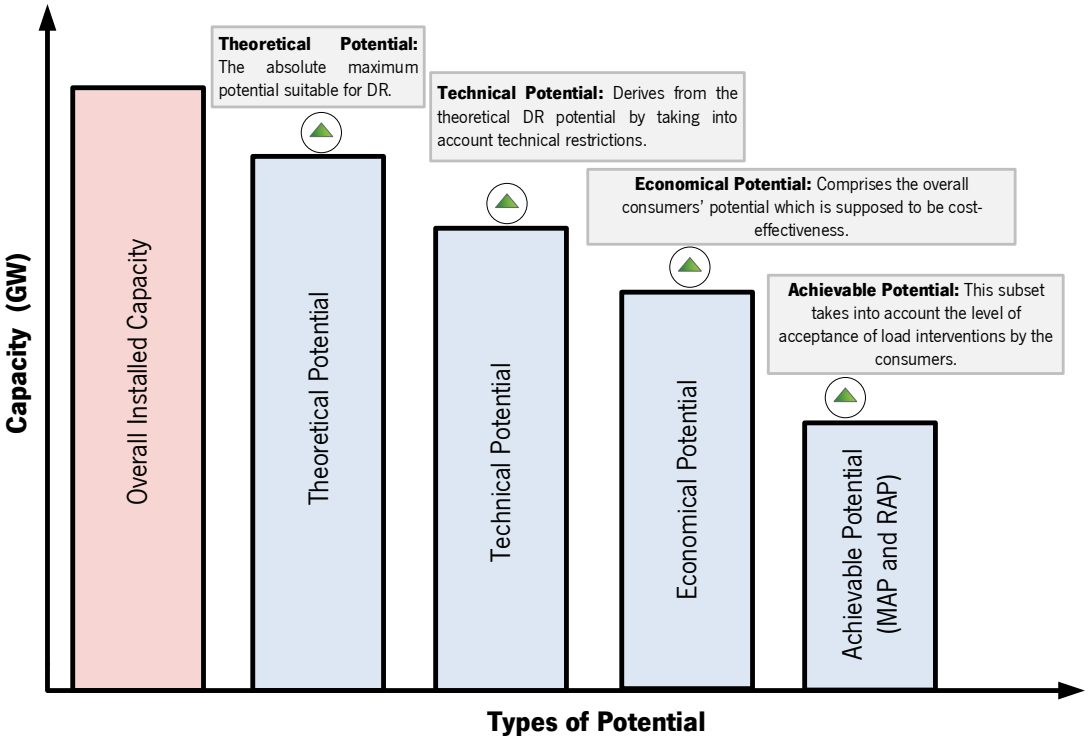


Figure 2.7: Categories of demand response potential versus capacity (GW). Source: Adapted from [200,242,243,246].

The concept of the 'Theoretical DR Potential' is well established within the literature, referring to the overall DR potential available in a power system. This finding is supported by Ref. [200], arguing that *"the theoretical potential comprises all facilities and devices of the consumers suitable for DR."* A similar definition has been further proposed by Ref. [246], who have argued that the *"theoretical potential generally defines the absolute maximum potential and consists of the entire unrestricted electricity demand."*

However, more recently, literature has emerged (see for example [200], [246], and [248]) that offers contradictory definitions for the 'Technical DR Potential' concept. Ref. [200], for example, highlights that "*the technical potential includes only those* [equipment] *that can be controlled by the existing information and communication infrastructure".* In contrast to [200], Ref. [248] defines that *"the technical potential is the amount of the load that is temporally available for load shifts when taking into account technical peculiarities and legal regulations".* In agreement with [248], Ref. [246] argues that *"the technical potential is generally smaller than the theoretical potential, as it takes technical restrictions, such as the number and duration of interventions into account".* Therefore, while a variety of definitions for the 'Technical DR Potential' have been suggested, this research will use a similar term definition such as proposed by Ref. [246], which is also considered in the evaluation of the technical DR potential[30] in [233] and [249].

The economic DR Potential (also referred to as Techno-Economic DR Potential in [242]) derives from the technical DR potential. In this case, however, the costs to activate this technical potential should be taken into account. According to [242], *"the economic potential describes the cost-effective application of load management".* The overall costs usually comprise both the investments and operational costs [217].

A general list of definitions derived from the literature review is presented in Table 2.3 aiming to propose standard definitions for each DR potential category.

[30] Differently from [246], the authors of these papers do not mention directly the definition of 'Technical Potential'. However, we have inferred it because of the assumptions made by these research works to establish such DR potential.

Table 2.3: Definition of each category of DR potential.

DR Potential	Definition	Ref.
Theoretical	The **theoretical DR potential** comprises the overall (i.e., all facilities and devices) consumers' potential suitable for DR.	[200,246]
Technical	The **technical DR potential** derives from the theoretical DR potential by considering technical restrictions (e.g., the shifting time, duration, and the number of interventions).	[246]
Economic	The **economic DR potential** derives from the technical potential when the costs for implementing DR (e.g., investments and operational) are taken into account. Therefore, it comprises the overall consumers' potential which is supposed to be cost-effective.	[217,242,246]
Achievable	The **achievable DR potential** takes into account the level of acceptance of load interventions by the consumers. **(1) Maximum Achievable Potential (MAP)**: The MAP is restricted by the attitudinal (e.g., consumers' resistance), societal, and market barriers, limiting customer participation in DR programs. For this case, it is presumed that no impediments to implementing DR measures would occur. **(2) Realizable Achievable Potential (RAP)**: The RAP is derived from the MAP by considering other impediments to DR program implementation (e.g., regulatory, political and financial barriers), limiting the savings from DR programs.	[44]

A set of recommendations to incorporate DR into resource planning models is proposed by [52]. Due to a set of legal, policy, economic and societal barriers, the DR implementation is restricted only to selected markets, and the traditional DR programs mostly focus on large industrial loads [200]. Therefore, literature has focused, in general, on estimating the DR potential in large-scale and energy-intensive industries [247]. However, a significant number of works [250–252] have been recently focusing on assessing the residential and commercial DR potentials, which are considered promising sectors that would contribute to the power system flexibility [200]. Country-specific analysis of DR potential has been extensively addressed by previous research (see Ref. [246] and Ref. [253] for the specific case of Germany and Ref. [254] for Denmark).

Traditionally, DR assessments have been evaluated mostly through qualitative approach analysis [253]. However, the DR potential evaluation as a quantifiable resource has been assessed only by a few works in the available literature. The precise quantification of the load flexibility potential is considered a complex

task [232]. In [253], for instance, the authors emphasize that the significant benefit of employing DR is reducing the peak power system capacity, which represented about 10 GW for the power system evaluated (12% of peak load). For the power system analyzed in [253], the DR contribution for integrating VRE was found to be not significant.

A significant number of studies have estimated the potential of DR resources across different sectors (i.e., industrial, commercial, and residential) at varying scales (e.g., local, regional, national, and even across continental regions) [244]. An up-to-date review analysis is undertaken by [188], which concluded that *"existing DR programs around the world demonstrated a highly asymmetrical development between different regions".* Ref. [226] highlights the need to develop novel DR modeling approaches that incorporate as many applications as possible and consider the interactions of DR with other system resources. Ref. [255] reviewed the DR in the residential sector, including the latest Information and Communications Technology (ICT) developments. The authors of [220] conducted an extensive literature review of DR programs and proposed a communication and computation-based DR program for the residential sector.

The long-term impact of DR measures in the industrial, residential, and tertiary sectors is assessed in [53] for the Portuguese electricity system using the OSeMOSYS software tool. The authors of [53] concluded that the implementation of DR measures would decrease both the overall system capacity (reaching up to 2.2% compared to scenario BAU) and the total system costs (decreasing up to 2.23%), and it would also increase the share of renewable energy in the Portuguese power system. However, Ref. [53] underlined the need to assess the costs to implement such DR measures.

The study of [98] investigated the role of sector coupling in the Brazilian power sector. A deterministic linear optimization model was considered in this last paper [98]. A simplified model for the DR representation was used, considering only part of the commercial and industrial sectors as potential flexible loads. The duration of load interventions is not considered in their modeling approach. The authors of [98] also concluded that for the specific case of Brazil, the DR contribution is limited to load balancing (reaching up only to 0.04% of the total annual electricity demand), which can be mostly explained because of its high renewable potential. On the other hand, peak load reductions of about 3.3 GW are projected due to the DR implementation for the power system evaluated in [98].

Several recent studies [219,226] addressed the key barriers and the challenges to the DR deployment. Findings of Ref. [226] revealed that DR contributes only to a limited extent in current electricity markets, restricting the exploitation of its full benefits. Ref. [91] considered that consumers would have a more active behavior in the future, giving more importance to quality and sustainability aspects. Technology

advancements on the demand-side have also contributed to an increasingly active behavior of consumers [91,256]. The growing market share of smart appliances brought about by smart grids' evolution may strongly facilitate the insertion of demand-side resources such as air conditioning, washing machines and refrigerators without compromising user comfort. Ref. [91] presented proposals for public, regulatory, and business strategy policies to be implemented by the Brazilian government in the 2030s. In [162], the authors proposed a coordinated optimization model for the generation and transmission expansion problem considering the inclusion of DR into the optimization problem. The authors of [257] presented a method to assess the so-called realizable DR potential for ancillary services purposes.

Based on this background, Table 2.4 gives a general overview concerning the different DR potentials addressed along with previous research. The papers were selected considering those works which (i) explicitly refer to the category of DR potential assessed or (ii) the category of DR potential assessed could be indirectly retrieved. Further, a set of assumptions is reconsidered to shape the addressed DR potentials considering the standard definitions proposed along with this chapter.

Table 2.4: Overview of each potential DR category.

Ref.	Year	DR Category	Sectoral Coverage	Spatial Resolution
[258]	2009	Technical/Economic	Commercial	Local Consumer
[44]	2009	Achievable (MAP and RAP)	Industrial, Commercial and Residential	National (U.S.)
[259]	2010	Achievable (RAP)	Industrial, Commercial and Residential	Regional (Midwest ISO region)
[217]	2010	Technical/Economic	Industrial, Commercial and Residential	National (Germany)
[233]	2011	Technical/Economic	Industrial[31]	National (Germany)
[242]	2011	Theoretical, Economic and Achievable	Refrigeration systems[32]	National (Germany)
[260]	2012	Technical and Economic	Industrial, Commercial and Residential	Regional (Eastern Interconnection – U.S.)
[261]	2013	Theoretical	Commercial	Commercial Building

[31] The focus was on energy-intensive industries.

[32] The load management potential is evaluated with a particular focus on refrigeration systems considering the potential for each sector that uses this cross-sectional technology. The base data for the city of Mannheim is used and further extrapolated to the national power system of Germany.

[200]	2014	Theoretical → Technical	Industrial, Commercial and Residential	Continental (Europe and North Africa)[33]
[254]	2014	Technical	Industrial, Commercial and Residential	National (Denmark)
[262]	2014	Technical	Residential	National (Denmark)
[263]	2014	Technical	Residential	Local (Kainuu)[34]
[264]	2015	Theoretical[35]	Industrial, Commercial and Residential	Continental (Europe - 34 countries)
[265]	2015	Theoretical[36]	Residential[37]	National (Belgium)
[266]	2015	Technical and Economic[38]	Residential and Commercial	National (Germany)
[244]	2015	Market → Achievable[39]	Industrial, Commercial and Residential	Regional (Shangai - China)
[253]	2016	Economic /Social→ Achievable[40]	Industrial, Commercial and Residential	National (Germany)
[249]	2016	Technical/Economic	Industrial, Commercial and Residential	Continental (West-European)
[267]	2016	Theoretical	Industrial and Residential[41]	Continental (Europe)
[250]	2017	Social → Achievable[42]	Residential and Commercial	National (Germany)
[240]	2017	Technical	Commercial	Company (Germany)

[33] The analyzes were undertaken for 30 countries (Europe and North Africa). However, for North African countries only energy-intensive industries were considered due to the scarcity of data. Although the authors mention that the theoretical DR potential is assessed, a set of technical restrictions are also considered. Therefore, following the definitions proposed along with this work, the DR potential assessed in [200] should be interpreted as the 'Technical Potential'.

[34] The focus of this work was in the residential sector with metered data collected from 1630 households from Kainuu (Finland).

[35] For inference (because the authors do not mention which DR potential is analyzed).

[36] The authors also mention that this potential may be underestimated since the results were extrapolated based on a pilot program.

[37] Here, the flexible potential of five household smart appliances was evaluated based on a set of measurements.

[38] The authors mention that *"the results determined a practical shifting potential"*. However, following the definitions used along with this work and the results presented in the paper [266], this definition should be interpreted as the 'Economic Potential'.

[39] Following the definitions used along with this work, the "Market" DR potential cited in the paper would correspond to the "Achievable" DR potential.

[40] The author mentions that "a model-based assessment of the economic DR potential in Germany is presented". Further, the author refers to the estimation of an "approximated social potential".

[41] The following sectors were considered by the authors: industrial, cooling, households, heat pumps and e-mobility.

[42] Following the definitions used along with this work and the results presented in the paper [250] this definition should be interpreted as the achievable potential.

[268]	2018	Theoretical	Industrial, Commercial and Residential	Northern European Countries
[269]	2018	Achievable	Residential	National (Germany)
[251]	2018	Technical	Residential and Service	National (Finland)
[246]	2018	Technical	Industrial, Commercial and Residential	National (Germany)
[270]	2018	Technical	Plug-in electric vehicles	National (Germany)
[239]	2018	Economic	Industry and Commercial	Local (Texas)
[252]	2018	Technical and Economic	Industrial, Commercial and Residential[43]	National (Nigeria)
[53]	2018	Theoretical/Technical[44]	Industrial, Commercial and Residential	National (Portugal)
[245]	2018	Technical, Economic and Achievable	Industrial, Commercial and Residential	Regional (Michigan)

The following paragraphs will focus on a review analysis regarding the different DR potentials illustrated in Figure 2.6.

- **Theoretical DR Potential**

The authors of [242] addressed the theoretical (4.2 GW), economic (3.2 GW), and achievable (2.8 GW) DR potential for Germany with a particular focus on the refrigeration systems across different sectors (i.e., industrial, commercial, and residential). The achievable DR potential corresponds to 66% of the theoretical DR potential for the power system evaluated [242].

Ref. [268] estimated the theoretical DR potential across different sectors for seven Northern European countries (Denmark, Norway, Sweden, Finland, Lithuania, Estonia, and Latvia) as 12-23 GW considering a peak load of about 77 GW.

The total theoretical DR potential for Europe (34 countries) was assessed by [264], estimating 800 TWh for suitable DR processes across industrial, commercial, and residential sectors, which represents a value slightly higher than 52 GW (9.4% of peak load) reflected into the residential (42%), industrial (31%), and commercial (27%) sectors. The authors of [264] concluded that the share of flexible loads for the industrial

[43] The DSM potential is assessed considering different levels of industrialization.

[44] The authors mention that *"the theoretical potential of DR is computed"*. However, they also consider a set of technical restrictions in the model formulation. Therefore, following the definitions used along with this work, the definition that would be considered here is precisely the 'Technical DR Potential'.

sector seems higher for countries with high percentages of industrial electricity consumption, such as Sweden and Norway [264].

- **Technical DR Potential**

The technical DR potential is addressed in [266] for the German power system (specifically for the residential and commercial sectors), which reach up to 8 GW by 2030. Ref. [266] also conducted an economic analysis for the residential sector and concluded that the income generated by load management is not enough to cover the investment in ICT. Therefore, the DR implementation was proved to be not cost-effective.

The technical DR potential of flexible demand for the Danish power system is assessed in [254] across industrial, commercial, and residential sectors using two approaches. Firstly, a bottom-up approach is considered to determine each sector's flexible load potential (i.e., industrial, commercial, and residential) for a 100% RES in 2050. The EnergyPLAN software is then applied to perform the simulations to identify the adequate levels of the flexible loads for the power system assessed. It is worth mentioning that the software EnergyPLAN has been extensively used in the simulation of future energy scenarios focusing on the large-scale integration of RES into the power system [103], and it has also been recently used to the inclusion of DR into long-term simulation models (see [254]).

- **Economic DR Potential**

Traditionally, the DR potential that is considered cost-effective would suggest that the overall costs of implementing such DR measures are lower than the cost of energy supply. The incremental cost of electricity from peaking generators and the use of both cost and risk combination of portfolios with and without DR (i.e., portfolio analysis of DR) are other examples of how literature has evaluated the cost-effectiveness of DR strategies [245].

The technical and economic DR potential for wind integration is assessed by [217]. The authors of [249] identified the least-cost options for West-European countries for the year 2050 by assessing five possibilities that included the flexibility potential of DR strategies. This last research paper assessed the economic DR potential and considered the costs for load shifting ranging from 2 to 100 €/kW and the costs for load shedding varying between 200 and 5000 €/MWh, depending on the process assessed. For the power system evaluated in [249], the total system costs were reduced to 3% by implementing such DR measures. Ref. [226] points out that currently, one of the most fundamental questions about DR implementation is how it should be priced in terms of investment and operational costs. These cost aspects remain still unclear and should receive attention in future works.

- **Achievable DR Potential**

The authors of [271] highlight that the effective implementation of DSM strategies (e.g., DR measures) strongly depends on social acceptance. Few published studies have attempted to evaluate the achievable DR potential, which considers the consumers' level of acceptance of load interventions. Most of the studies that attempted to assess the achievable DR potential have been limited to convenience samples. In general, it has also been restricted to the analysis of small regions such as in [244] and [245]. For example, the achievable potential was estimated precisely for the German refrigeration sector in [242]. However, few published studies have attempted to systematically evaluate the achievable DR potential of large interconnected electric power systems.

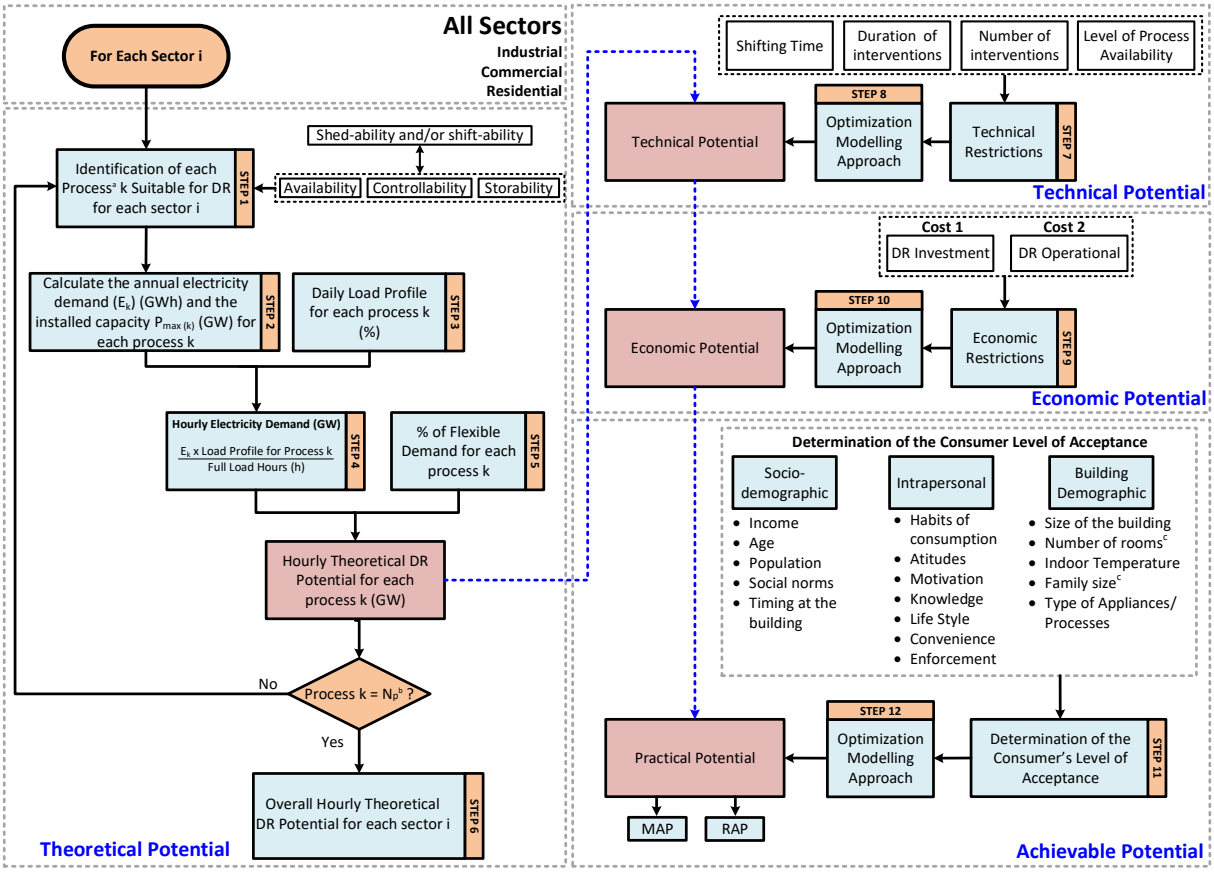
In [250], the shifting load potential is assessed for the German power system constrained by the consumers' acceptance and limiting the disconnection rates (meaning that the applications must be reconnected after a predefined time). Therefore, the authors of [250] considered the social acceptance of DR (specifically for the residential and commercial sectors). Ref. [226] emphasizes that *"human nature is a further issue which compounds the problem of market design for demand response. While large generators typically exhibit economically rational behavior through their profit maximising objective, smaller customers do not show the same rationality in their consumption decisions"*.

Ref. [253] considered the calculation of an *"approximated social potential."* Due to the set of complex features associated with estimating the achievable DR potential, the authors of [253] probably used the term 'approximated' because of the highly diverse, multifaceted, and complex nature of the achievable DR assessment.

2.5.3 A new conceptual framework to estimate each category of DR potential

There are two main methods for assessing the flexible load potential: aggregated and decomposition methods [254]. For the aggregated approach, market mechanisms are used to determine load changes under market conditions (e.g., electricity price change) [254]. For the methodology proposed in this research, the potential of flexible loads is assessed by broadly splitting up the potential candidates into a flexible and an inflexible component for each category (i.e., using the decomposition method) such as proposed by [246]. Then, for each sector, the decomposition of electricity consumption into several processes/appliances is performed and individually assessed, such as suggested and applied by several works in the literature [254]. Load flexibility may also be evaluated in terms of the amount of electricity (GWh), power (GW), time, type (e.g., load shedding and load shifting), as well as cost, just to name a few [271]. Depending on the variables used in the analysis, different DR potentials may be assessed (see Figure 2.8).

Ref. [200] points out that because of the different categories of DR potentials and considering the diverse set of constraints evolved, the DR potentials need to be treated separately. Therefore, after conducting a systematic literature review, the need for a framework that would systematically support each DR potential estimation was identified as the research gap. Besides, different methodological approaches have been considered, and literature mostly focuses on assessing country-specific potentials. Research on the topic has demonstrated the step-by-step procedure to evaluate each category of DR potential to a very limited extent. Consequently, based on the prior knowledge obtained by the conducted systematic review analysis, we propose an improved conceptual framework. The general overview of the methodological approach for assessing the different DR potential categories is illustrated in Figure 2.8.



[a]For the sake of simplicity, along with the flowchart, it will be used the term "process", which would refer to both "process" or "appliance".

[b] N_P represents the number of the processes.

[c]Specifically for the residential sector.

Figure 2.8: Key steps of the proposed framework for the estimation of each DR potential category.

This section proceeds by illustrating the proposed twelve-step methodology used to identify the different categories of DR potentials. The procedure is divided into four main DR categories: Theoretical - Step 1 to Step 6; Technical - Step 7 to Step 8; Economic - Step 9 to Step 10 and Achievable - Step 11 to Step 12.

- **Theoretical DR Potential: Step 1 to Step 6**

Step 1: Identification of each process/appliance k suitable for DR for each sector i

The starting point of the analysis comprises identifying the potential flexible loads (i.e., loads with some degree of flexibility, including processes and/or appliances) suitable for load shedding and/or load shifting for each sector. This identification has been traditionally undertaken through a qualitative assessment of technologies [240]. It is worth mentioning that this identification would require different criteria evaluation for each sector (i.e., residential, commercial, and industrial). Also, according to [200], traditionally, "*for processes with very high utilization rates - as they are found in energy-intensive industries - only load shedding without previous or subsequent balancing can be implemented. In residential and commercial sector, typically both load shifting and shedding can be realized*". The shed-ability and/or shift-ability characteristics of each process/appliance would be considered, interconnected with the following attributes of the technologies: availability, storability, and controllability [235].

Table 2.5 presents the main processes/appliances with some degree of DR potential but are not limited to only these applications and would vary between countries and sectors [240,264].

Table 2.5: Representation of the main processes with some degree of DR potential [243,264].

Residential	Industrial	Commercial
Air-conditioning	Paper machines	Air-conditioning
Washing machines	Non-metallic minerals	Ventilation
Tumble Dryers	Non-ferrous metals	Refrigeration
Dishwashers	Chemical and petrochemical	Storage water heater
Water heaters	Iron & steel	Storage heater
Refrigerators and freezers	Wood products	Wastewater treatment
Heating systems and electric boilers	Air Separation	Pumps in the water supply
	Cement Mills	Cold storages
	Wastepaper processing	

To give a well-known example for the sake of clarity, for the residential and commercial sectors, the controllability *versus* non-controllability and storability *versus* non-storability of the service might be taken into account for the selection of the processes/appliances suitable for DR. Therefore, the suggested criteria used along with this work to select the processes/appliances relevant for DR is whether it is storable and automatically controlled. This can be seen, for instance, in the refrigerator case (for the residential sector), which has a storability characteristic and could be considered suitable to contribute to DR purposes. Similarly, the washing equipment (e.g., washing machine, dishwasher and tumble dryers) would be suitable because of its controllability characteristic.

The independence between processes might also be considered for selecting suitable DR processes for the industrial sector, although this is not considered a trivial task [254]. For this reason, most of the

previous studies do not take into account this last aspect in the selection process. Other sectors are considered not relevant to the overall DR contribution and are usually not included in the DR assessment analysis.

Step 2: Quantification of Flexible Loads: Calculation of the Annual Electricity Demand and the Maximum Installed Capacity

The estimation of the annual electricity demand (GWh) and the maximum installed capacity (GW) for each process/appliance k over each sector i should be calculated in this step. However, this calculation might strongly vary among sectors. This aspect can be mostly explained by the technical differences across each process/appliance and the scarcity and sparsity of data that is generally available. Hence, for the industrial and commercial sectors, a top-down approach is traditionally considered, whereas a bottom-up approach is usually employed to estimate the annual electricity demand for the residential sector. These assumptions are taken into account in this step. The following set of equations are typically employed to quantify the flexible load potential for each sector and it is mostly driven based on the assumptions[45] presented in [243].

a. Industry Sector (Energy-intensive processes)

The quantification of the DR potential for energy-intensive industries is traditionally estimated based on the specific electricity consumption and production capacities. The annual electricity consumption ($\boldsymbol{E^k}_{\boldsymbol{year_ind}}$) is calculated considering the specific electricity consumption ($\boldsymbol{E^k}_{\boldsymbol{spec}}$), production capacities ($\boldsymbol{A^k}_{\boldsymbol{year}}$), and the capacity utilization level ($\boldsymbol{s^k}_{\boldsymbol{util}}$) for each process k as illustrated by Equation (2.1).

$$E^k{}_{year_ind} = A^k{}_{year} \cdot E^k{}_{spec} \cdot s^k{}_{util} \quad (GWh) \tag{2.1}$$

The annual self-electricity production ($E^k{}_{year_self_ind}$) should be discounted from Equation (2.1) for each sector and year based on the available data[46]. Therefore, the estimated yearly electricity demand ($E^k{}_{total_year_ind}$) for each energy-intensive industrial process can be calculated according to Equation (2.2) for the reference and future years.

$$E^k{}_{total_year_ind} = E^k{}_{year_ind} - E^k{}_{year_self_ind} \quad (GWh) \tag{2.2}$$

[45] The author of [243] also includes equations for estimating the overall potential of load reduction and load increase for each hour. We highlight that these equations could also be included in the framework proposed in this section. In this case, the calculation of the potential of load reduction and increase should be performed after Step 2 using the set of equations presented in [243].

[46] In our future assessment of the Brazilian theoretical DR potential, the annual self-electricity production was extracted from Ref. [90].

The maximum installed capacity $(P^k{}_{max_ind})$ for each process k is estimated using Equation (2.3) by considering the revision outages $(f^k{}_{rev})$ and the number of hours in a year (N_{h_year}).

$$P^k{}_{max_ind} = \frac{E^k{}_{year_ind}}{N_{h_year} \cdot (1 - f^k{}_{rev}) \cdot s^k{}_{util}} \quad (GWh) \tag{2.3}$$

b. Commercial Sector

The available data for the commercial sector is traditionally much more restricted than for the industrial sector. For this reason, the annual electricity consumption available for DR $(E^k{}_{year_com})$ can be broadly estimated using the combination of each commercial individual process demand $(E^k{}_{com})$ with its respective average demand share $(s^k{}_{com})$ according to Equation (2.4).

$$E^k{}_{year_com} = E^k{}_{com} \cdot s^k{}_{com} \ (GWh) \tag{2.4}$$

The maximum installed capacity can be thus estimated using Equation (2.5), which also considers the number of full load hours $(n^k{}_{FLH})$ in a year for each process k.

$$P^k{}_{max_com} = \frac{E^k{}_{year_com}}{n^k{}_{FLH}} \quad (GW) \tag{2.5}$$

c. Residential Sector

For the residential sector, the specific electricity consumption might be calculated considering each appliance's technical characteristics, and therefore it would vary across different appliances and regions. The annual electricity consumption $(E^k{}_{year_res})$ for those appliances that offer some degree of flexibility for the residential sector can be estimated using Equation (2.6), which considers the market penetration rate $(f^k{}_{eq})$, the number of households (n_{house}) and the specific electricity consumption of each appliance $(E^k{}_{unit})$.

$$E^k{}_{year_res} = n_{house} \cdot f^k{}_{eq} \cdot E^k{}_{unit} \ (GWh) \tag{2.6}$$

The specific capacity $(P^k{}_{unit})$ is also considered to estimate the total installed capacity $(P^k{}_{\max_res})$ and it can be calculated through Equation (2.7).

$$P^k{}_{max_res} = n_{house} \cdot f^k{}_{eq} \cdot P^k{}_{unit} \ \ (GW) \tag{2.7}$$

Detailed calculation of the specific electricity consumption of each appliance can be found in [243]. To give a well-known example for the sake of clarity, the duration and frequency of use for washing equipment could also be taken into consideration for estimating its annual electricity consumption. Average values can also be used based on equipment datasheets. It is worth mentioning that the overall potential of flexible loads for the residential sector is highly dependent on the characteristics of the appliances (i.e., type, power, efficiency and rate of each equipment) but also on the pattern of consumption of these appliances, which are affected mostly by the per capita income and the consumer's willingness to use more efficient technologies [90].

Step 3: Daily load profile for each process

To calculate the hourly electricity demand in the next step (i.e., Step 4), and therefore, to account for the temporal availability of the DR resources, the typical load profiles for each process/appliance should be estimated by using metered data or considering the typical profile patterns according to the available literature [243]. The selection of representative load curves on a daily, weekly and/or seasonal basis is of particular importance and it would be considered if there is available data [243]. Traditionally, energy-intensive industries run at full capacity over the entire year due to their vast heterogeneity of processes and high utilization rates. Therefore, a constant load profile over the whole year has been traditionally employed by previous research such as [200] and [246].

The load profile is dependent on a set of diverse variables, and therefore, it can be considered dynamic, non-linear, and time-varying [226]. For this reason, future projections are usually considered to be highly uncertain. Detailed end-use load profiles for each customer segment considering both a reasonable sample and length of time would also potentialize future DR potentials estimations. Traditionally, all DR processes/appliances' load profiles remain unchanged to assess the flexibility potential in coming years, such as considered in [200] and [246].

Extrapolating each process/appliance's flexibility potential is necessary when the potential of flexible loads is quantified for future years. This stage would require a broad literature review, and in general, it is based on available statistics of recent technology developments. To give a well-known example for the sake of clarity, for the residential sector, the increasing intensity in the use of appliances should be used in the extrapolation of data [243]. Different shares of flexible demand would also be considered when

extrapolation for future years is considered since it could change over the years. This happens because of two main reasons: the electricity consumption would increase, and the future DR potential would also vary according to the technologies' deployment [246].

Step 4: Hourly electricity demand

The hourly theoretical load flexibility potential for each process/appliance k (GW) is estimated based on the combination of the annual electricity demand (Step 2) with the load usage pattern (Step 3) $(D^k{}_{profile})$ but also by taking into account the number of full load hours in a year $(n^k{}_{FLH})$ according to Equation (2.8) [246].

$$E^k{}_{hourly} = \frac{E^k{}_{year} \cdot D^k{}_{profile}}{n^k{}_{FLH}} \quad (GW) \tag{2.8}$$

Step 5: Percentage of flexible demand for each process/appliance

The flexible demand percentage for each process/appliance (FD^k) should also be considered to further estimate the overall hourly theoretical DR potential for each process/appliance k and year y. It is worth mentioning that the share of flexible demand for each process/appliance would strongly differ between each other.

Step 6: Overall hourly theoretical DR potential for each sector i

Lastly, for each sector i and year y, the sum (for each hour) of all suitable DR processes/appliances which contribute to the DR potential will comprise the overall theoretical load flexibility potential of the power system under evaluation as described by Equation (2.9) [246].

$$E^k{}_{hourly(i)} = \sum_{\bar{k}=1}^{N} (E^{\bar{k}}{}_{hourly} \cdot FD^{\bar{k}}) \quad (GWh) \tag{2.9}$$

- **Technical DR Potential: Step 7 to Step 8**

The following steps (Step 7 and 8) allows the estimation of the technical DR potential.

Step 7: Technical restrictions

This step comprises the inclusion of a set of technical restrictions to estimate the 'Technical DR Potential'. The shifting time, duration, and the number of DR interventions can be considered the most critical technical restrictions to be taken into account, in addition to the level of availability of each process/appliance.

Step 8: Optimization modeling approach

The use of an optimization modeling approach is usually[47] considered to support the assessment of the technical DR potential of the overall electricity system. Within the optimization model, the technical restrictions (Step 7) would constrain the planning model. Different optimization modeling approaches (e.g., linear programming or stochastic programming) can be used, but the detailed description of each optimization approach is out of the scope of this chapter.

- **Economic DR Potential: Step 9 to Step 10**

The economic DR potential can be further assessed using Step 9 and Step 10.

Step 9: Economic restrictions

The economic restrictions need to be taken into account to assess the economic DR potential. Two different costs are traditionally associated with DR implementation. The investment costs (i.e., associated with the ICT necessary to automatized adjustment control, smart metering systems and program design) and the operational costs (i.e., variable and annual fixed costs) [233]. The operating costs might also include marketing and other administrative maintenance costs [272].

Step 10: Optimization[48] modeling approach

For this case, the economic restrictions (Step 9) would also be used to constrain the optimization model, which would support the assessment of the 'Economic DR potential'.

Achievable DR Potential: Step 11 to Step 12

Finally, the following steps (Step 11 and Step 12) support estimating the 'Achievable DR potential.'

Step 11: Determination of the consumers' level of acceptance

The estimation of the achievable DR potential comprises a difficult task since it depends on the evaluation of a set of qualitative variables (e.g., informational, legal, technical, organization and financial barriers in addition to the lack of consumers' experience [242]) such as illustrated in Figure 2.8. These results seem to be consistent with other research, highlighting that *"the determination of the market potential for a certain technology imposes challenges in setting a valid scientific methodology* [232]*".* The main barriers include the lack of consumers' acceptance, lack of enforcement, market structure, and information gaps [217]. The end-user behavior also plays a significant role in the effective implementation of DR measures [220]. Ref. [250] point out that the maximum shift duration for each process/appliance, for example, depends on the customers' acceptance.

[47] The use of simulation models is still possible such as considered by [254].

[48] See Step 8 for detailed information about the use of optimization approaches.

Previous studies [273,274] demonstrate that consumers' responses to prices might be asymmetric, increasing their consumption considerably on off-peak periods but with limited electricity consumption reductions during on-peak times. Ref. [265] assessed the flexibility potential of five household appliances based on real measured data for a large pilot test in Belgium and reported that household smart appliances' flexibility potential is highly asymmetric. Therefore, the willingness to accept load interventions (i.e., load shedding and/or load shifting) by end-users may be evaluated using both qualitative and quantitative analysis [235]. The effective DR potential (i.e., the achievable DR potential) is lower than the economic DR potential since it depends on the level of consumers' acceptance.

Step 12: Optimization[49] modeling approach

For this case, the restrictions from Step 11 should also constrain the optimization model to properly account for the flexibility potential of the consumers and reach a final assessment of the 'Achievable DR Potential'.

2.5.4 Discussion of the findings

Findings of this study revealed that different methodologies had been used to evaluate the various categories of DR potentials. Ref. [275] reviewed the DR experience in Europe and highlighted that "*studies on the economic and technical potential of DR vary significantly in methods, sample sizes and results".* In [246], an overview with a focus on DR potentials is addressed. The authors of [247] point out that in the review analysis of DR potentials undertaken by [246], *"the authors remark significant variations in the considered studies, which may be explained by a different scoping and assessment method of the analyzed demand response potential".* Therefore, previous studies vary strongly in their findings concerning the estimation of DR potentials.

As reported by [255], the *"lack of experience with demand response has necessitated the employment of numerous assumptions in the modeling approaches adopted. As a consequence, it can be argued that the estimations of the benefit of demand response are dependent on these assumptions and an accurate evaluation has yet to be achieved"*. Consequently, the DR potential estimation varies between studies, even considering the same power system, such as better demonstrated by [246]. Because of both the lack of experience and understanding of the complex nature of DR, superficial results have been obtained by significant previous published research due to its simplistic models. Consequently, several analyzes might be oversimplified with unrealistic results and which do not represent reality correctly. Ref. [276] points out that these differences occur mostly because of the different methods typically employed to

[49] See Step 8 for detailed information about the use of optimization approaches.

estimate the DR potentials. To give a well-known example for the sake of clarity, some authors estimate the average load flexibility potential, whereas others use hourly temporal resolution.

Ref. [246] analyzed six different projections that estimated the DR potential for Germany and pointed out that most previously published works consider *"only the maximum potential and do not consider temporal availability in detail".* However, the DR potential is strongly dependent on temporal availability (e.g., the hour of the day), indoor temperature, and season, for instance [246]. The authors of [246] recently assessed the technical DR potential for Germany. The maximum technical DR potential considering both load shedding and load shifting estimated by [246] was nearly 25 GW (using data for the year 2013). However, the authors of [246] point out that this potential will never be available because the electricity consumption varies for each hour (i.e., daily, weekly, and season, for instance). Therefore, the temporal availability [277] and the spatial distribution [200] of the flexible loads are of particular importance. The temporal availability has been traditionally assessed through the identification of typical daily load profiles. Due to the lack of measurements, typical demand load patterns are traditionally considered based on data from the available literature. Flexible loads for commercial and industrial sectors have usually been estimated based on their annual electricity consumption. Ref. [246] also addressed whether the technical DR potential is available when needed (i.e., mostly during on-peak times) and concluded that the maximum DR potential for the power system evaluated occurs during off-peak times, i.e., only a small share of the DR potential is available when the power system mostly needs. The maximum hourly potential provides a flexible demand slightly lower than 14 GW (which is considerably lower than the maximum available capacity of about 25 GW) for the power system evaluated in [246].

Based on the literature review, it became evident that the classification of the different categories of DR potentials is far from being consensual, and the methods for their estimation are not yet fully established. The framework presented in Figure 2.8 might provide guidelines for bringing consensus to the DR potential classification and solving the estimation problem, supported by a solid scientific background derived from the literature review. Given the complex nature of the estimation problem and the heterogeneity of the sector and power systems, just a small sample of numerical approaches and equations are proposed. However, the user-friendly and step-by-step nature of the theoretical framework is deemed to be of high benefit for the power systems community and decision-makers.

2.6 Concluding remarks

The contribution of this chapter to the literature is multifold and is strengthened by three key accomplishments.

Firstly, we shed new light on the use of co-optimization approaches within the energy field, focusing on long-term power planning models. The analysis has been performed through a systematic literature review analysis of previously published high-quality research. Taken together, the reviewed studies provide important insights into the increasing risks and uncertainties over the short, medium, and mainly in the long-term, which are deemed to be very relevant challenges for policy-makers to address. The review also found evidence that the use of co-optimization strategies has increased markedly over the last few years, although many terms have been used interchangeably to refer to co-optimized models. The research findings reported here seem to be consistent with other research (see Ref. [278]), which systematically indicate that co-optimization might provide the capability of lower investment and operation costs. Overall, such approaches are likely to lead to less costly solutions than traditional optimization techniques.

Overall, the long-term co-optimization models differ considerably in terms of temporal resolution, geographical scope, technologies considered, and regional disaggregation but also on the programming strategy and tool used to solve such co-optimization problems. The majority of previous studies on generation-transmission co-optimization have applied MILP models. The great majority of previous co-planning models between generation and transmission expansion planning do not use high temporal resolution due to computational limitations. Recent research has also addressed short-term operational constraints in long-term power planning models, which are found to impact investment decisions.

Therefore, there are many challenges associated with expansion planning problems because of its long-term, large-scale, and nonlinear nature. Research has also consistently shown that the use of co-optimization approaches can be technically challenging. Overall, a set of techniques such as relaxation, decomposition, and linear methods have been proposed for reducing the inherent nonlinear model's complexities. Heuristic models have also been employed to support the complex nature inherent to co-optimization approaches. Our literature review revealed that different objective functions had been considered for the co-optimization, although, in general, the minimization of the total system costs is the most employed among the reviewed papers.

The evidence from our review seems to suggest a pertinent role for addressing real-case systems in future models instead of using theoretical test cases as considered by the majority of studies. However, regardless of all the benefits associated with the use of co-optimization approaches, our literature review also revealed that due to the increasing complexities and trade-offs of the energy sector, a set of challenges for future co-optimization models include (i) dealing with the treatment of uncertainties and (ii) taking into account the trade-offs between the temporal and spatial model's resolution. These findings are also in agreement with Ref. [279], which addressed the twenty-first-century energy challenges for

energy systems models which also pointed out the need for future energy models to integrate human and social risks/opportunities. Co-optimization is also revealed to be a data-intensive procedure. The need to coordinate the necessary data from multiples actors might increase the problem's complexity since security and confidentiality issues would also be put on the table. The inclusion of the distribution sector into the traditional energy planning models is considered a big challenge since it would be challenging to achieve the coordination of all sectors (generation, transmission, and distribution), primarily in electricity markets in which assets are unbundled, such as the case of Brazil [33].

The findings reported here should make an essential contribution to the energy field. The use of co-optimization was found to be very useful to address critical concerns in both short and long-term planning issues, but also evidence is presented showing that such approaches might be more effective in capturing the trade-offs between two or more sectors. For instance, the governments might have a deeper understanding of the risks, benefits, and costs of the available resource options but can also improve the decision-making process through integrated planning alternatives offered by co-optimization approaches. Although far from being exhaustive, our comprehensive literature review aimed to illustrate the diversity of approaches and models used by different research works and demonstrate their application potential to planning problems within the energy field.

Secondly, this chapter demonstrated along with Section 2.5 - through an in-depth systematic review analysis - that there is a lack of understanding regarding the different categories of DR potentials, which sometimes have been unduly used by the available literature. The DR potentials were standardized into four main categories: 'Theoretical', 'Technical', 'Economic' and 'Achievable'. Findings of this study also revealed that there is a general agreement regarding the definition of the theoretical and economic DR potentials. However, significant differences can be identified when distinguishing the so-called technical and achievable DR potentials, which have been defined in different ways within the literature. Therefore, the unification of these different classifications was proposed to avoid misleading research on this topic. This would simultaneously contribute to overcoming the barriers mentioned above by making easier future reviewing pathways, for example. The study presented here also confirmed that different terms had been used to refer to "DR potentials", which includes mostly: (1) Demand Response Potential, (2) Demand-side Flexibility, (3) Flexible Demand Potential, (4) Flexible Load Potential and (5) Load Flexibility Potential, which has been frequently used interchangeably in the literature.

The DR potential estimation may somewhat vary between studies for the same power system. This can be mostly explained by the fact that some works consider the theoretical potential, representing an upper bound for the other potentials (i.e., technical, economic, and achievable). Overall, the studies reviewed

here clearly indicate the importance of the temporal availability of DR applications, which has been neglected by part of the published works. The findings also raised critical theoretical issues that have a bearing on quantifying the DR potential in the long-term. The estimation of the future DR potentials is particularly valuable to contribute to a sustainable future. The evidence reviewed here suggests a pertinent role for using more effective approaches for the detailed estimation of end-use load profiles for each customer segment, considering both a reasonable sample and length of time, which would potentialize the future assessments of all categories of DR potentials. Also, the determination of the technical suitability and the load flexibility potential for each end-use-level and customer segment is considered to be essential to accurately reflect in realistic DR potentials future estimations.

To summarize, the holistic assessment of DR's potential contribution needs to surpass a set of barriers, including technical and non-technical ones. Regulatory barriers can be considered one of the most important aspects to be addressed to improve DR's deployment and enable customer participation in DR initiatives. The non-technical barriers to adopting DR mechanisms would also be taken into account to assess the achievable DR potential, for example.

It can also be concluded that although many advances have been observed over the past years, primarily in developing countries, many challenges and barriers (e.g., technical, market, and behavioral) associated with the DR deployment still exists and appears as potential challenges for the deployment and dissemination of DR strategies. The effectiveness of DR programs is also strongly dependent on government policies and regulations that should have a reliable and long-term support. Therefore, the outcomes of our literature review also lead to the conclusion that the evaluation of potential benefits of DR measures should be addressed holistically, considering the external benefits for the entire energy system (e.g., using a portfolio analysis), which would potentialize the cost-effectiveness of DR and become a more attractive demand-side option.

Thirdly, a well-founded and user-friendly framework - which would powerfully help quantify the DR flexibility across different sectors and applications – has been proposed. In contrast to other works that addressed different DR issues, the scientific contribution of this research relies mostly on the novel theoretical framework for the determination of the different categories of DR potentials.

Chapter 3. The Brazilian Power Sector

This chapter is subdivided into five key sections. The first section contextualizes the research by providing background information on the topic under study. An overview of the current and future characteristics of the Brazilian power sector is addressed in Section 3.2. The characterization, policy and regulatory framework are further discussed in Section 3.3, addressing the new trends for the sector and the main barriers and challenges associated with the future system expansion. Section 3.4 summarizes the smart grid trends and prospects for the sector. Chapter 2 provides the main concluding remarks in Section 3.5 by identifying relevant policy implications and outlining the possible avenues for further research.

3.1 Introduction

The growth of population and the cities expansion brought about new challenges associated with the increasing energy use. Meanwhile, RES has emerged as an essential solution for a sustainable, cost-effective, and environmentally friendly energy system [10,280]. The high integration of RES for electricity generation has been widely discussed worldwide to ensure long-term sustainable energy supply but also because the electricity sector stands out as a critical driving force of global climate change. The emergence of smart grids may provide a wide range of benefits, particularly for the population of developing countries, which includes reducing both power outages (proved to be costly for local economies) and the overall level of CO_2 emissions. In addition to lowering bill costs, improving energy efficiency, and increasing the power system's reliability, smart grids may also promote the optimized utilization of renewable energy and reduce system losses [281,282]. The combination of RES and energy efficiency measures is considered the main pillars of the energy transition towards a sustainable energy future [9]. The expected result of this energy transition is the contribution to the decarbonization of the energy-related activities. However, the result might not be exactly what is expected for the Brazilian electricity sector, mostly because the hydropower regularization capacity has been decreasing considerably over the last decade, which increased the use of thermal resources.

By contrast, new Brazilian government policies have been stimulating the insertion of Distributed Generation (DG) from RES, such as the case of the Normative Resolution (in Portuguese, RN) nº 687/2015 [283] - which is an improved version of RN nº 482/2012 [284] and regulates the grid connection of DG in the country. Over the past few years, the Brazilian government has also proposed different tariff schemes focusing on household consumers. Traditional energy conservation and efficiency measures have also been applied in the country, such as the National Electrical Energy Conservation Program (in Portuguese, PROCEL).

In addition to the large-scale hydropower system, several other paradigms shift have been verified over the past years in the Brazilian electricity sector, which pose critical challenges for the energy decision-making process towards a sustainable and resilient power system. This includes new government policies on renewable energy incentives [283,284]; an increasingly volatile consumption profile [189,285]; the possibility for the prepayment of electricity [286]; changes in electricity tariff composition [286,287]; the increasing environmental restrictions [87]; the falling cost and the growing insertion of DG [284,288]; the high level of uncertainty brought by intermittent sources [58,285]; the prospect of conscious consumption [289] and the growing change in energy consumers' behavior; the increasing environmental awareness [290]; the prospect for Demand-Side Management (DSM) strategies and storage technologies [58,77,188]; the new commercial and regulatory trends [91,284,288]; the high volatility of the energy prices [290]; the developing and disseminating of smart grids and inserting electric vehicles [91,291]; among others.

The adoption of these new technologies, e.g., DG, DSM, electric vehicles, and smart grids are likely to happen not only due to direct financial gains for consumers but also considering the consumers' preference (e.g., behavior and socio-cultural factors [33]), which goes beyond the classical economic rationality mindset [58,292]. The current public policies for a smart power system in Brazil are addressed and evaluated in [293]. This previous study also suggested the country's most favorable public policies based on several developing countries' successful experiences.

Therefore, the future trend is the establishment of several new complex features for the Brazilian electricity sector, which requires an in-depth discussion to provide a high level of energy security and reliability [3,91]. Although recognizing several technical and economic problems related to the increased penetration of RES, it is also essential to identify the great opportunities emerging for the electricity sector. A search of the literature revealed few studies (such as in Refs [91,293,294]) which attempted to address the leading prospects, challenges, and opportunities towards a smart grid power system in Brazil. As a result of this complex set of changes expected for the future, this chapter addresses a lively discussion related to the main issues involving the opportunities, challenges, trends, and latest developments of the Brazilian power sector towards a smarter grid structure, which also resulted in a published paper (see Ref. [68]). Our purpose is to provide an overview of how these features are interrelated and how they might affect the future of the power sector. The literature review includes scientific papers and reports, legal texts, and other publications from government institutions and organizations of the sector. The strengths and innovative aspects of this study include an in-depth analysis of the new regulatory structure and its interdependence, which represents a fertile field for research in which technological development

may go hand in hand with energy policy-making. Moreover, given the still relative immaturity of smart grid technologies and related concepts, the benefits from the findings of this research broadly extend beyond the case addressed as the identified challenges, opportunities and policy implications can provide valuable lessons for other electricity systems.

Therefore, this chapter proceeds by providing a broad picture and a discussion on the latest developments in the Brazilian electricity sector, including the main technical and regulatory advances towards a country's smart power system.

3.2 Overview of the Brazilian energy sector

The absence of exploitable natural resources is expected to be a future characteristic common to most countries worldwide. However, fossil fuel reliance for the energy sector becomes particularly vulnerable to fuel price fluctuations [11]. The growth of energy consumption is also a current characteristic of most developing nations, including Brazil. A large and growing body of literature has investigated the prospects for achieving a sustainable energy system through renewable energy. New studies are published each year addressing different perspectives such as technological development, climate change, and demand projections. The share of RES has substantially increased in the energy mix of developed and emerging countries, and Brazil is no exception. This trend is expected to continue in the future, primarily aiming to reduce GHG emissions and mitigate climate impacts [11]. Therefore, RES to power is seen as a fundamental strategy to reach these sustainability goals. Notwithstanding, several technical and economic challenges are to be surpassed to achieve a high share of RES integration [11].

Figure 3.1 illustrates the electricity share from RES in 2009 and 2016 for the Brazilian electricity system and other selected countries [295]. What can be clearly seen in Figure 3.1 is the dominance of renewable energy in Brazil compared to other countries, mainly because of its large hydropower system. Although the share from RES has decreased over time for the Brazilian electricity system, the share of wind and solar power has substantially increased, mainly in the last five years [54,296]. The percentage reduction in renewable electricity generation is mostly because of the continuous decrease in the hydropower source's supply share.

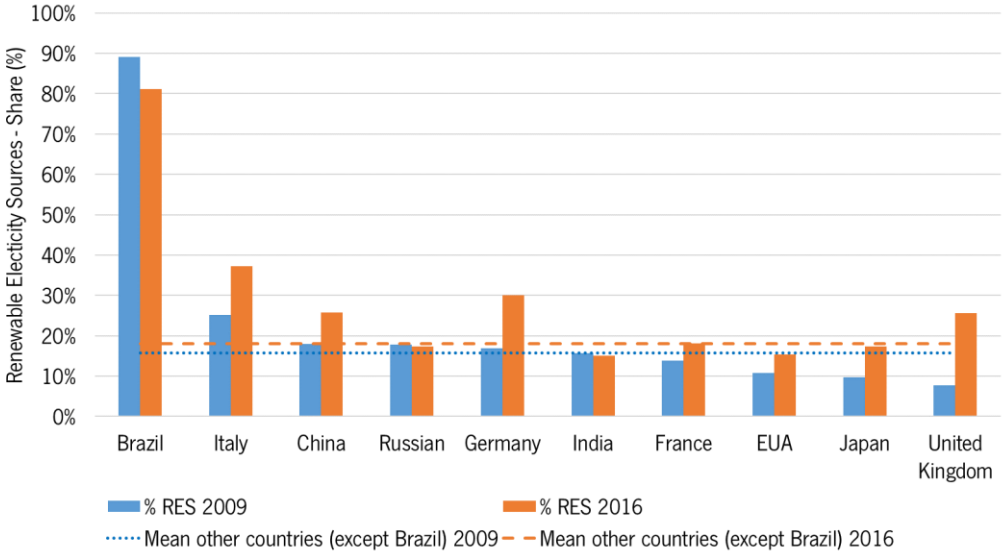


Figure 3.1: Electricity share from renewable sources in 2009 and 2016 for Brazil and other countries.

The Brazilian electricity system is a typical example of a highly interconnected arrangement. It stands out among other power systems because of its high-RES penetration with a major focus on hydropower, which has historically allowed for low carbon electricity production. Brazil's remaining electricity supply has been provided mostly by thermal and wind power sources [296]. Figure 3.2 illustrates the historical power output (left axis) and the Southwest[50] hydro storage level (right axis) in Brazil from 2000 to February 2018. Clearly, hydropower has a significant impact on managing the electricity system's operation in the country.

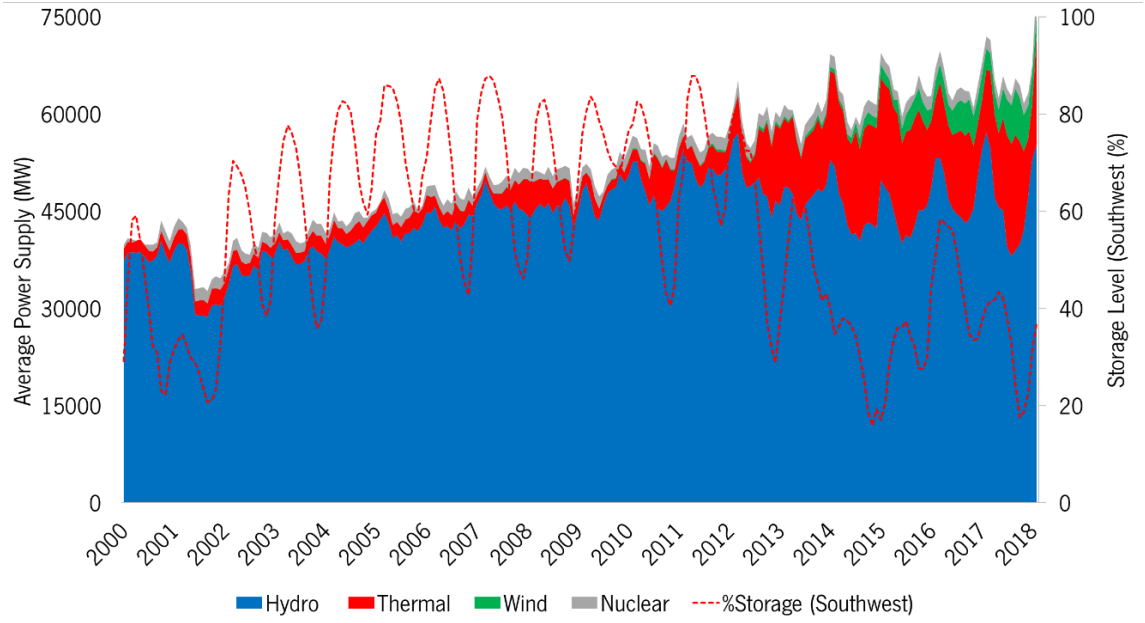


Figure 3.2: Brazilian power output between 2000 and 2018 (February) (left axis) and water storage level in SE (right axis).

[50] Technically, the Southwest hydropower system comprises both Southwest and Midwest Brazilian regions. The Southwest region represents 40% of the total hydropower capacity in the country.

The renewable share in electricity generation reached near 83% in 2018 [297]. Electricity generation from RES was composed of 66 % from hydropower; 8.5% biomass; 7.6% wind and 0.5% from solar power in 2018 [297]. Currently (Month/2020), the hydropower capacity accounts for near 62.5% of the total installed capacity [66,298]. Renewable energy in the country now accounts for over 82% of the overall installed capacity. Fossil fuel power sources also develop a key role in the country, accounting for near 29.3 GW (16.80%) in 2020. Wind power reached 15.9 GW of installed capacity (9.1%). The current overall installed capacity of biomass for electricity generation represents near 15.2 GW (8.75%), and the remaining installed capacity comes from solar power (2.9 GW – 1.68%) and nuclear power plants (1.99 GW – 1.14%). However, Brazil cannot be considered a self-sufficient country concerning electricity generation due to its continental dimensions and climate conditions, which resulted in energy importations representing about 6% of the total energy consumption in 2017, for example [296].

Therefore, because of its large-scale hydropower system, Brazil has been seen as one of the leading countries in renewable installed capacity worldwide and accounts for the largest renewable electricity market in Latin America. The estimated country's overall hydropower potential accounts for near 260 GW [299]. Until 2020 the exploited hydropower potential slightly exceeded 109 GW, meaning that more than half of its overall potential remains unexploited. Hydroelectricity presents many advantages over other power sources, including high efficiency, large storage capacity, low operating and maintenance costs, and a high level of reliability and proven technology. Hydropower is also considered the least-cost renewable electricity technology even though it usually requires substantial investments [300]. For the national grid operator, hydroelectricity is a valuable power source especially given the rapid growth of variable and intermittent generation from other RES, namely wind and solar power technologies. The hydropower source should offer sufficient dispatchable power capacity to compensate fluctuations mainly from wind and solar power without the need for additional storage, as simulated and supported by Ref. [98]. Traditionally, load modulation has been performed by hydropower resources in the country. The thermal power plants have been employed traditionally as baseload power plants, but these power sources might also provide load modulation during times of water scarcity. The hydropower generation system in Brazil comprises large reservoirs capable of multi-month regulation, arranged in complex cascades and distributed in several river basins [300]. In the future, the increasing share of several complementary non-hydro RES is expected to diminish the dependency on hydropower and drive to possible least-cost solutions [97].

Regardless of the remaining unexploited hydropower potential in Brazil, the future hydro projects are expected to be dominated by run-of-river hydropower with limited reservoir capacity. Therefore, water

resource availability due to climate change is assuming a vital role in the country [97,301]. Climate-driven changes may affect the future hydropower generation in the Brazilian power sector, such as better discussed in Ref. [301], which assessed Brazil's vulnerability to climate change in the coming years. The role of renewable energy in reaching the Paris agreement's goals has been recently highlighted in Ref. [302], which pointed out the Brazilian vulnerability to climate change mainly due to its high dependence on hydropower. The authors recommended the diversification of the country's electricity supply mix to meet the Paris agreement targets [302]. The challenge of climate mitigation for Brazil's specific case is studied in Ref. [303], pointing out that recent environmental licensing requirements were softened compared to previous legislation. This issue and the abandonment of deforestation control policies would put into question Brazil's capability to meet the Paris agreement targets [303]. However, it is essential to highlight that the Brazilian government set its first regulation (n° 419/2019) to establish its carbon credit system. This regulation may foster the country's energy transition by also helping to meet the Paris agreement targets.

Therefore, although hydropower is forecasted to remain the primary power source in the future, the overall hydropower capacity (in terms of percentage) is projected to be lower for 2026, 2040, and 2050 compared to the current installed capacity (see Figure 3.3). Figure 3.3 presents the overall Brazilian installed power capacity in 2017 [304] and the predictions for 2026 [58], 2040 [305], and 2050 [2] according to studies of different energy research institutions. According to [90], the Brazilian electricity consumption in 2050 is expected to increase by approximately 300% compared to 2013, which justifies the growing trend of the sector.

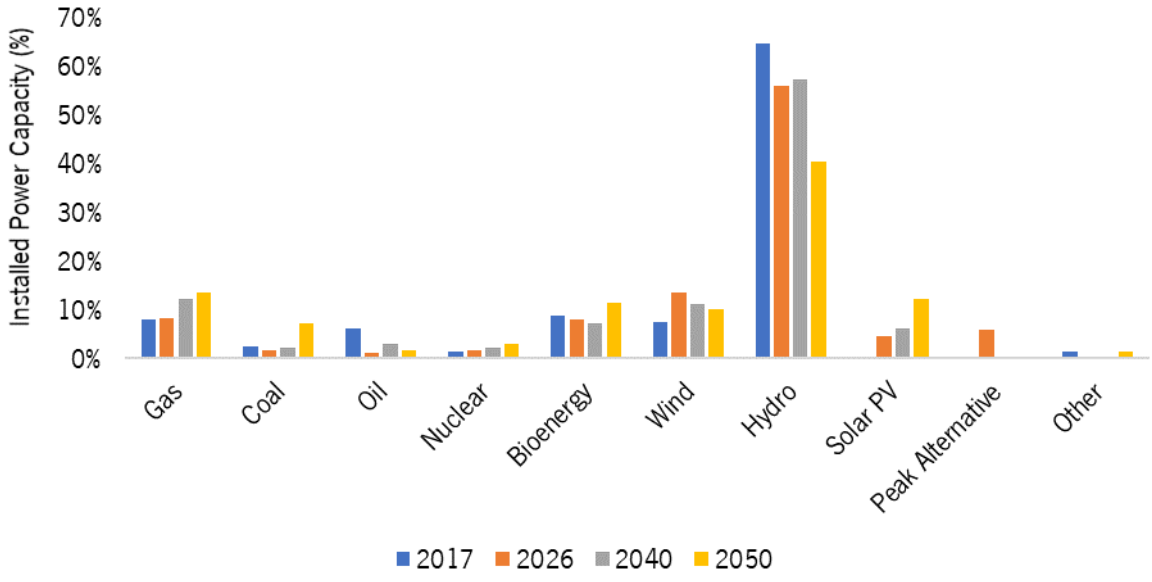


Figure 3.3: Brazilian installed power capacity (%)for 2017 and projections for 2026, 2040, and 2050 [2,58,304,305].

As previously mentioned, the hydropower share decrease is primarily due to environmental restrictions for constructing new hydropower plants with large reservoirs. The high dependence on rainfall and climate conditions can also severely affect future hydropower expansion and its role in electricity production [3]. The high hydropower regularization capacity in Brazil might also provide balancing services to allow higher shares of RES from wind and solar power systems, for instance. Figure 3.4 illustrates the historical values for the Brazilian maximum storage capacity (left axis - in GW) and the regularization capacity (right axis - in months) between 2001 and 2017. Although the Maximum Hydropower Storage Capacity (in Portuguese, EAR) increased (in absolute terms) along with the last years, the Brazilian hydropower regularization capacity has been decreasing considerably over the previous decade, as illustrated in Figure 3.4 [54].

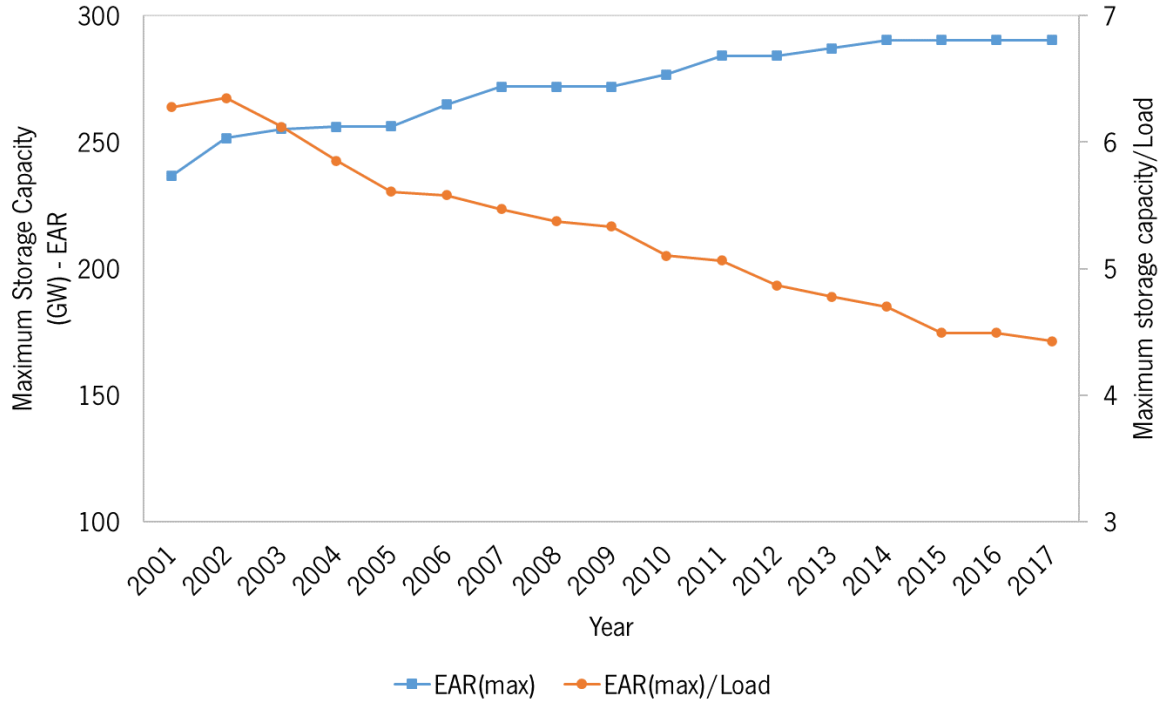


Figure 3.4: Brazilian maximum storage capacity in GW (left axis) and the regularization capacity in months (right axis) between 2001 and 2017 ([54]).

The regularization capacity in 2001 was slightly higher than 6.2 months. This means that considering the reservoirs' full availability, the stored capacity would supply the load for this period (6.2 months) without the need for other power sources. The regularization capacity decreased by 30% between 2001 and 2017 (from 6.2 months in 2001 to 4.4 months in 2017) [54], which can be mainly explained by the growth in the overall installed capacity of run-of-river power plants but also because of the demand increase in the country. This trend is set to continue since run-of-river hydropower plants with limited reservoir capacity are expected to dominate future hydro projects [306,307]. Thus, the future challenge is to provide a high

level of flexibility from other power sources and energy storage technologies that might be capable of linking geographic and temporal (daily, weekly and seasonal basis) gaps between energy supply and demand [308].

Additionally, since 2012, Brazil has been undergoing severe droughts (mainly in the Southeast, Midwest, and Northeast), leading to an increase of generation from thermal power (see Figure 3.2) [5,6]. This thermal power trend remained for the latter years (2013 to 2018). Notably, the amount of natural gas imported has significantly increased in these years to supply thermal generation [58]. Therefore, the marginal cost of electricity production enhanced substantially in the past few years [309]. Between 1999 and 2011, the average power output produced from thermal power plants was about 2425 MW, whereas between 2012 and 2016, this value increased significantly to 10947 MW [310]. This thermal generation increase comes primarily from the reduction in the maximum energy storage capacity of hydropower, mainly for Southeast (SE), Midwest (CO), and Northeast (NE) Brazilian subsystems over the period. The SE and CO regions represent approximately 70% of Brazil's total water storage capacity, and the maximum water storage level has been verified historically between March and April, whereas the minimum storage usually occurs between October and November [309]. Table 3.1 presents the overall installed power capacity and the corresponding hydro and thermal power share in Brazil from 2006 to 2018 [311]. The overall installed capacity increased by 74.7% in the last 12 years. Hydropower and thermal power increased respectively by 39.4% and 204.9% in the same period (2006 - 2018). However, the hydropower share decreased from 85% in 2006 to 68% in 2018, whereas the contribution of thermal power in the overall installed capacity increased from 13% (2006) to 22% (2018).

Table 3.1: Brazilian hydro and thermal power installed capacity from 2006 to 2018 [258].

Year	Overall Installed Capacity (GW)	Hydropower		Thermal	
		Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)
2006	88.99	75.57	85%	11.41	13%
2007	93.76	78.89	84%	12.65	13%
2008	98.25	82.05	84%	13.98	14%
2009	101.2	83.05	82%	15.82	16%
2010	105.42	84.32	80%	18.46	18%
2011	111.75	86.19	77%	22.63	20%
2012	114.79	87.68	76%	23.64	21%
2013	119.32	89.6	75%	25.85	22%
2014	125.20	91.12	73%	29.89	24%
2015	132.71	94.33	71%	31.47	24%
2016	138.96	97.15	70%	32.21	23%
2017	148.59	102.39	69%	33.99	23%
2018	155.49	105.37	68%	34.80	22%

After the severe drought in 2001, the Brazilian government decided to support the development of non-hydro RES as an alternative to the historical dependence on hydropower. Since 2009, auctions have been made exclusively for wind and solar PV systems, which increased the share of non-hydro RES in the country's energy mix [97]. The share of several complementary non-hydro RES is also expected to diminish hydropower dependency and lead to a least-cost solution [97]. Since hydropower is considered a well dispatchable power source, the Brazilian power system is not yet experiencing large frequency problems. However, as the wind and solar generation technologies grow up together with the decreasing storage capacity (see Figure 3.2), there would be some significant problems related to the system frequency regulation.

Therefore, wind and solar energy systems have been increasing rapidly over the last few years, and these sources are expected to lead the way towards a sustainable future [9,25,312] not only worldwide but also for developing countries, such as the case of Brazil [54,296,313]. Brazil has a high potential for generating solar energy with one of the highest insolation rates worldwide; however, this potential has been underused. Ref. [98] highlighted that wind and solar power expansion might be more cost-efficient than new hydropower plants in Brazil. This is mostly explained because the existing hydropower plants might provide sufficient storage capacity for renewable integration, even considering that only run-of-river power plants are being projected for the future. According to the 'Decennial Energy Plan 2026' [58] (in Portuguese, PDE), the wind power capacity is projected to increase from 7.3% (2017) to 13.40% (2026), and solar PV is forecasted to have a significant increase from 236.2 MW (2017) to 9660 MW (2026). The contribution of '*peak alternative'* sources (5,74%) - composed mainly of open-cycle thermal power plants, pumped hydroelectric, battery storage systems, and the contribution of DSM measures – is also highlighted by the PDE 2026 [58]. To meet the load during peak usage hours, the expansion proposed by the PDE 2026 is primarily in the Southwest region and on a small scale in the country's South region.

3.3 Characterization, policy and regulatory framework

Since the creation of the Energy Research Office (in Portuguese, EPE) in 2004, the Brazilian power sector has faced a new phase. The coexistence between state-controlled and private companies and competition in generation and commercialization sectors can be considered the main characteristics of this new model structure for the power sector. EPE is responsible for the development of the National Energy Plan (in Portuguese, PNE) with a long-term horizon (30-year horizon) and the decennial plan (in Portuguese, PDE), published annually with a 10-year horizon. Both energy plans form the basis of energy planning in Brazil, whose main aim is to construct and analyze medium and long-term expansion planning scenarios.

Notwithstanding, experts in the electricity sector have widely criticized both plans. Experts point out that the decennial plan should be changed into a steering and strategic energy plan. The Brazilian energy policy definition might be defined based on micro and macroeconomic factors, technological prospects, regional and international scenarios, and environmental impacts produced by power generation sources. In line with this, Tasso Azevedo, consultant and social entrepreneur in sustainability, highlighted that:

> *[Translated] There are many predictions and little planning strategies, i.e., the plans describe what should happen according to different choices rather than pointing out a clear objective of the energy matrix and the plan to achieve it. The plans are composed of plenty of "prospects", "expectations", "predictions", "projections," and "indicatives", but there are almost no goals, targets and progress indicators. In the absence of objectives and goals, the only reference to the desired direction is summarized in the so-called fundamentals of the institutional arrangement implemented in 2004 and expressed in the PNE: the security of electricity supply to support the country's development; fair electricity prices to support the competitiveness of the economy; the social insertion of the entire population in this public service; and the stability of the regulatory framework to attract investments for the expansion of the sector. This current approach also distances our energy matrix from a sustainable model, especially regarding socio-environmental aspects. Furthermore, the emergence of a new technology expected to provide benefits in the future but with high costs compared to other power options (e.g., the solar power technology) has been abandoned or treated as marginal instead of identifying the barriers to its development and the measures needed to boost it (Plataforma Cenário Energético, 2015, p. 70-73).*

Based on our literature review, Figure 3.5 illustrates the chronological flowchart of the prospective evolution of the leading Brazilian technologies and regulations towards smarter grids.

The Geographic Information System (GIS) was proposed in 2008 to store and manage electrical, topology, and utilities' structural parameters. In addition to managing outages and improving consumer satisfaction, this system also reduced information asymmetry. Later, in 2009, Power Line Communication (PLC) technology was implemented to support the smart grids' future deployment in Brazil. According to [314], "*Power Line Communication (PLC) is a communication technology in which bi-directional communication can be done using existing power lines*."

The consumer has also been targeted within this power system evolution. The small-scale DG was first introduced into the Brazilian power system through the RN n° 482/2012 [284]. Brazil's new smart metering regulation was set out in 2012 by the RN n° 502/2012 aiming to support the deployment of smart grids. To foster the potential of DR and minimize the differences between costs and revenues of

the utilities [315], the Tariff Flag System (TFS) was implemented through RN n° 547 in 2013 [316]. Driven by the possibility of reducing electricity distribution losses and operational costs, improving utilities collecting revenues, and reducing fraud, ANEEL approved the RN n° 610 in 2014 [286], regulating the electricity prepayment focused on a specific group of consumers. In 2015, ANEEL approved RN n° 687 [283], an improved version of the RN n° 482/2012, reducing some barriers to the DG development in the country. The White Hourly Tariff (WHT) was further proposed by the RN n° 733/2016 [287], and it is currently being implemented in the Brazilian electricity sector for household electricity consumers.

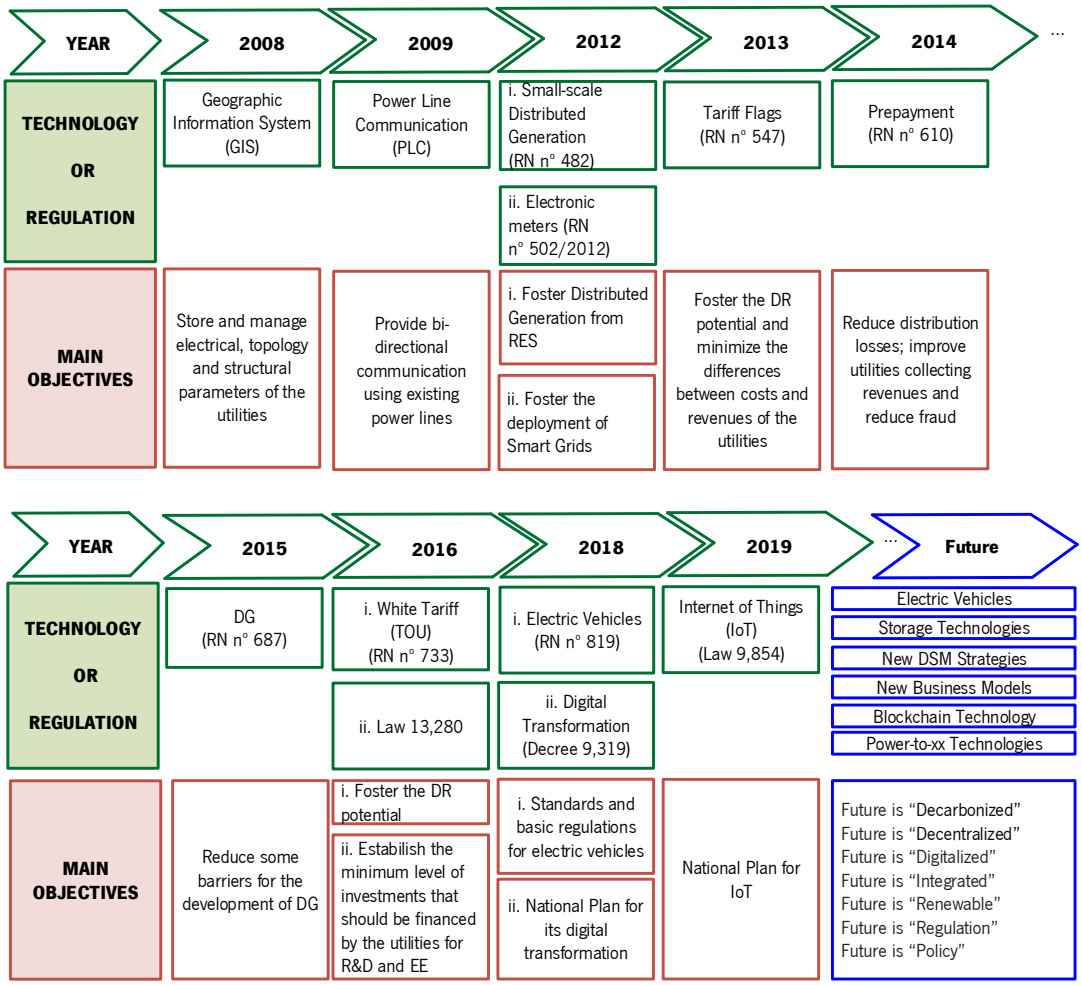


Figure 3.5: Chronological flowchart of the prospective evolution of the leading Brazilian regulations towards a smart grid power system.

By 2000, to support both Research and Development (R&D) and Energy Efficiency (EE) programs, Law 9,991/2000 [317] regulated the minimum level of investments to be financed by the utilities for R&D and EE. The EE Law was first proposed in 2001 through Law 10,295/2001 [318], which established the minimum energy efficiency levels for appliances and machines [319]. Later, in 2016, Law 9,991/2000

was amended by Law 13,280/2016 [320], which established that 20% of the fund for energy efficiency must be designated to PROCEL.

ANEEL approved the legal requirements (RN n° 819/2018 [321]) for charging electric vehicles in the Brazilian power sector in 2018, which is considered the first published normative resolution about EVs in the country. The Brazilian National Plan for Digital Transformation was launched through Decree 9,319/2018. The growth in influence of the IoT (Internet of Things) technology worldwide stimulated the Brazilian government to launch its first regulation on this crucial topic through Law 9,854/2019 [322], which set the national plan for IoT in the country. This regulation is focused firstly on the industry, city, health and rural sectors. It is essential to underline that these IoT actions should be developed in agreement with the guidelines presented by Decree 9,319/2018 [323], which shows the Brazilian strategies for its digital transformation and highlights the energy sector as one of the critical pillars of the IoT regulation [73]. Further information about the national plan for IoT can be found in Ref. [73].

We have developed a comprehensive concept map (Figure 3.6), addressing the aforementioned new technologies and their associated regulations for the Brazilian electricity sector. The concept map briefly describes how these new technologies are connected with the new regulations/laws, allowing us to obtain tangible policy implications for the country. To give a well-known example for the sake of clarity, DG is regulated by RN n° 687/2015, an improved version of RN n° 482/2012. New tariff schemes are particularly illustrated using a different color that can be broadly split into the TFS, WHT and electricity pre-payment, regulated by the RN n° 547/2013, RN n° 733/2016, and RN n° 610/2014, respectively.

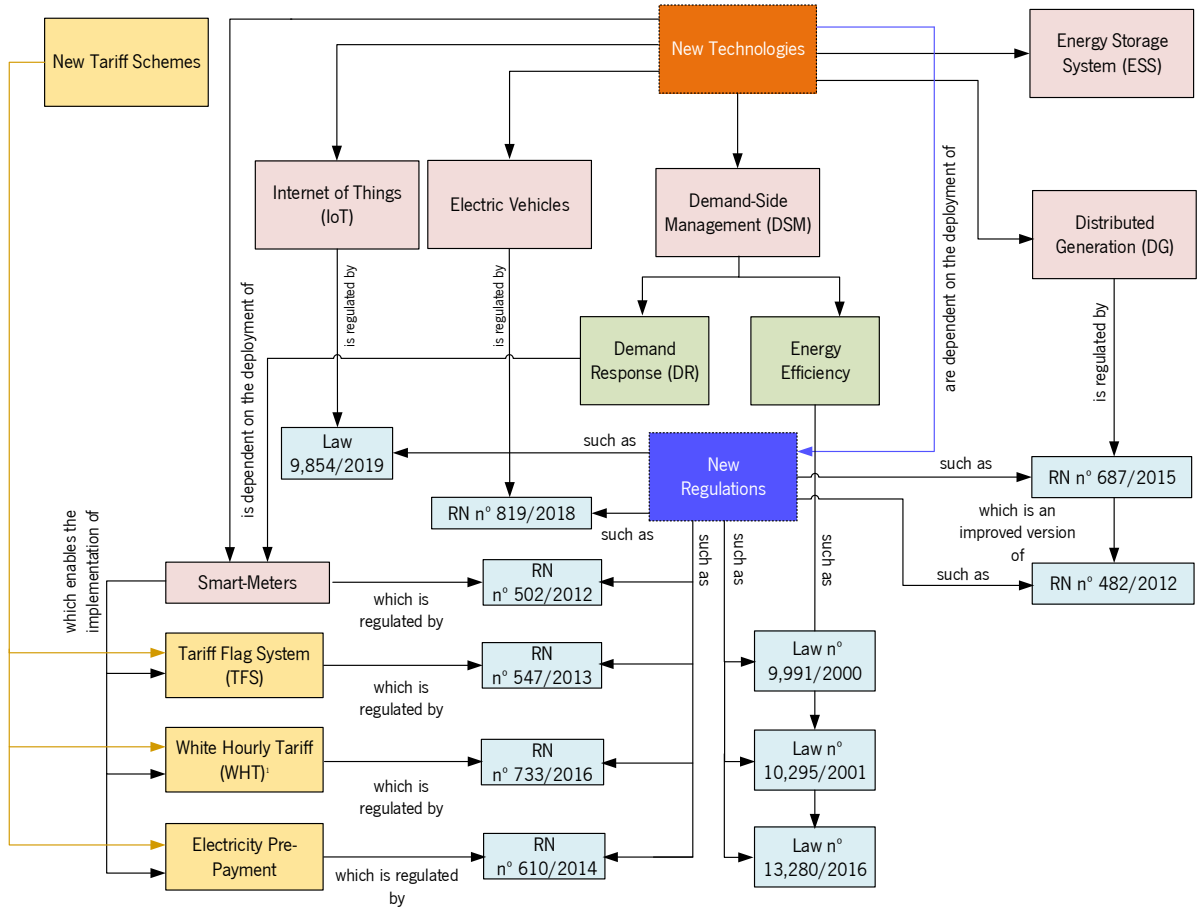


Figure 3.6: Concept map of the leading Brazilian regulations toward smarter grids.

The next subsections will describe with details the latest developments and new trends for the Brazilian power sector.

3.3.1 Tariff Flag System (TFS)

The Tariff Flag System (TFS) is regulated by the RN n° 547 [316], and it was firstly proposed by the ANEEL in 2013, although the starting point of its implementation is dated to 2015. The main objective of the TFS is to reflect monthly the real cost of electricity to promote consumer awareness [294,324]. It also attempts to foster the potential of DR by increasing the electricity tariff [315]. The TFS would also minimize the differences between costs and revenues of the utilities [315] and optimize the electricity system and energy resources usage [325].

The TFS might be considered a short-term warning signal to consumers [326], reflecting the current power generation costs, which is strongly associated with the thermal power plant dispatch [315,327]. Before the TFS's launching, the cost of electricity purchased by the utilities was computed annually, and consequently, the tariff adjustment took effect once a year. For the TFS scheme, the generation costs of electricity are monthly flagged to consumers, allowing them to adapt their electricity consumption. The

monthly flag is defined considering the overall required thermal power dispatch, according to the hydropower storage availability [328]. The monthly signals are triggered based on the Difference Settlement Price (in Portuguese, PLD), which corresponds to the spot price in the Brazilian electricity market [315].

The flags are divided into green, yellow, and red types. Since its implementation in 2015, the yellow and red flags' costs have changed over the years. Recently (May/2019), ANEEL improved the monthly flags calculation methodology by including the Generation Scaling Factor (GSF[51]). The green flag currently represents no additional costs in the final electricity tariff, whereas the yellow flag represents an increase of 0.015 R$/kWh. The red flag is divided into two baselines, representing an increase of 0.040 R$/kWh (baseline 1) and 0.060 R$/kWh (baseline 2) as summarized in Figure 3.7 (values established for 2019) [316,329].

The authors of [330] evaluated the economic impact of the TFS for both the Brazilian utilities and the consumers. A comprehensive analytical review of the TFS program is performed in [315]. The authors analyzed qualitative and quantitatively the expected results of this new tariff mechanism for both utility companies and consumers from different perspectives. The new risk-averse methodology was employed by the authors using real information on the Brazilian electricity system. The simulation results allowed us to conclude that the TFS would promote a reduction of thermal dispatch, an increase in the overall storage level, and a decrease in the overall operating system cost [315]. For utilities, a loss of revenue is expected due to the reduction in the overall electricity consumption.

TARIFF FLAG	CONDITIONS	INCREASE IN THE TARIFF
GREEN	"LOW COST" TO PRODUCE ELECTRICITY	NO INCREASE
YELLOW	"MEDIUM COST" TO PRODUCE ELECTRICITY	INCREASE OF R$ 1.50 FOR EACH 100 kWh CONSUMED
RED BASELINE 1	"HIGH COST" TO PRODUCE ELECTRICITY	INCREASE OF R$ 4.00 FOR EACH kWh CONSUMED
RED BASELINE 2	"HIGH COST" TO PRODUCE ELECTRICITY	INCREASE OF R$ 6.00 FOR EACH 100 kWh CONSUMED

Figure 3.7: Key features of the Brazilian TFS.

[51] GSF can be estimated as the ratio between the overall electricity produced by the power plants which integrate the Energy Relocation Mechanism (in Portuguese, MRE) and the total physical guarantee (in Portuguese, GF) of the plants.

3.3.2 White Hourly Tariff (WHT)

Some pricing mechanisms have been recently launched by ANEEL, expecting that different rates at different times can effectively drive desired end-user consumption behavior [331]. For open-loop price-based control strategies, higher electricity prices likely lead to lower consumption at peak demand times. For large consumers (supply voltage equal to or greater than 2.3 kV in Brazil), TOU rates have already been implemented (called blue and green tariffs), promoting a positive impact on peak load shifting. Critical Peak Pricing (CPP) and Real-Time Pricing (RTP) has not yet been implemented in the Brazilian electricity market.

ANEEL created the White Hourly Tariff (WHT) through RN n° 733/2016 [287], which is currently under implementation in the Brazilian electricity sector for household electricity consumers based on the calendar defined in [332]. The main reason for implementing this new rate regime is to encourage household electricity consumers to reduce their consumption, especially during peak demand periods (between 06 p.m. and 10 p.m.), thus optimizing the generation and transmission investment decision-making process [287,294,328]. This new tariff scheme might be considered the first hourly tariff ever implemented for residential consumers in the country [287]. The new WHT is optional for household electricity consumers and results in different electricity prices throughout the day, as illustrated in Figure 3.8, which compares the WHT with the conventional tariff [294,332]. The WHT is divided into on-peak (three hours per day on weekdays), intermediate (one hour before and after the one-peak period), and off-peak (composed of the remaining hours of the day plus the weekdays and holidays) periods. Therefore, the WHT results on three price levels, as shown in Figure 3.8 [287,294,332].

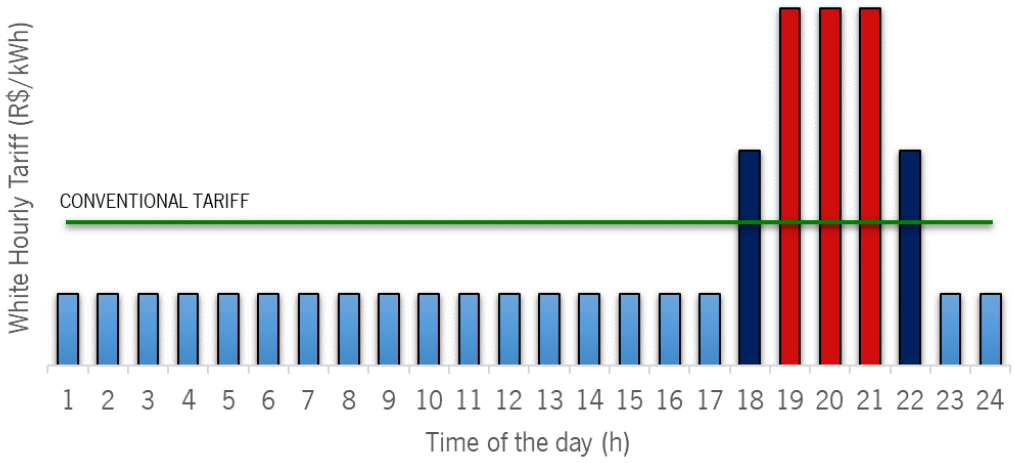


Figure 3.8: White Hourly Tariff versus conventional tariff ([332]).

3.3.3 Electricity prepayment and smart metering

The electricity prepayment system has been implemented in develop and developing countries motivated by the possibility of reducing electricity distribution losses and operational costs, improving companies collecting revenues and reducing fraud [333]. From the consumers' perspective, experiences show that they feel empowered to manage and control billing costs and consumption using the electricity prepayment system.

For the specific case of Brazil, in addition to the TFS and the WHT schemes, the ANEEL approved the RN n° 610/2014 [286], regulating the possibility of electricity prepayment for a specific group of consumers (mostly focused on household electricity consumers) [286,334]. The electricity prepayment system is supposed to offer advantages for both consumers and distribution companies. From the consumers' point of view, the electricity prepayment allows them to better control their budget, promote a better quality of life and social inclusion and reduce the risk of disconnection. The avoidance of debts and fees is considered an additional benefit for consumers. Higher consumer satisfaction, reduction of operational costs and billing reclaims, the anticipation of revenues and decrease of non-technical losses are considered the main advantages of the electricity prepayment system from the utilities' point of view.

In Brazil, the utilities are presumed to provide all the prepayment meter acquisition costs [286]. The shift from the post-payment to the prepayment system is voluntary and free of charge for consumers [334]. Additionally, consumers can freely migrate between systems, i.e., prepayment and post-payment systems [286]. Ref. [333] underline the importance of defining the group of consumers that can adopt the prepayment system, primarily due to the high level of investment costs. In this sense, some consumers are not allowed to adopt the prepayment system, e.g., consumers who selected the WHT or those with a micro or mini DG system connected to the grid [286].

The electricity prepayment and the WHT are dependent on the deployment and availability of smart meters. Therefore, this section proceeds by presenting a brief review addressing the current state of smart grids (with a particular focus on smart metering deployment) in the Brazilian electricity sector.

The smart grid deployment will have a crucial role [9,33] in the integration of Variable Renewable Energy (VRE) resources, Demand-Side Management (DSM) strategies [335,336], storage systems, and smart technologies[52] and this would represent a breakthrough in future electricity management [337]. A smart grid includes a variety of new technologies such as smart meters, storage systems and devices for small-scale renewable energy generation. The concept of a smart power system is intrinsically related to

[52] Such as the use of smart charging for electric vehicles, big data, blockchain and machine learning [68].

decarbonization, digitalization, and decentralization, which are considered the main drivers of the future electricity grid and would strongly impact the development of demand and supply of electricity at a remarkable and unprecedented pace [68,71,72].

Although there have been some advances in the Brazilian regulatory structure, many gaps still stand as barriers to developing smart grids in the country. According to [291], smart grids will be at an intermediate level of development in Brazil by 2030. A state-controlled electricity company (in Portuguese, Companhia Paranaense de Energia – COPEL) has recently proposed a disruptive project towards a smart grid power system. This project is based on the implementation of an Advanced Distribution Management System (ADMS[53]), which will support the optimization of the distribution grids of the Paraná state by also enabling the self-healing process. The implementation of this project was projected to start in 2019 and it has been designed to last about three years [338].

A set of other pilot programs regarding the implementation of smart grids in Brazil is better described in Ref. [339]. Ref. [339] reviewed developing countries' experiences towards a smart grid power system, including Brazil and India cases, in particular. Concerning the case of Brazil, Ref. [339] underlined the efforts of the government to enable the deployment of smart grids since 2008. The authors also pointed out the leading country's challenges reinforced by its continental dimensions, which are considered a barrier to the smart grid deployment in remote regions such as in the Amazon and rural areas. The problem of illegal connections and the lack of regulation in the sector are also considered additional barriers to the country's smart grid deployment.

The deployment of smart meters is a fundamental step for the deployment of smart grids. Smart metering is considered an emerging and current development technological system in Brazil and the main challenges related to its implementation rely on technical and regulatory aspects [291]. ANEEL edited the RN n° 502/2012 [340], which regulates the energy metering systems for group B consumers (e.g., household electricity consumers). ANEEL proposed two types of smart meters. The first one is targeted at those consumers who chose the WHT scheme. In this case, the smart meter should be installed at no initial costs to consumers. The other type of smart meter presents additional functionalities and provides access to specific information to consumers. Consumers that chose this latter smart meter have to pay a price difference between this one and the former [340]. Smart meter deployment is considered an essential enabler to the adoption of new tariffs, e.g., Time-Of-Use (TOU), Critical Peak Pricing (CPP), and

[53] ADMS is composed by a set of subsystems namely, Energy Management System (EMS), Supervisory Control And Data Acquisition (SCADA), Distribution Management System (DMS) and the Outage Management System (OMS) [338].

Real-Time Pricing (RTP). TOU rates have already been implemented in the Brazilian electricity market (e.g., WHT), while CPP and RTP have not yet been implemented in the country.

A comparative analysis regarding the smart meter policies in Europe and Brazil was addressed in [291]. The authors suggest that European policies consider the multiplicity of stakeholders involved in the technology, creating better conditions for investments and consumer engagement, differently from Brazil, in which only the electricity regulator takes the decisions by itself. This study suggests that Brazil's government might present an economic assessment to guide smart meters' technology deployment and then provide the consumer's engagement. Therefore, smart meter adoption for household electricity consumers in Brazil is difficult to predict due to limited consumer knowledge and awareness. Regardless of all the benefits of smart meters' development, the lack of support, incentives, and proper information dissemination about the possible benefits of the smart meter technology might not result in the expected benefit for both consumers and utilities [291]. Literature also supports the need for a general assessment framework to evaluate the economic benefits brought about by the use of smart meters [291,293]. These uncertainties also cause difficulties for distribution utilities, mainly because they need to make the smart meters' initial investments [291]. Ref. [341] studied the smart meter adoption in Indonesia and concluded that the critical determinants of consumer acceptance of smart meters were mostly related to their usefulness and ease of use.

Therefore, smart metering in Brazil is currently restricted to pilot smart grid projects of specific distribution utilities. The Brazilian utility companies might develop policies and strategies for the dissemination of the smart meter technology. Future studies should focus on measuring consumer propensity to adopt smart meters in residential buildings and investigate electricity consumers' perceptions and behaviors concerning the country's potential deployment.

3.3.4 Distributed Generation (DG)

Although the current insertion of DG is still relatively small in Brazil, new Brazilian government policies have been stimulating the DG from RES. RN n° 482/2012 is considered the first regulation for grid connection of DG in the country under a net metering system approach [284]. Several factors have been contributing to the DG evolution in the Brazilian electricity sector, e.g., the increasing electricity demand, restrictions for constructing new hydropower plants with large reservoirs, concerns about climate changes and resource depletion, regulatory incentives (e.g., RN n° 482/2012 [284] and RN n° 687/2015 [283]), cost reduction in solar PV and wind systems in addition to the increase in electricity tariffs over the past few years in the country.

ANEEL approved RN n° 687/2015, an improved version of RN n° 482/2012, reducing some barriers to DG development in the country. These changes include a higher range over the installed capacity (i.e., between 75 kW and 5 MW); increased validity of credits from 36 to 60 months. Two new business models have also launched, namely the possibility of shared generation between consumers and the opportunity for installing DG in apartment complexes. RN n° 687/2015 also made adjustments in utilities' procedures for connecting the DG to the grid, making the process faster and simpler for consumers. Regarding the future projections for micro DG, Ref. [288] outlines a significant increase in the number of new consumers that will adopt micro DG in residential and commercial sectors, reaching up to 886,700 new consumers and a total installed capacity of 3.2 GW in 2024 as illustrated in Figure 3.9 [288].

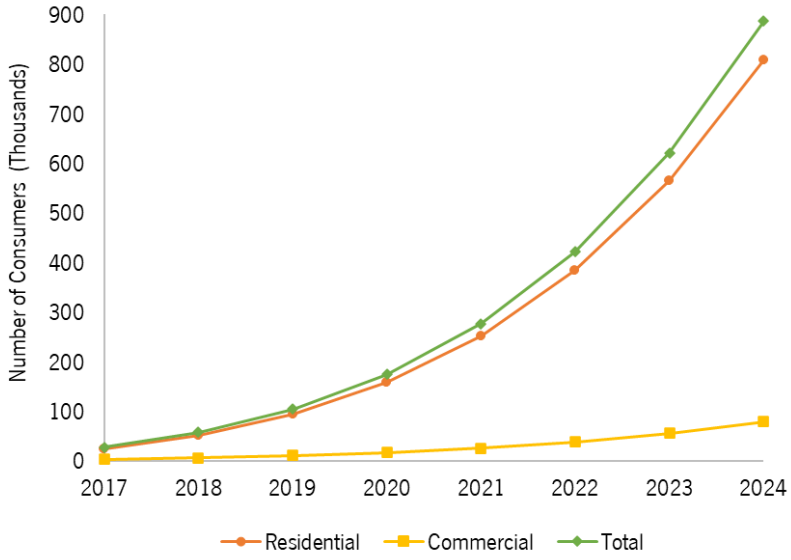


Figure 3.9: Distributed Generation (DG) projection for the period 2017 - 2024 [288].

Distributed generation has been implemented in the Brazilian electricity sector using the net-metering system in which the electricity injected into the grid is valued the same as the electricity consumed from the grid [284]. The net-metering system, together with the monomial tariff, might bring a problem for the balance of electricity tariffs for utility companies [58]. By 2024, due to the DG insertion, EPE projected a decrease in revenues for distribution utilities of approximately 1.1% compared to 2016. Brazilian utilities argue that the current sector regulation does not offer adequate incentive to modernize distribution networks or even investing in new technologies [342]. In this sense, structural changes in the distribution sector are projected for the near future to minimize the economic problems brought about by the DG insertion. The growth of DG in the Brazilian electricity sector is also expected to affect the electricity supply quality and operational costs of distribution utilities. It is worth mentioning that the grid supply quality can be severely affected by voltage and frequency fluctuations produced in power systems with high levels of RES penetration [343].

3.3.5 Storage technologies

The future deployment of RES-based systems is strongly linked to energy storage options and, consequently, to decentralization and decarbonization policies [71]. The need for grid storage is also a prospect to the Brazilian power system, providing more flexibility, resiliency and reliability for the power system. Much of the attention in previous research has been to consider different methodologies for coupling RES and storage systems, such as in [344] and [345]. Some of the problems brought about by the increasing RES-based systems with great unpredictability and variability (e.g., frequency regulation) can be smoothed by supporting fast-responding storage technologies (e.g., hydro-pumping power plants, which are considered the most common storage technology across the world). On the other hand, hydro-pumping might not be considered well suited to the DG model since it cannot be deployed in urbanized areas [71].

Currently, Brazil has one of the highest capacity ratios for Hydropower/Renewable and Renewable/Electricity generation in the world. Therefore, Brazil reached a high-RES share (mostly based on hydropower) without significant problems for the power system's operation. This fact can also be explained by the high degree of flexibility offered by natural gas power plants. There are currently quite a few operational storage projects in the Brazilian power system [346] and few studies that address this issue. The deployment of storage technologies is at a slow pace of growth in the country. However, the significant changes expected for the near future, such as the new market structure and the decreasing of the hydro storage capacity, would require new frameworks to support the increasing share of renewables, e.g., the deployment of fast energy storage resources such as batteries and flywheels. Ref. [346] addressed the role of storage technologies for the Brazilian power system and concluded that the most promising technologies are batteries, pumped hydro storage, flywheel and compressed air energy storage.

There is also a historical lack of funding in storage technologies research in Brazil, mostly because of its high hydropower system. However, to foster investments in storage technologies, ANEEL proposed an R&D program in 2016. This R&D program focuses on Battery Storage Energy Systems (BESS) technologies, and 23 proposals were approved from different country distribution companies [347].

3.3.6 Electric Vehicles (EVs)

Several challenges for the energy and transportation sectors are arising from the wide range of alternative developments worldwide. The current light vehicles fleet in Brazil is composed primarily of flex fuels and gasoline vehicles. However, a steady increase for both hybrid and EVs is projected for the future, as

illustrated in Figure 3.10 - which describes the projected light vehicles fleet profile by fuel in the country between 2014 and 2050 [90].

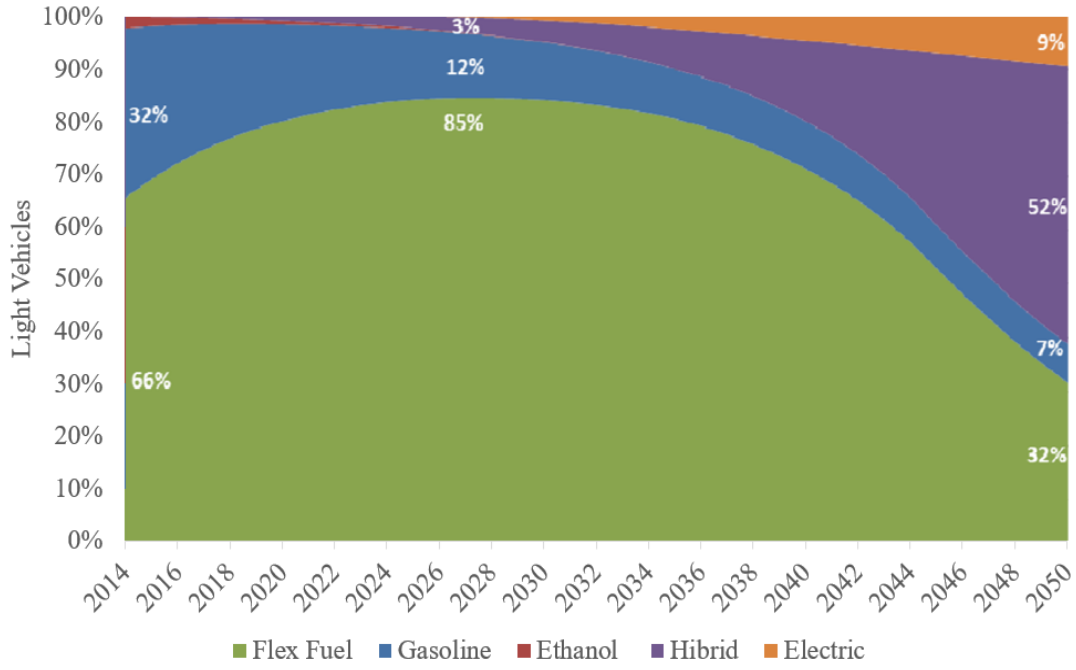


Figure 3.10: Projected light vehicles fleet profile by fuel in Brazil between 2014 and 2050.

Electric vehicles would represent a disruptive model and have emerged as a valuable resource for the transportation sector and a potential source of flexibility to power systems. According to the Bloomberg New Energy Finance, EVs are expected to be cheaper than internal combustion engines by 2025. The markets of EVs are still in the early stages of development, and there is a long way before EVs may become dominant [348] not only in the global market but also for developing countries such as Brazil. EVs' deployment may also represent a great opportunity for the power sector since it would offer a significant level of flexibility through its vast storage capacity [349].

The benefits brought about by the use of EVs cover a broader scope. It is now generally accepted that the introduction of EVs might contribute to reducing GHG emissions. Ref. [349] emphasizes the lower level of GHG emissions for EVs compared to Internal Combustion Engines (ICE) vehicles, even in the case of charging the EVs with electricity from fossil fuels. However, the overall CO_2 emissions from EVs depend on the electricity supply mix of each power system. Ref. [350] underline that although it is a consensus that EVs can reduce carbon emissions, their real effectiveness depends mostly on the electricity mix of each country. Therefore, the extent to which it can support the carbon dioxide reduction would enormously vary among countries depending primarily on the share of renewables in each power system. However, it may also differ depending on the set of categories included in the CO_2 evaluation. The authors of Ref. [350], for instance, evaluated the electric cars' emissions for twenty countries based on their current

electricity mix and concluded that even for some coal-dominated power generating systems such as China, the EV's emissions could be compared to average petrol vehicle levels. However, for low carbon systems such as Paraguay and Sweden, the emissions can be less than half the best petrol hybrids.

In addition to the possibility of decarbonizing the electricity system, EVs will provide valuable flexibility requirements for the power system, which includes (i) optimizing the renewable resources usage, (ii) reducing the reliance on imported oil [350], (iii) lowering the transmission system utilization and (iv) reducing local air pollution and carbon emissions [350], just to name a few. Literature reveals that cars are idle in parking between 90% and 95% of their lifetime [349] and combined with its storage capacity, EVs fleet can provide a high level of flexibility to support power system operations. The insertion of flexible loads in power systems may also offer reduced costs for larger integration of renewables. However, new market rules would be required to achieve lower-cost solutions. However, the transition towards a smart power system configuration requires an integrated energy planning approach that should also take into account the synergies between electricity and transportation sectors. Notwithstanding, there is a relatively small body of literature that is concerned with the impact analysis of EVs penetration in the future power generation mix of renewable-based electricity systems.

A previously published paper[54] with a particular focus on the Brazilian sector revealed a clear positive effect of increasing the share of EVs on reducing the overall level of CO_2 emissions in the country. However, this is highly dependent on the share of RES in the power system, the use of biofuels in the transport sector and the credits resulting from the battery recycling materials credit and battery reuse credit. Strong evidence of reducing the overall level of CO_2 emissions was found from the base case scenario compared to the entire replacement of the vehicles by an EV-fleet, representing a reduction of 34%. The evidence from the simulation results and the Life Cycle Assessment (LCA) [351] suggested that a positive impact would occur by substituting the entire light vehicles fleet for EVs since CO_2 emissions slowed down compared to scenarios with lower shares of electric vehicles. The potential to decrease CO_2 emissions in the country varied among scenarios and increased as renewable generation grows. The study [351] also shed a contemporary light on the contentious issue that the potential to reduce carbon dioxide emissions depends on the power mix of each country and the share of biofuels use in the transportation sector.

Findings of [351] revealed that the combined use of EVs and biofuels could, therefore, enhance Brazil's capability of meeting the Paris agreement targets. With a 100% light electric vehicle fleet, road

[54] The paper "*Electric vehicles and biofuels synergies in the Brazilian energy system*" [351] has been published by the authors of this Ph.D. thesis addressing the role of EVs in a system with high reliance on renewable energies for electricity production and biofuels in the transportation sector based on the case of Brazil.

transportation might significantly reduce fossil fuel consumption. It is also well known that transport policies in the country focus primarily on land-based biofuel production. In the particular case of Brazil, the avoided biofuels consumption in the road transportation sector could be partially shifted to the electricity sector, providing synergies between road transportation and electricity generation sectors. However, such synergies require a holistic and integrated approach from the government side since structural and conjunctural changes may occur in the future for both the biofuels industry and in the electric vehicles sector.

Findings of [351] also have important implications for the government to develop medium and long-term political frameworks that may integrate and take advantage of the synergies in using bioresources between transport and electricity sectors once the combined effect from sector coupling will become increasingly important in the future. In the case of a high share of electric vehicles, this would also increase the exportation potential of bioresources. It is also well known that harvesting periods for biomass from sugar cane occur typically between April and October in the country. A more favorable wind-profile is typical in this period, but reduced reservoir water levels are also predictable due to unfavorable hydrological conditions. Therefore, the coordinated use of bioresources could benefit the entire energy sector to fully exploit the synergies between the use of bioresources and the availability of wind and hydro-based resources according to seasonal variations.

The authors of [351] also found that synergies might exist between EVs' needs and solar power generation, mainly if a daily charging strategy is considered. There is also a higher need for battery storage for the overnight charging strategy during the day with higher solar power production. The insights gained from [351] may be of assistance to the government and policy-makers. The transition towards an electric fleet may also benefit the country, reducing gasoline imports and increasing biofuels' exportation. A critical determinant for the success of this transition is the support of the local government for promoting incentives for the adoption of EVs, but the support for the development of the necessary charging infrastructure is also essential.

Recently, ANEEL established the first regulation (RN n° 819/2018 [274]) for EVs, such as better discussed in Ref. [68], which is considered the first normative resolution about EVs ever implemented in Brazil. RN n° 819/2018 aims to reduce the uncertainties to entrepreneurs who wish to invest in developing the infrastructure for charging electric vehicles. This new normative resolution also enables the utility distributor to install in its area of concession electric vehicle charging stations. Therefore, public or private charging stations are allowed by the RN n° 819/2018. It worth mentioning that RN n° 819/2018 does not allow the bidirectional power flow between the battery of the EV and the power grid

as well as the participation in the electricity compensation system, regulated by RN n° 482/2012 [321]. The number of recharging points shall be equivalent to the maximum number of electric vehicles connected and charged simultaneously in each station [321].

Therefore, the current challenges include increasing the charging infrastructure, which would allow the diffusion of EVs in the country. Regulatory improvements are imperative, as well as new incentives for a sustainable transport system in Brazil. The nation as a whole would also be beneficiated by using an integrated approach into urban planning, helping the transition to sustainable mobility. The co-benefits of EVs should also be better addressed by identifying its role for citizens, renewable energy providers and electricity grid operators.

Further investigations are also needed to assess the extent to which bioenergy might compete not only for food production and land use but also for water resources. The sustainability of non-carbon alternatives (e.g., biofuels) depends mostly on the feedstock source [352]. Therefore, the direct and indirect Land-Use Change (LUC) emissions should be further evaluated (see Ref. [353] for details). To give a well-known example for the sake of clarity, Ref. [354] underline the importance of taking into account the resulted biofuel emissions in the case that "*the crop were produced on a parcel of land that previously grew soybeans, and as a result a forest was cleared somewhere else to grow soybeans to meet the same soybean demand*." Therefore, further studies, which take the indirect CO_2 emissions from biofuels into account, will need to be undertaken in order to provide a deeper insight into the full assessment of carbon dioxide emissions from both the transport and electricity in the Brazilian energy sector.

3.4 Summarize of the smart grid trends and prospects for the Brazilian electricity sector

It is well known that the global electricity sector has been witnessing a significant share of innovations together with a high increase in renewable energy, and Brazil is no exception. Decarbonization, Digitalization, and Decentralization of the energy sector will be the main three key drivers of the power system's evolution. These main drivers would also promote essential benefits for the country, but it requires potential changes in the electricity sector's current structure.

The shift towards low-carbon economies throughout renewable energy integration has also intensified the disruption of traditional utility business models. For the future, utilities would change their traditional business models by providing ancillary services to end-users through innovative contracting offers, e.g., smart contracts that could include the energy price, quantity and delivery date. Therefore, the development of innovative approaches to fulfill this new market would be required. This coming up future would also be disruptive for the Distribution System Operators (DSO) and Transmission System Operators

(TSO), affecting substantially its role, since new actors would appear on the energy market due to new business models. It is worth mentioning that the shift towards low-carbon economies throughout the integration of renewable energy is intensifying the disruption of traditional utility business models [355].

The role of DG for the different stakeholders (e.g., consumers and distribution companies) has received increased attention in recent years in Brazil. The economic and risk analysis of small-scale PV systems in Brazil was recently addressed by [313]. Ref. [356] assessed the impact analysis of wind power mini-generation for industrial consumers considering different countries' tariff modalities. Understanding the complexity of the trade-offs of increasing DG is vitally important. Specialists have criticized RN n° 687/2015 since it does not foresee the possibility of energy commercialization, but instead, it defines a "sharing" mechanism through the net-metering system. The option of trading the excess of electricity produced by DG systems could help to pave the way towards potential new business models that would make DG more competitive in Brazil.

Recently (2018), ANEEL collected a set of contributions through a public consulting process (CP n° 10/2018), aiming to enhance the current DG regulation established firstly by RN n° 482/2012. One of the most significant recent discussions is related to the need for changing the current net-metering system. For most consumers who already have a DG system installed, the maintenance of the current regulation should proceed, driven by the benefits brought about by this technology to society. On the other hand, from the non-DG users' point of view, the current regulatory system shifts the costs to them, which is not considered a sustainable measure for the long-term. The Brazilian government, through ANEEL, evaluated five different alternatives for the current net-metering system by analyzing two facets [342]. The first one refers to the consumer who still has or is willing to install a DG system. The second facet relates to non-DG users. Findings of Ref. [342] revealed that non-DG users would pay a higher share of the overall costs in the case of maintaining the current net-metering system.

The general issue of cross-subsidization has been widely discussed by literature such as in [357] and [358]. Ref. [358] highlight the problem brought about by the net-energy metering system, *"leading to cross-subsidization of DG network users by customers without DG".* This problem could be surpassed by using hourly tariffs. However, for the case of Brazil, this is not yet a reality, and other solutions should be found to address this problem, at least for the short-term. Ref. [359] analyzed the use of a price-based demand response program together with photovoltaic distributed generation and concluded that regulatory changes would be necessary to stimulate the use of DR with these DG systems. The authors of [359] also emphasize that the simultaneous use of a price-based DR program with a photovoltaic

distributed generation system may not be economically attractive for the WHT non-flat tariff. Therefore, improvements in the current DG regulation were also proposed by [359].

The deployment and dissemination of DG, DSM strategies and storage systems are expected to reduce the need of consumers to be supplied by the grid and are expected to play a growing role in balancing electricity demand and supply in the future. DSM has become a key instrument available to the electricity sector and can postpone capital investments to expand primarily distribution and sub-transmission systems. The new tariff schemes created by ANEEL (e.g., tariff flag, WHT and the electricity prepayment) aim to foster the potential of DR and specifically may motivate price-based DR programs in Brazil. The development of smart grids enables the implementation of DSM measures. The smart meter deployment is also considered essential to allow the WHT to work effectively. Given the increasing electricity demand growth rates and consequently the new projected power sources that should be installed in the future, DSM might significantly contribute and affect positively, reducing the total installed capacity projected by Brazilian institutions and enhancing the power system security and reliability. Most of the future projections do not consider the DSM contribution. Thus, the future projected installed capacity from previous studies might be oversized.

The delay in smart meter deployment considerably affects the development of the new tariff schemes and, consequently, underuses Brazil's DSM potential. As discussed earlier, for those consumers who adopted the WHT, the utilities should install the smart meter with no initial costs for the consumer. This smart meter, however, has only a few functionalities. We call attention to the potential that should be achieved, mostly from the customer's point of view, if a modern smart meter would be installed, allowing the consumers to manage their energy consumption profile more efficiently. It is worth mentioning that this smart meter is already available, but the customer should pay the difference between this smart meter and the conventional one.

New technologies are also gaining considerable attention worldwide, such as power-to-gas, power-to-heat and power-to-mobility, but they are not on a path of accelerated deployment in the case of Brazil [77,97].

The new trends and regulatory aspects that have been proposed for the Brazilian electricity sector are correlated and occasionally mutually dependent, as detailed in Table 3.2, which summarizes the last Brazilian regulations concerning the electricity sector and the main future trends expected to be implemented in the country [58,77,291,294,315,316,325,326,328,332–334,162,340–342,360–362,188,234,283,284,286–288]. A set of highlights is presented in Table 3.2, aiming to discuss the main concerns of each trend considering the studies addressed by literature and the expected time horizon of each one. Most of these highlights can be seen as challenges for the power sector stakeholders

and significant academic problems to be addressed in future research targeting Brazil and other countries moving towards smarter electricity systems.

Table 3.2: Summarize of the smart grid trends and prospects for the Brazilian electricity sector

Technology/ New Trend and Regulation	Time-horizon[55]	Highlights
TARIFF FLAGS RN n° 547/2013	Already working (Regulated in 2013 and implemented in 2015)	▪ The main aim is to reflect the real cost of electricity generation and promote consumer awareness. ▪ The monthly flag is defined considering the required thermal power, according to hydropower availability. ▪ It attempts to foster Demand Response (DR) potential by increasing the electricity tariff and minimizing the differences between the utilities' costs and revenues. ▪ TFS would promote a reduction of thermal dispatch, an increase in the overall storage level, and a decrease in the overall operating system cost. ▪ A loss of revenue for utilities is foreseen due to the reduction in the overall electricity consumption. ▪ The costs for the yellow and red flags have been changing over the years, and currently, the calculation methodology includes the Generation Scaling Factor (GSF).
WHITE HOURLY TARIFF RN n° 733/2016	Short-term (available since January 01, 2018)	▪ The WHT is a type of TOU rate in which electricity tariffs are differentiated along the day in on-peak, intermediate (mid-peak), and off-peak periods. ▪ This new tariff scheme is considered the first hourly tariff ever implemented for household electricity consumers in Brazil. ▪ The main reason for implementing this new rate regime is to incentive household electricity consumers to reduce their consumption, especially during peak demand periods (between 06 p.m. and 10 p.m.) ▪ The possible benefits of the WHT should be better presented to consumers, giving them the possibility to choose or not to choose this new regime rate considering their load profile. ▪ This new tariff scheme might optimize investments in generation and transmission in the future.
ELECTRICITY PREPAYMENT RN n°610/2014	Short-term (1 – 5 years)	▪ A prepayment system is supposed to offer advantages for both consumers and distribution companies. ▪ The system has been primarily motivated by the possibility of reducing electricity distribution losses and operational costs, improving companies collecting revenues, and reducing fraud. ▪ From the consumers' perspective, experiences show that they feel empowered to manage and control billing costs and consumption using electricity prepayment. ▪ In Brazil:

[55] The time-horizon was established considering the first consumers' adoption of the new technologies and it was established based on the literature review.

		I. Companies are supposed to provide all the prepayment meter acquisition costs; II. Consumers can freely migrate between systems (i.e., prepayment and post-payment); III. The shift from the post-payment to the prepayment system is voluntary and free of charge for consumers. IV. Some group of consumers is not allowed to adopt the prepayment system, e.g., consumers that adopted the WHT or those who have a mini or micro DG system connected to the grid; V. There are some technical constraints related to the lack of standardization that should be better addressed in the future.
SMART METERING RN n° 502/2012	Short-term (1 – 5 years)	▪ Smart metering is considered an emerging and under technological development system in Brazil. ▪ Currently, smart metering in Brazil is restricted to pilot smart grid projects of specific distribution utilities. ▪ The deployment of smart meters is a fundamental step for the deployment of smart grids in Brazil. ▪ The smart meter deployment is considered essential to enable the implementation of the WHT system. ▪ Smart meter adoption for Brazilian residential buildings is difficult to predict due to the limited consumer knowledge and awareness. ▪ The lack of support, incentives, and proper information dissemination about the possible benefits of the smart meter might not result in the expected benefit for both consumers and utilities. ▪ Utility companies of the Brazilian system might develop policies and strategies to disseminate smart meter technology. ▪ Although there have been some advances in the Brazilian regulatory structure, many gaps still stand as barriers to smart grids' development. ▪ Future studies should measure consumer propensity to adopt smart meters in residential buildings and investigate electricity consumers' perceptions and behaviors concerning the potential deployment of smart meters in the Brazilian electricity sector.
DISTRIBUTED GENERATION **(**RN n° 482/2012 and RN n° 687/2015)	Short-term (already available since 2012)	▪ Solar PV represented 99% of total mini and micro DG already installed in Brazil up to 2017. ▪ The overall installed small-scale DG energy systems are relatively small compared to Brazil's potential. ▪ The forecast for 2024 is 886,700 new consumers and an overall installed capacity of 3.2 GW for DG. ▪ The net-metering system and the use of monomial tariff might bring a problem for the balance of electricity tariffs for utilities. ▪ DG growth might decrease distribution utility revenues by 1.1% in 2024 compared to 2016. ▪ According to Brazilian distribution utilities, there is no adequate incentive to modernize distribution networks or even invest in new technologies. ▪ There is little emphasis on previously published works related to the social impacts and benefits of distributed technologies.

DEMAND RESPONSE[56]	Medium to long-term (5 - 20 years)	▪ The deployment of DR programs has been seen as an alternative to generation and transmission expansion. ▪ Peak demand reduction is considered one of the main goals of DR. ▪ DR might contribute to power system regulation capacity to promote wind power integration, mainly in Brazil's Northeast region. ▪ The potential of DR in Brazil is considered by authorities a vital variable to delineate the medium and long-term electricity expansion planning. ▪ Most of the studies so far addressed by literature worldwide regarding DR role have been focused on power system operation and emphasize that the effects of DR should be considered in power system planning. ▪ The changes in tariff schemes promoted by ANEEL may considerably motivate price-based DR programs in Brazil. ▪ There is great potential in Brazil for the wider penetration of DR programs. ▪ The new tariff schemes created by ANEEL (i.e., TFS, WHT, and the pre-payment system) aim to foster DR in the country.

3.5 Concluding remarks

The main concluding remarks of this chapter can be summarized as follows. Brazil is considered one of the worldwide leading countries in installed renewable energy capacity. However, the transition towards a more sustainable energy system is a challenge for the government and essential structural and regulatory changes (e.g., new business models) would be necessary to support this transition. The main challenges towards a sustainable and full-decarbonized energy system rely on increasing the power system flexibility while at the same time maintaining adequate levels of reliability. Many potential challenges brought about by the high growth of VRE have also been pointed out in the literature - particularly in the last couple of years - which should be considered in future power planning models.

The future volatility of the demand and uncertainties in fluctuating generation from RES tend to increase in most countries and Brazil is no exception. The increase in demand and climate change concerns impact these renewable resources' availability and represents critical challenges for long-term power planning. The high level of uncertainty brought about by intermittent sources is also expected to result in an overall trend to increase the thermal generation in the future. Consequently, thermal power plants are expected to develop a critical role for baseload generation and flexible generation and system provision in the country. In the case of Brazil, their role will be particularly relevant mainly between September and December due to the lower hydropower storage level. Thermal power plants already provide some system services, such as inertial response to maintain system stability during sudden generation loss or network fault. Additionally, thermal power plants' technological developments will be needed to include new

[56] A full review analysis of DR strategies will be provided along with Chapter 5.

flexibility requirements, e.g., reduced startups and shutdowns, increased ramping rates, reduced minimum generation and capacity to adapt to frequent load changes.

Several challenges for the power sector are arising from the wide range of alternative developments. The large structural transformations define the current stage of the Brazilian electricity sector, such as a gradual shift towards non-hydro RES. The development and dissemination of new technologies are strongly affected by political and business guidelines and several technologies currently in the developmental stage should be available in the future.

The Brazilian electricity sector faces a complex and non-trivial problem related to its traditional planning strategies, mostly based on hydropower exploitation and the power system is highly subjected to hydrological risks. The future electricity supply risks and the high level of vulnerability to climate change in the country have been acknowledged by previous research by emphasizing that future climate change issues could strongly impact the increased reliance on hydropower resources. The future rainfall decrease is also projected, particularly for the Northwest and North regions of the country.

Once the technical, economic, social, political, environmental and institutional factors have limited the construction of new dams, the overall hydropower storage capacity (or "regularization capacity") of the country has been decreasing over the years. This reduction should occur mainly due to climate changes and the characteristics of the target rivers, as most of the unexploited resources are in the Amazon river basins in which the projects are expected to be dominated by run-of-river power plants [324]. This fact associated with concerns about achieving a fully decarbonized energy matrix for reducing the overall emissions represents a big challenge for the Brazilian electricity sector since the decreasing storage capacity has been increasing the need for additional thermal power production. The trade-off among environmental restrictions for constructing new hydropower plants, operational security, and GHG emissions should be well debated by society, government and decision-makers to achieve sustainable energy planning pathways. Therefore, hydropower expansion faces several environmental challenges that, together with the high dependency of rainfall and climate conditions, can severely affect hydropower's future expansion for energy production. Consequently, the maintenance of the high share of renewable sources in the country is one of the most significant challenges to be addressed by policymakers. A new model for the expansion of the electricity system is, therefore, a current need. The problem surpasses only a conjunctural problem (high dependency of rainfall, for instance) as it evolves large structural transformations.

Our findings suggest that DG, DSM and the new tariff schemes are on a path of accelerated deployment in the country due to the government's new policies and regulatory frameworks, mainly in the last five

years. The possibility of future deployment of TOU tariffs for electricity to reduce the peak demand can also lead to reductions in the current country's expansion requirements. The majority of the new normative resolutions proposed by the Brazilian government (e.g., WHT and electricity prepayment) are mostly related to household electricity consumers and a lesser extent, to commercial consumers. This can be explained mainly because the residential and commercial sectors are the main contributors at times of heavy demand or peak usage (between 06 p.m. and 10 p.m.). Our findings also imply that the WHT should be better presented to the Brazilian consumers, giving them the possibility to choose or not choose this new rate regime, considering their load profile and consequently getting economic advantages from its choice.

The economic impact of DG growth in the country is considered one of the most critical issues presented by utilities. The transformation of the regulatory structure and the habits of consumption, together with the commercial feasibility of technologies and human resources training, appear as additional challenges for the sector. New business models have been proposed to address the high insertion of DG in the Brazilian electricity market, such as the ones presented by RN n° 687/2015. However, we underline the need to develop other new business models to address the various decentralized energy technologies and services emerging in the sector, such as the ones related to the so-called "*prosumage*" concept. Education activities that simultaneously clarify the new regulatory framework to consumers and its possible benefits are considered actions to encourage them to adopt or not adopt the proposed new tariff schemes (e.g., WHT and the prepayment system).

Since 2005, the Brazilian government has been conducting energy auctions to contract electricity. Notwithstanding, the current auction system does not consider in the contracts the power demand to support peak load and the variations of intermittent sources. Therefore, the present auction model design is not enough to correct the market and regulatory failures. The improvement of regulations, including the creation of auctions well suited for the entry of innovative energy sources, is also imperative for the country.

The creation of additional indicators that can measure the impact from the integration of DG in future scenarios; the use of a parameterization of measures to represent the environmental, cultural, and social externalities related to each option and also the technological competitiveness of electric vehicles over time are some of the aspects that should be included in future works. Regulation for electric vehicles is still emerging in the country, e.g., RN n° 819/2012. However, its impact on the power grid is not yet assessed and this aspect is a future essential regulation that should be addressed. In [363], for example, the use of the EVs for system frequency regulation has been discussed and gives useful insights into EVs'

technical impacts on the power grid. All these aspects offer essential problems for the industrial and scientific community and for which a multidisciplinary perspective would benefit energy systems research beyond the Brazilian case. We also emphasize the need for system integration and sector coupling, which is also considered a key point to be addressed by the Brazilian government towards a full-scale decarbonized energy system, but at the same time, this would require a long-term political framework.

The ambitious transition on moving towards a sustainable future is clearly a great challenge for Brazil. However, if we desire to surpass the economic, environmental and social impacts of fossil fuel exploitation, these measures are necessary and may set a landmark for future generations. Although there have been some advances in the Brazilian regulatory structure, many gaps still stand as a barrier to the development of the electricity sector. The integration of the new aspects discussed in this research work remains challenging for several reasons. Several uncertainties might cause difficulties for utilities, e.g., the net-metering system and the use of monomial tariffs might bring a problem for the balance of electricity tariffs. Conclusively, we believe our results offer insights into the future trends for the Brazilian electricity sector, emphasizing the critical role of smart grid technologies in creating a more efficient grid and the intelligent management of the entire energy system. This would also allow households to manage their electricity needs, having more active behavior in electricity management. The planning and design of a sustainable power sector are also indispensable to developing the Brazilian electricity sector. The inclusion of the concept of sustainability in the energy sector reinforces the need to assess these problems using an integrated and multidisciplinary approach, resulting in additional challenges to the Brazilian electricity operation and planning. Although simplified, our analysis underlines the main barriers, challenges and opportunities for the future power sector.

Chapter 4. Integrated Brazilian Electricity System Model (IBESM)

This chapter begins by illustrating the proposed enhancements implemented in the original optimization model in Section 4.1. The proposal of the newly Long-term Average Cost of Saved Electricity (LACoSE) is also illustrated along with Section 4.1. The objective functions used are further described in Section 4.2. Section 4.3 attempts to describe the data collection procedures together with the main case study assumptions.Chapter 4 proceeds by validating the model considering 2018 as the reference year in Section 4.4. The Business as Usual (BAU) scenario (without DSM) is also established in Section 4.4 to be further compared with the results that include different DSM strategies in Chapter 6 and Chapter 7.

4.1 Modeling approach

Several energy modeling tools are currently available to design national energy planning strategies considering technical and/or economic analysis. The integrated co-optimization modeling approach used along with this research is based on the Open Source Energy Modeling System (OSeMOSYS) implemented in the General Algebraic Modeling System (GAMS) software through linear programming. Additional information about the modeling assumptions and the full OSeMOSYS model description can be obtained at www.osemosys.org and in references [364–367]. Other specific information related to the particular power system evaluated in this research can be found in Section 4.3.

Along with this research, the term 'Integrated' refers to the joint implementation of both supply and demand-side resources into the same co-optimization approach. The Integrated Brazilian Electricity System Model (IBESM) proposed in this research comprises the integration among (i) the original OSeMOSYS code [366] (translated initially into GAMS by Ref. [368]) with (ii) the inclusion of a set of DR strategies based on the code improvements proposed by Ref. [187]. Therefore, we combined these models into a single and therefore integrated model in GAMS language with additional code enhancements. The code additions in the original DR code attempt to compute the unmet demand seasonally. Last, but not least, IBESM is also enhanced by including (iii) a set of code additions to account for the inclusion of EEMs within the long-term model using the proposed concept of the LACoSE. This third enhancement is performed within the model to recognize and account for the reinvestments in energy efficiency under a long-term perspective. Therefore, the detailed modeling enhancements proposed for the long-term assessment of the co-benefits between energy efficiency and demand-response on renewable-based energy systems are summarized in Figure 4.1. The proposed framework (Figure 4.1) can be reflected into three main parts: Part I (model enhancements), Part II (model integration), and Part III (model evaluation), whose description follows.

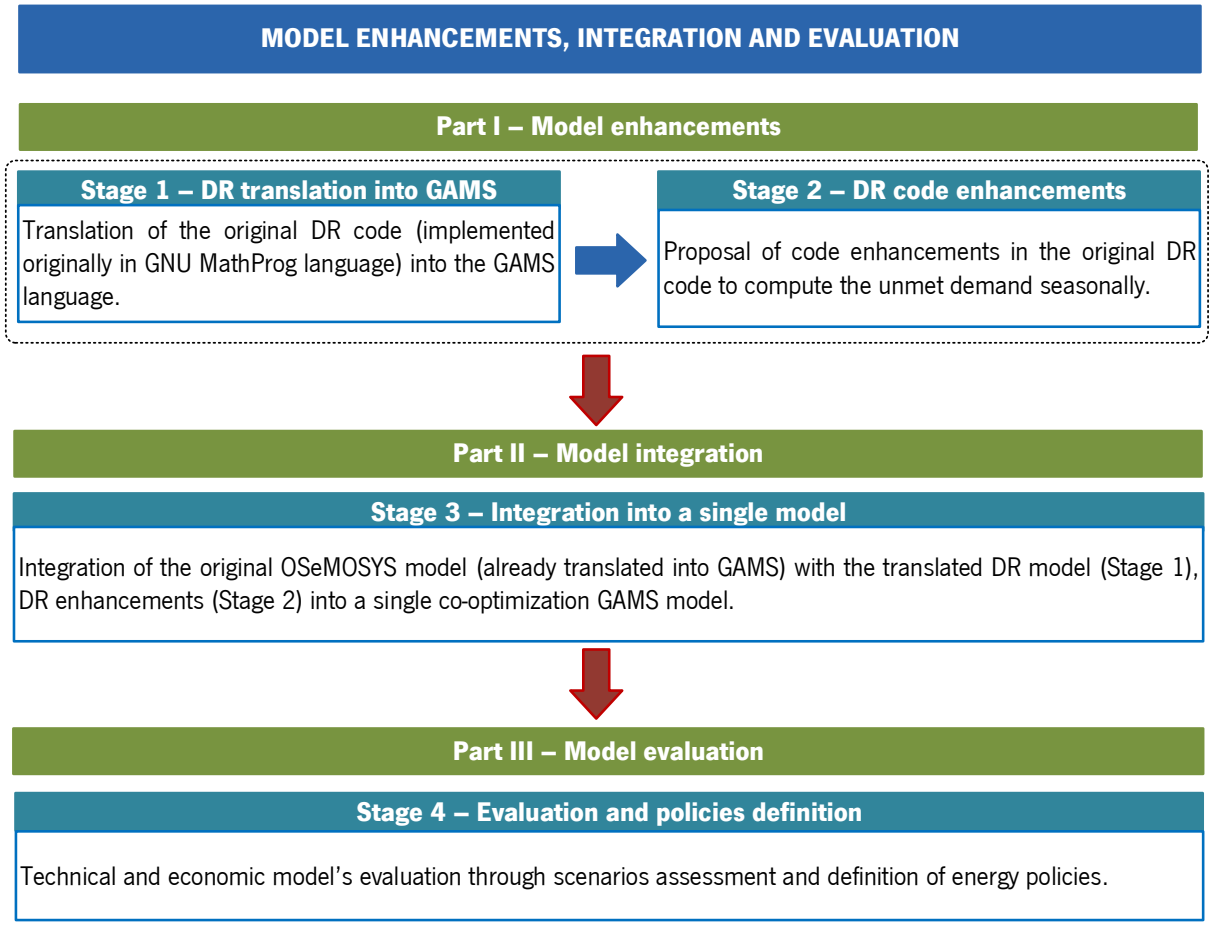


Figure 4.1: Model enhancements (Part I), model integration (Part II), and model evaluation (Part III).

PART I – MODEL ENHANCEMENTS

Stage 1 – DR translation into GAMS

The translation of the original DR code (implemented initially in GNU MathProg language [187]) into the GAMS language is provided in Stage I. Two strategies are considered for DR implementation in [187], i.e., (i) load shedding (also referred to as prioritizing demand types [187] or even load curtailment [38]) and (ii) load shifting, which are described along with this section.

Load shedding is usually considered for energy-intensive industries with high utilization rates, such as suggested by Refs. [200,246]. Although load shedding could also be applied for commercial and residential sectors [200], this could imply high losses of comfort for these users. Therefore, only load shifting is traditionally considered for these particular sectors (i.e., commercial and residential) in traditional DR assessment analysis.

Different flexible demand categories can be included within the modeling approach, which should be specified for each day-type, season and year. For the power system evaluated in this research, four categories of flexible demands are included. As previously mentioned, load shedding will be only allowed

for the industrial sector (LS_Industry), whereas demand shifting is considered for all sectors (DS_Industry, DS_Resident, DS_Commercial). The theoretical, technical, and economic load flexibility potential is also established for each power subsystem within the country. The full theoretical load flexibility assessment across regions and sectors will be fully described in Chapter 5. Chapter 7 evaluates the technical and economic DR potentials). The full model's set and parameters are described in Annex A.1 and Annex A.2, respectively.

(i) DR strategy - Load shedding

The prioritization of specific categories of loads may be envisaged aiming to provide flexibility to the power system. This prioritization (also referred to as load shedding) can be implemented by the utility or the consumer depending on the employed load control technique (e.g., Direct Load Control, Local Load Control, or Distributed Load Control - see Section 2.5 for details).

The model extended by [187] allows leaving a predefined demand category (set 'FLEXIBLEDEMANDTYPE') unmet in the case the cost for supplying it exceeds a value defined by the parameter 'PriceOfUnmetDemand(r,f,ls,fdt,y)', where 'r' represents the region of the model, 'f' are the fuels that enter or leave each technology (e.g., fossil fuels and electricity consumption), 'ls' allows to represent different seasons across the year, 'fdt' allows to include categories of flexible loads with different load profiles and flexibility levels (e.g., industrial, residential and commercial sectors) and 'y' is considered to model the years of the planning model (see more details in Annex A). Literature usually refers to this parameter as the Value of Lost Load (VoLL) or the cost of unserved energy. It is worth mentioning that this cost could be understood as the baseline cost in which it would be cheaper to curtail the load instead of meeting it by other means such as by other power generating sources. For our research, this value has been established based on the concept of the so-called opportunity cost. The opportunity cost can be defined as *"the value of the next best alternative that the decision forces the decision-maker to forgo* [369] *"*. Therefore, the price of not meeting the demand (i.e., for load shedding) can be considered a cost of an opportunistic planning strategy. In our case, the opportunity cost refers to the opportunity of shedding the load during a predefined time and subjected to a particular variable cost (US$/MWh), which is based on the spot price of each region.

The daily flexible demand is defined for each flexible category throughout the parameter 'SpecifiedDailyFlexibleDemand(r,f,ls,ld,fdt,y)'. The flexible demand rate is defined as an amount of electricity per timespan and can then be established for each daily time bracket (D3[57]). The rate of flexible

[57] Annex A.3 describes the translated parameters, variables and equations (from GNU MathProg language to GAMS) related to DR implementation. The proposed code additions are also illustrated along with this annex.

demand that is allowed to remain unmet for each daily time bracket can be further calculated (UD1) using the parameter[58] 'MaxShareUnmetDemand (r,f,fdt,y)'. The unmet demand is then estimated for each time slice (UD2) and subsequently for each year (UD3) of the planning period. The seasonal (UD4) and the annual (UD5) cost of not meeting each flexible demand-type can be then established. Finally, the discounted cost of not meeting each flexible demand-type can be calculated by combining both the 'CostOfUnmetDemand(r,fdt,y)' and the 'DiscountRateDemand' parameters' (UD6).

(ii) DR strategy - Load shifting

The original set of equations proposed by [187] for load shifting are considered in our model. We attempt to translate this set of equations into GAMS language. Load shifting is implemented considering that each process/appliance can function with a 'storage' ability during a predefined time. Once the original demand is reduced, the storage is charged. However, when the demand is met again, the storage is discharged, increasing the original demand during that period. The maximum time allowed for each flexible load to be met earlier (or in advance) or later (or delayed) should be defined through the 'MaxAdvance(fdt)' and 'MaxDelay(fdt)' parameters, respectively.

For load shifting purposes, the rate of flexible demand should also be calculated for each flexible demand-type which offers some degree of load shifting flexibility[59] (D3). The net charging process (DS1) can be divided between both the loads that are postponed (DS2) and the ones that are met in advance (DS3). It also means that the storage of a flexible load that is met earlier is independent of the storage of a load that is met later. For each daily time bracket, the overall load that is allowed to be met earlier or postponed is restricted by the parameter 'MaxShareShiftedDemand(r,f,fdt,y)' (DS4). The load shifting process is also constrained by a set of equations for the flexible loads that are delayed (DS5, DS6 and DS7) and the ones that are met in advance (DS8, DS9 and DS10), such as detailed in Annex A.3 where the full DR model description translated in GAMS can be found.

The next equations account for multiplying the overall amount of load which is met later (DS11) or earlier (DS12) by the shifted time. This would allow obtaining the cost incurred for shifting the load by one hour (DS13). It is worth mentioning that the costs to implement load shifting are included in the model as a penalty per each hour shifted (US$/MWh) for each flexible load defined in the parameter 'CostFactorShiftedDemand(fdt)'. The cost for shifting the load can be understood as the value paid for

[58] In the case of our model, the maximum share of demand allowed to remain unmet has been defined as 100% of the estimated overall theoretical load flexible potential for each region (see Chapter 5 for details).

[59] It means that each category of flexible load should be defined for load shedding or load shifting. Therefore, the model assumes that each category of "*flexible demand is stored in a different 'storage'* [187]".

those consumers, which provide a certain degree of flexibility by shifting (partly or entirely) their flexible loads. Finally, the discounted cost for shifting the load can be calculated (DS14).

Stage 2 – DR code enhancements (GAMS)

Stage 2 proposes enhancements in the original DR code. These code enhancements are proposed to compute the unmet demand seasonally since the original model computes the unmet demand for the entire year. Therefore, the upgrades are explicitly linked with the load shedding strategy and are described in Figure 4.2.

The key focus of the proposed enhancements in the original DR code [187] is based on the addition of the index 'ls' - representing each season of the year - over the original parameter 'PriceofUnmetDemand(r,f,fdt,y)' which now becomes 'PriceofUnmetDemand(r,f,ls,fdt,y)' (**Step 2.1** in Figure 4.2. This revised parameter allows now to insert data specifically for each season of the year. This is particularly important for systems with both a high share of RES and continental dimensions in which the spot prices vary significantly among regions and seasons, such as the case of the power system evaluated in this research.

A new variable is also included within the original model called 'CostOfUnmetDemandSeasonal(r,ls,fdt,y)' (**Step 2.2**). This new variable is used within the model in a new equation, 'UD4_CostOfUnmetDemandSeasonal (r,ls,fdt,y)', responsible for computing seasonally the price of not meeting a demand (**Step 2.3**). The overall cost of not meeting the demand is then calculated using the revised equation 'UD5_CostOfUnmetDemand (r,fdt,y)' (**Step 2.4**).

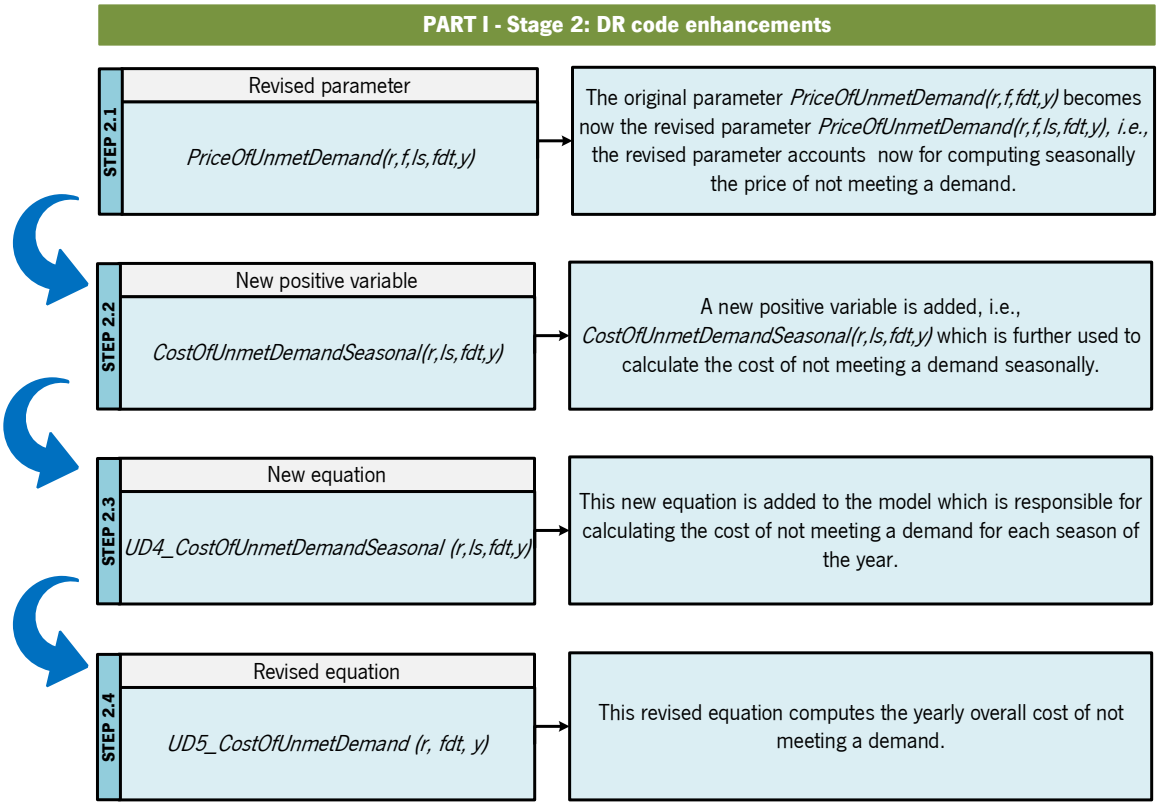


Figure 4.2: Enhancements in the DR code (Part I - Stage 2).

Stage 3 – Inclusion of EEMs into the model

A set of code enhancements has also been defined within the IBESM to account for the inclusion of different levels of EEMs. These improvements allow simulating the effects of investing in EEMs and comparing the results with scenarios without the inclusion of such energy efficiency improvements. It is worth mentioning that the inclusion of EEMs within the model is performed by reducing the final electricity demand projected for each year (see Ref. [370] and Chapter 6 for details).

Therefore, Stage 3 (Part I) comprises the estimation of the so-called Long-term Average Cost of Saved Electricity (LACoSE) firstly. Although studies have recognized and assessed the short-term impact of using EEMs by broadly focusing on the base Cost of Saved Electricity[60] (CoSE) (US$/MWh) concept, research has yet to systematically investigate a general calculation procedure for this variable when the analysis is mainly focused on the long-term. Therefore, our analysis revealed a lack of understanding about how to calculate this CoSE for EEMs under a long-term power planning perspective. The proposed new approach, coined hereafter as the Long-term Average Cost of Saved Electricity - LACoSE (US$/MWh) of using EEMs would allow for a fair comparison with results from the long-term power planning models. The term

[60] The concept of the base Cost of Saved Electricity - CoSE (US$/MWh) is defined purely by dividing the total cost (US$) by the estimated saved electricity (MWh) for each energy efficiency measure per year.

LACoSE relates then to an extended value for the CoSE in which both the Capital Recovery Factor (CRF) and the years of the planning period (extracted from the long-term power planning model) are also taken into account.

Therefore, we propose a new methodology (illustrated in Figure 4.3) to calculate the LACoSE, which will allow us to compare scenarios with and without EEMs in long-term power planning models. The proposed methodology aims to develop a clear argument related to the economic impact brought about by the use of EEMs by estimating the LACoSE for the entire planning period.

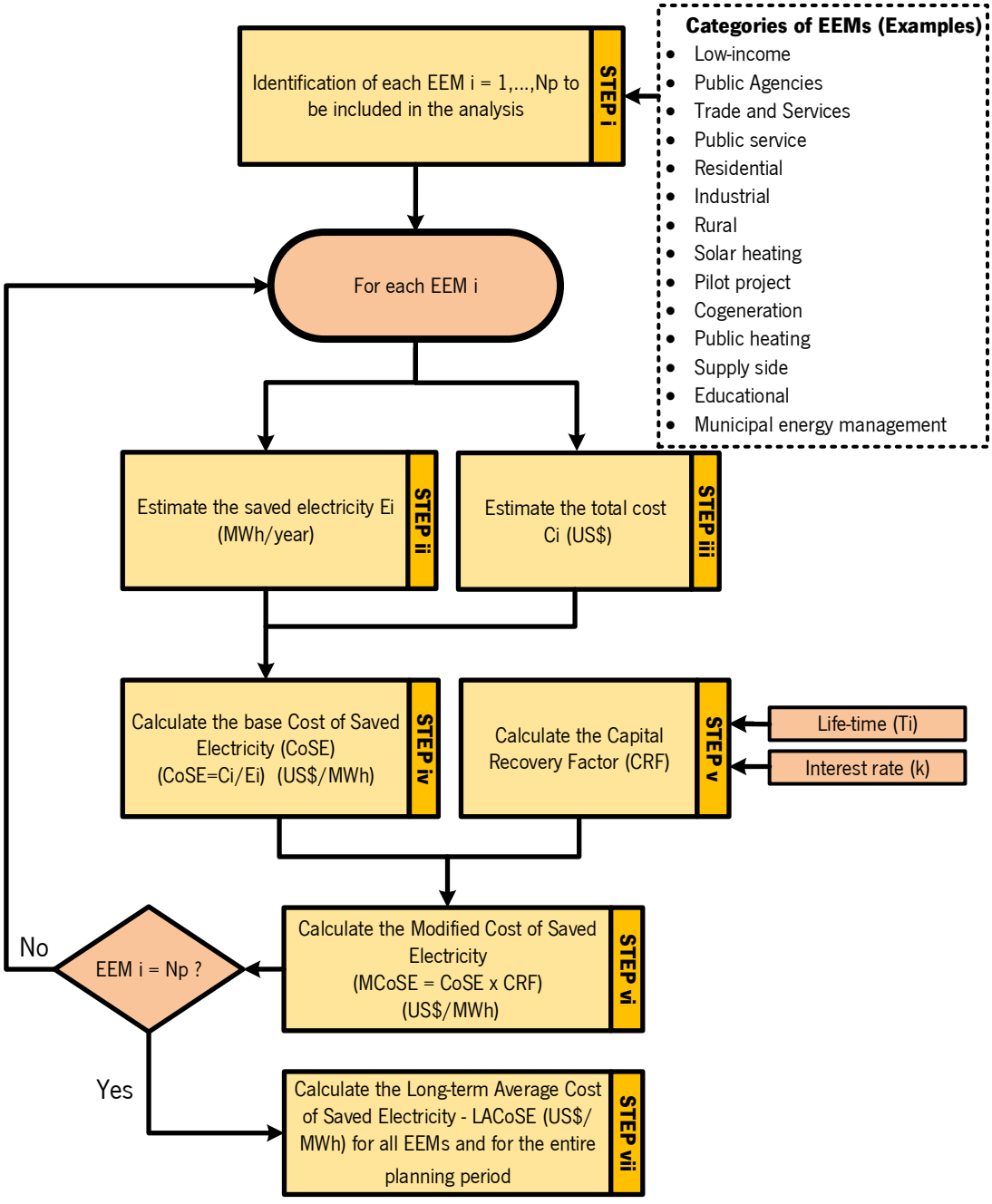


Figure 4.3: Methodology for calculating the Long-term Average Cost of Saved Electricity (LACoSE).

The LACoSE can be estimated by applying Equation (4.1) where k (%) is the interest rate, ΔT (years) represents the overall planning period of the long-term model, and C_i is the estimated total cost of implementing each EEM(i) (US$). T_A characterizes the average lifetime of all EEMs and it can be calculated by applying Equation (4.2), where T_i and E_i represent respectively the lifetime (years) and the energy saved (MWh/year) of each EEM(i) (where i represents each EEM included in the analysis) and N_P corresponds to the last category of each EEM(i) included in the analysis. This new approach recognizes and accounts for the reinvestments in energy efficiency under a long-term perspective.

$$LACoSE = \left(\left[\frac{k \cdot (1+k)^{T_A}}{(1+k)^{T_A} - 1}\right] \cdot \frac{\sum_{i=1}^{N_P} C_i}{\sum_{i=1}^{N_P} E_i}\right) \cdot \frac{\Delta T}{T_A} \quad (4.1)$$

$$T_A = \frac{\sum_{i=1}^{N_P} T_i \cdot E_i}{\sum_{i=1}^{N_P} E_i} \quad (4.2)$$

The original long-term planning model requires a set of code enhancements to account for the inclusion of the EEMs[61] correctly. Therefore, a five-step methodological approach is proposed enclosing the main changes needed in the original model (Figure 4.4).

[61] It is worth mentioning that energy efficiency improvements are included within the model as permanent reductions in the overall electricity demand.

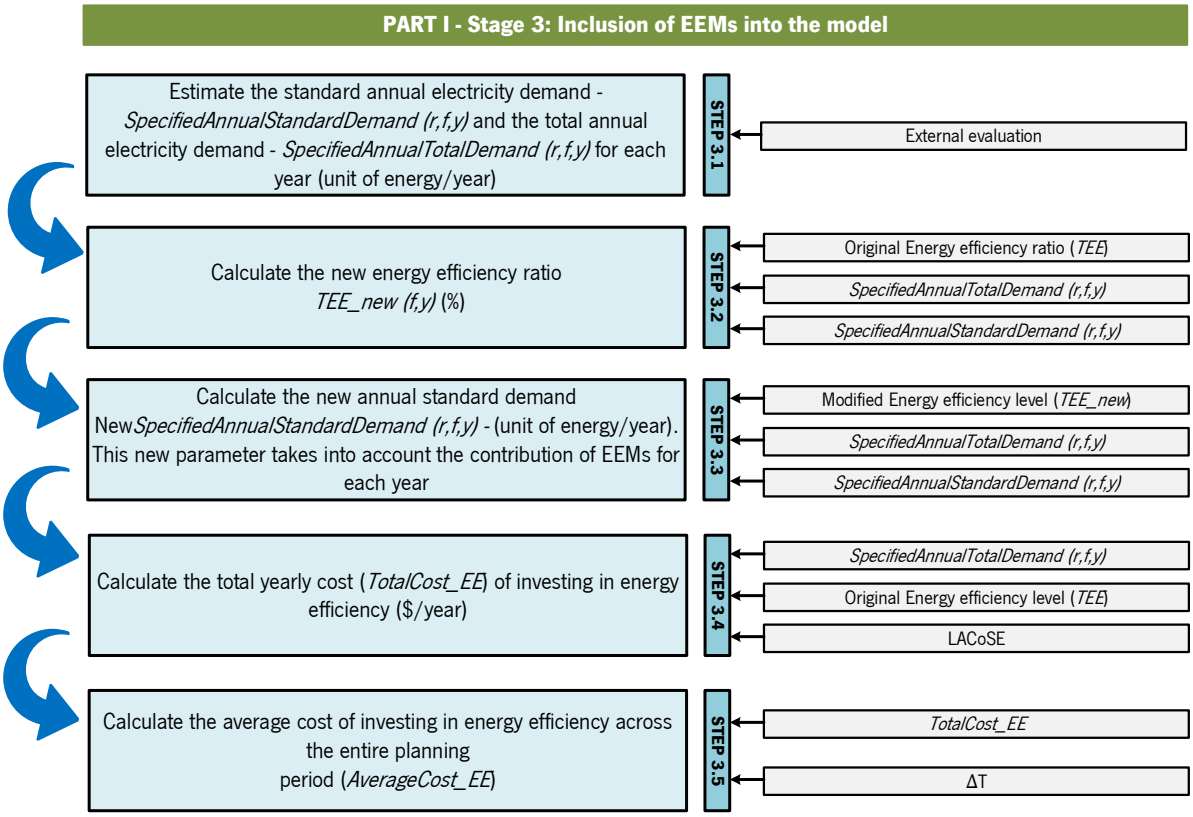


Figure 4.4: A five-step methodological approach to account for the inclusion of EEMs into the long-term power planning model (Part I - Stage 3 in Figure 4.1).

The standard annual electricity demand 'SpecifiedAnnualStandardDemand(r,f,y)' and the total yearly electricity demand 'SpecifiedAnnualTotalDemand(r,f,y)' should be exogenously estimated and included within the long-term co-optimization model (**Step 3.1**). The 'SpecifiedAnnualTotalDemand(r,f,y)'[62] comprises both the flexible and inflexible demands, whereas the 'SpecifiedAnnualStandardDemand(r,f,y)' discounts the estimated power system's flexible demand.

The original energy efficiency ratio 'TEE' corresponds to the level of reduction in the final electricity consumption (expressed in decimals). This parameter is used to calculate the modified energy efficiency ratio 'TEE_new(f,y)' according to Equation (4.3) - **Step 3.2**. The modified energy efficiency ratio is included within the co-optimization model to fairly account for the reductions in the final electricity demand for each year of the planning period when considering both EEMs and DR strategies. It is worth mentioning that in the case the model takes into account only the inclusion of EEMs (i.e., DR strategies are not considered), 'TEE_new(f,y)' assumes a value equal to TEE since the 'SpecifiedAnnualTotalDemand(r,f,y)' is equal to the 'SpecifiedAnnualStandardDemand(r,f,y)' in this particular case. However, if both EEMs

[62] This parameter is included exclusively to consider issues related to the inclusion of energy efficiency measures within the model.

and DR strategies would be considered in the long-term model, 'TEE_new(f,y)' assumes an adjusted value, such as represented in Equation (4.3).

$$TEE_{new}(f,y) = \frac{\sum_{\mathrm{r}} \mathrm{SpecifiedAnnualTotalDemand\ (r,f,y)}}{\sum_{\mathrm{r}} \mathrm{SpecifiedAnnualStandardDemand\ (r,f,y)}} \cdot \mathrm{TEE} \tag{4.3}$$

The 'NewSpecifiedAnnualStandardDemand(r,f,y)' (**Step 3.3**) can be further estimated by applying Equation (4.4), which takes into account the contribution of the estimated ratio of energy efficiency 'TEE_new(f,y)'.

$$\begin{aligned}&\mathrm{NewSpecifiedAnnualStandardDemand\ (r,f,y)}\\&\qquad = \mathrm{SpecifiedAnnualStandardDemand\ (r,f,y)} \cdot [1 - \mathrm{TEE_new(f,y)}]\end{aligned} \tag{4.4}$$

The value of the LACoSE estimated in **Stage 3.2** is then used to calculate the total yearly cost of investing in energy efficiency 'TotalCost_EE(r,y)' such as illustrated in Equation (4.5) - **Step 3.4**.

$$TotalCost_EE(r,y) = \sum_{f} [SpecifiedAnnualTotalDemand\ (r,f,y) \cdot TEE \cdot LACoSE] \tag{4.5}$$

Finally, Equation (4.6) accounts for estimating the average cost of investing in energy efficiency 'AverageCost_EE(r)' across the entire planning period (**Step 3.5**).

$$\mathrm{AverageCost_EE(r)} = \frac{\sum_{\mathrm{y}} \mathrm{TotalCost_EE(r,y)}}{\Delta \mathrm{T}} \tag{4.6}$$

PART II – MODEL INTEGRATION

Stage 4 – Integration into a single model

This stage comprises the integration of the original OSeMOSYS model (already translated into GAMS by Ref. [368]) with the translated DR model (Stage 1), DR enhancements (Stage 2) and EEMs additions (Stage 3) into a single co-optimization GAMS model.

PART III – MODEL EVALUATION

Stage 5 - Evaluation and policies definition

The last stage of the proposed framework (Stage 5) addresses the technical and economic evaluation through scenario assessment. Last, but not least, the energy policies definition can be further established for each scenario, such as suggested by the proposed framework. This stage will be addressed in Chapter 8.

4.2 Objective function

Optimization models usually consider an economic objective, a set of decision variables, constraints and boundary conditions [371]. The co-optimization problem of this study is subjected to a large number of technical, economic and environmental constraints used to attend the system requirements derived from physical processes and capacity limitations but also to ensure minimum levels of reliability and security for the electricity system [119,371,372].

The objective function of the long-term generation expansion planning model accounts for the minimization of the total discounted costs[63] of each region (r) and each year (y) such as specified in Equation (4.7).

$$\begin{aligned} \min z &= TotalDiscountedCost\,(\mathrm{r},\mathrm{y}) \\ &= \sum_{t} TotalDiscountedCostbyTechnology(r,t,y) \end{aligned} \tag{4.7}$$

The 'TotalDiscountedCostByTechnology(r,t,y)' presented in Equation (4.7) can be reflected into operating, capital, emissions and salvage costs[64] such as described in Equation (4.8). The discounted capital investment cost represents the cost per unit of capacity of each technology. The operating costs can be disaggregated by the variable and fixed O&M costs per unit of capacity of each technology. The emissions penalty is also included in Equation (4.8) (which corresponds to the overall level of CO_2 emissions in this study). The emissions penalty can be endogenously or even exogenously included within the model. Finally, Equation (4.8) discounts the salvage (or residual) value, representing the economic value expected for each technology at the end of its useful life.

[63] In this study, all the costs are discounted back with a predefined discount rate assumed to be equal to 9%, which is based on Refs. [2,376].

[64] We highlight that other 'cost categories' could be easily added to the original objective function.

$$
\begin{aligned}
&TotalDiscountedCostByTechnology(r,t,y) \\
&\quad = DiscountedOperatingCost(r,t,y) \\
&\quad + DiscountedCapitalInvestment(r,t,y) \\
&\quad + DiscountedTechnologyEmissionsPenalty(r,t,y) \\
&\quad - DiscountedSalvageValue(r,t,y)
\end{aligned} \tag{4.8}
$$

However, for those scenarios which include any category of DR strategy, the total discounted costs illustrated in Equation (4.7) would also include (i) the discounted costs of not meeting the load for the load shedding strategy - 'DiscountedCostOfUnmetDemand(r,fdt,y)' - and (ii) the discounted costs for shifting the load - 'DiscountedCostofShiftedDemand(r,fdt,y') - within the co-optimization approach, such as illustrated in Equation (4.9).

$$
\begin{aligned}
&\min z = TotalDiscountedCost\,(\mathrm{r},\mathrm{y}) \\
&\quad = \sum_{t} TotalDiscountedCostbyTechnology(r,t,y) \\
&\quad + \sum_{fdt} DiscountedCostOfUnmetDemand(r,fdt,y) \\
&\quad + \sum_{fdt} DiscountedCostOfShiftedDemand(r,fdt,y)
\end{aligned} \tag{4.9}
$$

The IBESM has also been adapted to enable the inclusion of different levels of energy efficiency investments (see details in Section 4.1 – Part I, Stage 3) and consequently evaluate whether or not the employment of this strategy is cost-effective. Therefore, for those scenarios which consider (i) only EEMs and for scenarios that consider (ii) both EEMs and DR strategies, the objective function should also include the amount of energy efficiency investments '*AverageCost_EE(r)'* such as illustrated in Equation (4.10).

$$
\begin{aligned}
&TotalDiscountedCost_EE(\mathrm{r}) = \\
&\quad = \sum_{y} TotalDiscountedCost(r,y) + AverageCost_EE(r)
\end{aligned} \tag{4.10}
$$

The model constraints include primarily capacity, investment and activity constraints whose full description and details can be found in Refs. [187,364–368].

4.3 Data collection and case study description

The proposed model is a large-scale and long-term deterministic linear optimization problem driven by exogenously defined demands that should be met by a range of technology-specific resources that

compete against each other. The model is restricted to the electricity sector and the scenarios are built based on the Open Source Energy Modeling System – OSeMOSYS[65] (GAMS version) to obtain the least-cost expansion plan for the Brazilian power sector. The input data consists of sets and parameters, including basically technical, economic and environmental ones. Technologies, fuels and emissions are examples of the most essential sets used in the model formulation. The list of sets and parameters are described in Annex A.1 and Annex A.2, respectively.

The model formulation used along with this research relies on linear programming to keep the co-optimization problem manageable in terms of time and computational resources. Linear optimization approaches support the power system modeling from a high level of detail but do not bring about higher complexity levels, such as mixed-integer or nonlinear programming approaches [100]. However, this comes at the expense of a set of limitations, such as the impossibility of using integer variables to represent future capacity expansions. Therefore, in our model, generation capacity investments are only allowed on a continuous scale. The use of integer programming investment modeling approaches may also be envisaged in future research.

Electricity demand data was extracted from the National Grid Operator (in Portuguese, ONS) [311]. Assumptions for the annual demand growth were based on specific-regional data and considering different rates for each period as presented in Annex B.2 [90,373]. The base year of the model is 2018 and the technologies considered are summarized in Figure 1.7 (Chapter 1). Distributed Solar Photovoltaic (PV) is included within the co-optimization model as an exogenous technology based on government forecasts for the entire planning period (see Ref. [90] and [373]). These projections have been established for 2027 [373] and 2040 [90]. Therefore, linear extrapolation is considered for the intermediate years of the planning period for distributed solar PV technology. This research also includes the country's geographical heterogeneity to achieve more reliable results. The power system is therefore split into four main subsystems, namely North (NO), Northeast (NE), South (SO), and Southeast (SE), to represent more effectively its continental dimensions.

The parameters can also be included distinctly for each subsystem, such as the annual demand growth (see Table A.2), transmission capacities and prices of not meeting the load, for instance. The South's international transmission connection is also included within the model since this interconnection is considered the most critical border trade between Brazil and neighborhood countries. The already

[65] Detailed information and the full original model description are available at www.osemosys.org [364–367].

centralized contracted capacity for the medium-term (2018-2023) is also included as a residual capacity[66] based on the medium expansion plan of the country (in Portuguese, PDE [373]).

The high-resolution dataset for representing the temporal model resolution is considered worthwhile. However, the computational complexity associated with the modeling approach is strongly affected as the time-resolution of the model increases [99]. For this reason, the use of time slices to represent the temporal resolution of long-term models has been increasing over the years since this approach may significantly reduce the computational requirements. This practice is especially worthwhile for long-term capacity planning [187], but its importance is even more remarkable when short and long-term model integration is required. The time slices have as the main aim to combine representative times within a year [187]. One time slice could represent, for instance, all the weekdays mornings in winter and another one the weekend evenings in spring. Time slices would also support the integration between supply and demand-side resources under long-term optimization models. The use of linear optimization techniques coupled with time slices leads to shorter computational solution times.

The use of representative time slices is of great significance as it allows to better tackle the trade-offs between short-term modeling constraints and long-term investment decisions under the same approach [143]. Therefore, the model enables us to consider a high time resolution dataset for an entire year using time-slices. Our model is split up into ninety-six time-slices used to represent the demand/supply characteristics of each year of the planning period considering the four seasons (Summer, Fall, Winter, and Spring). Each season is divided into twenty-four daily time-brackets representing each hour of a typical day in each season. The specified demand profile for each time slice was calculated based on the hourly data extracted from the National Grid Operator for 2018 [54].

The premises undertaken to build the model have been based on the primary evidence for the future of the Brazilian power sector. Therefore, after the systematic literature review, we have identified that the future Brazilian power system is projected to rely on two main pillars: (i) the new hydropower projects are expected to be dominated by run-of-river power plants and (ii) a high increase in household solar PV systems is foreseen. Therefore, these particular aspects envisioned for the country in the years ahead are also considered in the input data modeling.

IBESM takes into account the following existing technologies: large hydropower (greater than 30 MW), Small-scale Hydropower Plants (SHP) (less than 30 MW), biomass, natural gas, nuclear, coal, fuel oil, wind power, and solar PV (utility-scale). Distributed solar photovoltaic (PV) and Concentrated Solar Power (CSP) are considered future technologies.

[66] The only exception is for the distributed solar PV.

The input data also includes the existing interconnection capacities (i.e., transmission lines) between Brazilian subsystems (i.e., NE, NO, SE and SO), taking into account the minimum and maximum electricity exchange between the subsystems. The South international connection is also included within the co-optimization model as a possible technology. The co-optimization model also allows power generation technologies to compete against transmission technologies, restricted to Alternating Current (AC) input data in the current model.

Power generation technologies are represented considering their available, minimum and maximum installable capacity, capacity factor, costs (i.e., investment, fixed and variable costs) and efficiency. The minimum and maximum installed capacity set, respectively, the lower and the upper limits for the capacity in the optimization procedure. The minimum planned system expansion (2018 - 2027) is included as a restriction based on the medium-term power capacity expansion plan of the country (Decennial Plan 2027[67] - in Portuguese, PDE [373]) developed by the Energy Research Office (in Portuguese, EPE). The upper threshold values are not included for all power options, i.e., they are restricted only for selected technologies based on technical and economic relevant aspects. The variability of intermittent renewable technologies such as wind and solar PV are represented considering different capacity factors for each time slice.

Based on the power system's historical operation [54], it was also established a minimum target for the overall electricity produced by thermal power plants to enhance both the security and reliability of the modeling approach. This is required due to both the high share of RES in the current power system (highly based on hydropower) and also because of the different factors which condition the real hydropower dispatch, such as the minimum and maximum volume restrictions, water inflows downstream and upstream, flood control measures and environmental protection [103]. Together, these factors cannot be fully captured by the technical nature of the optimization model. Therefore, a minimum target for the thermal power plants was established. This minimum target is also essential to consider once the energy sector is highly vulnerable to the impacts of climate change, particularly in systems with a high share of RES, such as suggested by Ref. [30] which studied Brazil's vulnerability to climate change in the future.

The most relevant technical and economic input data considered in the modeling approach were established based on the current and future projections for the power sector. Annex B.1 shows the capital expenditure CAPEX (US$/kW) [374–376], variable costs (US$/GJ) [374,375], fixed costs (US$/kW) [374,375], fuel costs (US$/GJ) [375], technologies efficiency (%) [374,376], capacity factors [54,374,376] and the projected lifetime for each power source (years) [374]. Other data required for

[67] The detailed information about the expansion plan of the Brazilian power sector can be found in Ref. [373].

modeling, e.g., the discount rate (%) [376], the emissions factor ($MtCO_2/TWh$) and the emissions penalty (US$/ tons of CO_2), are displayed in Table A.3. The emissions factor for the first year of the planning period was established based on the power system's average values from 2014 to 2016 [377]. The emission factor for the remaining years of the planning period was extrapolated based on Ref. [305]. The projected CO_2 emissions allowances prices were established considering the average prices for each year of the planning period based on Ref. [378].

4.4 Model validation and reference scenario (BAU)

The primary aim of this section is to validate the model and describe the Business as Usual (BAU) scenario (Scenario 1) projected for 2040, which will be further used to compare with scenarios that include the implementation of different categories of DSM strategies in Chapter 6 and Chapter 7. Scenario BAU considers that no DSM strategies will be implemented during the forecast planning period (2018-2040). The results are concentrated on the following variables: overall system costs, CO_2 emissions and the total installed system capacity. The input modeling data were described along with Section 4.3 and the details can be found in Annex B.

The reference scenario is used to validate the model, comparing the simulated outputs to the real values for each technology/generation option considering 2018 as the base year. The power system's current characteristics are used in the model as an initial guess for the optimization procedure. Figure 4.5 illustrates the overall electricity generation in 2018, considering the real data extracted from ONS [311] and the results obtained. The obtained results revealed to be quite similar to the real data, as illustrated in Figure 4.5.

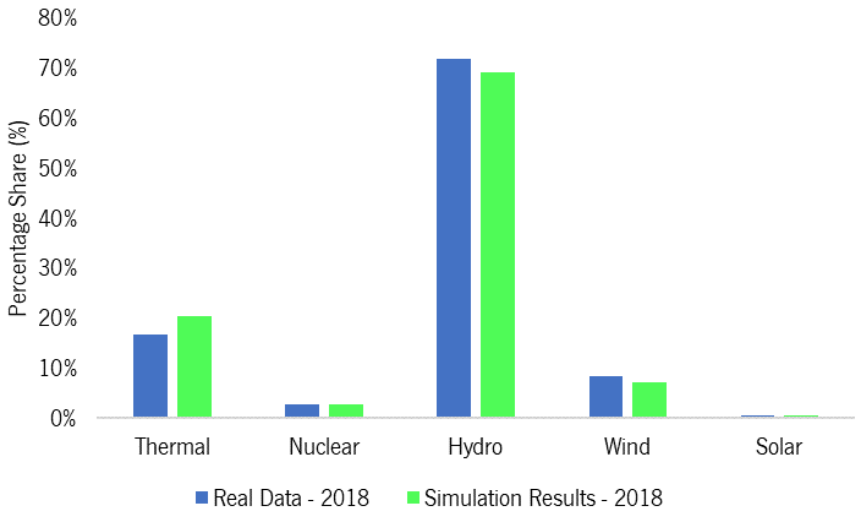


Figure 4.5: Comparison between simulated results and real data for the electricity generation in 2018.

The overall level of CO_2 emissions resulted for scenario BAU accounted for near 32.2 $MtCO_2$ (2018), which was found to be near the real value (near 33.7 $MtCO_2$) extracted from Ref. [379].

The comparison between simulation results and government projections for the overall installed capacity between 2018-2027 (which correspond to the period where there is available data from the government [56]) is illustrated in Figure 4.6. In summary, the results displayed in Figure 4.6 reveal no significant differences between the simulation results and government projections for the period analyzed.

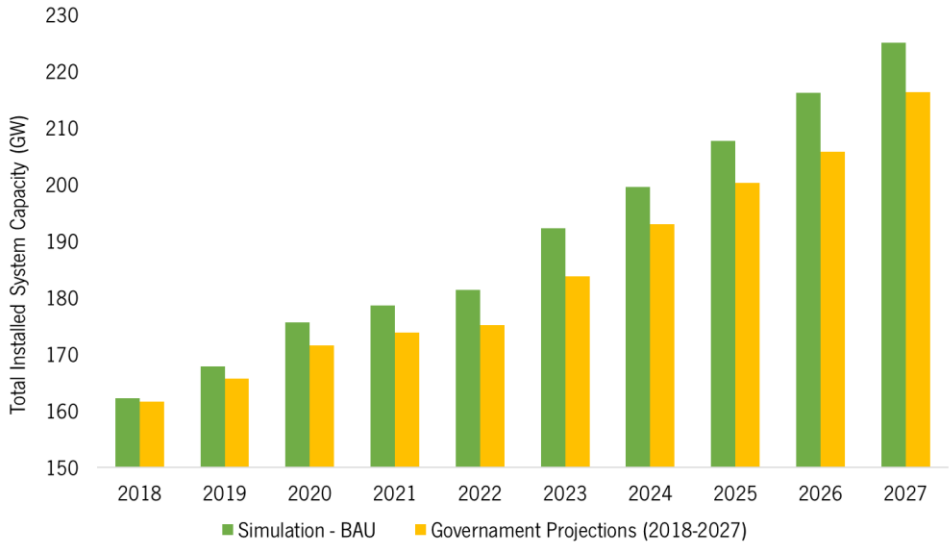


Figure 4.6: Comparison between simulation results and government projections for scenario BAU.

Figure 4.7 illustrates the results for the total installed capacity for each power source across the entire planning period for Scenario BAU (in percentage).

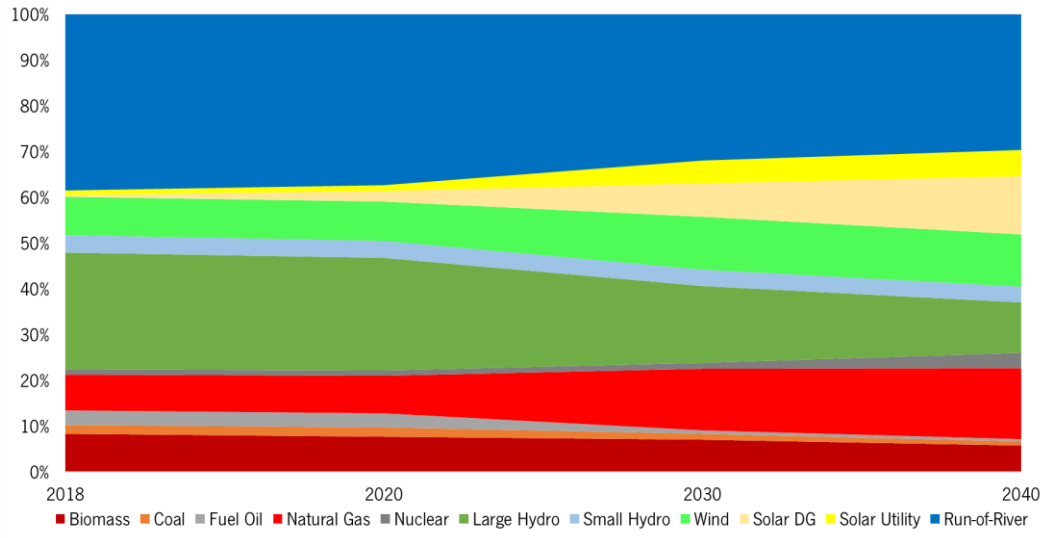


Figure 4.7: Total Installed capacity for each power source for scenario BAU (%).

For the sake of clarity, the power sources were grouped into five key categories in Figure 4.8: thermal (biomass, coal, fuel oil and natural gas); nuclear; hydro (small hydro, large hydro and run-of-river plants);

wind and solar (solar PV distributed, solar PV utility and CSP). Clearly, the overall percentage share of hydropower plants is projected to decrease steadily along with the planning period. The contribution share of solar PV[68] systems seems to have the highest growth in the period, following the government projections. A flat contribution from thermoelectric power plants is also forecasted along with all the planning period. Together, these results provide important insights into the future role of each power source in the Brazilian electricity system. The growth of VRE (especially from solar PV systems) can be particularly outlined.

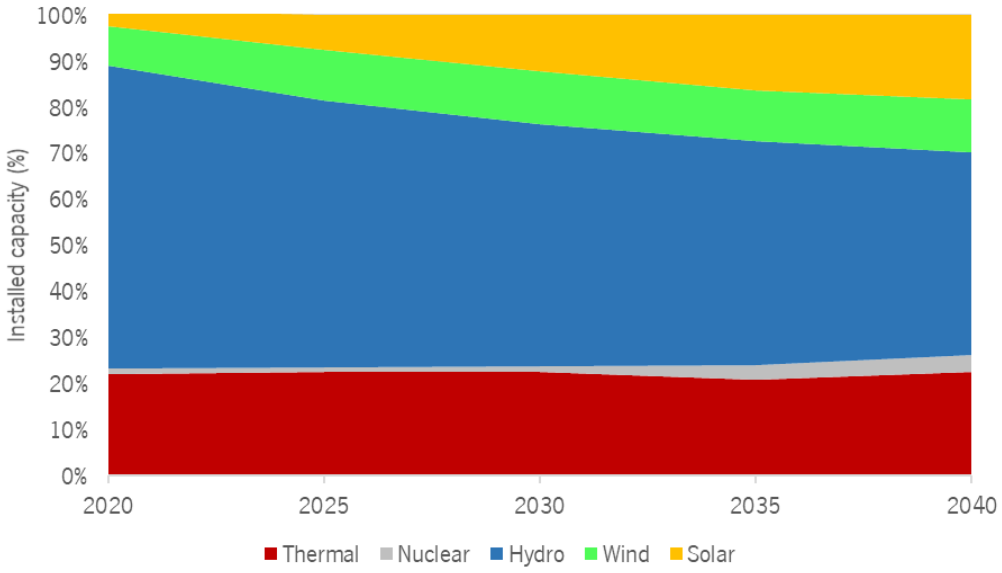


Figure 4.8: Total Installed capacity for the Brazilian power system for scenario BAU (%).

The total installed capacity for each year of the planning period for scenario BAU is shown in Figure 4.9.

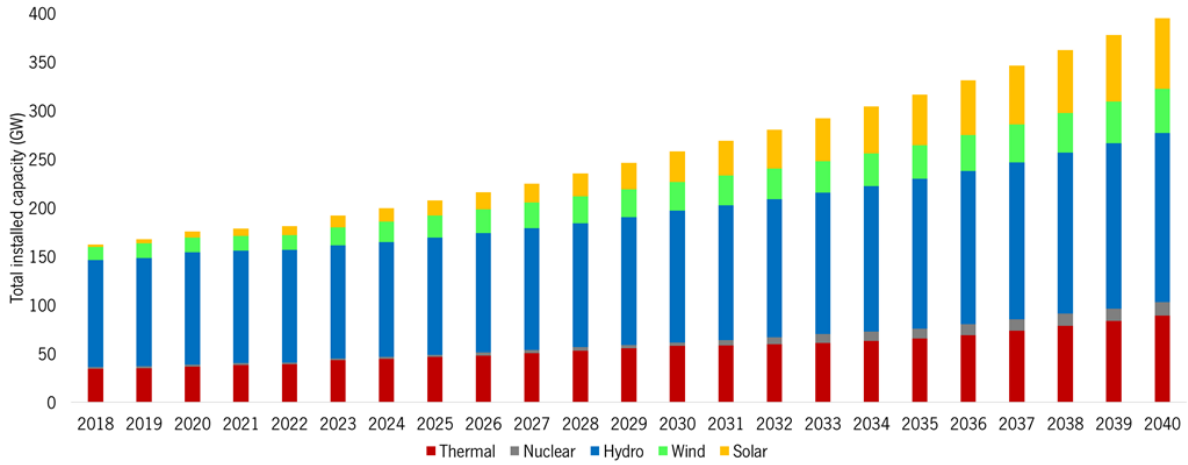


Figure 4.9: Total installed capacity by source for scenario BAU (2018-2040).

[68] It is important to highlight that the distributed solar PV was exogenously included in the model over the entire planning period based on the current government projections [90,373].

Figure 4.10 and Figure 4.11 illustrate the projected overall installed capacity and the total electricity generation for each power source and selected years of the planning period for scenario BAU.

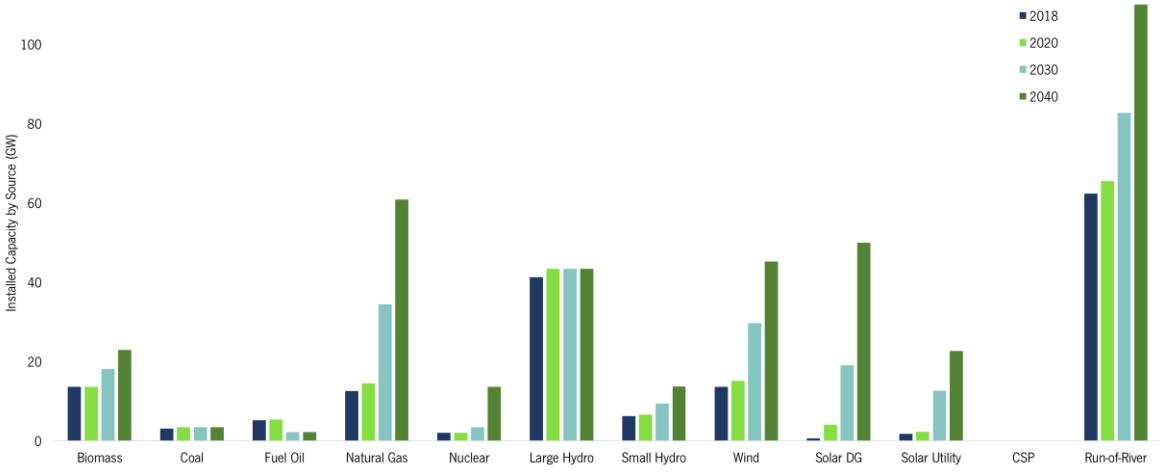


Figure 4.10: Installed capacity by source for scenario BAU.

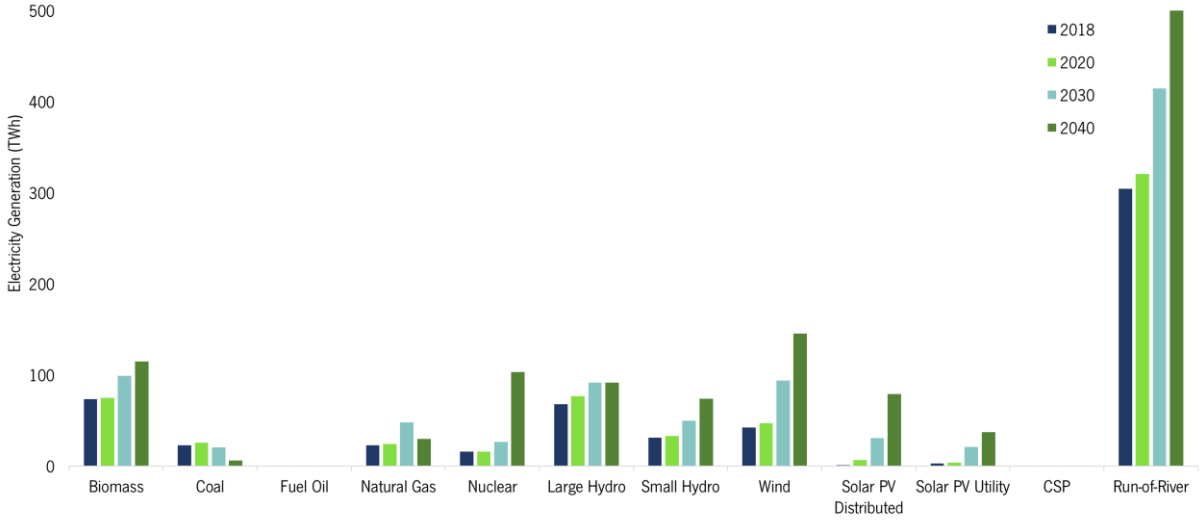


Figure 4.11: Electricity generation by source for scenario BAU.

The overall new installed capacity reaches a value slightly higher than 212 GW in 2040 (Scenario BAU). New investments in thermal power plants for the period 2019-2027 are expected to be based mostly on natural gas technologies, such as projected by the strategic power plan of the country [373]. The importance of natural gas in the Brazilian energy sector has grown considerably over the last 20 years. The construction of the Bolivia-Brazil gas pipeline (GASBOL) in the late 1990s (expanding the current installations by 50%) and the discoveries in the so-called "Campos" Basin (Southwest region) raised the supply of natural gas in the country [90]. The overall demand for natural gas is projected to increase from 62 million m^3/day (2013) to 218 million m^3/day (2050), representing an increase of 3.6% per year for the period 2013-2050 [90].

Therefore, it can be clearly seen from the data in Figure 4.10 the high growth rate in the installed capacity of natural gas among fossil fuel power plants, which is expected to more than quadruple along with the planning period (i.e., increasing from 12.5 GW in 2018 to 60.8 GW in 2040) for scenario BAU. This finding broadly supports the ones reported by the Brazilian Energy Research Office, highlighting that natural gas will have a significant role throughout the decades as electricity demand grows in the country. This future high reliance on natural gas may be explained by numerous factors, including (i) the high reserves from the so-called "*Pré-sal*" layer [56]; (ii) the low capital costs for implementing this technology; (iii) the short leading times for constructing new power plants and last, but not least, (iv) because this power source is considered the cleanest burning and the least polluting fuel among fossil fuel power plants [380]. For this reason, the Brazilian expansion plan (PDE 2026) also attempts to consider the crucial future role of this power option in the country. However, it is worth noting that the electricity generation from natural gas during the planning period seems not to increase at the same rate as its newly installed capacity. A possible explanation for this might be related to the higher electricity production from biomass and nuclear power plants, with lower operating costs than the natural gas power source. The increase in the overall installed capacity of thermal sources, especially from biomass, natural gas, and nuclear power sources, is strictly related to the power system's security and reliability, which relies mostly on hydropower.

Further analysis of the data reveals a small increase in the overall installed capacity of coal between 2018 and 2040 - reaching over 3.4 GW in 2040. The differences between the installed capacity for fuel oil technology during the same period are also described in Figure 4.10. For this case, however, a slight decrease from 5.2 GW (2018) to 2.1 GW (2040) can be verified regarding the overall installed capacity of this fossil fuel power source. These results are also in agreement with the strategic plan of the country [373], which accounts for the decommissioning of these types of fossil fuel power plants over the forecast period. Biomass is also expected to develop a critical role in the power sector, increasing from 13.6 GW in 2018 to 22.9 GW in 2040, which corresponds to a growth of nearly 70% along with the planning period. According to the simulation results, nuclear power plants are also expected to play an essential role in expanding the future system capacity. The optimization model restricts the construction of new nuclear power plants to the Southwest and Northwest regions, reaching an overall installed capacity of approximately 13.5 GW in 2040, almost seven times higher than the current installed capacity. Currently, Brazil has two nuclear power plants in operation (Angra I and Angra II), both located in the Southwest region of the country. A new nuclear power plant (Angra III) is likely to enter into service in 2026 [373], with a slightly higher projected power capacity than 1.3 GW. Although the new nuclear power plant

projected to enter into service in 2026 (in the Southwest region) represents a small share of the overall installed system capacity, its technical impact is significant since this region accounts for more than half of the electricity consumed nationwide. The optimization model also includes Angra III, considering its projected entry into service date (2026).

Wind and solar power are also considered in the country's expansion plan leading the way towards a sustainable future. The increase of wind and solar power in the electricity mix seems to result in considerable growth of the electricity produced by these renewable sources along with the planning period. More than 20% of Brazil's electricity generation is expected to come from variable renewable resources (i.e., wind and solar power) by 2040. Distributed solar PV, solar PV (utility-scale) and wind power are likely to have the most remarkable increase rate among renewable technologies. The results indicate that solar power will also have a determinant role and might considerably moderate the thermal generation in 2040. Wind power more than triples its current renewable electricity capacity between 2018 and 2040, increasing its contribution share in the overall installed system capacity from 13.6 GW in 2018 to 45.2 GW in 2040. This growth over the forecast period is even higher for distributed solar PV reaching an overall installed capacity near 50 GW in 2040. Therefore, the most striking result is related to the overall installed capacity for distributed solar PV. The share of wind and solar power regarding its overall installed capacity exceeds 30% in 2040. The installed capacity for CSP appeared to be unaffected by the optimization process. This fact can be mostly explained by the high up-front costs of this technology compared to the other technologies, which considerably conditioned the obtained results.

The results also indicate that the overall installed capacity for run-of-river hydroelectricity would increase by almost 88% between 2018 and 2040. Hydropower generation is also expected to remain Brazil's largest renewable electricity generation source over the entire forecast period. However, its share in the overall electricity production is projected to decrease from 69% in 2018 to 59% in 2040. The overall installed capacity for SHPs is forecasted to increase from 6.2 GW (2018) to 13.7 GW (2040) over the planning period. This small increase is likely to be related to the fact that hydropower is a highly site-specific technology and the best sites have typically already been exploited. Also, the future up-front costs for SHPs are not predictable to decrease [381] compared to other RES, such as the case of wind and solar power technologies, which are foreseen to decline steadily over the medium-long term [382].

Thereby, the high share of renewable generation in the overall electricity production would strongly contribute to reducing the energy-related CO_2 emissions level and contributing to the transition towards a more sustainable future. The overall CO_2 emissions released over the forecast period are estimated to be slightly higher than 674 million tons of CO_2 for scenario BAU.

Concerning the total installed capacity by region (i.e., NE, NO, SE and SO), Figure 4.12 compares the obtained results for scenario BAU. It can be seen from the data in Figure 4.12 the high installed capacity of wind power in the Northeast region. The current literature clearly supports this finding concerning the high wind power potential in this region, followed by the South [373]. According to the simulation results, the overall wind power installed capacity for the Northeast region is projected to almost quadruple – reaching over 40 GW in 2040 compared to 2018. The second significant finding is related to solar power growth in the NE and SE regions, as illustrated in Figure 4.12. It is worth recalling the great importance attached to the complementarity[69] between hydro and wind power in the Brazilian power sector, as better discussed by Ref. [103].

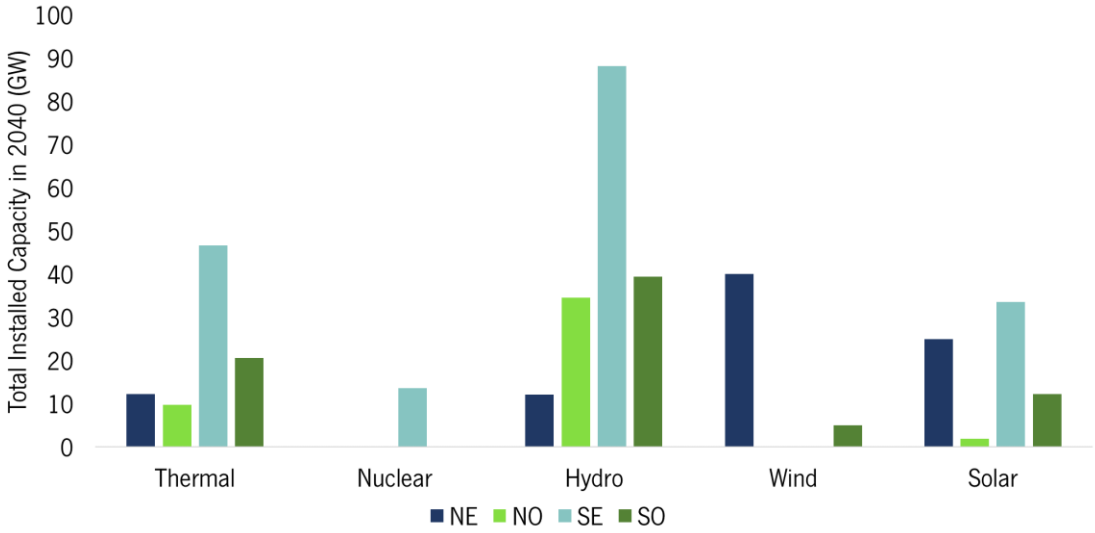


Figure 4.12: Total installed capacity by region for scenario BAU (GW).

The simulation results for the overall regional installed capacity for the first and last year of the planning period are illustrated in Figure 4.13 and Figure 4.14, respectively. It can also be seen that although a decrease in the overall installed capacity seems to arise in the Southwest (SE) (reducing from 53% in 2018 to 46% in 2040), this region is projected to have the highest contribution share among all regions for the entire planning period. However, no significant differences in the overall installed capacity were found for the North (NO) (12 % in 2018 and 12% in 2040). The single most striking observation to emerge from the data comparison comes from the increase in the overall installed capacity for both South (SO) (15% in 2018 and 20% in 2040) and Northwest (NE) (increasing from 20% in 2018 to 23% in 2040) regions.

[69] The Brazilian power sector is discussed with details in [103] in which renewable scenarios are compared for technical, cost, emissions and risk parameters. The study [103] outlines the importance of seasonal complementarity of hydro and wind power for the future and also point out the determinant role of solar power, expected to moderate considerably the thermal generation in the country by 2050.

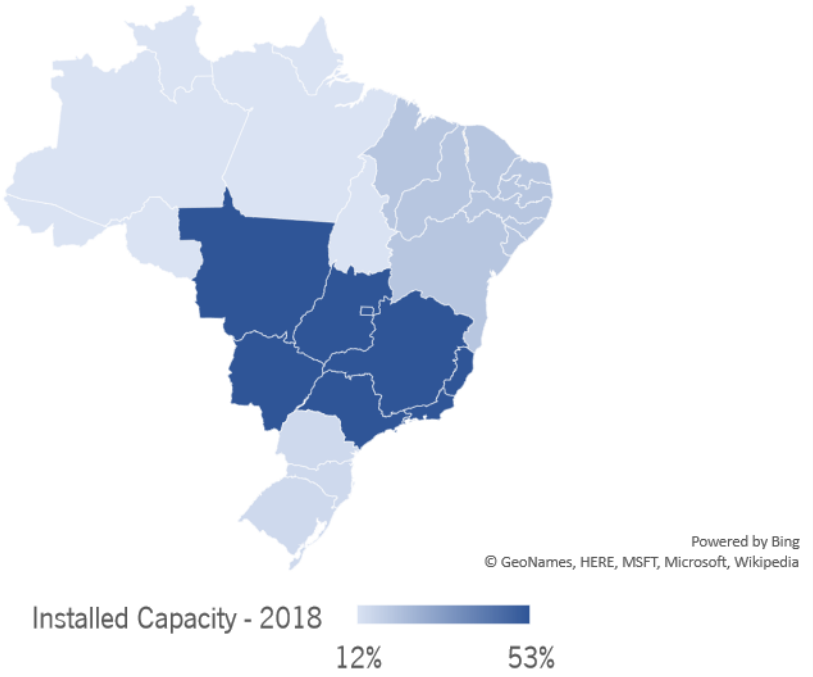


Figure 4.13: Overall regional installed capacity for scenario BAU in 2018 (%).

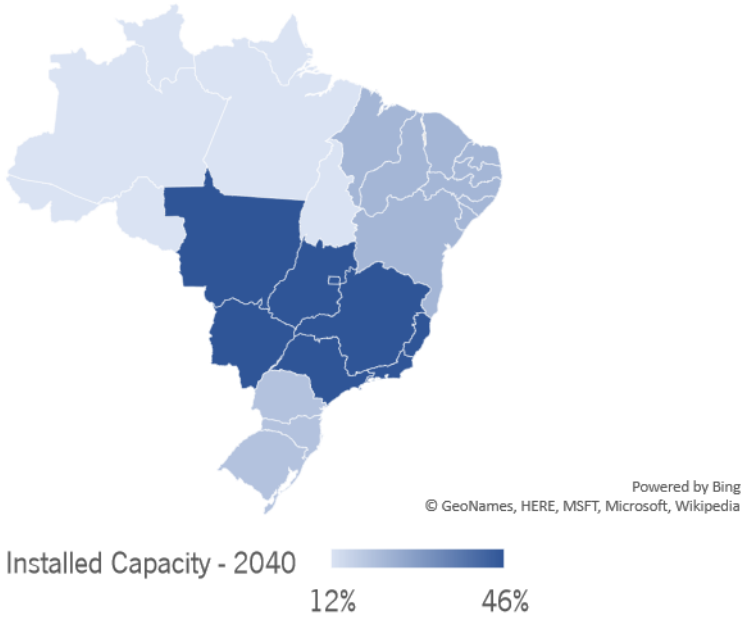


Figure 4.14: Overall regional installed capacity for scenario BAU in 2040 (%).

Figure 4.15 illustrates the cost-share for each category (in percentage) along with the planning horizon. Clearly, for the first years of the planning period, the investment costs are much lower compared to the remaining years. This can be explained by the fact that the already contracted capacities for the period 2018-2023 are modeled as residual capacities. The emissions cost and the cost of importing electricity

represent only a small percentage of the total costs for the entire planning period, as shown in Figure 4.15.

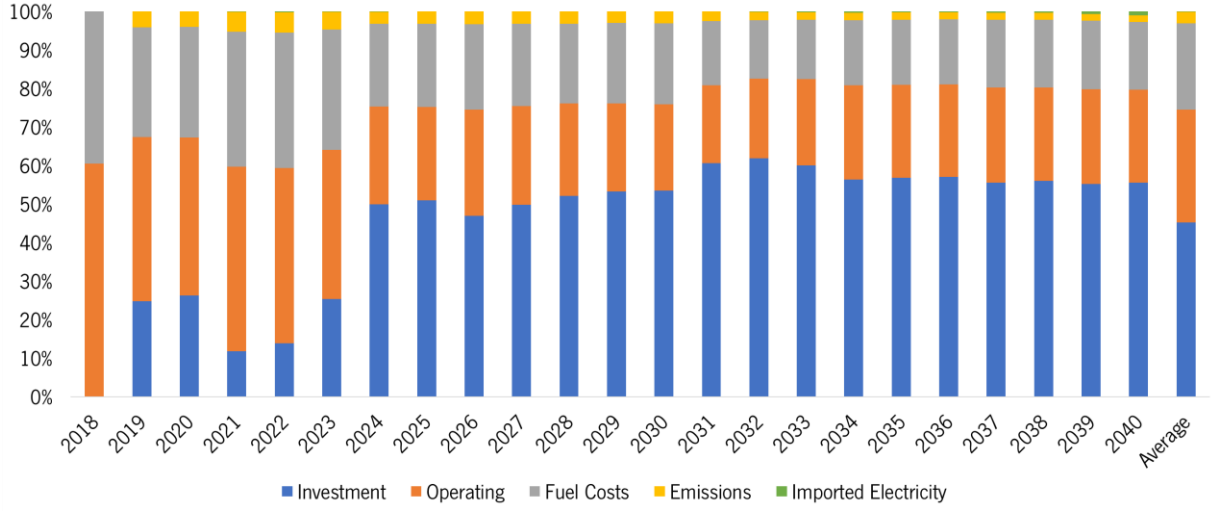


Figure 4.15: Cost-share by category for scenario BAU (%).

4.5 Concluding remarks

This chapter introduced the details of the modeling approach followed along with this research, including the case study description, model validation and the establishment of the reference scenario. The Brazilian electricity system is a typical example of a power system that deeply relies on RES, and therefore, it was used as the case study. Our model attempted to include a set of specific characteristics such as distributed generation, regional and international transmission capacities, and splitting up the country into four main subsystems to represent the country dimensions effectively.

Our findings also provide important insights into the future overall installed capacity, CO_2 emissions and total system costs for scenario BAU. Overall, the results obtained allowed us to conclude the accuracy of the obtained results and this was confirmed by comparing the obtained simulation results to the real collected data. The small differences still exist due to (i) the uncertainties (e.g., the stochastic and intermittent characteristic of RES) but also because (ii) the particular strategic dispatch characteristics of the National Grid Operator cannot be fully captured by the model. These uncertainties combined lead to small errors for the entire year, which can be considered acceptable considering the long-term nature of the study. Findings of this study demonstrated that RES should remain predominant in the Brazilian energy sector in the medium-long term. The overall renewable electricity production for 2040 is expected to remain steady and hydropower is likely to remain the dominant power source in the electricity mix over the entire forecast period (2018 – 2040).

Chapter 5. Theoretical DR Potential in the Brazilian Power Sector

This chapter aims to assess the current and future theoretical DR potential across the Brazilian power system, whose results will be further used in Chapter 7 to assess both the technical and economic DR potentials. After introducing the topic in Section 5.1, Section 5.2 proceeds to present the data collection techniques employed to quantify the flexible load in the residential, industrial and commercial sectors. This chapter will use quantitative data collection techniques from multiple-source secondary data. Section 5.3 illustrates the main results obtained for the case study under analysis and Section 5.4 summarizes the main research findings by discussing the implication of the results to future research into the field.

5.1 Introduction

Renewable energy sources coupled with energy efficiency and demand-side flexibility measures have been targeted as great potential contributors to address the climate-related challenges towards a more sustainable future [13,66,88]. Meanwhile, the flexibility in grid operations has become a valuable solution to respond to the several problems brought about by intermittent renewable generation growth and the use of DR measures has emerged as a promising option to tackle these challenges.

In Brazil, the potential of DR is considered by authorities a vital element to delineate the medium and long-term electricity expansion plan of the country [58], which might postpone investments in distribution and transmission[70] systems, for example. Additionally, considering the high demand increase and consequently the new projected generation power sources that should be installed in the future, DR might bring about a set of advantages such as reducing the need for new power installed capacity and enhancing the power system's security and reliability. However, to give a well-known example for clarity, the country's historical low DR contribution intensified the electricity supply problems brought about by the severe droughts in 2014, resulting in a substantial increase in the electricity production from thermal power sources. Therefore, the decrease in the regularization capacity of the reservoirs (as discussed in [68]) together with both the increasing electricity demand and the upward trend in the overall level of emissions, led the government to promote a set of DSM (including Demand Response - DR and EMMs) strategies to ensure a more resilient, reliable and efficient power system for the coming years.

Meanwhile, the authors of [188] emphasize the future country's potential for a wider penetration of DR programs. A well-known example regarding the recent developments of DR in Brazil - specifically focused

[70] The main challenges regarding the transmission system expansion in Brazil are highlighted by the Brazilian Energy Research Office (in Portuguese, EPE) in its Decennial Plan (i.e., PDE 2027), which can be summarized into three main challenges: (i) socio-environmental and land ownership complexities associated to new transmission lines projects, (ii) the increasing rise in regional temperatures due to global climate change aspects and (iii) the aging of the Brazilian transmission system (expected to become more critical in future years).

on the residential sector - encompasses the implementation of the Tariff Flag System (2013) [316], the White Hourly Tariff (2016) [287] and the consumer's opportunity to opt for the electricity prepayment [286]. The White Hourly Tariff, for example, is considered a type of TOU rate, in which the price of electricity is split up into off-peak, mid-peak and on-peak periods. These recent new policies and regulations also expect to motivate price-based DR programs in the country. For the industrial sector, a pilot DR program [55] (focusing on large industrial consumers of North and Northwest regions) has been implemented by the ANEEL in 2017. This industrial DR program is based on the consumers' previous information regarding their willingness to accept a given level of load reduction bids and load recovery [383].

Therefore, the current status of DR implementation in Brazil is very restricted, with only a few DR programs effectively implemented. However, the sector authorities agree with the increasing importance of DR strategies to delineate the medium and long-term strategic energy plan of the country [58]. Most previous research focused on long-term planning models has neglected the potential contribution from demand-side resources, particularly for the Brazilian case.

Most of the previous studies (e.g., [188,226,227,238,255]) that investigate DR issues across different countries are primarily based on qualitative approach analysis [253]. In recent years, however, a growing number of publications have focused on assessing the different categories of DR potentials (also referred to as load flexibility potential). Nonetheless, these analyzes have been usually limited to European countries (see for example [245,246,251,268,270]). A systematic review of the different categories of DR potentials (i.e., theoretical, technical, economic and achievable[71]) has been recently addressed (see Chapter 2 and Ref. [234] for details), which revealed a lack of understanding regarding the different categories of DR potentials in the current literature. The theoretical DR potential can be defined[72] as the overall consumers' potential suitable for DR. The theoretical DR potential does not take into account any technical (e.g., the shifting time), economic (e.g., investment and operational costs for DR implementation) or practical (e.g., the level of consumers' acceptance) restrictions [200,246,253].

A detailed examination of the literature also revealed few research studies (e.g., Ref. [98]) which have attempted to quantitatively assess the long-term potential of DR for the case of the Brazilian power system. The authors of Ref. [98], for example, addressed the specific role of sector coupling within the country using a long-term energy model and considering a simplified approach for estimating the DR potential.

[71] The achievable DR potential can be divided into the Maximum Achievable Potential (MAP) and the Realistic Achievable Potential (RAP). The achievable DR potential has also been interchangeably referred by the available literature as social, practical, market, realizable, feasible or even acceptable DR potential [234].

[72] This definition is used along with this paper to refer to the theoretical DR potential.

Also, to account for the load flexibility potential within the Brazilian power system, Ref. [98] considered (partly) the DR potential of both the commercial and industrial sectors. The authors concluded that because of the high renewable potential in the country (mostly from hydropower resources [103]), the contribution of DR strategies is limited to load balancing purposes, for instance. However, great potential for peak load reductions (estimated to be about 3.3 GW) is projected for the future [103].

Therefore, the vast majority of published research has not yet provided a holistic assessment of the load flexibility potential for the case of Brazil. This may be understood by a set of factors. Firstly, this is considered a complex task and relies mostly on extensive data collection and analysis. The data scarcity (e.g., the load profile for each process/appliance) figures out as another potential challenge and usually, studies need to rely on a set of assumptions based on estimated data. In this context, to the best of the authors' knowledge, few research works have been able to draw on any structured research into the current and future DR potentials for the case of the Brazilian power sector. The results are usually somewhat limited to oversimplified analyzes, considering only partly the available DR potential and generally focusing on particular sectors. However, the existing assessments may not be representative in terms of the full DR potential available across the main sectors within the country.

Therefore, given the background mentioned above, this chapter presents a first attempt to establish the Brazilian power sector's theoretical load flexibility potential. Two central issues are addressed: (i) a sectoral assessment across the residential, commercial and industrial sectors is provided together with (ii) a regional analysis - splitting the Brazilian power system into four main subsystems.

5.2 Data collection and analysis

The methodological approach followed in this chapter for assessing the theoretical DR potential within the Brazilian power system is based on Figure 2.8 – Steps 1 to 6 presented in Chapter 2. The proposed methodology is broadly divided into (i) the identification of the main processes (i.e., for the commercial and industrial sectors) and appliances (i.e., for the residential sector) suitable for DR, followed by (ii) the quantification of each flexible load in terms of the overall annual electricity (TWh) and the hourly potential (GW). Afterward, (iii) the assessment of the load profiles[73] for each process/appliance is undertaken, followed by (iv) the hourly theoretical DR potential assessment for each process/appliance[74] k. Then, (v) the calculation of the overall hourly theoretical DR potential for each sector i is assessed. Finally, the result analysis for each year, region and process/appliance is conducted.

[73] The assessment of the load profiles can be performed independently of the previous stages.

[74] This calculation would also include the percentage of flexible demand for each application, as it will be further described.

Given the available data and the technical differences among sectors, different approaches have been taken into account to quantify the potential of flexible loads in each sector. For the residential sector, a bottom-up approach (which distinguishes individual technologies) is considered, whereas a top-down approach is followed to assess the theoretical DR potential for the commercial and industrial sectors. The potential of flexible loads for the commercial and industrial sectors is estimated based on their annual electricity consumption.

The set of equations (2.1)-(2.9) presented in Chapter 2 allows the estimation of the theoretical DR potential for each region, sector and process/appliance. The temporal availability of DR is taken into account through the identification of typical daily load profiles. Due to the lack of measurements, typical demand load patterns are considered based on available literature. The residential sector load profiles were estimated based on a tool developed by the National Electricity Conservation Program (in Portuguese, PROCEL) known as Information System on Possession and Habits of Consumption (in Portuguese, SINPHA). It is worth mentioning that the overall potential of the flexible demands (primarily for the residential sector) is highly dependent on the characteristics of the appliances (i.e., type, power, efficiency and penetration rate) but also on the pattern of consumption of these appliances which are affected mostly by the consumer's per capita income and their willingness to use more efficient technologies in the future [90]. Typical load curve profiles are considered for the commercial and industrial sectors because of data scarcity. For energy-intensive industries, due to both the considerable heterogeneity of processes and its high utilization rates, a constant load is considered for each year [200,246].

The use of daily, weekly and/or seasonal load profiles for each process/appliance should be considered when there is enough data availability [243,264]. However, load profiles for the Brazilian power sector are restricted to average values. For this reason, we do not distinguish the load profiles across seasons and years. However, a lively discussion is further presented to better understand the main seasonal implications by comparing the estimated theoretical DR potential with metered data from typical load power profiles for extreme seasons (e.g., winter and summer). The data used for the load profiles of each process/appliance are displayed in Annex B.3. Although the presumed non-linear and time-varying characteristics of the load profiles in the future, there is no precise available data regarding the future end-use load profiles for the Brazilian power sector. Therefore, we assumed that the load profiles for all DR processes/appliances remain unchanged to estimate the flexibility potential in future years, such as considered in Refs. [200,246].

The suitable DR applications should be selected based on a qualitative evaluation of each process/appliance [240], including the availability, storability and controllability analysis for each application [235]. The selection of the main processes/appliances with some degree of load flexibility for the specific case of Brazil has been based on data presented in Table 2.5 (Chapter 2). These characteristics are then correlated with the shed-ability and shift-ability of each application. The particular processes/appliances selected to contribute to the overall DR potential are shown in Table 5.1.

Table 5.1: Selected processes/appliances suitable for DR.

Energy-Intensive Industries	**DR Action**	**Commercial**	**DR Action**
Bauxite	Shedding	Air-conditioning/ cooling	Shifting
Alumina	Shedding	Direct Heating	Shifting
Primary Aluminum	Shedding	Storage water heater	Shifting
Iron and Steel	Shedding	**Residential**	**DR Action**
Ferroalloys	Shedding	Freezer	Shifting
Soda	Shifting	Refrigerator	Shifting
Petrochemical	Shifting	Washing machine	Shifting
Cellulose	Shifting	Laundry dryers	Shifting
Paper Machines	Shifting	Dishwashers	Shifting
Cement mills	Shifting	Air Conditioning	Shifting

The projected number of households (million), market penetration rate (%) and specific energy consumption (kWh) for years 2017, 2020, 2030, 2040 and 2050 are presented in Table 5.2, Table 5.3 and Table 5.4, respectively. The data presented in Table 5.2, Table 5.3 and Table 5.4 was linearly extrapolated when no specific information was available between periods. The projected number of households between 2017 and 2027 was retrieved from Ref. [56] and for the remaining years (2030 – 2050) based on Ref. [90]. Data for each market penetration rate was retrieved from different sources, such as illustrated in Table 5.3. Due to data scarcity, the authors established the market penetration rate for the laundry dryers and dishwashers based on both the available literature and authors' expertise. The specific energy consumption for each appliance (Table 5.4) was estimated based on Ref. [243] and Ref. [56]. Other relevant data for the industrial and commercial sectors used in this study are illustrated in Table 5.5.

Table 5.2: Projected number of households (million).

Region	**2017**	**2020**	**2030**	**2040**	**2050**	**Reference**
NE	18.3	19.3	22.1	24.4	26.7	[56,90]
NO	6.1	6.4	7.3	8.1	8.9	[56,90]
SE/CO	33.6	35.3	40.5	44.7	48.9	[56,90]
NO	9.6	10.1	11.6	12.8	14.0	[56,90]
Total	**67.7**	**71.1**	**81.5**	**90.0**	**98.5**	**-**

Table 5.3: Market penetration rate (%).

Equipment	2017	2020	2030	2040	2050	Reference
Freezer	18.0%	15.4%	14.6%	13.3%	12.0%	[90]
Refrigerator	110.0%	110.6%	112.0%	112.0%	112.0%	[56]
Washing Machine	69.0%	74.4%	81.0%	87.5%	94.0%	[90]
Laundry Dryers	6.9%	7.2%	8.2%	9.4%	10.8%	-
Dishwashers	2.0%	2.1%	2.4%	2.7%	3.1%	-
Air Conditioning	42.0%	46.2%	60.7%	62.8%	65.0%	[90]

Table 5.4: Specific energy consumption (kWh/Equipment).

Equipment	2017	2020	2030	2040	2050	Reference
Freezer	473	459	413	372	335	[56]
Refrigerator	324	314	284	257	233	[56]
Washing Machine	64	62	58	55	51	[56]
Laundry Dryers	308	314	335	357	381	[243]
Dishwashers	272	277	296	315	336	[243]
Air Conditioning	654	640	595	554	515	[56]

Table 5.5: Other input data.

Industrial Sector	Value
Revision outages (%)	5%
Capacity utilization level (%)	90%
Number of hours in a year	8760
Flexible share (%)	100%
Commercial Sector	**Value**
Annual Growth (%) - 2017-2020	5.1%
Annual Growth (%) - 2020-2030	5.2%
Annual Growth (%) - 2030-2040	4.4%
Annual Growth (%) - 2040-2050	4.5%
Number of full load hours	5840

5.3 Estimating the theoretical load flexibility potential

This section will provide the results regarding the DR potential assessment for each sector and year for the specific case of the Brazilian power system. The theoretical DR potential is estimated considering both load shedding and load shifting strategies, depending on the process/appliance.

5.3.1 DR potential in the industrial sector

The specific electricity consumption (kWh/t) and the yearly production (Mt)[75] for each energy-intensive industrial process were estimated based on different data sources, as presented in Table 5.6.

[75] Mt stands for 'Millions of tons'.

Table 5.6: Specific electricity consumption and yearly production for energy-intensive processes.

Process	2017		2020		2030		2040		2050		Ref.
	kWh/t	Mt/year	kWh/t	Mt/year	kWh/t	Mt/year	kWh/t	Mt/year	kWh/t	Mt/year	-
Bauxite	13	40.0	13	42	12	55	12	67	12	81	[90,384]
Alumina	290	11.7	284	13	267	16	259	20	255	25	[90,384]
Primary Aluminum	14373	0.9	14089	1	13405	1	13099	1	12978	2	[90,384]
Iron and Steel	505	38.6	500	42	462	62	444	75	447	81	[90,385]
Ferroalloys	8809	1.0	8957	1	8661	2	8535	2	8480	2	[90,385]
Pellets	48	46.3	48	46	47	46	46	46	46	46	[90,386]
Primary Copper	1503	0.2	1476	0	1425	0	1404	0	1394	0	[90,386]
Soda	2675	1.5	2639	2	2558	2	2515	3	2479	4	[90,385]
Petrochemical	1552	3.0	1524	3	1490	5	1491	7	1471	9	[90,385]
Cellulose	957	22.4	939	28	899	43	882	52	877	61	[90,385]
Paper Machines	774	11.7	761	13	731	20	717	28	712	33	[90,385]
Cement mills	109	71.1	107	72	101	106	97	137	93	131	[90,385]

To assess the regional load flexibility potential, the data presented in Table 5.6 was split into the four main Brazilian subsystems, namely Northwest (NE), Southwest[76] (SE), North (NO) and South (SO) - each one comprising a set of states (see Figure 5.1). Figure 5.1 illustrates the central Brazilian regions, which are split up into RS, SC and PR (South); SP, MG, RJ, ES, MS, GO, DF and MT (Southwest and Midwest); BA, SE, AL, PE, PB, RN, CE. MA, PI (Northwest) and AC, RO, TO, PA, AM, AP, RR (North). The regional assessment is performed based on each process's percentual contribution to the overall industrial electricity consumption according to the data retrieved from Ref. [377].

[76] The Southwest (SE) subsystem comprises both Southwest and Midwest regions in Brazil (SE/CO). Therefore, along with this paper, the term SE will be used to represent both power subsystems SE and CO.



States of Brazil: Acre (AC), Alagoas (AL), Amapá (AP), Amazonas (AM), Bahia (BA), Ceará (CE), Distrito Federal (DF), Espírito Santo (ES), Goiás (GO), Maranhão (MA), Mato Grosso (MT), Mato Grosso do Sul (MS), Minas Gerais (MG), Pará (PA), Paraíba (PB), Paraná (PR), Pernambuco (PE), Piauí (PI), Rio de Janeiro (RJ), Rio Grande do Norte (RN), Rio Grande do Sul (RS), Rondônia (RO), Roraima (RR), Santa Catarina (SC), São Paulo (SP), Sergipe (SE) and Tocantins (TO).

Figure 5.1: Regions of the country (Brazil).

The overall DR potential (TWh) for each region and energy-intensive industrial process in 2017 and 2050 is illustrated in Figure 5.2 and Figure 5.3, respectively. It is worth mentioning that the DR potential might be categorized in load shedding or load shifting depending on the process. However, for the sake of simplicity, these categories of DR potentials are summed up in Figure 5.2 and Figure 5.3. Specifically, the overall energy shedding potential increases by 102% - from 31.2 TWh (2017) to 63 TWh (2050) - whereas the energy shifting potential is projected to increase 115% in the same period (from 27.8 TWh in 2017 to 59.8 TWh in 2050).

As shown in Figure 5.2 and Figure 5.3, the Southwest region (SE) accounts for the higher contribution share in the overall DR potential for the industrial sector compared to other regions. The North (NO) has a particular high contribution for the following processes: iron and steel, primary aluminum and ferroalloys and lower but still substantial potentials are found to alumina, pellets and bauxite processes. The South (SO) accounts for the lowest contribution in the overall industrial DR potential (6.2 TWh in 2017 and

16.8 TWh in 2050) compared to other regions, but a high load flexibility potential can be found for paper machines and cellulose in this region. Although the highest growth rate might be attributed respectively to the petrochemical and paper machines processes in the period 2017-2050, the iron and steel category stands out with the highest contribution in the overall DR potential increasing from 12.2 TWh in 2017 to almost 21.6 TWh in 2050.

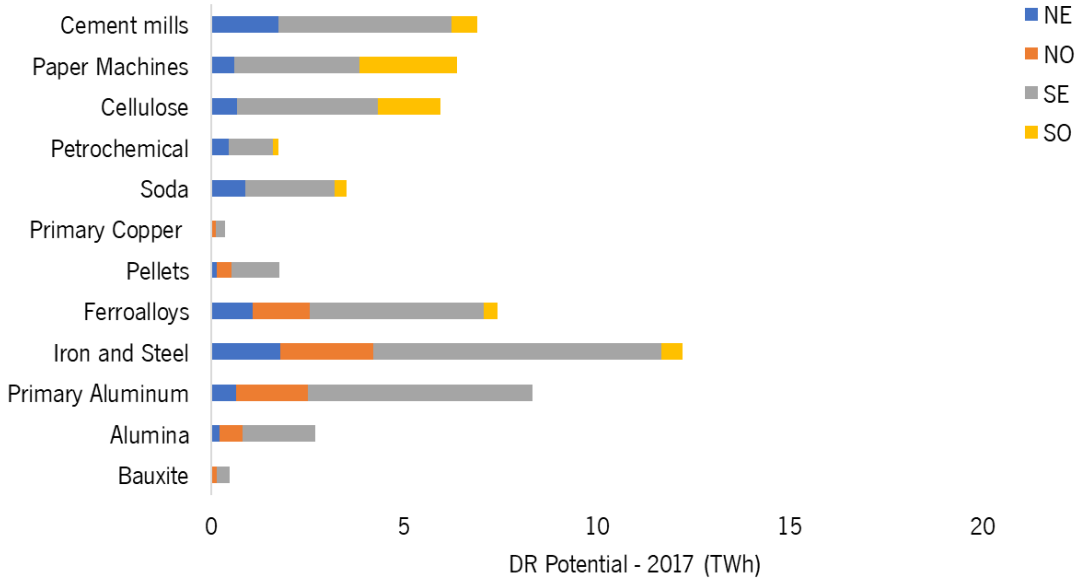


Figure 5.2: DR potential for each region and energy-intensive industrial process in 2017 (TWh).

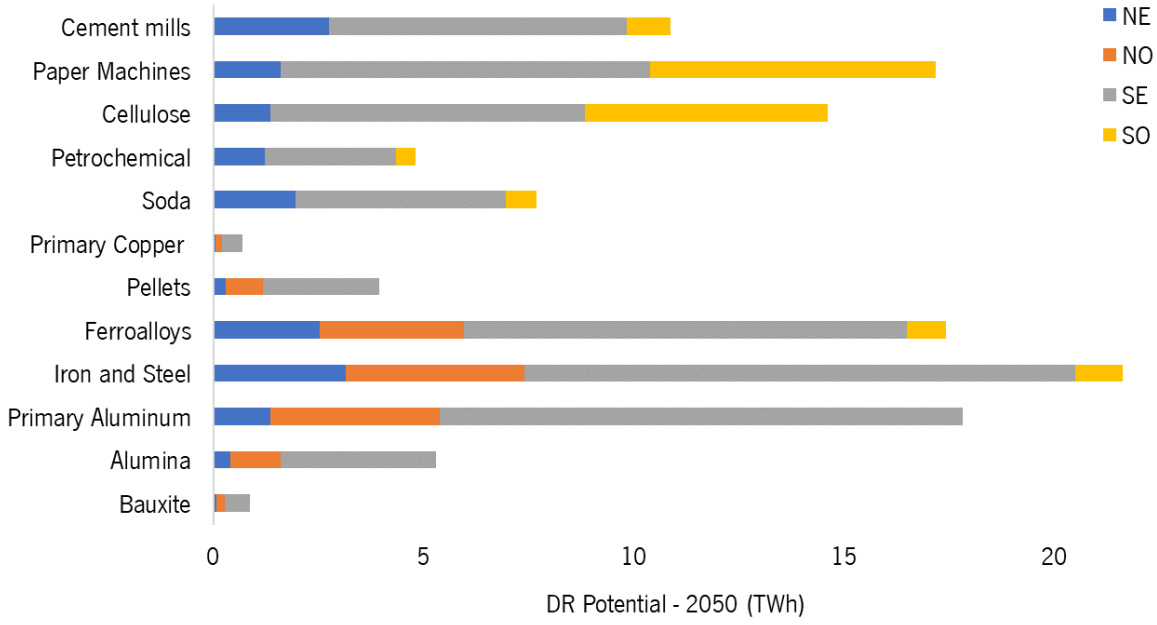


Figure 5.3: DR potential for each region and energy-intensive industrial process in 2050 (TWh).

Further analysis of the data illustrates the overall DR potential by region and year for each energy-intensive industrial process (Figure 5.4) and what stands out, in this case, is the vast disparity between the DR

potentials for each region. The Southwest (SE) represents the highest DR potential for both load shedding and load shifting. A lower load shifting potential can be observed for the North (NO) across all the years compared to its overall load shedding potential. The opposite occurs for the South (SO), in which the load shifting potential is substantially higher than its load shedding potential.

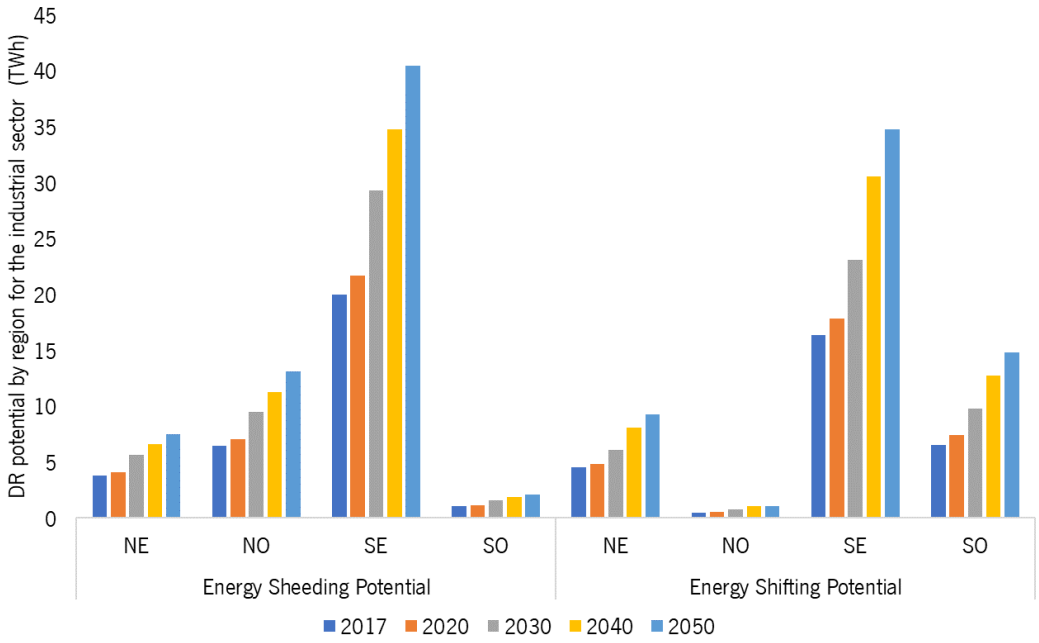


Figure 5.4: Overall theoretical DR potential by region and year for energy-intensive industrial processes (TWh).

The overall DR potential (GW) for each energy-industrial process is illustrated in Figure 5.5. Our findings suggest that the overall load flexibility potential (i.e., maximum DR capacity in GW) for energy-intensive industries would increase from 7.9 GW in 2017 to approximately 16.4 GW in 2050.

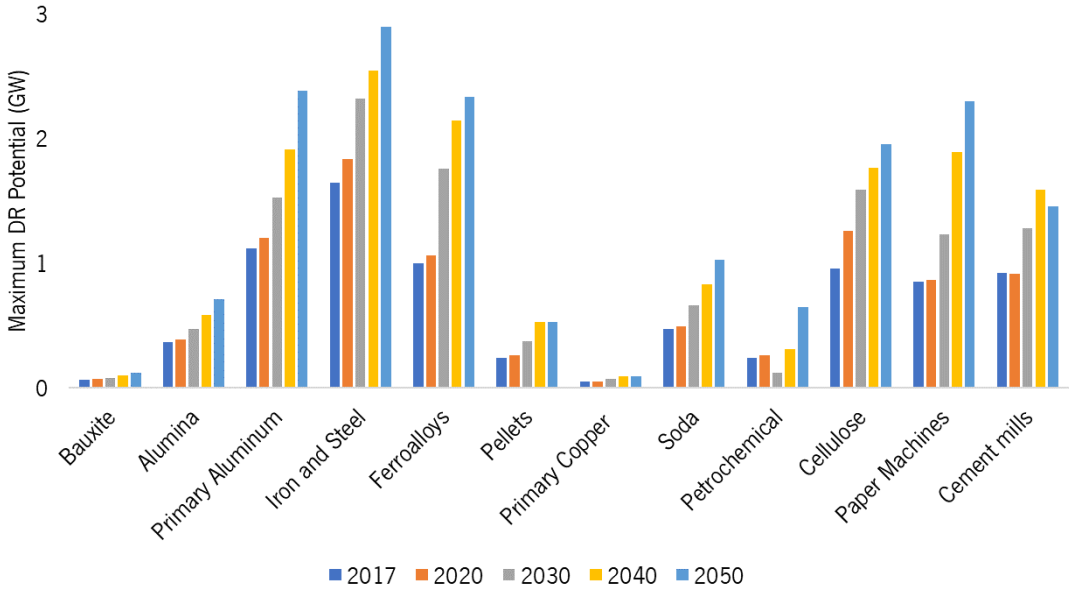


Figure 5.5: Maximum DR potential for each energy-intensive industrial process (GW).

5.3.2 DR potential in the commercial sector

Due to data scarcity, the combination between each process and its share is frequently used to categorize the overall electricity consumption for the commercial sector. To estimate the DR potential for the commercial sector, it is also assumed that 10% (for each year) of the total electricity consumption would come from self-generation systems. Therefore, this share is discounted from the commercial sector's overall DR potential (see Equation (2.4))).

The overall DR potential (TWh) for each process considered suitable for DR in the commercial sector is illustrated in Figure 5.6. According to these results, we can infer that the air-conditioning/cooling systems are responsible for the highest commercial DR potential, which more than quadruple its share, increasing from 11.5 TWh in 2017 to 52.8 TWh in 2050. Heating processes represent a very limited contribution compared to the air-conditioning/cooling systems. However, we point out that the results for the commercial sector were based upon restricted available data, and therefore, the lack of detailed data in the sample adds further caution regarding the generalisability of these findings.

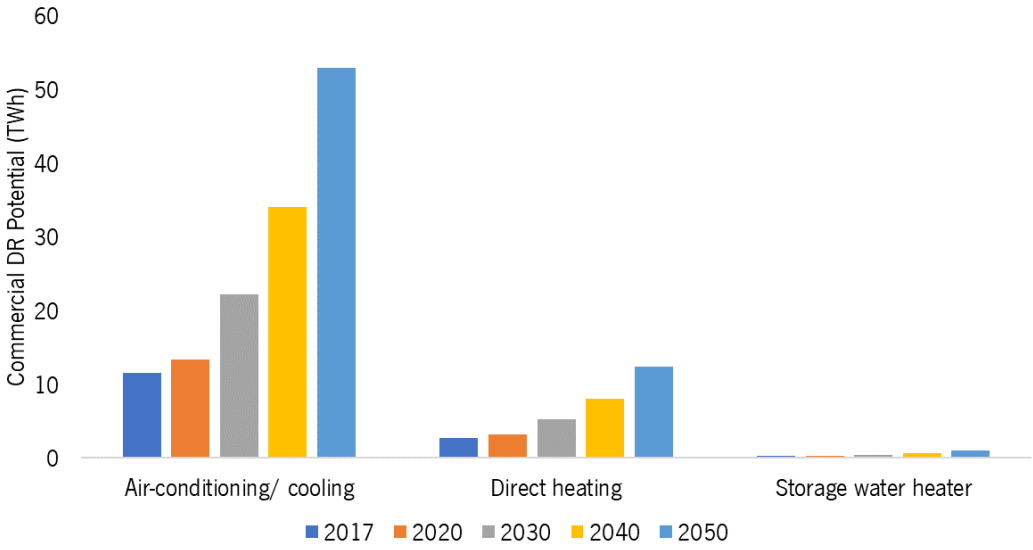


Figure 5.6: Overall DR potential (energy shifting potential) for commercial processes (TWh).

The number of full load hours in a year is based on the typical workday hours (i.e., 5840 h) for all processes in the commercial sector. Table 5.7 illustrates the overall DR potential (GW) for each commercial process and selected years. As shown in Table 5.7, the air-conditioning/cooling systems provide the most significant DR potential contribution in the commercial sector.

Table 5.7: Commercial DR potential for each process and year (GW).

Process	2017	2020	2030	2040	2050
Air-conditioning/cooling	2.0	2.3	3.8	5.8	9.0
Heating	0.5	0.6	1.0	1.5	2.3

At this point, we underline that the data presented in Table 5.7 consider the maximum DR capacity for each process. This implies that the hourly temporal availability[77] would be generally lower than these values. Figure 5.7 illustrates the typical DR daily availability profile (GW) for the commercial sector (left axis) and the typical daily load curve of the interconnected power system (GW) in the right axis for the year 2017. It can be observed in Figure 5.7 that the DR potential is estimated to vary between 0.1 GW and 1.6 GW across a typical day, which corresponds respectively to 5% and 67% of the estimated maximum DR capacity presented in Table 5.7 (for the year 2017). The results illustrated in Figure 5.7 clearly indicate the significant contribution of air-conditioning and cooling systems - representing more than half of the commercial sector's DR potential - mostly evidenced during daily hours (especially from 8 a.m. to 6 p.m.). This result is somewhat counterintuitive since the higher DR potential for the commercial sector occurs during typical workday hours. A very limited DR contribution comes from the heating processes. As expected, due to the limited commercial activity at night, the DR potential at this period is minimal. We also underline that the commercial DR availability seems to best match the power system's daily load curve (see the right axis of Figure 5.7). These results provide further support for the hypothesis that the commercial sector will develop a key role in offering the most valuable load flexibility potential (i.e., when the power system mostly needs) comparable to other sectors (e.g., the industrial and residential sectors).

[77] This conclusion is also valid for the other sectors evaluated (i.e., residential and industrial).

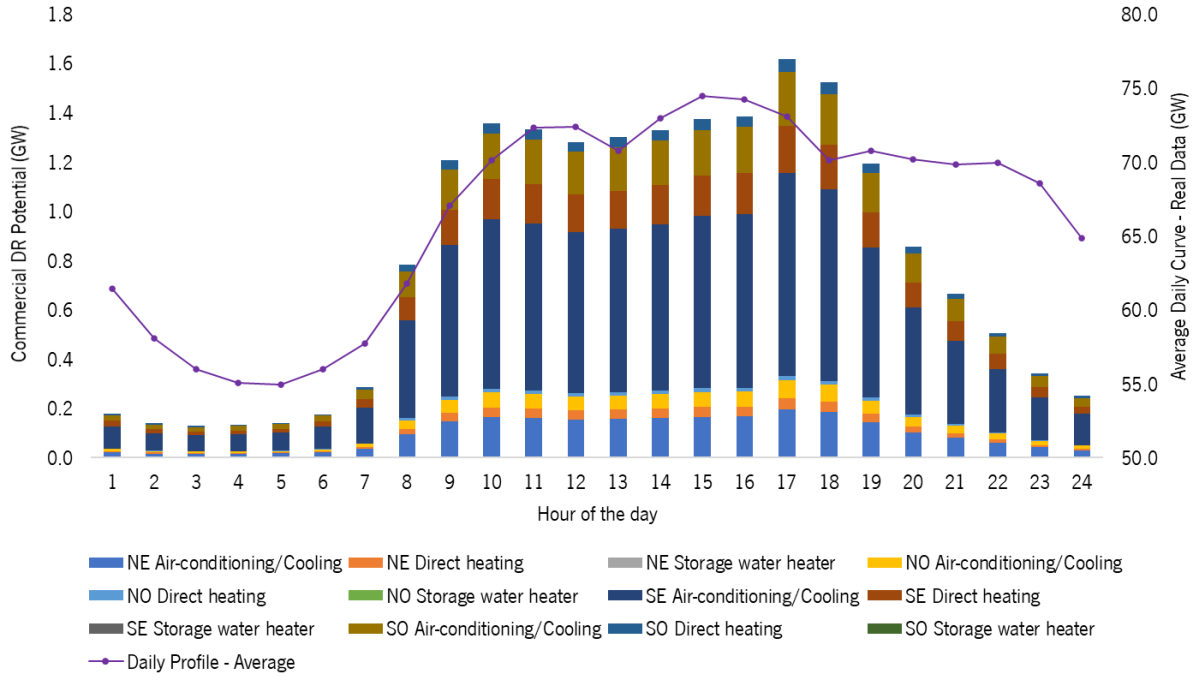


Figure 5.7: Overall DR potential for each commercial process (left axis) and the average daily load curve of the interconnected power system (right axis) (in GW for a typical day of 2017).

5.3.3 DR potential in the residential sector

This section attempts to assess the residential load flexibility potential for each appliance, region and year. The overall DR potential (TWh) for selected years and each region is illustrated in Table 5.8. Clearly, the highest and the lowest load flexibility potential seems to be, respectively, in the Southwest (SE) and North (NO) regions across all the years.

Table 5.8: Residential DR potential (TWh) for each region and year.

Region/year	2017	2020	2030	2040	2050	% of each region
NE	14	15	19	20	22	27.1%
NO	5	5	6	7	7	9.0%
SE	26	28	34	37	40	49.7%
SO	8	8	10	10	11	14.2%
Total	**53**	**56**	**69**	**74**	**81**	100.0%

Figure 5.8 illustrates the hourly contribution of each region in the overall DR potential (GW) considering a typical day of 2017. As expected, a significantly higher DR potential can also be noted for the Southwest (SE). However, contrary to the industrial sector, the higher DR contribution from residential applications in the Northwest (NE) is evident. According to these results, we can also infer that the highest DR potential for the residential sector would be nearly 5.5 GW (10 p.m.) for the entire power system for a typical day.

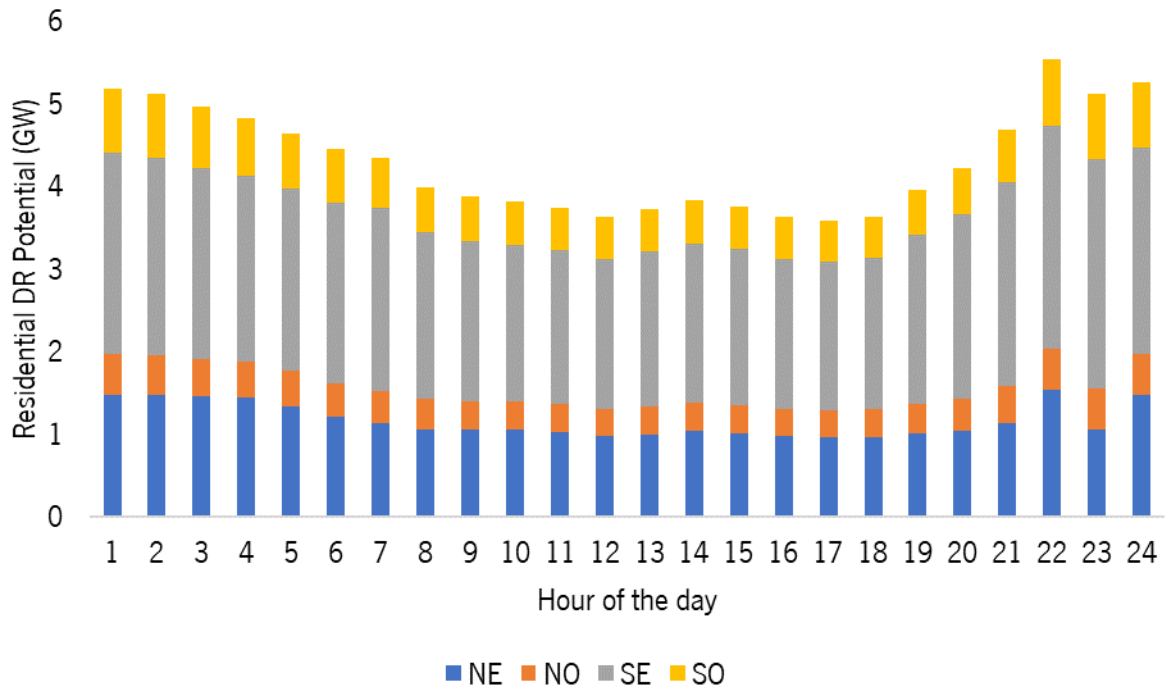


Figure 5.8: Overall hourly DR potential for each region in the residential sector - 2017 (GW).

The average theoretical hourly residential load flexibility potential of each appliance is illustrated in Figure 5.9 for a typical day (left axis). The results illustrated in Figure 5.9 clearly indicate that the major contribution to the overall load flexibility potential for the residential sector comes mainly from refrigerators' use (with a constant load factor during all day). These results are similar to those reported by Ref.[200] in which the refrigerator represented the highest DR potential for the residential sector in the power system evaluated[78]. However, one of the most marked differences between our results and those reported in Ref. [200] refers to the air-conditioning contribution in the overall DR potential. For our case, this appliance is projected to have a considerable contribution to the overall DR potential (with a particular higher assistance between 10 p.m. and 6 a.m.), whereas, in the German power system, this appliance represents a very limited DR contribution. These different results are likely to be strictly related to the diverse climate conditions of each country. Our results seem to be consistent with the strategic energy plan of Brazil [56], which projected that air-conditioning systems are projected to be the leading equipment responsible for the increase in electricity consumption in the residential sector (with a growth rate of 4.5% between 2017 and 2027) and consequently the overall load flexibility potential of this appliance is also likely to increase in the future. The projected high load flexibility contribution offered by air-conditioning systems for the residential sector can be mostly explained by the growth rate of household

[78] Ref. [200] assessed the theoretical DR potential for the German power system.

per capita income, which would potentialize its selling (i.e., the market penetration rate) in the Brazilian electricity market. On the other side, it is worth mentioning that even considering a decrease in the specific electricity consumption (kWh) of air-conditioners (decreasing[79] to near 21% between 2017 and 2050), this category of appliance seems to appear as one of the most critical drivers to the future residential load flexibility potential.

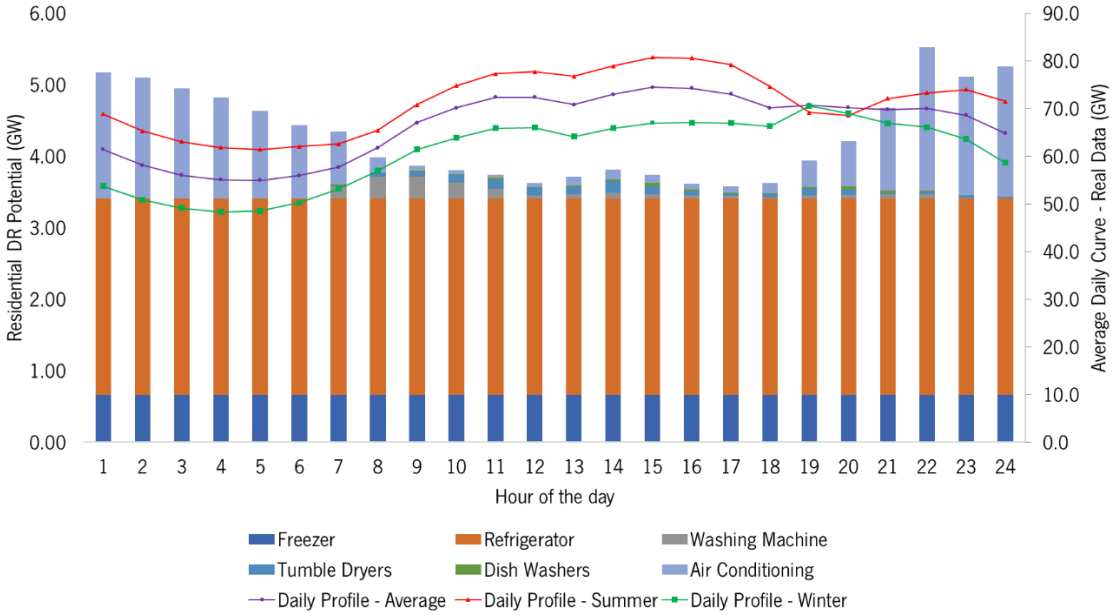


Figure 5.9: Overall hourly DR potential for each appliance in the residential sector (left axis) and the average daily load curve of the interconnected power system (right axis) (in GW for 2017).

It is clear from the findings that the washing equipment has only a small contribution to the overall DR potential, mostly during daily hours. In this last category, the washing machines represent the highest contribution followed by the tumble dryers and to a very limited extent appears the dishwashers. The small contribution of both tumble dryers and dishwashers is mostly related to its low penetration rate in the Brazilian electricity market even in future years.

Thus far, our analyzes have been focused on sectoral and regional DR assessments. It would be useful at this stage moving on to consider the relationship between the typical daily load curve profiles of the power system (i.e., with a particular focus on extreme seasons) considering real data extracted from the National Grid Operator [54] with the DR potential for each hour of the day. Due to data availability, these analyzes are not focused on DR's contribution across seasons since no specific data (across all sectors) is available for the country. However, a set of analyzes can be inferred from the obtained findings. Analyzing the right axis of Figure 5.9 - which represents the typical daily load curve profile of the entire

[79] This decrease is mostly driven by the new normative resolutions proposed by the Brazilian government, which established minimum energy efficiency rates for air-conditioners [434].

power system for winter, summer and the average values across all seasons - it can be seen similar general load daily profiles for all seasons (although different numerical contributions occur across seasons). As stated previously, in general, the average electricity demand for the interconnected power system is higher for a typical summer day compared to a typical winter day. Therefore, our results provide further support for the hypothesis that the DR potential would be higher for the summer (considering the entire interconnected power system[80]). This higher summer contribution in the overall DR potential is expected to come from the air-conditioners[81] systems (mostly from the residential sector), although further research is required to confirm this finding using more detailed data.

Analyzing Figure 5.9, it is also possible to address whether or not the residential DR potential is available when the power system mostly needs. The most striking result to emerge from the data presented in Figure 5.9 is that during high electricity consumption[82] (e.g., 3 p.m. and 4 p.m.), the residential DR potential is much lower than in times of reduced load (e.g., during the night). Therefore, the highest residential DR potential would occur during off-peak times and a small share of this potential is foreseen to be available during on-peak times. Further analysis of the data reveals that refrigeration and air-conditioner systems are the flexible loads that mostly contribute to the high residential DR potential during off-peak times. Since the refrigerator has a constant load profile, it can be inferred that the higher DR potential for the residential sector at this time (10 p.m.) could be specifically attributed to the higher contribution of these appliances from 10 p.m. until the beginning of the morning. The lowest and the highest DR potential for the residential sector is estimated to occur at noon (3.6 GW) and 10 p.m. (5.5 GW), respectively. Our results are in line with those of previous studies such as the ones reported by Ref. [246], which addressed the relationship between the time dependency of DR resources with the typical load profiles for the German power system explicitly and concluded that large amounts of flexible loads might not be necessarily available during on-peak times.

Analyzing the data illustrated in Figure 5.9, we can also infer that the load is significantly higher for a typical summer day than in a typical winter day during almost all day, except for a few periods (i.e., 6 p.m. – 8 p.m.). Although it is well-known that the higher residential consumption occurs at this period (i.e., 6 p.m. – 8 p.m.), this load profile pattern can be mostly explained because, typically, the industrial

[80] The generalisability of these results considering each region is subject to certain limitations, mainly due to data availability of the typical daily load profiles for each appliance and region.

[81] See, for example, the real daily curve during 10 p.m. and 6 a.m. (Figure 5.9). It can be noted that during this period, the typical summer load curve is significantly higher than the winter load curve and it is therefore likely that such connections exist mostly because of the use of air-conditioners in the residential sector.

[82] It is important to note that the maximum demand in the Brazilian power system has occurred at different times depending on the month of the year. In general, the maximum demand has occurred between 2 p.m. and 4 p.m. or between 6 p.m. and 7 p.m. This maximum demand also varies according to each subsystem.

consumers switch part of their electricity consumption to self-generation systems due to the high costs for producing electricity during this period.

The main aim of our investigation at this point is to highlight the particularities between regions within the country. Figure 5.10 and Figure 5.11 illustrates the overall load profile for two particular regions (i.e., SE and NO) retrieved from metered data from the National Grid Operator [54] for a typical winter and summer day (right axis) and the estimated theoretical DR potential for the residential sector (left axis) for SE and NO regions, respectively. According to the data illustrated in Figure 5.10 and Figure 5.11, we can identify similar load profile curves for both regions (i.e., SE and NO) across winter and summer seasons. Particularly for the Southwest (SE), the average numerical load (considering a typical day) diverges significantly in a typical summer day compared to a typical winter day. This behavior, however, cannot be identified for the North (NO). Therefore, we underline the importance of future research in assessing the theoretical DR potentials across sectors considering each region's particularities. Due to its continental dimensions, the climate conditions strongly vary between regions (see Figure 7.1), which, together with other asymmetric characteristics, make the regional analysis of the load flexibility potential particularly important. This could lead to possible synergies between subsystems across the country. Future assessments considering both the regional DR potential and transmission capacities analyzes, for example, would potentialize the synergies between these sources of flexibility and, consequently, support the integration of higher VRE levels into the power system.

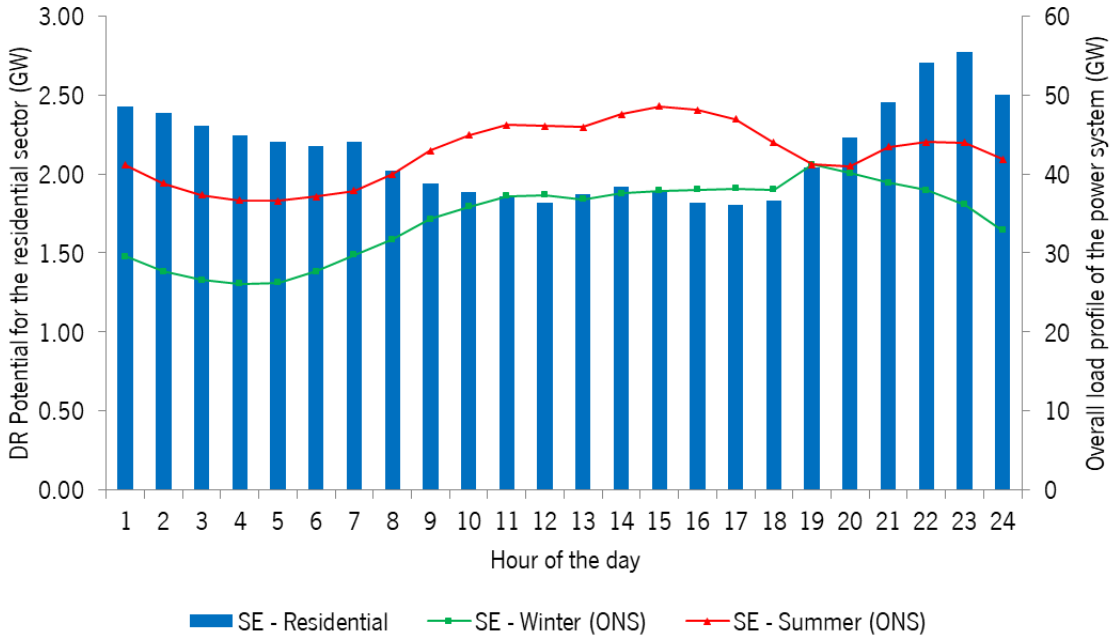


Figure 5.10: Overall load profile of the power system for winter and summer (right axis) and DR potential for the residential sector (left axis) for the Southwest (SE) - 2017.

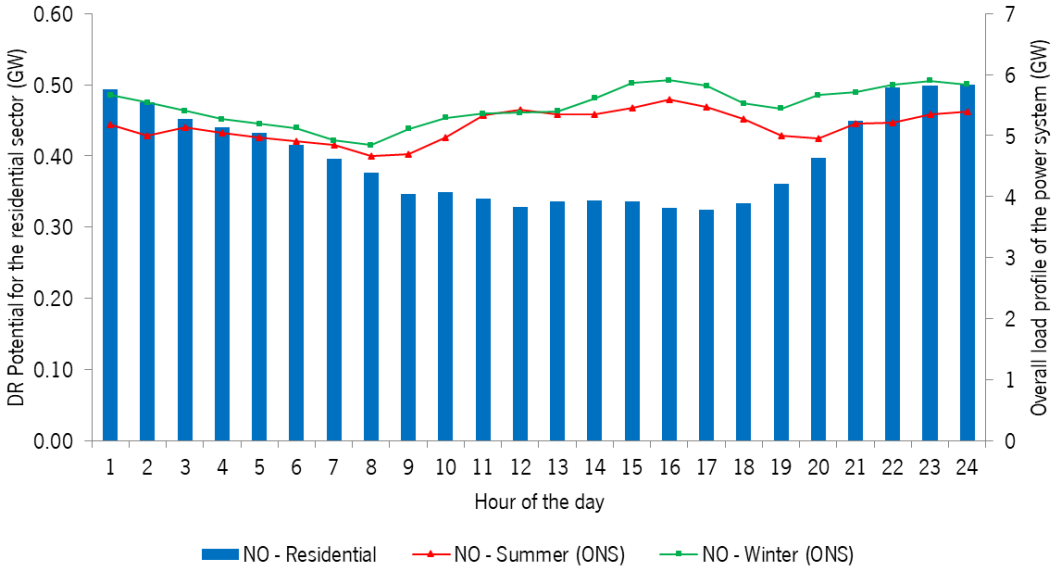


Figure 5.11: Overall load profile of the power system for winter and summer (right axis) and DR potential for the residential sector (left axis) for the North (NO) - 2017.

Figure 5.12 illustrates the overall DR potential for the residential sector in 2050 based on the data extrapolation. As no changes in the load profile have been considered for future years, the load profile is identical to 2017. However, as expected, a higher DR potential can be observed for the coming years, mostly driven by the population increase and the appliances' market penetration growth. A further issue that emerged from these results is the steadily decreasing contribution share of freezers for future years. This finding is supported by Ref. [56], which associated this reduction with the changes in the habits of consumption of households, occurred in the last decades across the country but also because of the new normative resolution (see Ref. [387]) which established minimum energy efficiency rates for refrigerators and freezers.

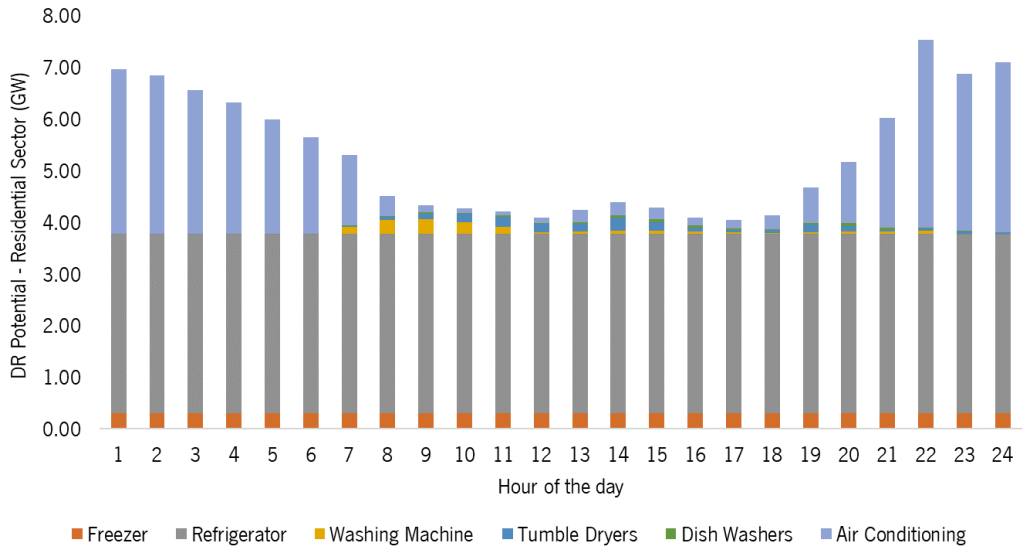


Figure 5.12: Overall hourly DR potential for each appliance in the residential sector – 2050 (GW).

5.3.4 DR potential across all sectors

This section attempts to assess the general findings across all sectors. Firstly, the sectoral share of the overall load flexibility potential for the reference year (2017) and future years (2020, 2030, 2040 and 2050) is evaluated as illustrated in Figure 5.13. A slight decrease in the residential contribution share (for all regions) in the overall DR potential can be seen. This small decrease is likely to come about mostly because of the markedly higher rates for the commercial DR contribution and the lower but still significantly high growth rate for the industrial sector's load flexibility potential.

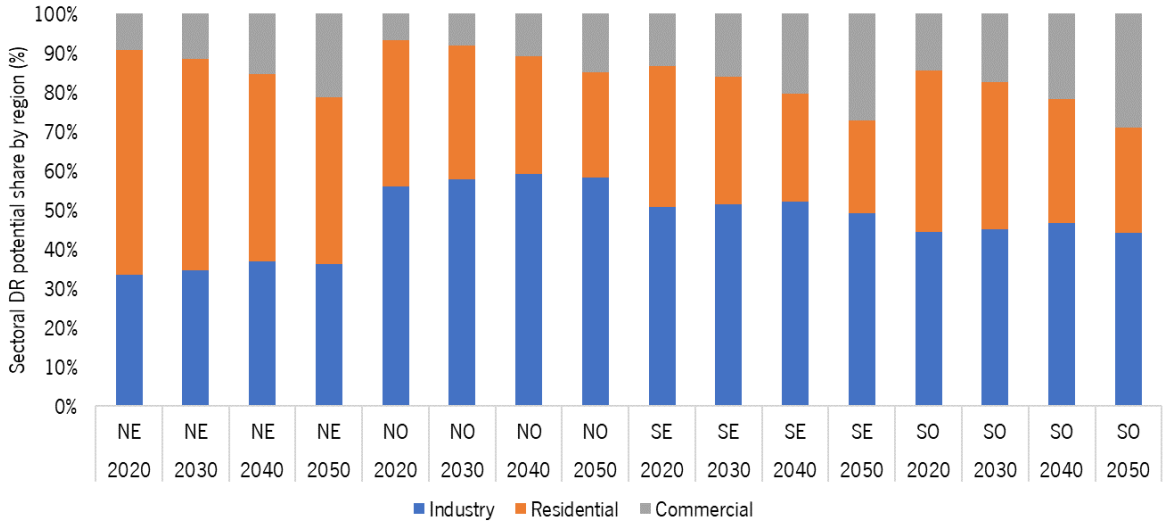


Figure 5.13: Sectoral share for the overall load flexibility potential (%).

For the sake of clarity, it would be useful at this stage to consider the comparison between the estimated DR potential (see Figure 5.13) with the respective regional share in the overall country's electricity consumption (Figure 5.14) projected by the Brazilian Energy Research Office for future years [90]. Figure 5.14 shows that the sectoral share for the overall electricity consumption is projected to change over the period analyzed [90]. In 2020, for example, the industrial sector is responsible for the highest share in the overall electricity consumption (45.8%), followed by the residential (24.1%) and commercial sectors (17.2%). Ref. [90] found a steadily decreasing rate for the share in the residential sector's overall electricity consumption, particularly between 2030 and 2050. In contrast, a steady decrease in the industrial sector's contribution share can be verified for future years. What stands out is the markedly increasing electricity consumption share for the commercial sector, rising from 17.2% in 2017 to 26.6% in 2050. Therefore, the commercial sector would exceed the residential sector share by 2040, as illustrated in Figure 5.14) (which concerns the overall electricity consumption).

On the other hand, our results suggest a different pattern in each sector's total share regarding the overall DR potential, varying across regions, as illustrated in Figure 5.13. Although the commercial contribution

share in the overall DR potential steadily increases along with the years (see Figure 5.13), it seems insufficient to surpass the residential load flexibility potential in 2040. Furthermore, it can be seen from the data in Figure 5.13 that for the North (NO), Southwest (SE) and South (SO) regions, the overall DR potential follows the same order across sectors, i.e., the industry with the highest DR potential, followed by the residential and the commercial sectors[83]. However, for the Northwest (NE), a different pattern can be observed. For this case, the residential sector contributes significantly more than the industrial sector to the overall load flexibility potential for the entire period and this might be related to the low energy-intensive industrial activities in this region.

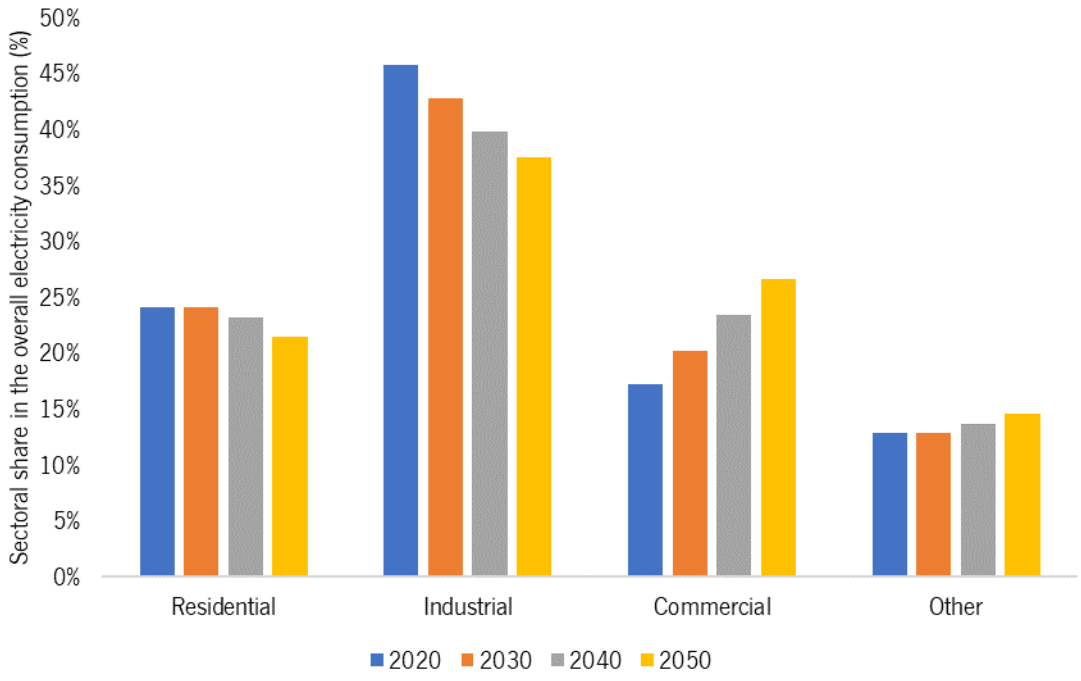


Figure 5.14: Projected sectoral share in the overall electricity consumption in Brazil (%). Source: Extracted from [90].

A sensitivity analysis has also been undertaken considering specific input variables to verify the robustness of the obtained results. For the residential sector, the first sensitivity analysis is focused on evaluating a constant market penetration rate (between 2017 and 2050). In this case, our findings revealed the small impact of this variable on the overall hourly DR potential (GW) since only small changes have been verified for daily hours. However, the effect of a constant market penetration rate tends to be more significant for night hours. In this case, due to the use of air-conditioning systems during the night, the overall DR potential for this period decreases by an average value of 9%. If no energy efficiency

[83] The only exception is for the South (particularly for 2050), in which the contribution of the commercial sector is slightly lower (i.e., 8%) than the residential sector.

improvements were considered between 2017 and 2050 for the residential sector (i.e., fixing the specific energy consumption), the overall hourly DR potential (GW) would increase by 35% (on average) for a typical day. The impact of energy efficiency improvements for the industrial sector on the available DR potential is smaller and less noticeable than for the residential sector since the considered gains in energy efficiency between 2017 and 2050 are smaller (see
Table 5.6) than those considered for the residential sector.

5.4 Concluding remarks

The increasing reliance on clean energy supply options and the emergence of DR measures in smart power systems have attracted considerable critical attention of researchers and society, mainly in the last decade. This chapter attempted to introduce a model-based assessment of the theoretical DR potential focused on the Brazilian power sector since this evaluation had not yet been fully addressed in the available literature. Findings of this chapter suggest several contributions to the current literature. Although extensive research has been carried out on different DR issues, thus far, the research has been inclined to focus essentially on qualitative rather than quantitative assessments on DR potentials. To give a well-known example, fewer research studies have attempted to evaluate the theoretical DR potential for developing countries, such as the case of Brazil. The strengths of this study include two central issues addressed (i) a sectoral assessment across the residential, commercial and industrial sectors together with (ii) a regional analysis by broadly splitting up the Brazilian power system into four main subsystems. This study set out to test the hypothesis that the overall Brazilian theoretical load flexibility potential is expected to increase considerably in the long-term. Data for this study were collected using different sources, including the future government prospects for the sector. The research is limited by using secondary data for future projections (e.g., market penetration rate, the projected number of households and specific energy consumption). Data was linearly extrapolated when no detailed information was available between periods. The methodology is based on a set of equations (2.1)-(2.9), which allows calculating the theoretical DR potential for each region and process/appliance.

Our analysis reveals that the overall maximum hourly theoretical DR potential in Brazil is expected to double, increasing from 12.8 GW in 2017 to almost 25.6 GW by 2050. The results point out that the majority demand-side response potential seems to lie in the industrial sector. Even considering the efficiency improvements, the load flexibility potential for energy-intensive industries is projected to increase in future years, mainly due to the projected sectoral growth during the period. Lower but still substantial DR potential for the residential and commercial sectors has also been identified. The high

expected increase in the overall electricity DR potential for the residential sector is driven mainly by the rise in the number of households and the number of appliances per house. It is worth mentioning that literature estimates that near half of household loads might provide a certain flexibility level [187]. For the residential sector, it can be noted that more than half of the DR potential is expected to derive from refrigerators. The use of air-conditioning systems also expects to represent a significant contribution to the residential load flexibility potential with particular high assistance between 10 p.m. and 6 a.m. The DR potential from air conditioning systems increases considerably between 2017 and 2050 since the number of buildings with this appliance category is expected to increase substantially.

Although the highest load flexibility potential is theoretically found to lie in the industrial sector, this research does not profoundly investigate the effect of specific industrial processes and further research is therefore highly recommended. It is worth mentioning that the high level of integration and dependence between industrial processes would affect the effective achievable DR potential. The available data for the commercial sector is much more restricted than for the industrial sector. For this reason, the annual electricity consumption available for DR in the commercial sector was broadly estimated using the combination of each process demand with its respective average demand share. The DR resources availability best matches the daily load curve of the power system for the commercial sector. These results support the hypothesis that this sector will develop a key role in offering the most valuable load flexibility potential (i.e., when the power system mostly needs it).

Unfortunately, part of our results is rather difficult to interpret because, to date, we have no sectoral load profile patterns available for the country. However, our findings support and evidence that each region's particularities should be considered in future analysis. Further studies that take these regional particularities into account will need to be developed to understand better the association between the sectoral profiles and the regional impacts of DR strategies. However, we underline that future research studies can benefit from our findings since the results presented in this research could be easily adapted to optimization (or simulation) long-term energy planning models. Using our results, future works could focus on several directions, addressing the extent to which DR resources might reduce supply costs and CO_2 emissions or even assess the extent to which DR can cost-effectively compete with other supply-side options.

Although this study has successfully demonstrated the expected theoretical DR potential for Brazil, a number of limitations need to be noted regarding the present study. This study is unable to encompass the full assessment of the load flexibility potential across regions. This research's scope is also limited in terms of the selected DR applications and other suitable processes/appliances should receive more

attention in future analyzes. Our findings are also somewhat limited because of the use of approximate data. Specifically, the lack of specific regional information may have influenced our results. We underline that a set of assumptions were made (e.g., estimated load profiles for each process/appliance) to assess the DR potential for each region within the country. We also considered the full availability of the flexible load potential. This is considered an optimistic assumption and of course, the achievable DR potential would be much lower. Therefore, the lack of data adds further caution regarding the generalization of the obtained findings. Also, we underline that the DR potential largely depends on user acceptance, which was not assessed in this study. This would imply a lower load flexibility potential in reality. This limitation means that our findings need to be interpreted cautiously since only the theoretical DR potential has been assessed, and no technical, economic or practical restrictions have been considered.

The DR contribution of EVs is not assessed in this research because of the lack of reasonable data for the sector. Although the EVs currently represent a low contribution in the country, for the future, it is expected that this type of load would offer a significant demand-side flexibility potential. Thus, future works could assess the expected load flexibility potential of this flexible demand for the Brazilian power sector. The growth of the IoT (Internet of Things) technology will also be disruptive and it is likely to develop a critical role in the Brazilian power sector since the first regulation has been recently proposed in the country through Law 9854/2019. However, our theoretical DR potential assessment does not take into account the effects of IoT integration and further research is required to establish the potential influence of this technology in the overall estimated theoretical DR potential. The practical implementation of DR strategies in the country largely depends on regulatory improvements to enable customer participation in DR initiatives. This suggests that novel regulatory frameworks and business models are fundamental to fostering the country's demand-side potential.

This study attempted to capture the most significant variables that would affect the country's future load flexibility potential. We also make an effort to consider the model disaggregation, including the Brazilian regional characteristics. To summarize, despite the previously mentioned limitations, we call attention to the main aim of this work which has been to perform an initial attempt to assess both the current and the future theoretical DR potential across sectors and regions within the Brazilian power system and consequently bringing some light on this crucial issue for the country. The theoretical DR assessment for the country is also essential in this research work since these results will be further incorporated within the co-optimization model supporting future scenarios with DSM in the country.

Chapter 6. Cost-Effectiveness of Energy Efficiency Measures (EEMs)

This chapter deals, in particular, with the problem of Generation Expansion Planning (GEP) of systems with a high share of RES. The GEP study is carried out focused on the Brazilian power system for the period 2018-2040 and it concentrates on evaluating the long-term effects of investing in energy efficiency measures in the country. After introducing the topic in Section 6.1, a brief overview of the leading Brazilian energy efficiency programs is presented in Section 6.2. Section 6.3 compares scenario BAU with scenarios that consider different percentages reductions in the overall electricity demand, which would characterize a portfolio of EEMs in the country. A discussion on the key findings of this research is provided in Section 6.4 and Section 6.5 draws the main concluding remarks.

6.1 Introduction

To achieve a full-scale decarbonized energy system, the use of RES, together with Energy Efficiency Measures (EEMs), has been widely proposed in the literature [9]. However, although several studies have recognized the challenges of the high integration of RES, research has yet to systematically investigate the long-term impacts of investing in different levels of EEMs on power systems with a high share of RES. To the best of the authors' knowledge, thus far, the cost-effectiveness of energy efficiency investments has not been thoroughly assessed by previous research for the specific case of Brazil.

The Brazilian electricity system is a typical example of a power system that deeply relies on RES. Therefore, the country is used along with this chapter to allow a more in-depth insight into the effects of energy efficiency improvements and evaluate the effectiveness of these types of DSM strategies. The Brazilian electricity market has unique characteristics over other electricity markets worldwide primarily due to its continental dimensions, regional features and high hydropower contribution for electricity generation. Although most of Brazil's electricity comes from RES, the increasing dependence on hydropower and the decrease in water storage levels in the last years leads us to recognize the need to evaluate the impact of EEMs not only in the short-term but also in the long-term. While hydropower is used as a complement of thermal generation for most countries, this power source predominates in the Brazilian power sector [388]. For the future, the percentage share of hydropower in the country is projected to decrease, whereas the percentage share of thermal power tends to increase. Thermal power is also expected to support the baseload, flexible generation and system provision [285]. Distributed generation from small-scale PV systems is expected to lead the way towards an environmentally sustainable energy system, although some risks for future deployment for this power source are foreseen in the case of Brazil [68,313]. Additionally, the percentage share of non-hydro RES (e.g., biomass, solar

and wind power) is predicted to substantially increase along with the next decades in the Brazilian power sector.

Therefore, the primary aim of this chapter is to critically and quantitatively evaluate the economic impacts of investing in different shares of EEMs in the Brazilian power sector. The study sought to answer the following specific research question: *What are the major significant medium-long term impacts of energy efficiency measures for the Brazilian power sector?* Precisely, the impacts on the future overall system costs, installed capacity and CO_2 emissions are addressed for 2018-2040. The analysis carried out in this chapter is conducted using the newly proposed Long-term Average Cost of Saved Electricity (LACoSE) (see Section 4.1 for details), which is employed for the economic evaluation of long-term electricity scenarios with and without EEMs.

6.2 Brazilian energy efficiency programs

This section aims to provide a brief overview of Brazil's efforts to promote the rational use of electricity. According to Ref. [7], *"energy efficiency measures include all permanent changes on equipment or enhancements on the physical properties of the system"*. The EEMs are expected to provide long-term electricity-saving and reductions in the overall emissions level [7].

The Brazilian government has been implementing a portfolio consisting of multiple energy efficiency programs to achieve specific policy goals through the National Electric Energy Conservation Program (in Portuguese, PROCEL) set up in 1985 [389], the Energy Efficiency Program (in Portuguese, PEE) and the energy efficiency law. These energy efficiency programs/measures are typically implemented at the consumer level and are predominantly focused on household and industrial consumers. The main aim of PROCEL is to promote national awareness regarding the efficient use of electricity and encourage and motivate the target customers to implement EEMs to achieve the expected results, such as the reduction of environmental impacts [389]. PROCEL also supports funding for energy conservation projects, including educational and training information campaigns for energy conservation, encouraging the target consumers for installing or upgrading inefficient equipment, implementing demand-side reduction actions, promoting the use of more efficient technologies such as high-efficiency motors, air conditioning, and lighting equipment. According to Ref. [390], in 2018, PROCEL accounted for 23 TWh in energy savings, representing 4.87% of the country's overall electricity consumption. Effectively, this prevented an increase of 7.25 GW in the peak demand, which means 1.7 million tons of avoided CO_2 emissions. The overview of the leading Brazilian energy efficiency proposals is illustrated in Table 6.1.

Table 6.1: Overview of the leading Brazilian EEMs proposals.

Year	Regulation Type	Description	Ref.
2000	Law n° 9,991/2000	Regulation of the minimum level of investments that should be financed by the utilities for Research and Development (R&D) and Energy Efficiency (EE).	[317,391]
2001	Law n° 10,295/2001	It has established the minimum levels of energy efficiency for appliances and machines.	[318]
2016	Law n° 13,280/2016	It has established the minimum level (20%) of the fund for energy efficiency that must be designated to PROCEL.	[320]

6.3 Evaluation of different levels of Energy Efficiency Measures (EMMs)

6.3.1 Data collection

To assess the effects of different shares of EEMs on the power system under evaluation, the study uses a sensitivity analysis over the BAU scenario (see Section 4.4) to gain insights into the impacts on the overall installed capacity, costs and CO_2 emissions. The sensitivity analysis is performed considering five levels of reduction in the electricity demand projected for each year, with percentages varying from 1% (Case 1), with a step increase of 1% for each new case until reach a reduction in the final electricity demand up to 5% (Case 5). Therefore, the independent variables are precisely the reduction level (%) in the final electricity demand (due to EMMs), whereas the dependent variables are the installed capacity, costs and CO_2 emissions. Simulations were conducted to explain the effects of the independent variable on the dependent variables. The LACoSE is considered at this stage for the economic analysis assessment. The reduced electricity consumption (MWh) achieved by the level of EEMs considered (i.e., different for each scenario) is multiplicated by the LACoSE (US$/MWh). The result of this multiplication is, therefore, a corrected levelized cost of energy efficiency investments for each scenario (US$).

Our estimated value for the Modified Cost of Saved Electricity (MCoSE) is 0.0468 US$/kWh considering the average lifetime of historical data for EMMs applied within the country, which includes the following categories of EEMs: low-income, public agencies, trade and services, public service, residential, industrial, rural, solar heating, pilot projects, cogeneration, public heating, supply-side and educational and municipal energy management (see Table 6.2 for details) [49]. MCoSE was calculated based on real energy efficiency programs implemented by the Brazilian government in the last decade [49] and also supported by the methodology calculation of Ref. [392].

However, to correctly assess the economic impact of using these sets of EEMs in the long-term energy planning model, it is also required to levelize the costs of saved electricity yearly and multiply the obtained value with the total years of the planning period. Therefore, the value for the new so-called LACoSE is estimated to be near 0.0772 US$/kWh considering the planning period from 2019 to 2040. This value

for the LACoSE (0.0772 US$/kWh) is higher than the MCoSE (0.0468 US$/kWh) because the new proposed approach explicitly recognizes and accounts for the reinvestments in energy efficiency which would be required during the planning period. For the case under analysis, the planning period of the long-term model is higher (21 years) than the average lifetime of all the EEMs considered (about 13 years), and for this reason, LACoSE is higher than MCoSE.

Table 6.2: Energy efficiency programs in Brazil (based on Ref. [49] and Ref. [392]).

Category	Saved Energy (GWh/Year)	Total Cost (10^3 US$)	Cost of Saved Electricity (US$/MWh)	Life-Time (Years)	Modified Cost of Saved Electricity (US$/MWh)
Low-income	2489	880703	354	13	47.26
Public agencies	382	140508	367	12	51.31
Trade and services	141	39661	281	12	39.20
Public service	140	45654	326	12	45.50
Residential	683	178516	261	10	40.72
Industrial	174	32247	185	15	22.94
Rural	33	7192	220	15	27.26
Solar Heating	24	22453	947	20	103.78
Pilot project	75	21294	283	12	39.49
Cogeneration	146	42403	290	20	31.77
Public Heating	6	2377	425	20	46.58
Supply Side	0	1669	3477	20	380.88
Educational	-	70680	-	-	-
Municipal energy management	-	2892	-	-	-
Total/Average	**4294**	**1488249**	**347**	**13**	**46.82**
Long-term Average Cost of Saved Electricity – LACoSE (US$/MWh)					**77.20**

The following section will quantitatively describe the major long-term impacts of EEMs for the power system evaluated along with this research, which deeply relies on renewable energy.

6.3.2 Simulation results

The results obtained comparing scenario BAU (Section 4.4 for details) with the scenario that accounts for reducing the overall final electricity demand by 5% (Case 5) for 2040 are summarized in Figure 6.1. Scenario BAU assumes that there will be no significant energy efficiency improvements in the power sector over the forecast period (2019 – 2040). As shown in Figure 6.1, for 2040, the high reduction in the final electricity demand would strongly affect the newly installed system capacity reducing from 395 GW (Scenario BAU) to 374 GW (Case 5) in 2040. Notably, it can be seen from the data in Figure 6.1 the reduction in the total installed capacity of natural gas, small hydro and wind power followed by smaller but still relevant reductions for nuclear and run-of-river power plants in 2040 compared to scenario BAU given the assumed decrease in the overall electricity demand.

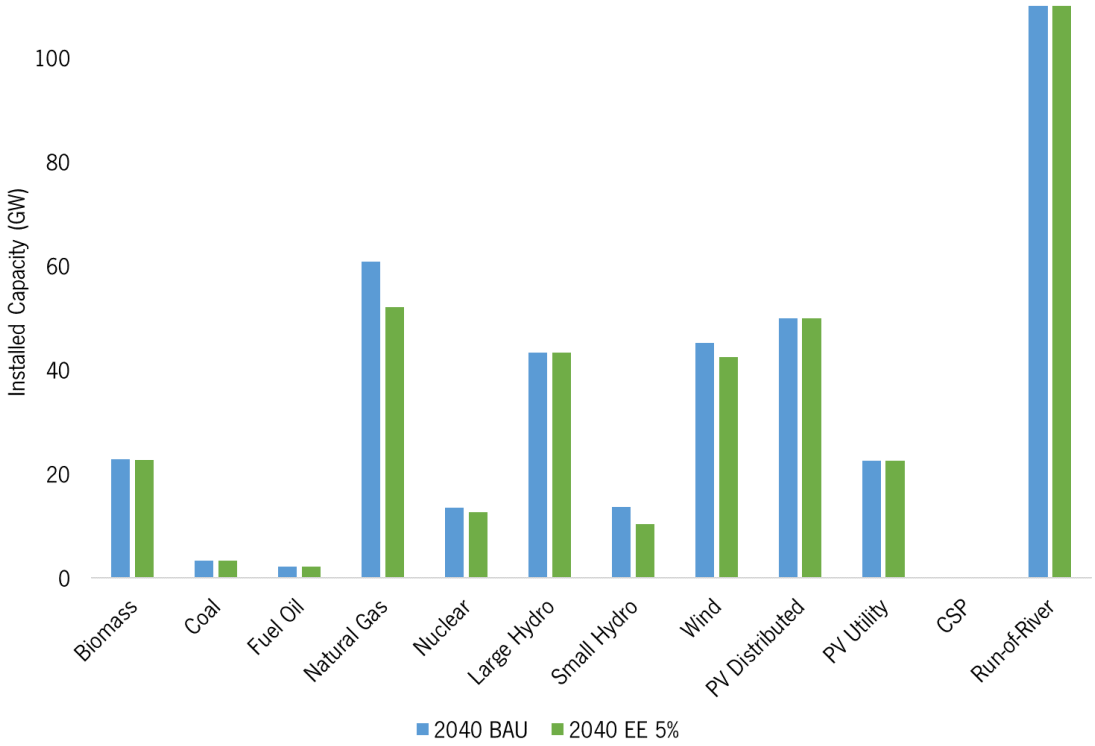
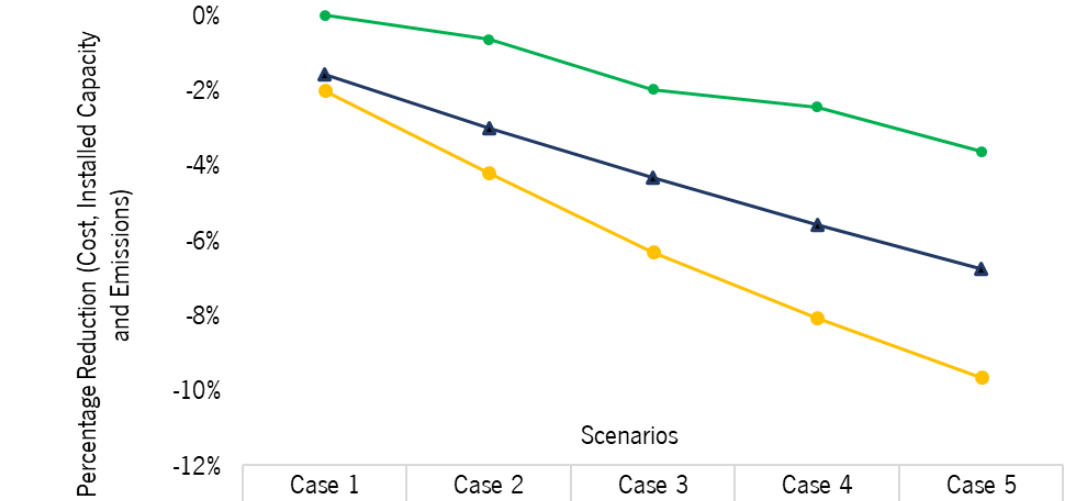


Figure 6.1: Installed capacity for scenario BAU and Case 5 (2040).

Together these results provide important insights into the effects of energy efficiency investments in the long-term for the power system evaluated in this research. One of the more significant findings to emerge from these results lies in the overall installed capacity for hydropower, which is predicted not to be deeply affected for the scenario with EEMs compared to scenario BAU. The only exception comes for small-hydro power plants, which considerably reduces its new installed capacity from 13.7 GW to 10.3 GW in 2040 for Case 5 compared to scenario BAU. This result may be explained mostly because of the future up-front costs for SHPs, which are not predictable to decrease compared to other RES [330].

The resulting emission-cost tradeoff curve is illustrated in Figure 6.2. Each point of the figure attempts to describe the percentage variations for each case (Case 1 to Case 5) compared to scenario BAU. Figure 6.2 also presents the percentage variation in the new installed capacity for each case. Both the installed capacity and CO_2 emissions decrease in all scenarios and the magnitude of the impact is driven mostly by the level of investment, which directly reflects in energy savings. Figure 6.2 also illustrates a clear trend of decreasing the new installed capacity as the level of EEMs increases. The results from Figure 6.2 also indicate a steady decline in the rate of CO_2 emissions as the level of EEMs increases. The reduction in the overall level of CO_2 emissions is likely to occur mainly because of the reduced need for fossil fuel power sources in scenarios with energy efficiency. In particular, the reduced installed capacity of natural gas would strongly contribute towards the long-term goals of reducing the overall levels of greenhouse gas emissions in the country.

However, what stands out is the evident percentage cost reductions as the level of energy efficiency increases. The results demonstrate the cost-effectiveness of energy efficiency investments for high renewable electricity systems, even when considering the proposed LACoSE approach, which explicitly accounts for the cost of these EEMs and recognizes the need for reinvestments under a long-term perspective.



	Case 1	Case 2	Case 3	Case 4	Case 5
Costs	-1.6%	-3.0%	-4.3%	-5.6%	-6.8%
Installed Capacity	-2.0%	-4.2%	-6.3%	-8.1%	-9.7%
Emissions	0.0%	-0.7%	-2.0%	-2.5%	-3.6%

Figure 6.2: Percentage variation for the new installed capacity, CO_2 emissions and costs compared to scenario BAU.

Figure 6.3 attempts to illustrate the new installed capacity for scenario BAU and each Cases 1 to 5.

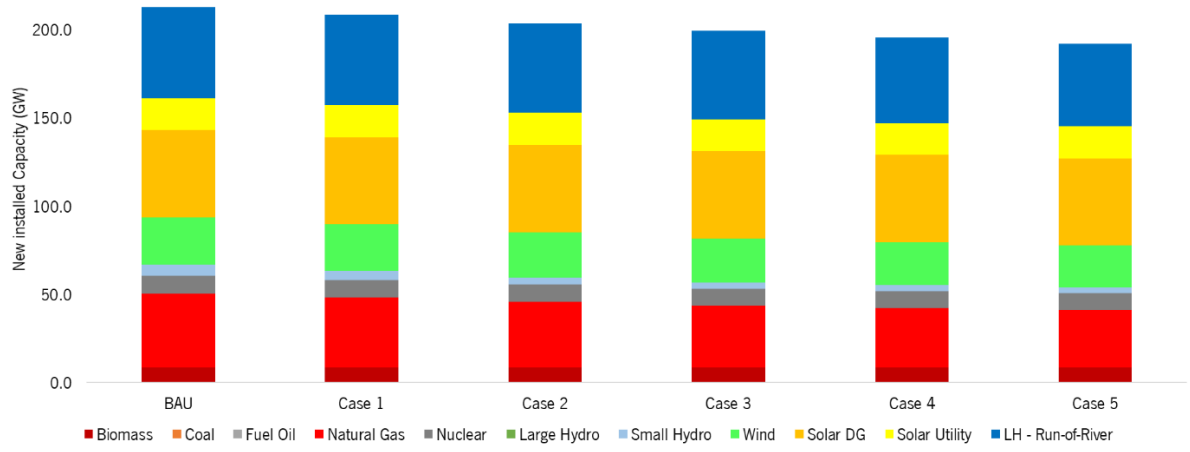


Figure 6.3: New installed capacity for each case (2018-2040).

Figure 6.4 presents the simulation results for the remaining period (until 2040) considering scenario BAU and the reduction in the overall installed capacity assuming 5% of EMMs (Case 5), which reduced the overall installed capacity from 395 GW (BAU) to 374 GW (5% of EEMs) in 2040.

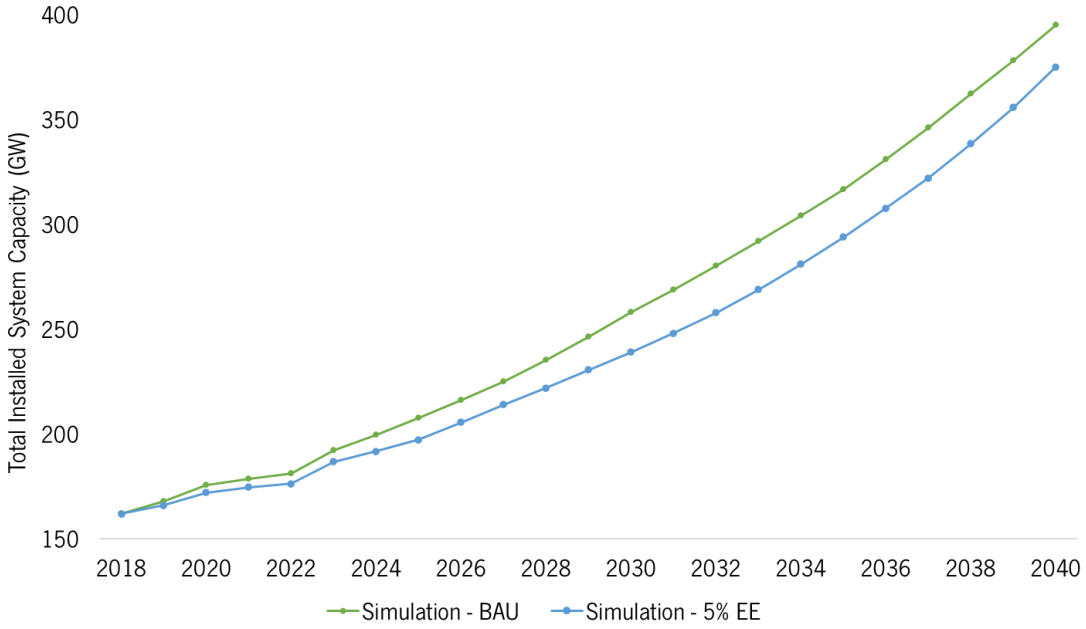


Figure 6.4: Comparison between simulation results for scenario BAU and Case 5 for the overall installed capacity (GW).

6.4 Discussion of the findings

Traditionally, EEMs have an up-front cost smaller than traditional investments (i.e., supply-side), as suggested by the Lawrence Berkeley National Laboratory [393]. Energy efficiency-related investment expenditures are supposed to be compensated by energy bill savings since such investments are expected to reduce electricity use. Therefore, we concluded that the economic benefits of energy efficiency investments are favorable for the power system assessed in this research since it reduced both the installed system capacity and the emissions with a lower cost than scenario BAU (without EMMs). These results are also in agreement with other studies in which the investments in EMMs had positive economic impacts on the power system evaluated [393].

Findings of this research indicate that the economic impacts of energy efficiency investments and their cost-effectiveness are affected by the share of RES in the power system. This aspect is crucial for systems with high reliance on hydropower, as the power system addressed in this research. However, it seems evident that even for high-RES systems, the economic benefits of EEMs still outcomes the required investments resulting in an overall and long-term cost reduction. According to the simulation results, the overall electricity generated by the hydropower projects (including large hydro and run-of-river power plants) over the forecast period is projected to still predominate under other power sources, with an average value slightly higher than 69% for 2018 and 59% for 2040. These findings have significant implications for understanding how renewable energy may affect the overall economic viability due to the implementation of EEMs.

To date, there has been little agreement about the economic feasibility of EEMs. More recently, literature has emerged that offers contradictory findings for this concern [394–397]. This fact can be mostly explained by the diverse and non-trivial task of estimating the real cost of saved electricity due to the implementation of EMMs. Ref. [397], for example, dealt with the transition towards a renewable power system for Ukraine. The authors concluded that the final energy consumption in Ukraine would have a reduction of up to 42% in 2050 for the case of a RES scenario. Ref. [397] also point out that the "*implementation of the energy efficiency measures proofs to be the most cost-efficient set of policies towards low emission development in Ukraine*" [397]. These results are also in agreement with recent studies. Ref. [394], for instance, emphasizes that *"energy efficiency is recognized as a key strategy for energy sustainable development and a main tool to tackle three energy-related challenges: climate change, energy security and economic development – at the least cost to the society".* On the other hand, the European Court of Auditors Report [396] supported the idea that the investments made in energy efficiency by the European policy funds have not been made cost-effectively since the projected average payback period for energy efficiency investments exceeds 50 years. Ref. [395] also supports the idea that some EEMs programs are not cost-effective.

Therefore, given the high uncertainty about the real costs of saved electricity, we performed a sensitivity analysis (Figure 6.5) over this variable, decreasing LACoSE by 50%, and increasing by 50% and 100%, respectively.

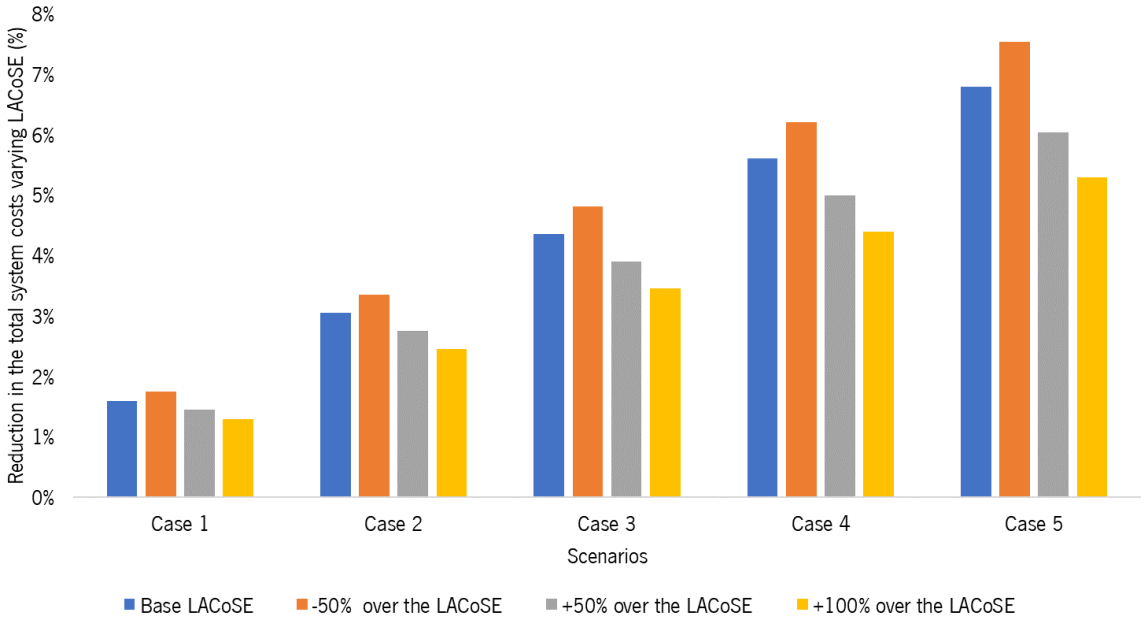


Figure 6.5: Sensitivity analysis for the estimated LACoSE.

Analyzing Figure 6.5, it is possible to infer that the results are not highly influenced by the estimated long-term average cost of saved electricity. In our analysis, this variable was based on historical data collection

and, as such, represents the cost-effectiveness of past EMMs implemented in the country. For example, if the estimated cost of saved electricity would be higher (i.e., +50% or +100 %), the investments in EEMs would still be justifiable under a pure cost-effectiveness approach since the overall system costs would decrease (see Figure 6.5). If the estimated long-term average cost of saved electricity reduces by 50%, the economic benefits brought about by EMMs would be even higher. This last aspect is important to consider since the future costs of EMMs are expected to decrease and these types of measures may be even more cost-effective in the future.

These conclusions draw our attention to the importance of evaluating the cost-effectiveness of the investments made in energy efficiency projects and assessing their relevance. However, our findings also need to be interpreted with caution and any attempt to generalize the results is not advisable since each power system has its particular characteristics regarding the share of each RES and non-RES. Hence, the extent to which these specific findings would have broader relevance should be further explored. However, it could conceivably be hypothesized based on evidence that similar results would emerge to other power systems with similarities to the one evaluated in this study, i.e., systems with a high reliance on hydropower, such as the case of China and Canada power systems [171].

6.5 Concluding remarks

The primary goal of this chapter embodied the assessment of the economic impact of different levels of energy efficiency investments in systems with a high share of renewable energy. Overall, this study strengthens the idea that for the power system evaluated in this research, EEMs would reduce the overall installed capacity of fossil fuel power sources (e.g., natural gas) mainly because of its high operational costs and this reduction would strongly contribute towards the long-term goals of reducing the overall levels of greenhouse gas emissions in the country. Therefore, taken together, these findings suggest a role for energy efficiency in promoting the decarbonization of the power sector. The study also carried out a sensitivity analysis over the BAU scenario to get a comprehensive picture of the impacts on the installed capacity, costs and CO_2 emissions for each energy efficiency level. Expectedly, findings of this study suggest that the implementation of EEMs may result in a reduction in the new installed system capacity varying between 2.0% and 9.7% and from 1.6% and 6.8% for the total system costs (for reductions in the final electricity demand from 1% to 5% respectively). This research has also shown that EEMs would decrease the total CO_2 emissions up to 3.6%. These results together provide further support for the hypothesis that the economic impacts of EEMs are mainly driven by the share of RES in the power system.

Our analysis also revealed a lack of understanding of how to calculate the Long-term Average Cost of Saved Electricity (LACoSE). Therefore, the methodological contribution of this research also lies in the proposition of a step-by-step procedure to estimate this variable. We also highlight the need to evaluate further the impact brought about by the use of EEMs when considering the participant costs (i.e., related to the consumers) in addition to the administrative costs. The inclusion of the participant costs would affect the economic potential of energy efficiency investments and this analysis would bring more light on the cost-effectiveness of EEMs in power systems in general. In further research, the use of externalities costs such as the environmental and human health impacts should also be taken into account to better assess the long-term impacts of energy investments as well discussed by Ref. [394]. We underline that the benefits of implementing EEMs would largely outweigh the costs, such as reducing both the overall level of CO_2 emissions and the peak system demand.

The insights gained from this study may be of assistance to energy decision-makers in supporting the development of large-scale energy efficiency programs, identifying the multiple benefits of EEMs and bringing some light on the importance of seeking other economically viable energy efficiency investments. For the future, we underline the need for developing new strong policies for Brazil to achieve a smart, economical, socially fair and sustainable energy system. The lack of support and incentives for the possible benefits of a more efficient energy system might not result in the expected benefits for both consumers and utilities. Future studies should also investigate the electricity consumers' perceptions to evaluate additional benefits from the demand-side point of view. The rebound effect should also be further explored since energy efficiency improvements may lead to smaller savings than expected.

Future research could also focus on specific categories of energy efficiency potentials such as the technical, economic and achievable potentials. The scientific contribution of this research goes beyond the Brazilian case, as the proposed modeling approach and methodology might support the decision-making process in different systems with both high shares of RES and under different levels of energy efficiency. A few limitations need to be noted regarding the present study. First, it is worth mentioning that the generalizability of the model for other power systems is not considered a trivial task since each power system has its particular characteristics. Second, more research on this topic needs to be undertaken before associating the potential economic advantages of different energy efficiency levels. However, despite these limitations, we highlight the potential of replicability of the methodology to other power systems with a high share of RES and subjected to different levels of EEMs.

Chapter 7. Integrating Supply and Demand-Side Management

This chapter brings together the lessons from the case study addressing, in particular, the least-cost capacity expansion plan for the country, taking into account the contribution of both supply-side and demand-side strategies. The methodological details used in this chapter were presented in Chapter 4. After introducing the topic in Section 7.1, the main scenario assumptions are described in Section 7.2. The assessment of the technical and economic DR potentials is presented in Section 7.3 by evaluating four scenarios. The efforts of Section 7.4 are oriented to the integrated assessment of scenarios with both DR and EEMs. Section 7.4 also carries out a sensitivity analysis over the LACoSE variable (i.e., -50%, +50% and +100% over the base value), focusing on verifying the extent to which the LACoSE might have over the general research findings. Chapter 7 moves on to discuss the main results and draws together the main conclusions of the chapter in Section 7.5.

7.1 Introduction

Driven by the recent trends towards a smart power system configuration [68], there has been a greater focus within the literature placed upon the integration between supply and demand-side resources. The relevance and the innovative aspects of this study are strongly related to a framework proposal for assessing the co-benefits between energy efficiency and demand-response on renewable-based energy systems under a long-term perspective (see Chapter 4 to see the methodological details used along with this chapter). Although DSM may offer a set of advantages and plays a critical role in decarbonizing the power sector [203], many barriers [398] still stand for its effective deployment and implementation mostly because of its highly diverse and multifaceted nature.

Although a few research works have recently addressed the scenario construction for Brazil, less attention has been paid to the integration between supply and demand-side resources within the country. The Brazilian power system is therefore considered as the case study throughout this chapter mainly due to its (i) continental dimensions; (ii) high current reliance on RES; (iii) high future RES potential; (iv) vulnerability to climate change but also because (v) few works attempted to evaluate the synergies between investing in DR strategies and EEMs in the country.

Brazil is considered a large developing nation and a country with high RES share highly based on hydropower (which accounts for about two-thirds of its overall production). The historical high RES share put the country as one of the most renewable electricity systems worldwide. However, the recent severe droughts in the country led to a substantial decrease in the reservoirs' levels and, consequently, in the

electricity generation from hydropower. The Brazilian water seasonal variability[84] is also projected to be at high risk in the future, as illustrated by the water risk atlas [399]. The increasing restrictions related to the use of fossil fuel resources and the challenges for exploiting the remaining hydropower potential are primarily because of the need to mitigate the climate change impacts and reduce the social and environmental effects from the construction of new hydropower sources with large reservoirs, respectively. The country's climate conditions strongly vary from North to South regions [400,401], as illustrated by Köppen's climate classification map for Brazil (Figure 7.1).

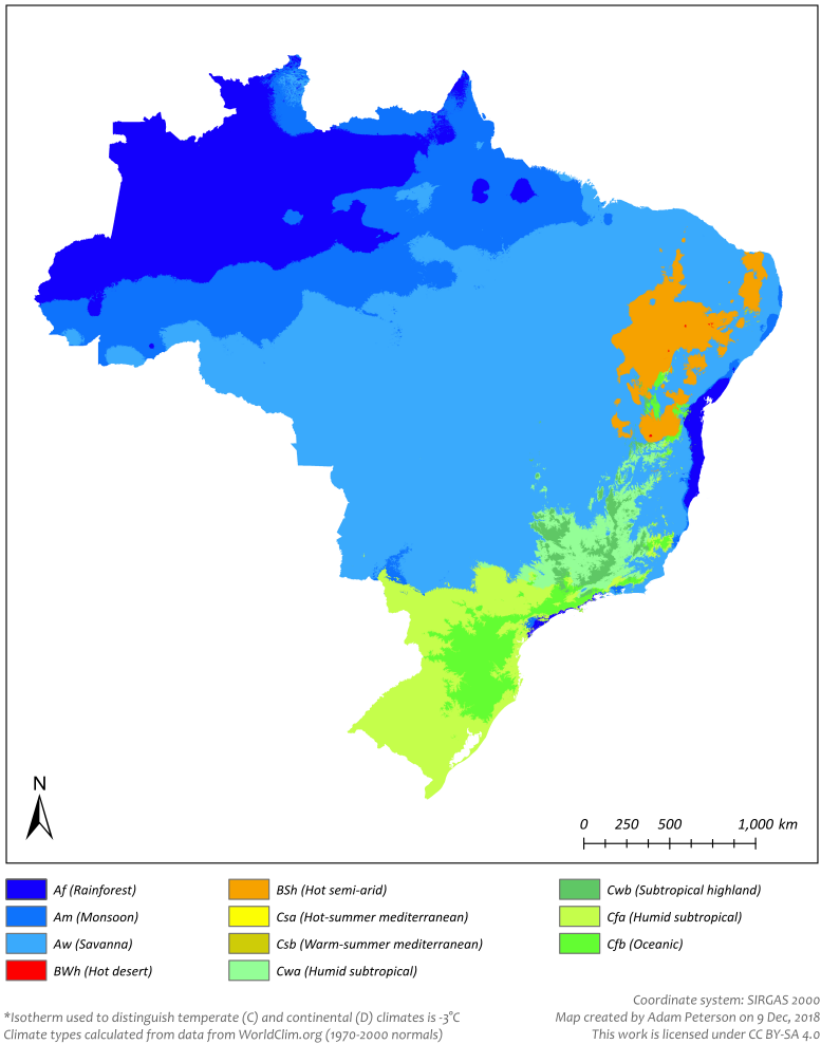


Figure 7.1: Köppen's climate classification map for Brazil (Ref. [400]).

Brazil's population has reached the level of 208.4 million in 2018, according to the Brazilian Economic & Geographical Institute (in Portuguese, IBGE). The number of households in Brazil is expected to increase by about 40 million in 2050 compared to 2012 [90] and the average per capita income is expected to be slightly lower than US$ 36 thousands/person (2050), which currently can be compared

[84] The "seasonal variability (SV) is an indicator of the variability between months of the year. Increasing SV may indicate wetter wet months and drier dry months, and higher likelihood of droughts or wet periods" [399].

to the average level of Germany and France, for example. The growth of population coupled with the future climate change challenges will require the development of holistic approaches for the energy sector, including integrating DSM strategies into long-term models. As such, the consumers are expected to play a critical role in the future electricity market [90] and the growing market share of smart appliances brought about by the evolution of smart grids may strongly facilitate the insertion of demand-side resources such as air conditioning, washing machines and refrigerators without deeply compromising user comfort. Although only a few DR programs are currently implemented in Brazil, considerable growth is projected along with the years to come across all sectors, particularly for the residential.

Most of the previous works have focused on the short-term impact assessment of DR strategies and little work has centered on the long-term impacts - such as in the changes in the future optimal base power capacity and peak system load - in consequence of the implementation of such policies [52,53]. As a matter of fact, many traditional power system models have neglected to include DR issues in long-term power GEP problems [219]. These conventional models have been usually focused on the expansion of the supply-side. However, researchers have recently dedicated valuable efforts to model and assess the impact of DR measures not only in the short-term but also in long-term power planning studies. Ref. [219] supports that "*DR represents a paradigm shift in how we view electricity markets since electrical load can now appear on both sides of the supply-demand equation*". The use of DR strategies has been considered in [105] focused on the Texas power system's long-term model. The reserve margin impacts have been recently addressed by Ref. [215], which takes into account the use of both DR measures and energy storage systems and considers the impact of different shares of wind power. With the increasing wind penetration, reserve margin reductions have been observed for the power system evaluated in [215]. The load management benefits focused on the CO_2 emissions reduction was particularly addressed by Ref. [196] for the Swedish power system.

Therefore, a growing body of literature recognizes the importance of integrating supply-side and demand-side options in long-term power system planning studies. The analytical frameworks to incorporate DR in long-term resource planning models have also been recently investigated [52]. A set of recommendations (e.g., assessing the optimal DR portfolio and accounting for the geographical distribution of DR participants) for incorporating DR as a competing resource option was proposed by Ref. [52]. The authors highlighted that some utilities located in the U.S. have been considering the inclusion of DR measures in planning models as resources that compete with traditional supply-side options when determining the optimal mix for the future, pointing out that this strategy might lead to a least-cost resource portfolio [52].

Most of the previous research concerning the expansion of the Brazilian power sector (i.e., GEP problems) has neglected the potential of the demand-side and it has focused mostly on the supply-side (see Refs. [2,103] for example). However, there has been a growing body of literature over demand-side issues that have been increasingly recognized as a powerful tool to manage the operation and the power systems' planning. In this context, it is now well established from a variety of research studies the importance of including DSM strategies within long-term planning models, although these concerns have been traditionally neglected for the specific case of the Brazilian power sector. It is worth mentioning that the low DSM contribution of the Brazilian electricity sector aggravated and extended the energy supply crisis in 2014 due to the severe drought that occurred in the country leading to a significant increase of generation from thermal power.

Investments in DSM strategies would avoid investments in the supply-side and new transmission grids [48]. According to [47], it is more cost-effective to invest in DSM strategies than in the supply-side for most power systems. The extent to which the DSM implementation might reduce the power peak load of the interconnected power system is also linked to the Load Duration Curve (LDC). To give a well-known example for the sake of clarity, the LDC for the Brazilian power system is illustrated in Figure 7.2 (2017).

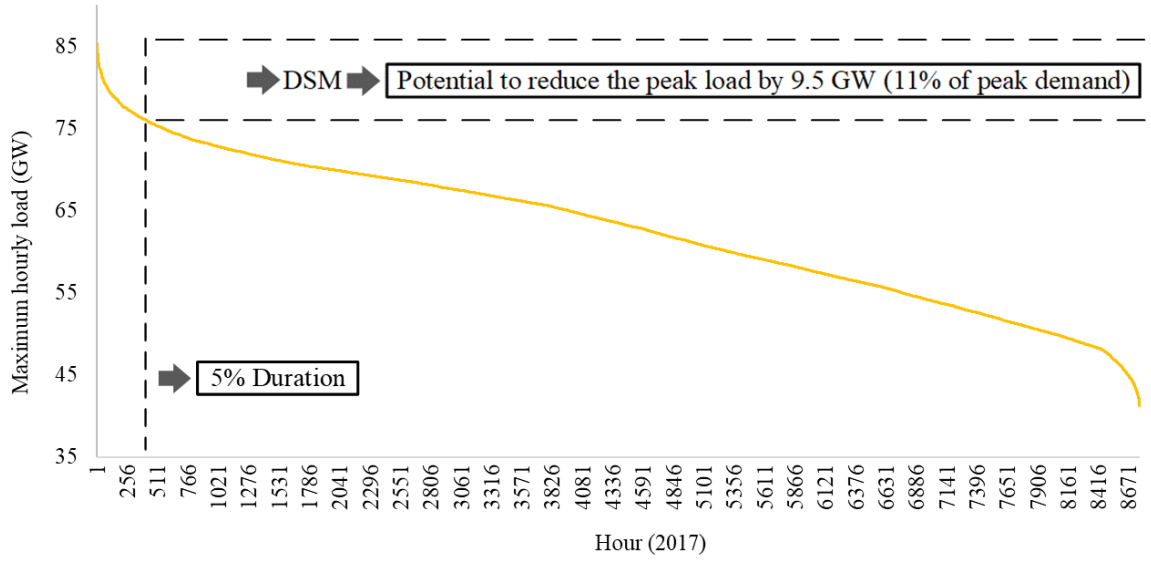


Figure 7.2: Load duration curve for the Brazilian power grid (2017).

In such circumstances, as shown in Figure 7.2, the use of DSM strategies might promote a reduction in the maximum power system's peak load. This would decrease the future need for additional installed capacity, but it would also increase the potential to defer investments in transmission and distribution network grids. The potential to reduce the peak power capacity by 9.5 GW (i.e., 11% of peak load) would be achieved if load management would be implemented during 5% of the load duration curve (see Figure

7.2). Together these results provide important insights into the potential of DSM in the country to reduce the need for future power capacity. At the same time, a significant increase in the grid load factor would be achieved and consequently, it would promote additional benefits regarding the generation units scheduling, for example. The significant grid load factor improvement [201] and saving energy resources are considered additional benefits from implementing DSM strategies.

The key focus of this chapter is to revisit the topic of high RES scenarios in developing countries with a high RES potential, as is the case of Brazil (classified as an Emerging Market and Developing Economy by the International Monetary Fund [402]), analyzing and comparing different future scenarios with DSM strategies. The vision presented here is the development of a comprehensive comparison among these future scenarios with DSM according to different perspectives, including technical, cost, environmental and risk dimensions. The impacts on the future overall energy system costs, installed capacity, and CO_2 emissions will be addressed for each scenario for 2019 – 2040.

7.2 Main scenario assumptions

Chapter 6 concentrated its efforts on assessing the long-term effects of using EEMs for the case study under evaluation. This chapter will use Case 5 assessed in Chapter 6, which considers a 5% reduction in the final electricity consumption for each year of the planning period (hereinafter, it will be referred to as Scenario 2 (EEM_5%)). As such, Section 7.3 will assess whether or not the use of DR strategies is technical and/or economically feasible for the same power system taking into account four scenarios (Scenarios 3, 5, 7 and 9). The efforts of Section 7.4 are oriented to the evaluation of scenarios with both DR and EEMs (Scenarios 4, 6, 8 and 10). For the sake of clarity and with the purpose of fairly compare scenarios that take into account the use of EEMs only - Scenario 2 (EEM_5%) - and scenarios which consider the integration between EEMs and DR strategies; the same amount of investment in energy efficiency is considered (i.e., equal to 5% for scenarios 4, 6, 8 and 10).

Scenario 3 (DR^T) attempts to assess the technical DR potential. The integration of EEMs is evaluated further in Scenario 4 (DR^T/EEM_5%) by also taking into account the technical DR potential. However, given the high variability[85] of the spot market prices, the assessment of the economic DR potential requires the definition of six scenarios. Scenario 5 (DR^N) considers the average spot price for each region and season in a typical year (i.e., a year in which no extreme weather conditions were perceived in the country). Scenario 6 (DR^N/EEM_5%) has the same conditions as Scenario 5 (DR^N) but integrates into the

[85] The high variability for the spot prices occurs across years and seasons in the country and this behavior is typical for systems which deeply relies on renewable energy such as the case of Brazil (mostly dependent on hydropower).

analysis 5% of EEMs. Scenario 7 (DR^{+}) and Scenario 9 (DR^{-}) take into account the spot prices for a typical drought (2014) and wet (2011) year, respectively, which were chosen based on real data retrieved from the national grid operator [54]. The main objective of this analysis is to predict the power system's behavior in the case of a critical year with reduced water inflows (e.g. 2014) and the case of a year with good rainfall conditions (e.g., 2011). Therefore, these assumptions are taken into account to better address the impact of different weather conditions and determine the extent to which the spot prices might have over both the overall installed capacity and the level of CO_2 emissions for each year and region. Scenario 8 (DR^{+}/EEM_5%) and Scenario 10 (DR^{-}/EEM_5%) takes into account the same conditions from Scenario 7 (DR^{+}) and Scenario 9 (DR^{-}), respectively but incorporates 5% of EEMs for a typical drought (2014) and wet (2011) year. Table 7.1 summarizes all scenarios evaluated along with this chapter.

Table 7.1: Scenarios description

Scenarios	Acronym	Description
Scenario 1	BAU	Business as Usual (BAU)
Scenario 2	EEM_5%	5% of Energy Efficiency Measures
Scenario 3	DR^{T}	Technical DR potential
Scenario 4	DR^{T}/EEM_5%	Technical DR potential + 5% of Energy Efficiency Measures
Scenario 5	DR^{N}	Economic DR potential
Scenario 6	DR^{N}/EEM_5%	Economic DR potential + 5% of Energy Efficiency Measures
Scenario 7	DR^{+}	Economic DR potential (drought year – 2014)
Scenario 8	DR^{+}/EEM_5%	Economic DR potential + 5% of Energy Efficiency Measures (drought year - 2014)
Scenario 9	DR^{-}	Economic DR potential (wet year – 2011)
Scenario 10	DR^{-}/EEM_5%	Economic DR potential + 5% of Energy Efficiency Measures (wet year - 2011)

The modeling approach relies on a set of theoretical, technical and economic assumptions. The assessment is based on the future impacts for the costs, CO_2 emissions and installed capacity considering the planning horizon from 2018 to 2040 and focuses particularly on evaluating the long-term effects of implementing a set of DSM strategies that competes with traditional supply-side options. The methodological assumptions regarding the existing and forecasted theoretical DR potential in the country are based on previous research [67,234]. The theoretical DR potential is used as part of the model input data and it can be assessed by identifying the most suitable appliances and processes for DR followed

by the assessment of the load profiles for each sector and finally by quantifying each flexible load (see Refs. [67,234] and Chapter 2 - Section 2.5 for details).

For both assessments (technical and economic DR potential), the theoretical load flexibility potential addressed in Chapter 5 is used as the basis for the input data of the co-optimization model. The evaluation of the theoretical DR potential performed along with Chapter 5, however, considered a regional and sectoral scope (dividing into processes/appliances suitable for DR). In this section, the estimation of both the technical and economic DR potentials is undertaken by also considering a regional analysis, but the sectoral assessment is evaluated by aggregating each sector's individual processes and appliances. This sector's aggregation is required because of the high computational times needed to solve the optimization problem since not grouping the individual processes/appliances increases the number of variables and constraints included in the model. We also considered that 100% of the load flexibility potential could be used for DR, although a further study focusing on the evaluation of different shares (e.g., for each sector and year) is highly recommended.

To evaluate the technical DR potential (Scenario 3 - DR^T and Scenario 4 - DR^T/EEM_5%), no costs are considered for DR implementation. This means that both load shedding and load shifting can be used by the co-optimization model whenever it considers valuable for minimizing the total system costs. However, a set of restrictions is included for the technical DR assessment, limiting the maximum share of flexible demand that may be shed or shifted for each sector and year.

For estimating the economic DR potential (Scenarios 5, 6, 7, 8, 9 and 10), in addition to the use of technical constraints, the variable costs to implement DR are also considered (see Ref. [234]). The assessment of the economic potential for DR is conducted by including two parameters that are responsible for computing the variable costs (US$/MWh) of shedding and shifting the load, respectively, such as proposed by Ref. [187].

The economic assumptions for load shedding are established based on the Brazilian short-term electricity price (in Portuguese, PLD[86] - Differences Settlement Price) of typical past years. Additional information about the country's historical spot prices can be found in Ref. [403]. A similar approach has been considered by the pilot DR program (demand bidding/buyback) implemented by the ANEEL for large industrial consumers. For this pilot program, the spot price (i.e., PLD) is used as the reference baseline for the consumers' financial rewards due to short-term interruptions to their supply [55].

[86] The spot price (PLD) in the Brazilian electricity market is determined based on the marginal operating systems costs (in Portuguese, CMO).

For load shifting, the costs to implement DR are included in the model as a penalty per each hour shifted (US$/MWh). This parameter can assume a different value for each model region, although we consider the same value for all subsystems[87]. The maximum delay and advance in which the load of each sector may be shifted are also considered for both assessments, i.e., for the technical and economic DR potential evaluation.

The main technical and economic scenario assumptions for DR implementation are presented in Annex B.4, including the estimated average short-term prices (in US$/MWh) for each Brazilian subsystem and season [404].

7.3 Assessing the technical and economic DR potentials

7.3.1 Theoretical background

Previous studies have assessed the technical and economic DR potential for different countries with different sectoral coverage and spatial resolution. In general, the studies related to the estimation of the technical DR potential have been mostly focused on selected countries within Europe, such as Germany [217,246], Finland [251], Portugal [53] and Denmark [254]. Similarly, the economic DR potential has been assessed for West-European countries [249], including Germany [217,266], Nigeria [252] and Michigan (EUA) [245], just to name a few. The economic load flexibility potential has also been assessed for the German power system using the REMix energy system model [253]. The authors of [253] concluded that DR could cost-effectively add up to 10 GW of avoided installed capacity in the power system. These are only a small sample of studies within the literature that assessed the technical and economic DR potentials. However, there is a current paucity of scientific literature focusing specifically on the contribution of DR for Latin American countries and Brazil is no exception. For the specific case of Brazil, the estimated theoretical DR potential was recently addressed by Ref. [67] (Chapter 5) by dividing the country into four main regions and by also considering a sectoral disaggregation (i.e. residential, commercial and industrial). Findings of Ref. [67] revealed an overall increase from 12.8 GW (2017) to 25.6 GW (2050) in the overall theoretical load flexibility potential in Brazil and the major part of this load flexibility potential seems to lie in the industrial sector.

A recent study undertaken by Ref. [98] focused specifically on the role of sector coupling for the Brazilian power sector but also attempted to include (partially) the DR potential (for the industrial and commercial sectors) within the modeling approach. Findings of Ref. [98] revealed a limited DR contribution for load

[87] After performing a set of simulations, it has been figured out that the economic DR potential for the power system evaluated in this paper is not affected even considering a high range for the price of shifted demand (e.g., 0.1 US$/MWh to 10 US$/MWh).

balancing in the Brazilian power sector's hypothetically because of its high reliance on hydropower [98,103]. The DR contribution reached up only to 0.04% of the total annual electricity demand and peak load reductions of about 3.3 GW were projected [98]. The authors also concluded that scenario assumptions influenced only to a very limited extent the implementation of such DR measures in the country [98]. Although the outcomes provided in Ref. [98] are very significant, little information about DR issues had been provided in their assessment since they focused on other issues such as the role of sector coupling in the country.

Therefore, what is not yet clear is the extent to which DR measures can technical and economically compete with other supply-side options across the country. In general, DR studies for the specific case of the Brazilian power system have been focused on qualitative analysis and are usually restricted to small areas and/or only for selected sectors.

7.3.2 Scenarios with DR

The extent to which DR measures can technical and economically compete with other supply-side options across the country is the key focus of this subsection. The assessment is conducted with a particular emphasis on the potential of DR in (i) decreasing the future power generation capacity; (ii) RES integration; (iii) delay in investments; (iv) reduced need for thermal capacity; (v) decrease in the level of CO_2 emissions and (vi) the possibility of enhancing the synergies between power subsystems within the country. Although the analysis is carried out focused on the complex and non-trivial Brazilian power system - which is highly interconnected and supplied mostly by RES - the proposed well thought out methodology can be further extended to the assessment of other power systems with both with high RES penetration and under different flexibility requirements (see Chapter 4 for details). Figure 7.3 illustrates the new installed capacity between 2018 and 2040 for Scenario 1 (BAU) and DR scenarios.

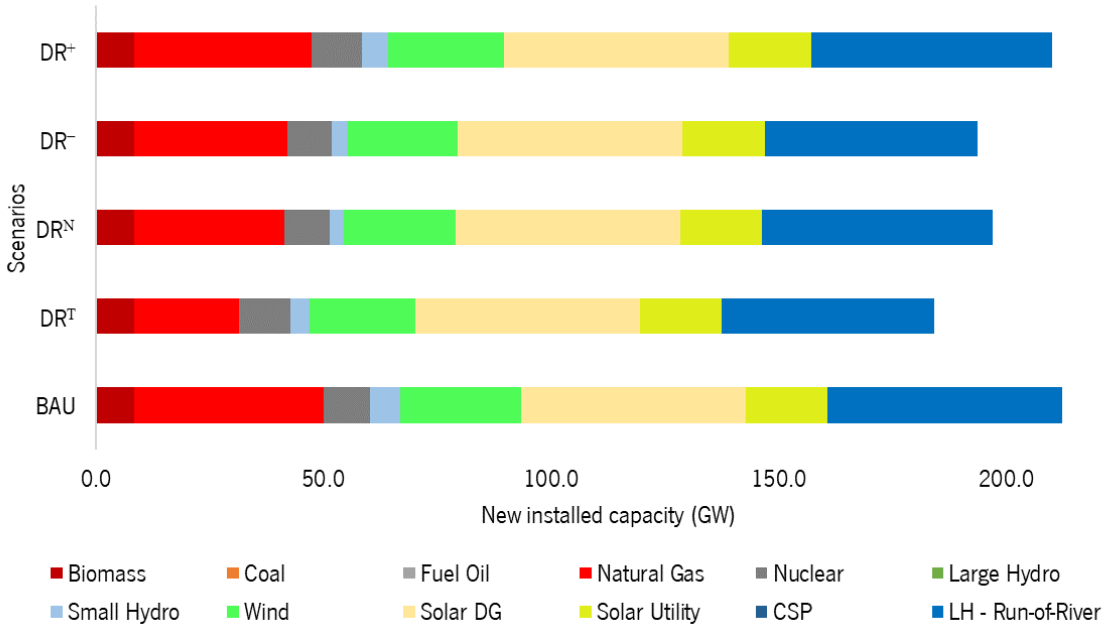


Figure 7.3. New installed capacity between 2018 and 2040 for each scenario with DR.

For Scenario 3 (DR^T), a decrease of about 13.3% (compared to scenario BAU) is projected in the overall new installed capacity along with all the planning period (reaching 184.1 GW) in case the entire estimated technical potential for DR would be exploited. However, when we analyze the scenarios that include economic restrictions for implementing DR, the potential to reduce the new installed capacity is smaller compared to Scenario 3 (DR^T). For Scenario 5 (DR^N), the overall new installed capacity reduces only by 7.2% compared to Scenario 1 (BAU) - from 212.3 GW to 196.9 GW. It is worth noting the high decrease in the overall natural gas capacity for all DR scenarios compared to Scenario 1 - BAU. Comparing, for instance, the new natural gas installed capacity for Scenarios 1 (BAU) - 41.7 GW and Scenario 3 (DR^T) - 23.1 GW, it can be seen a decrease of almost 45% between these scenarios. Although the difference is smaller for the new natural gas installed capacity between Scenario 5 (DR^N) and Scenario 7 (DR^+), it is still significant.

Small hydro projects and wind power are also affected for scenarios with DR implementation and, to a lesser extent, the expansion of the biomass power source. When the variable costs for implementing DR (load shedding) are considered to be higher (Scenario 7 - DR^+), compared to Scenario 1 (BAU), DR could cost-effectively add up to only 2.2 GW of avoided installed capacity in the power system. This finding might suggest a restricted potential in reducing the need for additional power system capacity (Scenario 7 - DR^+) in case the PLD prices tend to increase. Given the high reliance on hydropower resources and the vulnerability to climate change, the assumed prices represent an important source of uncertainty for

the model. Simulation results for each scenario regarding the new installed capacity (2018-2040) and its share in the total electricity production (2040) for each power source are presented in Annex C.1 and Annex C2, respectively.

Turning now to analyze the average regional potential for load shedding (Figure 7.4) for the entire planning period (2018-2040), our results may support the hypothesis that the highest load flexibility potential seems to lie in the Southwest (SE). Also, the findings reported in Figure 7.4 suggest that the differences for the average load shedding potential between Scenario 3 (DR^T) and Scenario 5 (DR^N) are rather significant for all regions varying from 47% (NO), 63% (SE), 66% (SO) to 68% in the Northeast (NE).

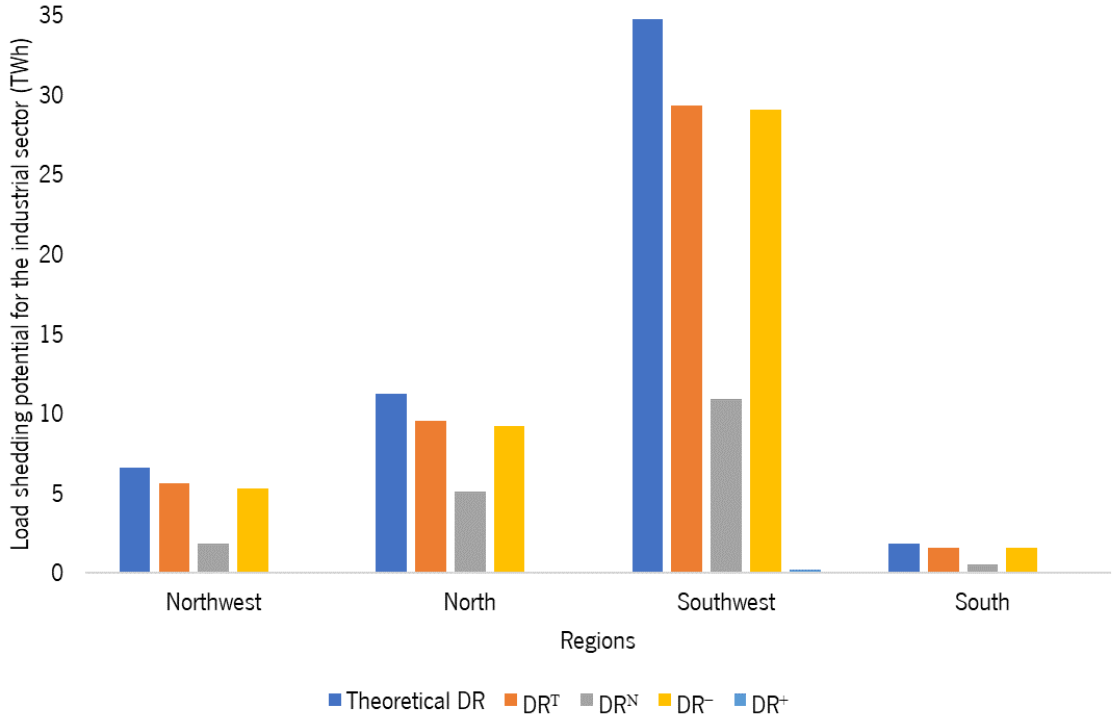
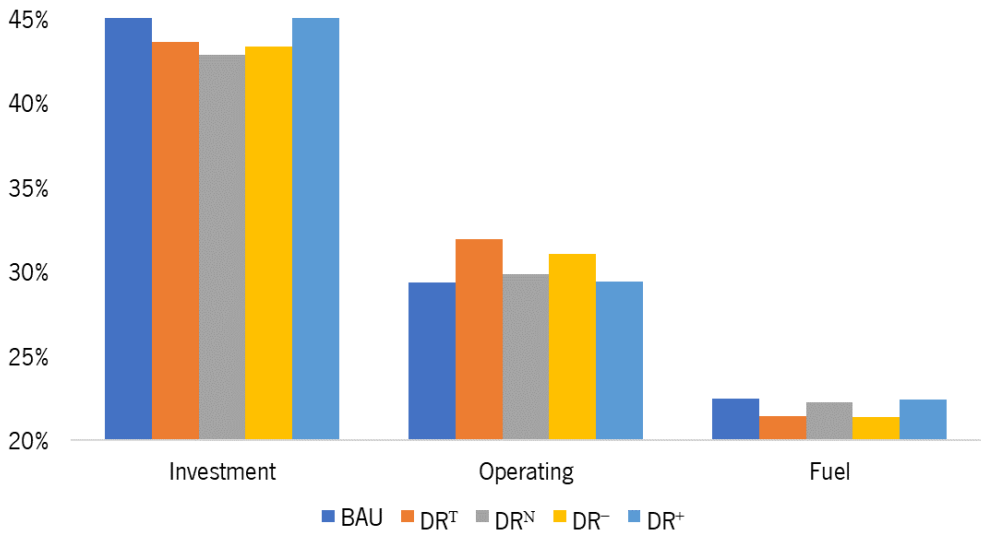
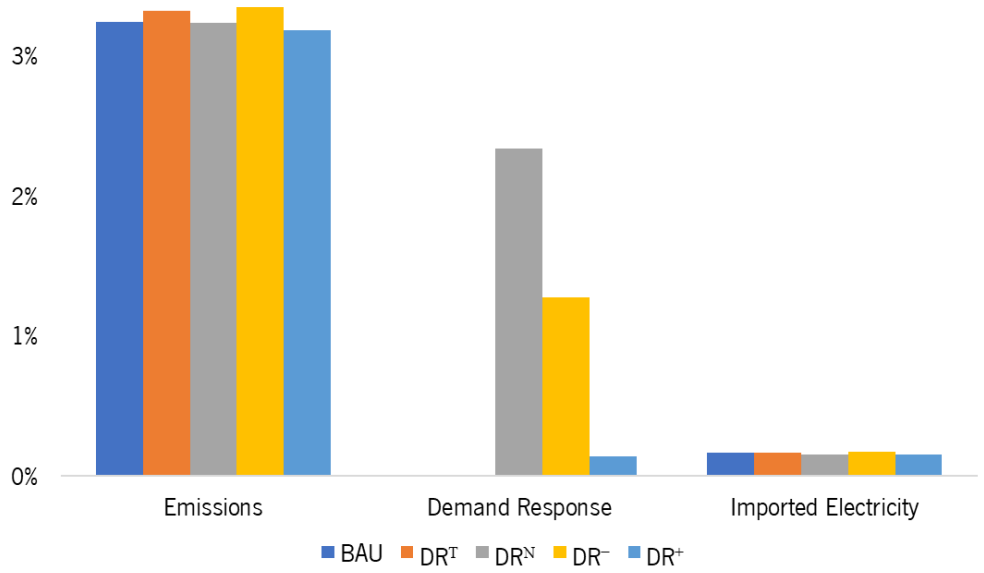


Figure 7.4. Average regional potential for load shedding for the industrial sector between 2018-2040.

The percentage share for each cost category is illustrated in Figure 7.5 for all scenarios with DR (Scenario 3 - DR^T, Scenario 5 - DR^N, Scenario 7 - DR^+ and Scenario 9 - DR^-). These costs were split by the ones incurred for expanding the power system during the planning period (investment, operating and fuel costs - Figure 7.5a) and the ones related to the avoided CO_2 emissions, imported electricity and variable DR costs (Figure 7.5b) for each scenario.



a)



b)

Figure 7.5: Contribution shares for each cost category: a) Investment, operating and fuel costs and b) Emissions, DR and imported electricity.

It can be seen from the data in Figure 7.5 the different contribution shares for each cost category. The investment, operating and fuel costs have the highest percentage contribution. No significant differences among scenarios were found for the cost participation share of CO_2 emissions (see Figure 7.5b). The cost contribution share related to the imported electricity for all scenarios with DR is found not to vary significantly among scenarios. Further analysis of the data reveals the impact of considering different prices for load shedding. The most striking result to emerge from the data analysis is that for prices of a typical drought year (Scenario 7 - DR^+), the contribution share of DR costs represents only 0.1% from the overall system costs, whereas, for Scenario 5 (DR^N), this share increases to a value near 2.1%. Therefore,

the sensitivity analysis carried out over the DR costs (through the simulation of different scenarios with DR) illustrates how weather conditions might affect load shedding in the case of considering the spot price as the basis for the industrial consumers' financial rewards.

Figure 7.6 shows the exploited and non-exploited potential for load shedding for each scenario with DR (average value in TWh between 2018 and 2040). Compared to the available theoretical DR potential (see Ref. [67]), the average technical DR potential (Scenario 3 - DR^{T}) exploited is slightly higher than 84%. For Scenario 5 (DR^{N}), on average, more than 33% of the theoretical load flexibility potential seems to be used between 2018 and 2040. A significant difference has been found between Scenario 9 (DR^{-}) and Scenario 7 (DR^{+}) (i.e., when different prices are considered for load shedding) since the exploited DR potential strongly varies between scenarios. For prices of typical drought years (Scenario 7 - DR^{+}), the simulation results indicate an exploited share of about only 0.4%, whereas, for a wet year (Scenario 9 - DR^{-}), this value considerably increases to almost 83%. This indicates the high impact of electricity prices over the potential for load shedding in the country.

Therefore, based on our premises related to the costs attributed to load shedding (which derived from average weather conditions, i.e., dry and wet years which conditioned the spot prices), we can infer that the uncertainties related to weather conditions across future years are considered a critical issue to be addressed in future assessments. Further research could be undertaken to investigate these effects more precisely using stochastic models, for example.

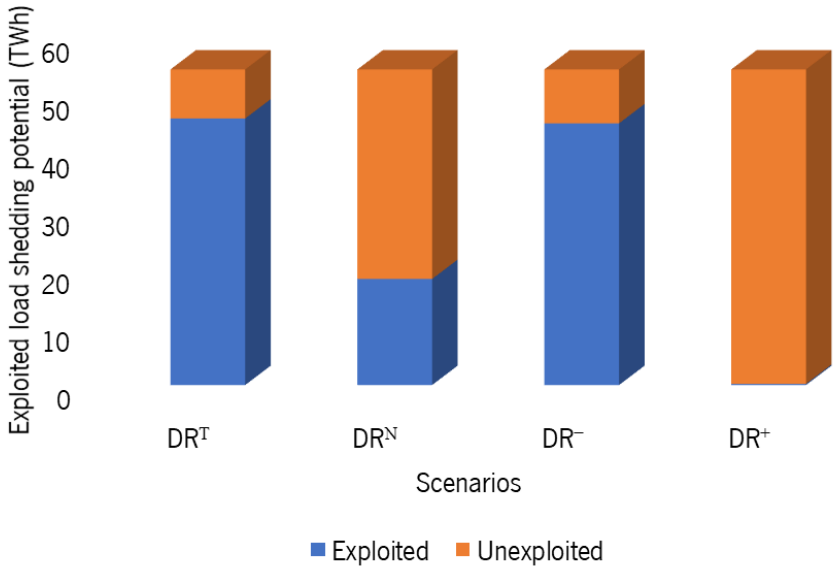


Figure 7.6: Exploited and non-exploited load shedding potential compared to the theoretical load flexibility potential.

The following paragraphs attempt to address the DR-related benefits for the power system evaluated in this research. Our efforts are focused on answering the potential of load flexibility to (i) delay future investments in expanding the supply-side; (ii) RES integration; (iii) reduced need for thermal capacity; (iv) decrease in the level of CO_2 emissions and (v) the possibility of enhancing the synergies between power subsystems within the country.

i. **Delay in investments:** The results revealed a delay in the investments for new power generation capacities, decreasing 28% (on average) between 2020-2030 for Scenario 3 (DR^T) compared to Scenario 1 (BAU). The delay in the investments for new power capacities has also been observed when the variable costs to implement DR are included. For these scenarios, however, the reduction varies from 3% (Scenario 7 - DR^+), 14% (Scenario 5 - DR^N) to 19% (Scenario 9 - DR^-) compared to Scenario 1 (BAU) between 2020-2030. Although the potential to delay investments for the last ten years of the planning period (2030 – 2040) still exists, it seems much lower than those from the ten first years (2020 – 2030).

ii. **Integration of RES:** A limited potential of DR to integrate additional renewable plants was found since only small changes were verified in the overall installed capacity from VRE sources between Scenario 1 (BAU) and scenarios with DR. There are two likely causes for this limited contribution: (i) the power system evaluated in this paper already relies mostly on RES (primarily from hydropower) and (ii) because of its high reliance on hydropower coupled with the decreasing regularization capacity of reservoirs, the maintenance of the high share of renewable energy is considered a challenge. These results provide further support for the hypothesis that for systems with a high share of RES from hydropower, the DR contribution is somewhat limited in integrating larger shares of renewables from VRE sources.

iii. **Reduced need for thermal capacity:** We also verified a great potential of DR for reducing the need for additional thermal capacity, especially for the natural gas power source, which decreased by 45% (Scenario 3 - DR^T), 21% (Scenario 5 - DR^N), 19% (Scenario 9 - DR^-) and 7% (Scenario 7 - DR^+) compared to Scenario 1 (BAU). Only small changes were verified among nuclear and biomass power plants among scenarios regarding the new future power system capacity.

iv. **Decrease in the level of CO_2 emissions:** The overall level of CO_2 emissions is also affected by the DR implementation and decrease for all scenarios compared to Scenario 1 (BAU). This result may be mostly explained because of the reduced need for using natural gas for producing electricity in the scenarios with DR implementation. Figure 7.7 illustrates the overall level of emissions (millions of tons - Mton) for each scenario for the entire planning period (2018-2040). The level of

emissions decreased by almost 9.8% and 3.4%, respectively, for Scenario 3 (DR^{T}) and Scenario 5 (DR^{N}) compared to Scenario 1 (BAU). However, no significant differences were found in the overall level of emissions between DR^{N} and DR^{-} scenarios (650.7 million tons for Scenario 5 (DR^{N}) and 641.2 million tons for Scenario 9 (DR^{-})), notwithstanding their significant difference in the overall system costs. This outcome can be mostly explained by the fact that the overall installed capacity of thermal sources (mainly from natural gas) has not been significantly affected by the optimization process between Scenario 5 (DR^{N}) - 32.9 GW and Scenario 9 (DR^{-}) - 33.7 GW and thus its share on the average electricity production was not deeply affected. Taken together, these results suggest that the reductions in the costs for load shedding (for Scenario 9 - DR^{-}) are not sufficient to significantly reduce the electricity production from thermal sources. Thus, the overall CO_2 emissions from Scenario 9 (DR^{-}) are not meaningfully affected compared to scenario Scenario 5 (DR^{N}).

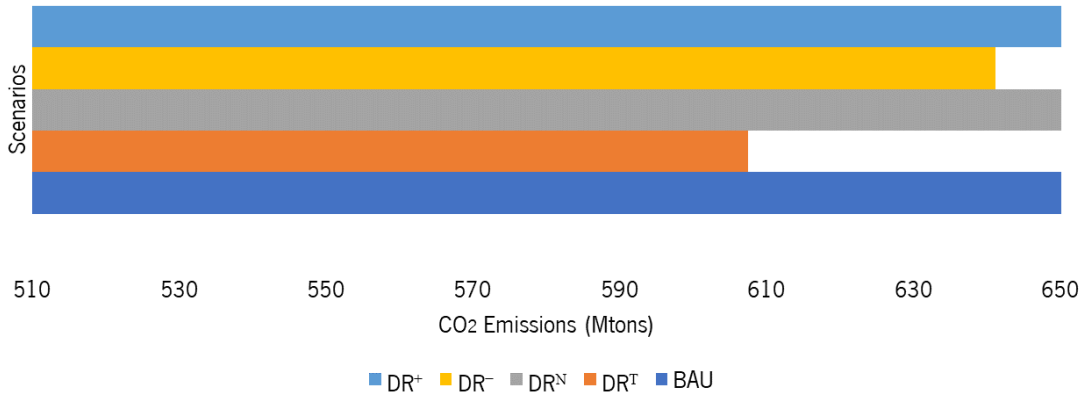


Figure 7.7: Overall level of CO_2 emissions for the period 2018-2040

v. **Possibility of enhancing the synergies between power subsystems:** DR may also provide additional benefits from the long-term power planning perspective. Findings of this research revealed the potential of DR to decrease by nearly 15% the need for additional transmission capacity for Scenario 5 (DR^{N}) compared to Scenario 1 (BAU). However, the most striking result that emerged from the data analysis is that a slight increase (8%) in the new transmission capacity was observed for scenario Scenario 7 (DR^{+}) compared to Scenario 1 (BAU). According to the simulation results, this increase might be mostly associated with the expansion of the international connection with the South region. This finding may be partly explained by the high spot price (i.e., PLD) for the South (SO) region (with an average value of 178 US$/MWh across seasons for Scenario 7 (DR^{+})). These results may further support how different prices for load shedding may strongly

change optimal scenarios with DR and how the different regional characteristics might affect the country's economic load flexibility potential.

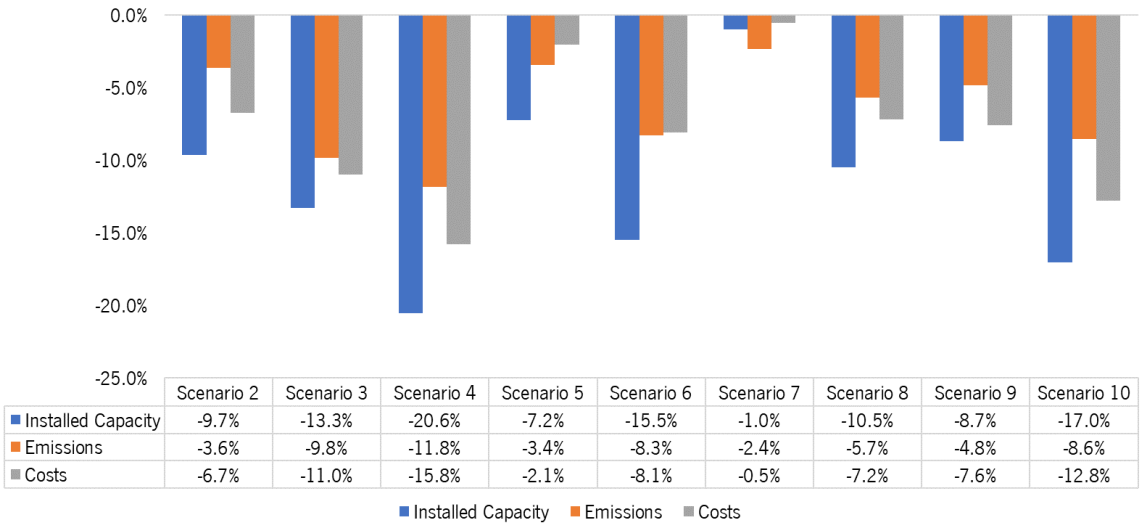
7.4 Integrated assessment of DSM strategies (DR and EEMs)

Although extensive research has been carried out on the multiple benefits of investing in energy efficiency and demand-response measures, these results are usually limited by qualitative assessments. The most significant recent developments in this direction have been those of individual assessments, i.e., focusing on the individual contributions of energy efficiency (Chapter 6) or demand-response strategies only (Section 7.3). The contribution of the current literature - particularly for high renewable-based systems – is, therefore, somewhat limited since few studies have investigated whether investing together in energy efficiency and demand response might be economically feasible for the long-term and a synergistic and well thought out approach is highly recommended.

The integrated DSM assessment is focused on the Brazilian power sector due to both its high level of RES and continental dimensions. To the best of the authors' knowledge, this is the first study that evaluates the combined use of both energy efficiency and demand-response strategies on a national scale. The proposed Integrated Brazilian Electricity System Model (IBESM) is used along with this research to evaluate the long-term impacts of implementing DSM in the country. The proposed model might support future research pathways into other-related demand-side assessments for different power systems.

This section moves on to quantitatively evaluate the most significant long-term impacts of implementing DSM measures for the power system assessed in this research. However, for the sake of promoting a fairly comparison among the results, the new scenarios addressed along with this section (Scenarios 4, 6, 8 and 10) will be presented and compared with the previously assessed scenarios, i.e., with Scenario 1 (BAU) (Chapter 4 - Section 4.4), Scenario 2 (EEM_5%) (Chapter 6 - Section 6.3) and with Scenarios 3, 5, 7 and 9 (Section 7.27.3).

Figure 7.8 illustrates the percentage changes for the new installed capacity, CO_2 emissions and total systems costs for all scenarios compared to Scenario 1 (BAU). It can be seen from the data illustrated in Figure 7.8 that compared to Scenario 1 (BAU), there is a percentage reduction for the new installed capacity (varying from -1.0% to -20.6%), CO_2 emissions (-2.4% to -11.8%) and total system costs (-0.5% to -15.8%) for all scenarios.



	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10
Installed Capacity	-9.7%	-13.3%	-20.6%	-7.2%	-15.5%	-1.0%	-10.5%	-8.7%	-17.0%
Emissions	-3.6%	-9.8%	-11.8%	-3.4%	-8.3%	-2.4%	-5.7%	-4.8%	-8.6%
Costs	-6.7%	-11.0%	-15.8%	-2.1%	-8.1%	-0.5%	-7.2%	-7.6%	-12.8%

Figure 7.8: Percentage change for the new installed capacity, CO_2 emissions and total system costs for each scenario compared to Scenario 1 (BAU).

Compared to Scenario 1 (BAU), the highest decrease for the new installed capacity, CO_2 emissions and total system costs were observed for Scenario 4 (DR^T/EEM_5%), whereas the smaller percentage reductions were observed for Scenario 7 (DR^+). As presented in Table 7.1, Scenario 4 (DR^T/EEM_5%) represents the exploitation of the technical DR potential together with the implementation of 5% of EEMs (i.e., representing a reduction in the final electricity demand of 5%). Compared to other scenarios, a possible explanation for the higher reductions in the overall costs, newly installed capacity and CO_2 emissions for Scenario 4 (DR^T/EEM_5%) compared to Scenario 1 (BAU) seems to be related to the scenario assumptions, i.e., for the technical DR potential estimation, no variable costs are attributed to DR implementation. Thus, the reductions in the costs, installed capacity and CO_2 emissions are higher than other scenarios. However, for Scenario 7 (DR^+) - which attempts to assess the economic DR potential for a typical drought year - the changes in the costs, newly installed capacity and CO_2 emissions are relatively small compared to other scenarios. The weakly associated benefits of implementing DR strategies for Scenario 7 (DR^+) is interesting, but not surprising since it can be partially explained because of the higher shedding costs attributed for this drought scenario - which increased the need for new installed capacity and consequently there seems to be a significant increase in the fuel costs compared to other scenarios.

However, the single most striking observation to emerge from the data comparison comes from Scenario 8 (DR^+/EEM_5%) - which differs from Scenario 7 (DR^+) by including 5% of EEMs (also for a drought year scenario). In this case, the reductions in the costs, installed capacity and CO_2 emissions are more insightful, indicating the great potential that the joint implementation of both DR and EE investments

might play in the power system evaluated, particularly for drought years. Further analysis reveals that for a wet year case (Scenario 10 - DR^-/EEM_5%), the economic benefits would be higher than for a typical drought year scenario (Scenario 8 - DR^+/EEM_5%). A possible explanation for these results may be related to the costs attributed to load shedding - which are considerably lesser for the wet scenario than the drought scenario. Hence, the need for additional installed capacity in the wet scenario is found to reduce from 189 GW (Scenario 8 - DR^+/EEM_5%) to 176 GW (Scenario 10 - DR^-/EEM_5%), whereas the fuel costs are reduced by 11%. It is worth mentioning that the decreasing costs for implementing load shedding for typical wet years can be strictly associated with the good rainfall conditions in these years.

Figure 7.9 breaks the costs for each scenario into seven categories (investment, operating, fuel, CO_2 emissions, demand-response, imported electricity and energy efficiency costs). The findings reported in Figure 7.9 clearly reveal that the investment cost represents the highest share for all scenarios, followed by the operating and fuel costs. The costs for importing electricity, CO_2 emissions, energy efficiency and the ones related to DR seem to be much lower compared to the investment, operating and fuel costs for all scenarios.

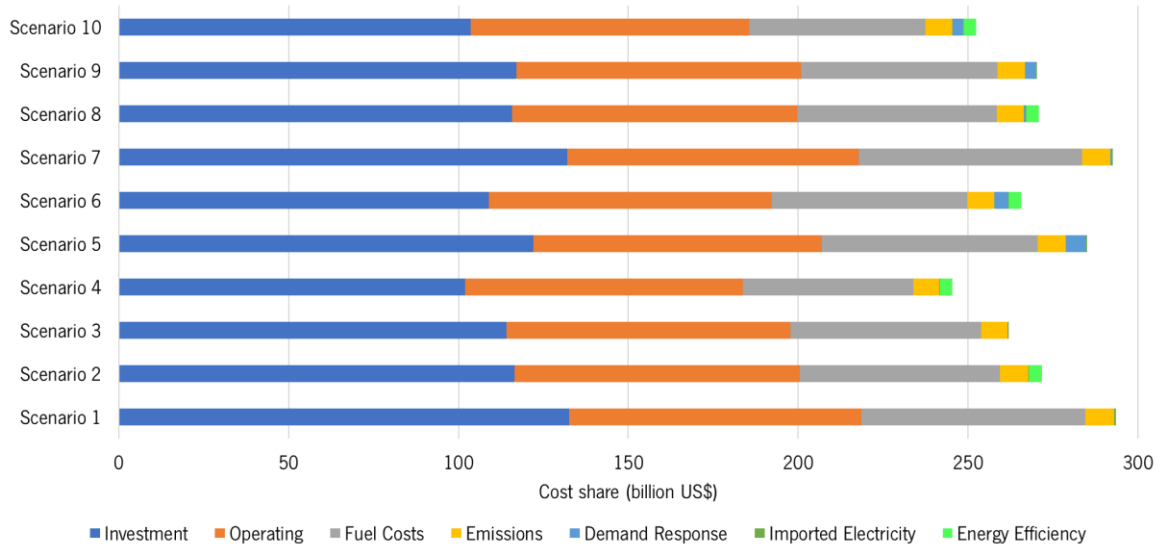


Figure 7.9: Cost categories for each scenario.

The interpretation of the results may be better supported if scenarios would be compared in pairs, i.e., Scenario 1 (BAU) with Scenario 2 (EEM_5%), Scenario 3 (DR^T) with Scenario 4 (DR^T/EEM_5%) and so forth; since the second scenario of each pair represents the conditions of the previous scenario by also adding up a level of 5% of EEMs.

Figure 7.10 illustrates the percentage variation for the new installed capacity, CO_2 emissions and costs for each pair of scenarios. It is also possible to hypothesize that among scenarios that assess the

economic DR potential, Scenario 7 (DR^{+}), Scenario 8 (DR^{+}/EEM_5%), Scenario 9 (DR^{-}) and Scenario 10 (DR^{-}/EEM_5%) are less likely to occur in reality compared to Scenario 5 (DR^{N}) and Scenario 6 (DR^{N}/EEM_5%) since the former of each pair represent extreme rainfall conditions. Therefore, the following analyzes will focus on evaluating Scenario 6 (DR^{N}/EEM_5%) compared to Scenario 5 (DR^{N}) since these scenarios would represent a typical year with average weather conditions and, therefore, may more accurately represent the future real power system conditions. As shown in Figure 7.10, a reduction in the total system costs of about -6.2% is projected for Scenario 6 (DR^{N}/EEM_5%) compared to Scenario 5 (DR^{N}). This would come with a decrease in the level of CO_2 emissions and the new installed capacity of -5.0% and -8.9%, respectively, for the entire planning period.

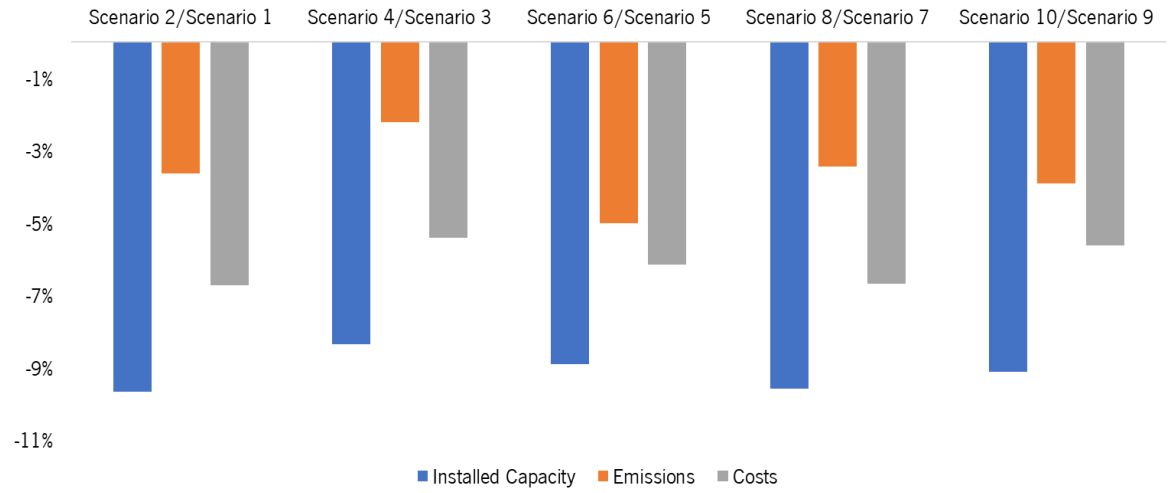


Figure 7.10: Percentage variation for the new installed capacity, CO_2 emissions and costs for the most relevant pair of scenarios.

If we now turn to analyze the long-term impact of using (i) only EEMs or (ii) only DR or (iii) both EEMs and DR strategies for the most likely to occur scenarios, i.e., Scenario 2 (EEM_5%), Scenario 5 (DR^{N}) and Scenario 6 (DR^{N}/EEM_5%), respectively, a set of significant conclusions can be drawn. Compared to Scenario 1 (BAU), the economic advantages for Scenario 2 (EEM_5%), Scenario 5 (DR^{N}) and Scenario 6 (DR^{N}/EEM_5%) can be clearly identified since there is a cost reduction for all scenarios (see Figure 7.9). In summary, these results also reveal a cost decrease slightly higher than -1.4% for Scenario 6 (DR^{N}/EEM_5%) compared to Scenario 2 (EEM_5%) in what concerns the total system costs over the entire planning period. This would also promote a reduction of -4.8% and -6.4% in the level of CO_2 emissions and new installed capacity, respectively.

The overall system costs for Scenario 2 (EEM_5%), Scenario 5 (DR^{N}) and Scenario 6 (DR^{N}/EEM_5%) are estimated to be about US$ 225.4 billion, US$ 236.7 billion and US$ 222.2 billion, respectively. What

emerges from these results is the higher estimated costs for Scenario 5 (DR^N) compared to Scenario 2 (EEM_5%). However, the single most striking observation to emerge from the data comparison relates to the higher but limited economic benefits for Scenario 6 (DR^N/EEM_5%) compared to Scenario 2 (EEM_5%). This suggests that the integration between energy efficiency and DR investments seems to represent the most cost-effective strategy, although the small differences in the overall system costs for Scenario 6 (DR^N/EEM_5%) compared to Scenario 2 (EEM_5%). Investments including energy efficiency are projected to be more economically valuable than investing in DR strategies alone. This rather interesting finding might be explained by the fact that the evaluated power system relies mostly on hydropower with low operating costs, which competes against the variable costs for implementing DR.

Our results also revealed that the new natural gas installed capacity would decrease from 32.9 GW (Scenario 2 - EEM_5%) to 26.4 GW (Scenario 6 - DR^N/EEM_5%), which corresponds to a reduction of near 20%. This decrease is even higher if we compare Scenario 6 (DR^N/EEM_5%) with Scenario 1 (BAU), reaching a reduction of almost 37%, which comes with a decrease of 8.3% in the overall level of CO_2 emissions. However, as expected, the new installed capacity for natural gas for Scenario 5 (DR^N) is substantially higher than for Scenario 6 (DR^N/EEM_5%) (+25%). No significant differences were found for the new natural gas installed capacity comparing Scenario 5 (DR^N) with Scenario 2 (EEM_5%) (+0.07%). The higher reduction in the natural gas installed capacity for the scenario with both EEMs and DR (Scenario 6 - DR^N/EEM_5%) compared to other scenarios with any category of DSM suggests that the synergies brought about by this combination of DSM strategies may empower the benefits for the power system evaluated in this research. A further interesting outcome that emerged from the simulation results is related to the projected decrease for the new capacity of run-of-river hydropower plants, which accounted for a reduction of 14% comparing Scenario 6 (DR^N/EEM_5%) with Scenario 1 (BAU).

The carbon emissions for the two selected scenarios are described in Figure 7.11. The increased electricity production from intermittent RES reduced the thermal needs (especially from natural gas and coal power sources) for both scenarios, explaining the reduced emissions for the last ten years of the planning period.

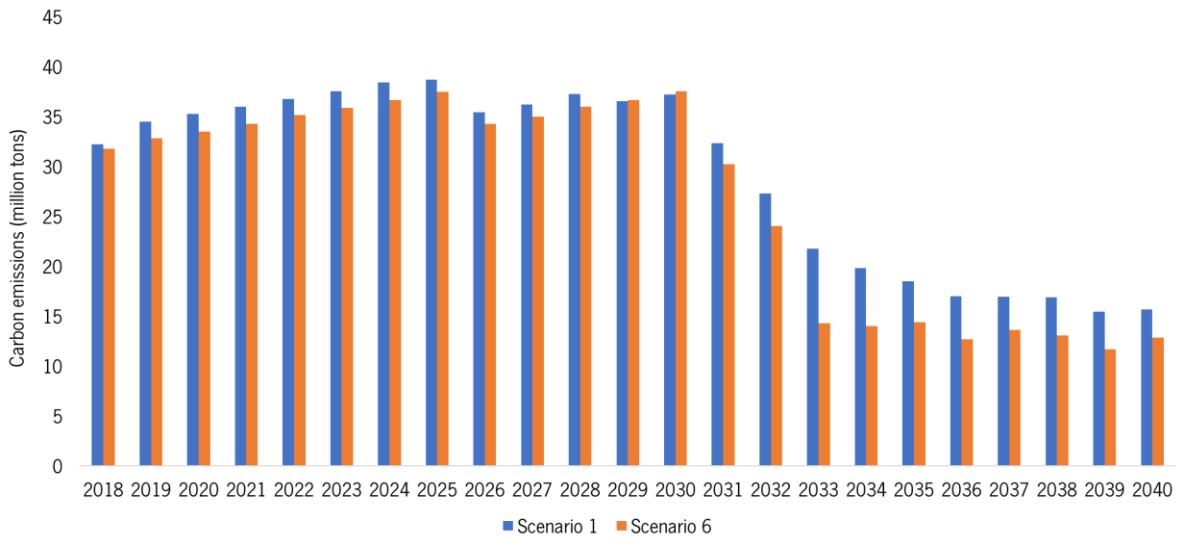


Figure 7.11: Carbon emissions for Scenario 1 (BAU) and Scenario 6 (DR^N/EEM_5%).

Figure 7.12 illustrates the delay in investments in new installed capacity for the most relevant pair of scenarios. Figure 7.12 is quite revealing in several ways and what can be clearly seen is the extent to which DSM might delay the investments in new installed capacity. Scenario 6 (DR^N/EEM_5%) compared to Scenario 1 (BAU), i.e., scenario 6/1 seems to have the highest potential to delay investments, particularly for the period 2020-2030, decreasing almost 26%. This finding might be partially explained by the combined benefits of implementing energy efficiency and DR in Scenario 6 (DR^N/EEM_5%) compared to Scenario 1 (BAU). Strong evidence for a higher potential to delay investments was found for 2020-2030 compared with the last period of the planning period (2030-2040) for all scenarios. Together these results provide important insights into the potential of delaying investments in the long-term, allowing at the same time the decision-makers to identify possible synergies between these different DSM strategies but also supporting the establishment of future energy policies.

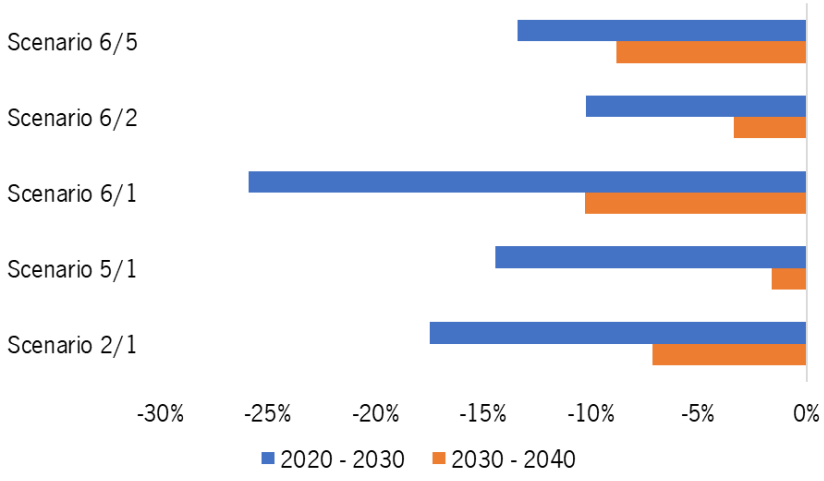


Figure 7.12: Delay in investments for the new installed capacity for selected scenarios.

A sensitivity analysis has also been performed, adjusting the LACoSE by -50%, +50% and +100% over the base value to analyze how this variable may affect the evaluated scenarios. Figure 7.13 shows the percentage cost variations for each pair of scenarios. Scenarios are compared in pairs to evaluate better the impacts of different prices for the LACoSE, such as previously discussed. Because of the small[88] costs related to the investments in EEMs compared to the total system costs for each scenario, no significant reductions were found between scenarios compared to the base LACoSE value. However, with successive increases in the LACoSE, it can be seen a substantial increase in the total system costs (see Figure 7.13).

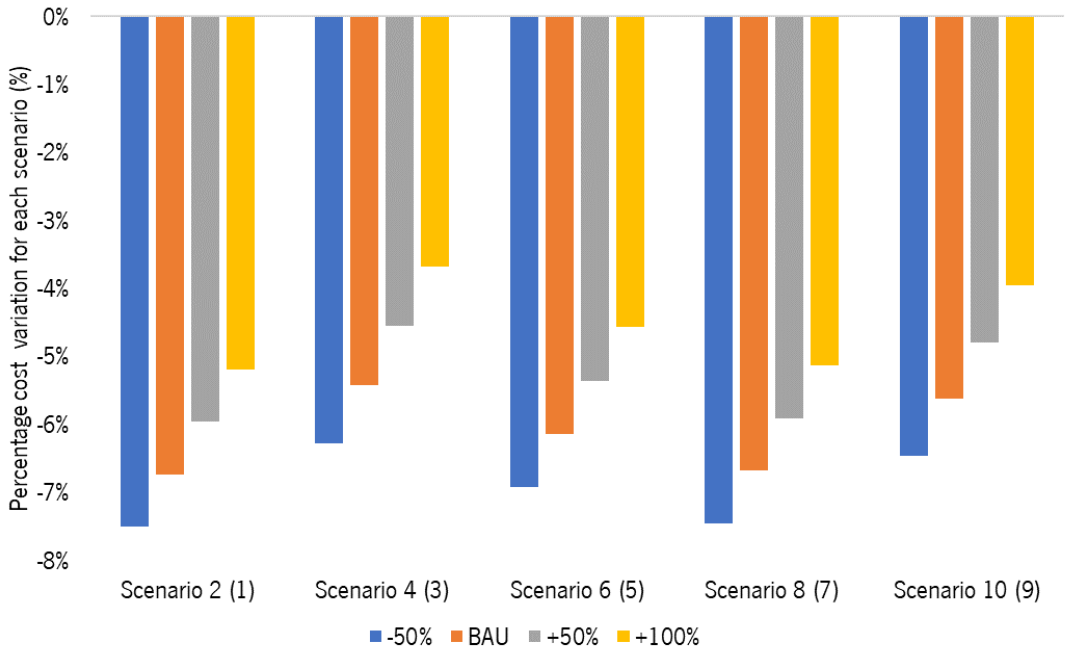


Figure 7.13: Sensitivity analysis over the estimated LACoSE.

7.5 Concluding remarks

This chapter has been strengthened by two key accomplishments. Firstly, (i) the assessment of the technical and economic DR potential has been performed by considering both load shedding and load shifting DR strategies, followed by (ii) evaluating the long-term effects of using both demand response measures and energy efficiency investments. Both analyzes were performed based on a high-RES system – the Brazilian case study.

The power system evaluated in this research deeply relies on hydropower energy. The Brazilian government's strategic plan still considers the use of hydro resources as an essential element for the future expansion of the power system [56]. However, the remaining hydro potential is almost entirely

[88] The average value among scenarios that consider the use of 5% of EEMs was found to be only around 1.8% of the total system costs.

concentrated in the North region and its exploitation raises a set of environmental and social challenges [56]. Although considered a dispatchable power source, the regularization capacity of the reservoirs has been decreasing over time [68]. This fact, coupled with the high increase of VRE from wind and solar power systems, suggests an increasing need to use new load balancing options such as DR strategies, which also justifies the importance of the present study.

We concluded that the economic benefits brought about by the implementation of only DR measures might be positive for the power system evaluated, decreasing the overall system costs from -0.5% - Scenario 7 (DR^{I}); -2.1% - Scenario 5 (DR^{N}); -7.6% - Scenario 9 (DR) to -11.0% - Scenario 3 (DR^{T}) when compared to Scenario 1 (BAU). This research also supports the hypothesis that DR implementation might reduce the future power generation capacity respectively by -7.2% and -13.3% for Scenario 5 (DR^{N}) and Scenario 3 (DR^{T}) compared to Scenario 1 (BAU). The CO_2 emissions are also affected by the DR implementation and decrease for all scenarios evaluated compared to Scenario 1 (BAU), varying from -2.4% to -11.8% across scenarios. The impact on RES integration has also been assessed and the results revealed a limited potential of DR to integrate additional renewable plants mainly because of the current high reliance on hydropower. A great potential of DR to reduce the need for additional thermal capacity has also been verified primarily from the natural gas power source. The impact of DR on the need for additional transmission capacity has also been assessed and the results suggest that the spot prices might significantly affect the optimal scenarios with DR.

Our findings also provide important insights into the future overall installed capacity, CO_2 emissions and total system costs if investments in both EEMs and DR would be implemented in the country. Overall, the results suggest positive future benefits of implementing DSM strategies for the power system evaluated. Findings of this study revealed that investments in energy efficiency are projected to be more economically valuable than investing in DR strategies only. The second significant finding indicates that the integration between energy efficiency and DR would empower the power system's overall benefits. The delay in supply-side investments was clearly identified for all scenarios. A clear advantage of implementing DR combined with EEMs, e.g., for Scenario 6 (DR^{N}/EEM_5%), is related to the synergies that might exist between these two categories of DSM strategies. Therefore, the economic impacts brought about by the use of EEMs and the economic DR potential exploitation - Scenario 6 (DR^{N}/EEM_5%) - were found to be more advantageous compared to Scenario 5 (DR^{N}). However, comparing Scenario 5 (DR^{N}) with Scenario 2 (EEM_5%), it can be noted the advantages of investing in energy efficiency compared to demand response investments only. This finding would also represent a limited contribution

of investing in DR strategies alone, particularly for the Brazilian power system, which could be attributed to its high reliance on hydropower with low variable operating costs.

The considered price of shifted demand was based on Ref. [187]. However, after performing a set of simulations, it was realized that the economic DR potential for the power system evaluated is not affected even considering a high range for the price of shifted demand (e.g., 0.1 US$/MWh to 10 US$/MWh). These findings are also in agreement with Ref. [98], which addressed (partly) the DR potential for the case of Brazil and highlighted the limited DR contribution for balancing purposes. Our results also support this conclusion since even when no costs are considered for load shifting (i.e., Price of Shifted Demand = 0 US$/MWh), the total system costs are reduced only by less than 0.3% compared to the scenario which considers the price of shifting demand with a value of about 10 US$/MWh. Hence, it could conceivably be hypothesized that the load shifting potential is somehow limited for load balancing purposes for systems with a high hydropower share. Therefore, these findings provide empirical evidence that the load shifting flexibility potential exists, but it is very limited for the Brazilian power system and its effect on the total system costs seems to be very small.

Although the findings should be interpreted with caution, this study has several strengths and contributions to the current literature, which comprises a detailed analysis of the Brazilian power system with (i) the inclusion of power grid interconnections between subsystems (the country has been divided into four main power subsystems) and with neighbors countries; (ii) DG from PV systems have been exogenously added up to the model; (iii) the DSM is included considering both DR strategies and EEMs; and (iv) a sectoral analysis (i.e., for the industrial, residential and commercial) is taken into account for the DR formulation. Last but not least, the present study also (v) extends our knowledge by expanding the cost of opportunity concept for shedding large industrial consumers' load based on the historical spot market prices.

Our findings provide valuable insights into whether the use of energy efficiency and demand-response strategies might be cost-effective. We also emphasize that the insights gained from this study may be of assistance to both practitioners and policy-makers by also empowering the development of more advanced DSM strategies. Therefore, despite its limitations, the study certainly adds to our understanding and the results might support the current government pathways by providing a national and sectoral evaluation of the long-term impacts of investing in energy efficiency and DR measures. The integration of both DR and energy efficiency may also be of great assistance in the future since it is predicted that climate change may affect the country’s hydro availability.

Chapter 8. Conclusions and Final Remarks

This final chapter summarizes the main concluding remarks that can be extracted from this study in Section 8.1. A summary of the main policy implications is further addressed in Section 8.2. A lively and broader discussion of the underlying study's strengths and weaknesses is then discussed in Section 8.3 by describing the opportunities and new avenues for further research.

8.1 Conclusions & outlook

Overall, this thesis has provided valuable insights into the role of the integration between supply and demand-side resources for long-term energy planning modeling and the findings from this study make several contributions to the current literature.

This research established transparency and shed new light on the complex effects of the use of DSM strategies as well the interactions among supply and demand-side resources in long-term electricity planning models. The modeling approach recognizes the impact of short-term variability of both demand and RES supply and it is well suited to systems with both a high share of RES and under different demand flexibility conditions. Brazil was used as the research case study given its particular features, making it a complex and heterogeneous electricity system with significant reliance on RES and a great potential for DSM penetration. The proposed methodology largely extends beyond the case addressed as it may provide valuable lessons for other electricity systems.

Findings of this study demonstrated that RES should remain predominant in the Brazilian energy sector. A large-scale shift towards renewable energy, however, might require a set of ambitious targets and policy changes from the current governments' energy plans and there are still several technical and economic challenges to be surpassed to achieve a high share of RES integration. Hydropower seems to remain the most important power source for all scenarios evaluated in what concerns the overall electricity production and installed capacity, although with a steady percentage decrease compared to other RES power options along with all the planning period (2018-2040). It is worth mentioning that the largest part of the Brazilian remaining hydro potential is located in the Amazon River basin (Northeast region) near indigenous lands and/or protected areas. Therefore, the challenges of exploiting the remaining hydropower potential are related primarily to social and environmental issues. Although these social and environmental impacts are out of the scope of this work, it is worth recalling that these aspects cannot be considered negligible in what concerns the Brazilian power planning as showed in previous works such as [405].

Overall, this study strengthens the idea that EEMs would reduce the overall installed capacity of fossil fuel power sources for all scenarios evaluated. Also, for all scenarios which evaluate the implementation of at

least one type of DSM strategy, it seems that the need for new installed capacity of natural gas is substantially reduced. This would also contribute to reducing the imports of natural gas from Bolivia and consequently moving towards Brazilian energy independence and increasing energy security issues. Notwithstanding, non-RES technologies (primarily thermal power plants) seem to continue developing in the country to provide a safer and reliable generation expansion plan. The results also indicate that the high share of several complementary non-hydro RES is expected to diminish the dependency on hydropower and result in a least-cost solution in the future. We conclude that RES could contribute significantly to the decarbonization of power systems, even for regions or countries for which demand is still expected to increase during the next years, as is the case of Brazil.

Conclusively, the main concluding remarks will be summarized, returning to each research question posed at the beginning of this study in Chapter 1.

RESEARCH QUESTION 1: ***How to assess the potential of flexible demand (DR potential) across different sectors? How can each DR potential category be distinguished?***

The strengths of this study include an in-depth systematic review analysis covering the different categories of DR potentials, which allowed not only to reach some consensus on the definition of DR categories but also on the main steps to be followed for its estimation. Findings of this study reveal that literature has extensively focused on assessing the technical DR potential followed by the economic, theoretical and achievable potentials, respectively. A lack of understanding of the different categories of DR potentials was also identified, which sometimes have been unduly used in the literature. A well-founded and user-friendly framework - which would help quantify the DR flexibility across different sectors and applications – has also been proposed. The proposed framework is supported on a small sample of numerical approaches and equations, which results in a structured approach to bringing consensus to the DR potential assessment. We also underline the potential of replicability of the methodology proposed in this research to evaluate the different categories of DR potentials across different customer segments and power systems.

RESEARCH QUESTION 2: ***Which is the most recent and relevant existing body of literature dealing with long-term co-optimization models within the energy field?***

This review found evidence that the use of co-optimization strategies has increased markedly over the last few years in long-term energy planning models. The majority of previous long-term co-optimization models have focused on finding least-cost plans. Overall, such approaches are likely to lead to less costly solutions than traditional optimization techniques. The review also established that the majority of long-

term co-optimization studies concentrate their efforts on generation-transmission planning model applications.

Research has consistently shown that the use of co-optimization approaches can be technically challenging. Overall, a set of techniques such as relaxation, decomposition and linear approaches have been proposed for reducing the inherent nonlinear model's complexities. The evidence from our review seems to suggest a pertinent role for addressing real-case systems in future models instead of using theoretical test cases as considered by the majority of studies. Co-optimization is revealed to be also a data-intensive procedure. The need to coordinate the necessary data from multiples actors might increase the complexity of the problem since security and confidentiality issues would also be put on the table. The identified challenges for future co-optimization models include (i) dealing with the treatment of uncertainties and (iii) taking into account the trade-offs between the temporal and spatial model's resolution.

Findings from our literature review revealed that many traditional power system models have neglected to include DSM strategies (in particular DR measures) within long-term generation expansion planning problems. Therefore, although there is also a growing body of literature that recognises the importance of co-optimization focused on integrating supply and demand-side options, there has been little work in the development of co-optimization models for long-term decision-making that recognize the impact of short-term variability of both demand and RES supply and well suited to systems with a high share of RES and under different demand flexibility conditions. The research results represent a further step towards the importance of developing more comprehensive approaches for integrating short-term constraints in future co-optimized planning models. The findings also provide a solid evidence base for the multi-dimensionality of the co-optimization problems and contribute to a better understanding of how future operating and planning models might be affected under the use of such co-optimization approaches.

RESEARCH QUESTION 3: ***What are the main prospects, challenges and opportunities towards a smart grid power system in Brazil?***

Our findings add to a growing body of evidence suggesting that policies for DG, DSM and new tariff schemes are on a path of accelerated deployment in the country. The deployment of storage technologies, however, is at a slow pace of growth. We call attention to the need to develop further new business models to address the various decentralized energy technologies and services emerging in the sector. The current net-metering system is considered a key issue to be discussed as this regulatory structure may shift the costs from DG to non-DG users. Evidence is found that regulation for electric vehicles is still emerging in the country. Despite the current small share of EVs and the slow pace of this technology's growth in the

past years, a steady increase is projected to come in the country. Finally, it can be concluded that many challenges and barriers associated with DSM deployment still exist, although many advances have been observed over the past years. Outcomes of this study revealed a great potential for the broader penetration of DSM programs in Brazil, but there is a significant gap between the current levels of DSM and the overall potential available.

RESEARCH QUESTION 4: ***What is the estimated theoretical load flexibility potential across different sectors and regions within the Brazilian power sector?***

Our findings revealed that the overall maximum hourly theoretical DR potential in Brazil is expected to double, increasing from 12.8 GW in 2017 to almost 25.6 GW by 2050. Although most of the demand-side response potential seems to lie in the industrial sector, a lower but still substantial potential for the residential and commercial sectors has also been identified. The evidence from this study supports the hypothesis that the commercial sector will have a key role in offering the most valuable load flexibility potential (i.e., when the power system mostly needs it). The high expected increase in the overall electricity DR potential for the residential sector is driven mainly by the rise in both the number of households and the number of appliances per house. However, large amounts of flexible loads in the residential sector might not be necessarily available during on-peak times. Findings of this research may be of great assistance for future analyzes to identify, for example, the extent to which DR can cost-effectively compete with other supply-side options.

RESEARCH QUESTION 5: ***What are the major significant medium-long term impacts of energy efficiency measures for the Brazilian power sector?***

This study suggests that EEMs may reduce the expected new installed capacity between 2.0% and 9.7% and from 1.6% and 6.8% for the total system costs (for reductions in the final electricity demand from 1% to 5%, respectively). This research has also shown that EEMs would decrease the total CO_2 emissions up to 3.6%. The results provide further support for the hypothesis that the economic impacts of energy efficiency investments and their cost-effectiveness are affected by the share of RES in the power system. These types of measures may provide holistic benefits, including economic advantages and environmental and social improvements. The cost-effectiveness of EEMs was assessed by considering the newly proposed LACoSE approach, which allows for a fair comparison with the obtained results from traditional long-term power planning models. Therefore, the methodological contribution of this research also lies in the proposal of a step-by-step procedure to calculate the LACoSE.

RESEARCH QUESTION 6

How would cost-optimal pathways change with the inclusion of DR measures within the co-optimization model?

DR scenarios revealed a high potential for delaying future investments in power capacity compared to scenario BAU. However, it was found a limited potential of DR to integrate additional renewable plants mainly because of the current power system's high reliance on hydropower. This research has provided additional evidence concerning the potential of DR to decrease the overall levels of CO_2 emissions, reducing from -1.9% to -8.5% across scenarios with DR compared to scenario BAU. This finding seems to be strictly related to the reduced need for natural gas power plants in the scenarios with DR implementation. Uncertainties related to future weather conditions might also affect the optimal scenarios with DR. This study lays the groundwork for future research into the role of demand-response in power systems. It would also support the definition of well-founded sustainable energy policy pathways for other power systems with high-RES share and under different demand flexibility conditions. Therefore, the methodology and findings broadly extend beyond the case addressed as it may provide valuable lessons for other electricity systems. The future development of DR implementation costs may also compete against other balancing technologies, e.g., electric vehicles and storage systems, which is considered a fruitful area for further research.

RESEARCH QUESTION 7

To which extent can DSM measures technical and economically compete with other supply-side options?

The present study makes several noteworthy contributions to the current literature. Prior to this study, little was known about the long-term effects of using both demand response measures and energy efficiency investments in the specific case of the Brazilian power system. Previous studies have relied upon small sample sizes focusing on particular sectors or regions within the country. The relevance and the innovative aspects of this study are strongly related to a framework proposal for assessing the co-benefits between energy efficiency and demand-response on renewable-based energy systems under a long-term perspective. These impacts are estimated by modeling and analyzing scenarios for Brazil in 2040. Investments including energy efficiency are projected to be more economically valuable than investing in DR strategies alone. Our results might provide valuable insights to both government and policy-makers by delivering supportive information in scaling-up energy efficiency investments in the country. The methodology proposed in this research also offers essential contributions to the scientific

community and for which a multidisciplinary perspective would benefit energy systems research beyond the cases addressed in this study.

8.2 Implications for policy-makers

The key strengths of this study are its long duration as it may provide developments for the scientific community working on energy planning but also support decision-making for both companies operating in the energy sector and policy makers.

The large-scale integration of RES in the Brazilian electricity sector faces several challenges and involves a radical technological change. The technologies' deployment depends on government financial incentives and new political regulatory approaches. Additionally, it is fundamental for the private sector to be supportive. From a technical point of view, the most critical question to be answered is related to which technologies should be used to ensure that the available resources would meet future demands. Moreover, the high amount of fluctuating renewable energy, such as solar PV and wind systems, has become a significant challenge to the power system's operation and planning. As stated by [406], the transition to a renewable energy system from traditional fossil-fuel-based systems includes modifications in energy efficiency and energy conservation, improvement of the efficiency of the supply system and integration of fluctuating RES. Therefore, for the next years, a paradigm shift in the Brazilian power operation and planning is foreseen, requiring an in-depth discussion to provide a high energy security and reliability level. A sustainable, resilient and clean energy transition would require long-term structural changes in the current energy planning strategies, including actions on the demand-side and the supply-side.

There are currently relevant limitations in Brazilian electricity planning, sometimes overestimating economic aspects to the detriment of others, such as social and environmental issues. Additionally, energy policies applied in the country have been focused on local needs and sometimes based on political interests. Notwithstanding, there is great potential for progress to be achieved in the country. The definition of energy policies must be guided by long-term strategies and based on integrated, interdisciplinary, and sustainable energy planning approaches. The country also faces a paradigm shift due to new policies and regulations emerging in the sector but also because of its complex organizational, regulatory, social and market structure. Therefore, a set of adaptations in the current operation and expansion planning practices strategies, including new normative-regulatory frameworks and market models that properly value the economic, environmental and social benefits are still required to reap the systemic benefits of the potential disruptions of the sector.

These findings suggest several courses of action for policy-makers. Therefore, in light of the results obtained in this research, the following policy-related recommendations are proposed.

First, the deployment and dissemination of DG projected by the national authorities of the power sector in Brazil together with the intermittent nature of RES, enforce the need for new policy designs for both the utilities and consumers and this can be considered a key issue to enable the ambitious transition towards a RES-based energy system in the country. Additionally, more significant efforts are needed to ensure that policy designs find the optimal balance between investments to update the current energy system (and thus take advantage of the smart grid model) and other climate-policy-related investments. In this sense, the regulatory framework, primarily including new network grid codes, grid investment incentives, market design and environmental regulation, will have a vital role in the future of the Brazilian electricity sector.

Second, the digitalization process can be seen as a key opportunity for the utilities to reduce technical and non-technical grid losses. This would also enhance the potential for new business models, promoting non-regulated services to the consumers, e.g., helping them understand and manage their energy profile consumption. The cognitive patterns of the electricity consumers would also impact the future of the electricity sector, which is considered another key factor to be further evaluated.

Third, the creation of positive inducements related to the insertion of RES and the importance of diversifying the electricity supply sources to ensure not only financial savings but also energy security and reliability for the electrical power system is an essential tag in the Brazilian power sector. Therefore, we underline the need for the government to develop flexible regulatory frameworks to address the disruptive models that may become available in the power sector in the years to come. The diversity amongst distribution companies and the trade-off between affordable tariffs and technological advances open up important avenues for further research.

Fourth, we believe that greater attention should be paid from policy-makers to implementing effective demand-side investments. The new policies may have a great potential to change business models among Brazilian utilities. The policy implications of the analysis carried out in this research include that we have learned that integrating DR resources into the Brazilian electricity market requires a set of regulatory changes. We have shown that policies are needed to foster the introduction of DR measures. These new regulatory changes may positively influence the potential benefits of DR usage for almost all stakeholders.

Fifth, this research may also contribute significantly to increase the potential for policy-makers to develop effective public policies by determining, for instance, the selection of long-term sustainable energy plans but also future optimal DSM portfolios for the country. The findings reported here would also support the

definition of cost-effective DSM portfolios for specific customer classes and technologies. Due to the country's size and heterogeneity characteristics, the DSM portfolio could be established differently for each region to meet particular stated policy goals such as envisaging environmental objectives and/or economic development targets. It is worth mentioning that through a suitable framework, the stakeholders involved in the process, e.g., the government, utilities and consumers, might take a set of advantages. From the governmental and consumers' perspective, a set of benefits can be listed in the medium and long-term horizon, such as preservation, conservation, and protection of the environment, job creation and international recognition.

Sixth, findings of this research also revealed the need for the government to scaling-up energy efficiency investments in the country. There are multiple reasons for making energy efficiency investments. The avoided supply-side investment due to the use of EEMs would decrease the future need for generation capacity, as illustrated in this research. Furthermore, it would defer the distribution and transmission system upgrades. We underlined the great potential to reduce the need for distribution system upgrades since most EEMs are related to the end-user level. The reduction in the need for distribution systems would also decrease the grid's losses and thus require less electricity production. However, the extent to which EEMs might provide these additional benefits are beyond the scope of the present study, but future studies would strongly contribute to evaluating additional synergies of implementing EEMs in the long-term. Although the emerging role for energy efficiency along with the last years in Brazil, there is still a great potential for new economically viable energy efficiency investments that have not yet been fully exploited. Promoting investment in energy efficiency programs is essential, but also changes in policies are fundamental to exploit all the potential of EEMs, such as suggested by Ref. [191], which underlines that "*IEA projections to 2035 show that as much as two-thirds of energy efficiency potential will remain untapped unless policies change*". Therefore, we highlight the great potential for progress in Brazil, although a key policy priority should be considered to select long-term sustainable energy plans based on holistic energy planning approaches.

The **seventh** and ultimate goal of this research comes from the support for policy-makers to decide whether the current policies and regulations in the country are focused on achieving the required energy transition goals. It would also conceive which technological innovation would have disruptive effects in the energy sector and which business, cognitive, institutional and financial behavior aspects should be addressed by future government policies. We highlight the future need from the policy makers to evaluate which improvements in renewable energy, energy efficiency and demand-response could be effectively

made. This could include, for instance, the integration of renewables technologies for new public buildings.

8.3 Opportunities for further research

A lively and broader discussion of the strengths and weaknesses of the underlying study is addressed along with this section by also emphasizing the opportunities for further research. We set out to provide a holistic assessment of the role of both energy efficiency and demand-response in a highly electrified hydropower-based energy system by evaluating how effective the implementation of a set of specific demand-side strategies is. One of the main strengths of this study is that it represents a comprehensive examination of the whole of DSM for renewable-based energy systems. Although the generalizability of much-published research on this topic is problematic, we underline the potential of replicability of the methodology for other systems with a high-RES share. Therefore, the scientific contribution of this research is expected to go beyond the Brazilian case, as the proposed modeling approach will support the evaluation of the economic impact brought about by different DSM strategies in other systems with a high share of renewable energy.

However, a few limitations need to be noted regarding the present study. Several uncertainties are evolved in the long-term horizon planning process, e.g., economic growth, government policies and technological development, just to name a few. The estimated future electricity demand, for instance, is dependent and interlinked with future technological developments. There is also a large number of uncertainties related to urban mobility standards, technological and raw material competitiveness, the growth of the standard of living, consumer consumption patterns as well as economic developments [90]. These features together might define the pathways in which the energy mix will be deployed in the future. The possibility of future deployment schedules of energy prices to meet the peak demand can also reduce the actual expansion requirements. The smart grid deployment might also develop a key role in implementing the energy transition through the high integration of RES technologies. The prospect for future technological developments such as storage technologies and vehicle-to-grid are expected to play a key role in the long-term, contributing to accommodate the critical excess of electricity production. The vehicle-to-grid technology could support the grid and create a more reliable, responsive and stable electrical system.

Additionally, the availability of wind and solar energy is strongly climate-dependent. However, if the electricity generated by this VRE could be temporarily stored in the short and long term, this problem would be minimized. The technologies' deployment depends strongly on both government financial incentives and new political regulatory goals, which should not be overlooked on long-term planning

problems. Supplementary planning studies related to the transmission interconnections between Brazilian subsystems would also benefit the country. While it is beyond our current analysis scope, it would be relevant to consider the possibility of additional international interconnections considering the effective exportation potential, the market interest and the bargaining power, as discussed, for example, by [374]. Other limitations could also be addressed in future research, including ramping and minimum operation times for thermal power sources. The cyclical characteristics of thermal power plants, e.g., maximum thermal ramp rate, should be better evaluated in future works, estimating the impact of a high RES share on thermal power operating conditions at a country scale, as discussed for example in [407] at a regional scale.

There is also abundant room for further progress in determining, for instance, the use of pump-hydro storage as a potential source of flexibility to the power system and the extent to which it could be cost-effective compared to the evaluated DSM strategies. Other scenarios might also be explored considering further prospects for the electricity sector, such as the inclusion of storage systems, new interconnections capacity and other demand-side management strategies. These new scenarios could be further compared to the ones presented in this research work. We also suggest including more sectors (beyond the electricity sector) such as heating, cooling and transportation to analyze the transition to a fully decarbonized energy system in Brazil. This should bring synergies and more affordable solutions to the transition of the entire energy system into future renewable and sustainable energy pathways. We underline that many other pathways towards achieving a decarbonized energy system for Brazil can be proposed, but a set of significant changes away from the current energy system would be required for each pathway.

At this point, it is worth mentioning that this work focuses on the traditional environmental analysis in which it is only considered the direct CO_2 emissions (i.e., the emissions at the point of production). However, according to [408], "*all technologies, even those that produce carbon-free energy, have energy and emissions embedded in the production process and material*". The indirect emissions are related, for example, to the manufacturing, construction and transport processes associated with the entire energy system. Therefore, we underline the need to assess the indirect CO_2 emissions costs, as discussed by [405,408].

The assessed DR potentials are deeply dependent on the set of assumptions of the long-term power planning model, such as the supply-side alternatives' costs (e.g., investment, operational and fuel costs). The technical assumptions regarding the DR implementation may also affect the results, i.e., depending on the maximum share of unmet demand and the shifting hours considered. If different assumptions for

future demand and supply characteristics are considered, it will imply different results for the available DR potential in the country. The geographical distribution of DR participants should be further addressed and the findings of this research may be of great assistance in this task.

For the sake of simplicity, the proposed methodology framework acknowledges that investments in energy efficiency are made in the first year of the planning period and the impact of investing in EEMs is precisely the reduction in the average electricity consumption for each year of the planning period. In future investigations, it might be possible to include the EEMs within the co-optimization model to compete against other supply-side options. This would bring another perspective on assessing whether the use of EEMs would be cost-effective under a co-optimization approach. Using a co-optimization approach, different objectives may also be envisaged. This also means that there is abundant room for further progress in determining, for instance, the impact of making annual investments in energy efficiency projects. Therefore, to develop a full picture of the effects of investing in energy efficiency in the long-term, additional studies are required. Research questions that could be asked include, for instance, what would be the economic effects in the case of distributing the energy efficiency investments along with the planning period. Because of both the lack of data regarding future energy efficiency projects and the possible future new technological developments, caution must be applied, as the findings might not be broadly generalizable. The Long-Term Average Cost of Saved Electricity (LACoSE) has been calculated based on administrative costs. However, future studies should also focus on considering the participant costs (i.e., related to the consumers), which would change the cost-effectiveness of future energy efficiency investments.

The findings reported here also rely on a set of assumptions and simplifications. The investment costs (e.g., related to smart equipment and grid infrastructure) for DR implementation are not computed mainly because there is little agreement on these values and the commercial viability of DR is a further step to be assessed. The investment costs to implement DR is complex to predict and would strongly vary within countries. Therefore, we point out the need to further evaluate the DR potential by considering these investment costs. The future development of the costs to implement DR may also compete against other balancing technologies (such as flexible power plants and electric vehicles) and this is a crucial issue to be addressed by future research. Moreover, the findings reported in this research are highly dependent on the costs assumptions for DR implementation (in US$/MWh), which are very difficult to predict. Therefore, more research on this topic needs to be undertaken before the association between the real costs to implement DR is more clearly understood.

A further study focusing on other balancing technologies such as batteries and electric vehicles is also suggested and may change the technical and economic potential for DR in the power system evaluated. It is essential to highlight that the sectors' aggregation may affect the real estimation of each category of DR potential. The assessment efforts have been focused on the residential, industrial and commercial sectors, but it is limited because individual processes/appliances were grouped to assess the technical and economic DR scenarios. A further study focusing on splitting up the country into individual processes/appliances is suggested, which would enhance the model granularization by assessing the technical and economic load flexibility potential for each process/appliance. Future research could focus, for instance, on simulating the DR potential by disaggregating each sector (e.g., evaluating the contribution of air-conditioners in the overall DR potential for the residential sector). It has previously been observed by Ref. [67], for example, that the use of air-conditioning systems in the residential sector would strongly contribute to providing a high level of flexibility for the Brazilian power system, with a particular high contribution between 10 p.m. and 6 a.m..

Although this research has successfully demonstrated the potential of integrating DSM within long-term power planning models, it has certain limitations in concentrating its efforts into the technical and economic assessments. Regulatory barriers can be considered one of the most important aspects to be addressed to improve the deployment of DR strategies and enable customer participation in DR initiatives. Specifically, social concerns are to be taken into account for the residential sector since not only economic aspects should be considered in the decision-making process. This study did not assess, for instance, the possible effects of biased consumer preferences or beliefs, which might condition the overall findings since it assumed that end-users are rational and active economic agents. This also means that consumers' acceptance of load interventions would be a fruitful area for further work, which might even take end-users' non-rational behavior into account. Ref. [409] addressed, for instance, the end user's psychological effects on DR actions, using behavioral economics for modeling DR. Future studies on the current topic are therefore highly recommended by assessing user's acceptance issues since social behavior should affect the effective potential for load management. Therefore, the flexibility of DR may be lower in reality and further studies with more focus on the estimation of the so-called achievable DR potential are therefore highly recommended.

More research on this topic should also be carried out, addressing the trade-offs between supply-side and demand-side investments, for instance. Apart from economic aims, technical objectives may also be assessed in future research evaluating, for example, the extent to which DSM might have on reducing the peak demand but also the consequences from the rebound effect. This study would also lay the

groundwork for future research into the synergies between energy efficiency and the rebound effect, such as better discussed in Refs. [410], [411] and [412]. Therefore, new methodologies to separate overlapping effects (i.e., between DR and EE) and analyze them individually also open up new avenues for further research. The multiple benefits of using an integrated assessment for DSM strategies may bring a broad range of potential positive impacts compared to evaluating the strategies independently. Establishing the multiple and the range of synergies and benefits of implementing DSM strategies is beyond the scope of this study and future studies with more focus on these issues are therefore highly recommended. The additional benefits from DSM implementation should also be assessed in further research using multicriteria decision analysis methods. The assessment of the externalities associated with DSM also opens up new avenues for further research. The combination of DR and EEMs into a well-thought-out integrated framework for both policy and implementation could be considered a further step to be developed by the government to increase the country's DSM potential.

Although the importance of co-optimization approaches, little work has been identified in the co-optimization of systems with high-RES share and responsive loads. Future studies on the current topic are therefore recommended. Our literature review also found few research works that included energy efficiency resources under co-optimization modeling approaches in both short and long-term models, opening new avenues for further research. There is also abundant room for further progress in determining the optimal market share among electric, biofuels and flexible-fuel vehicles, particularly for renewable-based energy systems such as highlighted by Ref. [351].

Notwithstanding the limitations mentioned above, this study lays the groundwork for future research into the role of demand-response and energy efficiency in power systems. The insights gained from this study may be of assistance to guide and support policy-makers and stakeholders since we attempted to shed contemporary light on the future role of demand-side management in high RES-based systems through a holistic and integrated assessment. Although the results may not be generalizable to a broader range of power systems, it is possible to hypothesize that these conditions are more likely to occur in power systems with similar characteristics to the power system assessed in this research. Hence, it could conceivably be hypothesized that the findings of this research might provide important insights into the leading role of DSM in power systems with high RES from hydropower, which are more focused on delivering power than energy.

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Supplementary Material

Annex A - IBESM Formulation – List of sets and parameters

This annex provides the model formulation for the extended OSeMOSYS model (implemented in GAMS) used along with this research (referred along with this work as IBESM). Annex A.1 and Annex A.2 illustrate the list of sets and parameters of the model, respectively. The translated DR model to GAMS language is provided along with Annex A.3. Additional information about the modeling assumptions and the full OSeMOSYS model description can be obtained at www.osemosys.org and in references [364–367].

Annex A.1 - List of model sets [187,413,414].

Set Name	Description
REGION (r)	The set of regions[89] to be modeled (e.g., countries)
YEAR (y)	Allows to represent the modeled years of the study (e.g., start year, year 1, etc.)
TECHNOLOGY (t)	The components are set up as technologies (e.g., power plants and transmission lines)
TIMESLICE (l)	Allows to represent fractions of the year with specific load profiles (e.g., one time slice could represent all the winter morning weekdays)
FUEL (f)	The fuels enter or leave each technology (e.g., fossil fuels and electricity consumption)
EMISSION (e)	Allows to represent the emissions produced by the technologies (e.g., CO_2 emissions)
MODE_OF_OPERATION (m)	The technologies can operate in different modes (e.g., a storage facility might be charged in one mode of operation and discharged in another or a CHP plant can produce heat and electricity depending on the mode of operation)
SEASON (ls)	Allows to represent different seasons across the year (e.g., winter, summer, spring and fall)
DAYTYPE (ld)	Allows to represent different day types (e.g., weekdays and weekends)
DAILYTIMEBRACKET (lh)	Allows to split the day into time brackets (timespan) (e.g., morning, afternoon, night)
STORAGE (s)	Allows to include different storage technologies (e.g., batteries or dams)
FLEXIBLEDEMANDTYPE (fdt)	Allows to include categories of flexible loads with different load profiles and flexibility levels (e.g., industrial, residential and commercial sectors).

[89] Ref. [413] highlights that "*it might be computationally more convenient to model different countries within the same region and differentiate them simply by creating ad hoc fuels and technologies for each of them*". This assumption is followed for modeling the Brazilian power system in which the four subsystems are modelled as different fuels. This also allowed us to split the technologies for each power subsystem within the country.

Annex A.2 - List of model parameters [187,413,414].

Parameter Name	Description
# Global #	
YearSplit (l, y)	Duration of each time slice in each year (i.e., represents the fraction of the year in each time slice).
DiscountRate (r)	Discount rate for each region expressed in decimals (e.g., 0.09 is equivalent to a discount rate of 9%).
DaySplit (y, lh)	Length of one daily time bracket in a day represented as a fraction of the year (e.g., for differentiating days and night: 12/(24*365)).
Conversionls (l, ls)	Assignment of a season to a time slice (i.e., assumes '1' in the case the time slice is linked to a specific season, '0' otherwise).
Conversionld (l, ld)	Assignment of a day type to a time slice (i.e., assumes '1' in the case the time slice is linked to a specific day-type, '0' otherwise).
Conversionlh (l, lh)	Assignment of a daily time bracket to a time slice (i.e., assumes '1' in the case the time slice is linked to a specific daily time bracket, '0' otherwise).
DaysInDayType (y, ls, ld)	Number of days in a week for each day-type (i.e., number from 1 to 7).
TradeRoute (r, rr, f, y)	Assignment of a region r with a region rr allowing the trading between regions (i.e., assumes value '1' when the regions are linked, '0' otherwise). This parameter is valid only for models with two or more regions).
DepreciationMethod (r)	Depreciation[90] method considered (i.e., assumes '1' for the sinking fund depreciation and '2' for the straight-line depreciation method).
# Demands #	
SpecifiedAnnualStandardDemand (r, f, y)	Specified demand for each fuel in a year. This demand should be met instantly, i.e., it is a non-flexible demand.
SpecifiedAnnualStandardDemandProfile (r, f, l, y)	Specified flexible demand for each fuel and time slice in a year. For each year, the sum must be equal to one.
AccumulatedAnnualDemand (r, f, y)	Demand which can be satisfied at any time in a year and it is not time slice dependent.
# Performance #	
CapacityToActivityUnit (r, t)	Conversion factor linking the amount of energy that would be produced in the case of one unit of capacity would be fully exploited in a year (i.e., it relates capacity [GW] into activity [PJ]).
CapacityFactor (r, t, l, y)	Maximum capacity available in each time slice expressed as a fraction of the overall installed capacity (i.e., the values might vary from 0 to 1).
AvailabilityFactor (r, t, y)	Maximum time a technology might run in each year ranging from 0 to 1 (i.e., it allows to account for planned maintenance and/or planned outage).
OperationalLife (r, t)	Represents the operational (or useful) lifetime of a technology expressed in years.

[90] The straight-line depreciation is a linear method whereas the sinking fund depreciation is a more advanced approach in which the salvage value is reinvested in such a way that the discounted value is then considered to estimate further salvage values [414]. Our model uses the sinking fund depreciation method.

ResidualCapacity (r, t, y)	Represents the residual capacity of a technology (i.e., the capacity that was available before the modeling period).
InputActivityRatio (r, t, f, m, y)	Rate of use of a commodity by technology, as a ratio of the rate of activity. This parameter, together with the OutputActivityRatio, represents the efficiency of a technology.
OutputActivityRatio (r, t, f, m, y)	Rate of commodity output from a technology, as a ratio of the rate of activity. This parameter together with the InputActivityRatio represents the efficiency of a technology.
# Technology Costs #	
CapitalCost (r, t, y)	Capital (or investment) cost per unit of capacity for each technology.
VariableCost (r, t, m, y)	Variable O&M cost per unit of activity for each technology.
FixedCost (r, t, y)	Fixed O&M cost per unit of capacity for each technology.
# Storage Parameters #	
TechnologyToStorage (r, m, t, s)	Represents the link between a technology with the storage facility it may charge (i.e., it assumes '1' in the case the technology and the storage option are connected and '0' otherwise).
TechnologyFromStorage (r, m, t, s)	Represents the link between a technology with the storage facility it may feed (i.e., it assumes '1' in the case that the technology and the storage option are connected and '0' otherwise).
StorageLevelStart (r, s)	Level of storage in the first modelled year (in units of activity).
StorageMaxChargeRate (r, s)	Represents the maximum charging rate for each storage facility (in units of activity per year).
StorageMaxDischargeRate (r, s)	Represents the discharging rate for each storage facility (in units of activity per year).
MinStorageCharge(r,s,y)	Represents a lower bound for the energy stored in each storage facility as a fraction of its maximum capacity (i.e., varying between 0 and 1).
OperationalLifeStorage (r, s)	Represents the operational (or useful) lifetime of each storage facility (in years).
CapitalCostStorage (r, s, y)	Represents the capital (or investment) cost for each storage facility.
ResidualStorageCapacity(r,s,y)	Represents the residual capacity of each storage facility (i.e., the storage capacity that was available before the modeling period).
# Capacity Constraints #	
CapacityOfOneTechnologyUnit (r, t, y)	Represents the quantity (or capacity) of each new unit to be installed of a technology. If this parameter is used, then the optimization problem turns into a Mixed Integer Linear Problem (MILP).
TotalAnnualMaxCapacity (r, t, y)	Represents the annual maximum capacity (residual plus cumulatively installed) allowed for each technology and year.
TotalAnnualMinCapacity (r, t, y)	Represents the annual minimum capacity (residual plus cumulatively installed) allowed for each technology and year.
# Investment Constraints #	

TotalAnnualMaxCapacityInvestment (r, t, y)	Represents the maximum investment capacity of a technology in each year expressed in power units.
TotalAnnualMinCapacityInvestment (r, t, y)	Represents the minimum investment capacity of a technology in each year expressed in power units.
# Activity Constraints #	
TotalTechnologyAnnualActivityUpperLimit (r, t, y)	Represents the upper limit for the level of activity allowed for a technology in each year. This upper level might represent, for instance, the maximum electricity that should be produced for a given technology.
TotalTechnologyAnnualActivityLowerLimit (r, t, y)	Represents the lower limit for the level of activity allowed for a technology in each year. This lower level might represent, for instance, the minimum electricity that should be produced for a given technology.
TotalTechnologyModelPeriodActivityUpperLimit (r, t)	Represents the maximum level of activity allowed for a technology in all the modeled period.
TotalTechnologyModelPeriodActivityLowerLimit (r, t)	Represents the minimum level of activity allowed for a technology in all the modeled period.
# Reserve Margin #	
ReserveMarginTagFuel (r, f, y)	Parameter which tags the specific fuels to which the reserve margin applies. It is a binary parameter and assumes '1' if the reserve margin is linked to the fuel and '0' otherwise.
ReserveMargin (r, y)	Minimum level required for the reserve margin. This parameter is specific for the tagged technologies. For instance, if 30% of reserve margin is required, the parameter might assume the value 1.3.
ReserveMarginTagTechnology (r, t, y)	Parameter which tags the technologies which can contribute to the system's reserve margin. It is a binary parameter and assumes '1' for the allowed technologies and '0' otherwise.
# RE Generation Target #	
RETagTechnology (r, t, y)	Binary parameter originally developed to tag the technologies which would support reaching the renewables generation targets. However, in our model, to enhance both the security and reliability of the modeling approach, this parameter is used to establish a minimum target for the overall electricity produced by thermal power plants based on the historical operation of the power system. Therefore, it assumes '1' for technologies that contribute to achieving the minimum production target defined in the 'REMinProductionTarget' parameter and '0' otherwise.
RETagFuel (r, f, y)	Binary parameter which tags the fuels to which the target defined in the 'RETagTechnology' applies to. It assumes '1' if the target applies, 0 otherwise.
REMinProductionTarget (r, y)	Minimum production ratio for the technologies tagged in the 'RETagTechnology' parameter.
# Prioritizing Demand Types and Demand Shifting #	
SpecifiedDailyFlexibleDemand (r, f, ls, ld, fdt, y)	Specified daily flexible demand for each output fuel that should be met in a day of a specific day-type, season and year.
SpecifiedDailyFlexibleDemandProfile(r,f,ls,ld,lh,fdt,y)	Specified daily flexible demand profile in each daily time bracket. The sum must be equal to one for each day.

DiscountRateDemand	Discount rate used to the costs related to the flexible demand (e.g., load shifting and/or load shedding). This parameter must be expressed in decimals (e.g., 0.09).
# Exclusive to Prioritizing Demand Types #	
MaxShareUnmetDemand(r,f,fdt,y)	This parameter allows fractioning the flexible demand that might remain unmet.
PriceOfUnmetDemand(r,f,ls,fdt,y)	Represents the cost (penalty factor) for not meeting the specified flexible demand. This price should be specified per unit of energy (e.g., US$/GJ).
# Exclusive to Demand Shifting #	
MaxShareShiftedDemand(r,f,fdt,y)	Allows fractioning the flexible demand that might be shifted in a day.
MaxDelay(fdt)	Represents the maximum number of time brackets (e.g., hours) the demand can be delayed within a day.
MaxAdvance(fdt)	Represents the maximum number of time brackets (e.g., hours) the demand can be advanced (or met earlier) within a day.
CostFactorShiftedDemand(fdt)	Represents the cost of shifting the flexible demand by one hour.
# Exclusive to Energy Efficiency Measures #	
TEE	Original energy efficiency ratio, which corresponds to the level of reduction in the final electricity demand (expressed in decimals).
TEE_new (f,y)	This parameter represents the modified energy efficiency ratio that fairly accounts for the reductions in the final electricity demand when considering both EEMs and DR strategies.
SpecifiedAnnualTotalDemand (r, f, y)	Specified total annual demand for each region, fuel and year. This parameter includes the sum of both the standard and the flexible demands.
NewSpecifiedAnnualStandardDemand (r, f, y)	This parameter is used to account for the new demand (i.e., the demand after discounting the new energy efficiency ratio).
LACoSE	The Long-term Average Cost of Saved Electricity (LACoSE) recognizes and accounts for the reinvestments in energy efficiency under a long-term perspective.
TotalCost_EE (r, y)	This parameter is used to represent the investment in energy efficiency for each year of the planning period.
AverageCost_EE (r)	This parameter is used to calculate the average cost (per year) of investing in energy efficiency. Further, this parameter is summed up with the original total discounted cost of the long-term model resulting in a new total discounted cost, which also considers the investments in energy efficiency.

Annex A.3 – Translated DR model (GAMS)

Demand-Response Assessment – Prioritizing Demand Types (Load Shedding) and Demand Shifting
SETS
set fdt FLEXIBLEDEMANDTYPE;
alias (fdt, FLEXIBLEDEMANDTYPE);
PARAMETERS
Common to both - Prioritizing Demand Types and Demand Shifting
parameter SpecifiedDailyFlexibleDemand (r, f, ls, ld, fdt, y);
parameter SpecifiedDailyFlexibleDemandProfile(r,f,ls,ld,lh,fdt,y);
parameter DiscountRateDemand;
# Exclusive to Prioritizing Demand Types #
parameter MaxShareUnmetDemand(r,f,fdt,y);
parameter PriceOfUnmetDemand(r,f,ls,fdt,y);
# Exclusive to Demand Shifting #
parameter MaxShareShiftedDemand(r,f,fdt,y);
parameter MaxDelay(fdt);
parameter MaxAdvance(fdt);
parameter CostFactorShiftedDemand(fdt);
# MODEL VARIABLES #
# Common to both - Prioritizing Demand Types and Demand Shifting #
positive variable RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y);
# Exclusive to Prioritizing Demand Types #
positive variable RateOfUnmetDemand(r,f,ls,ld,lh,fdt,y);
positive variable UnmetDemand(r,f,l,fdt,y);
positive variable UnmetDemandAnnual(r,f,fdt,y);
positive variable CostOfUnmetDemand(r,fdt,y);
positive variable DiscountedCostOfUnmetDemand(r,fdt,y);
positive variable CostOfUnmetDemandSeasonal(r,ls,fdt,y);
# Exclusive to Demand Shifting #
free variable RateOfNetCharge(r,f,ls,ld,lh,fdt,y);
free variable RateOfNetChargeDelayed(r,f,ls,ld,lh,fdt,y);
free variable RateOfNetChargeAdvanced(r,f,ls,ld,lh,fdt,y);
positive variable SumOfDailyNetChargeDelayed(r,f,ls,ld,fdt,y);
positive variable SumOfDailyNetChargeAdvanced(r,f,ls,ld,fdt,y);
free variable CostOfShiftedDemand(r,fdt,y);
free variable DiscountedCostOfShiftedDemand(r,fdt,y);
positive variable RateOfChargeDelayed(r,f,ls,ld,lh,fdt,y);
positive variable RateOfDischargeDelayed(r,f,ls,ld,lh,fdt,y);
positive variable RateOfChargeAdvanced(r,f,ls,ld,lh,fdt,y);
positive variable RateOfDischargeAdvanced(r,f,ls,ld,lh,fdt,y);
# CONSTRAINTS#
equation D1_SpecifiedDemand (REGION,TIMESLICE,FUEL,YEAR); D1_SpecifiedDemand(r,l,f,y).. RateOfStandardDemand(r,l,f,y)+sum((ls,ld,lh,fdt),(RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y)- RateOfNetCharge(r,f,ls,ld,lh,fdt,y)- RateOfUnmetDemand(r,f,ls,ld,lh,fdt,y))*Conversionls(l,ls)*Conversionld(l,ld)*Conversionlh(l,lh)) =e= RateOfDemand(r,l,f,y);
equation EQ_rev_NewSpecifiedStandardDemand(REGION,TIMESLICE,FUEL,YEAR); EQ_rev_NewSpecifiedStandardDemand(r,l,f,y)$(NewSpecifiedAnnualStandardDemand(r,f,y) gt 0).. NewSpecifiedAnnualStandardDemand(r,f,y)*SpecifiedAnnualStandardDemandProfile(r,f,l,y) / YearSplit(l,y) =e= RateOfStandardDemand(r,l,f,y);

```
equation
D3_SpecifiedFlexibleDemand(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
D3_SpecifiedFlexibleDemand(r,f,ls,ld,lh,fdt,y).. SpecifiedDailyFlexibleDemand (r,f,ls,ld,fdt,y)*
SpecifiedDailyFlexibleDemandProfile(r,f,ls,ld,lh,fdt,y)/DaySplit(y,lh) =e=
RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y);
```

```
equation
D4_UpperLimit(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
D4_UpperLimit(r,f,ls,ld,lh,fdt,y)$(MaxShareUnmetDemand(r,f,fdt,y) >= MaxShareShiftedDemand(r,f,fdt,y))..
MaxShareUnmetDemand(r,f,fdt,y)*RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y)=g=
RateOfUnmetDemand(r,f,ls,ld,lh,fdt,y)+RateOfNetCharge(r,f,ls,ld,lh,fdt,y);
```

```
equation
D5_UpperLimit(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
D5_UpperLimit(r,f,ls,ld,lh,fdt,y)$(MaxShareUnmetDemand(r,f,fdt,y) < MaxShareShiftedDemand(r,f,fdt,y))..
MaxShareShiftedDemand(r,f,fdt,y)*RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y)=g=
RateOfUnmetDemand(r,f,ls,ld,lh,fdt,y)+RateOfNetCharge(r,f,ls,ld,lh,fdt,y);
```

```
equation
UD1_UpperLimit(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
UD1_UpperLimit(r,f,ls,ld,lh,fdt,y).. RateOfUnmetDemand(r,f,ls,ld,lh,fdt,y) =l=
MaxShareUnmetDemand(r,f,fdt,y)*RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y);
```

```
equation UD2_UnmetDemand (REGION,FUEL,TIMESLICE,FLEXIBLEDEMANDTYPE,YEAR);
UD2_UnmetDemand (r,f,l,fdt,y)..
sum((ls,ld,lh),RateOfUnmetDemand(r,f,ls,ld,lh,fdt,y)*Conversionls(l,ls)*Conversionld(l,ld)*Conversionlh(l,lh))*YearSplit(l,y) =e= UnmetDemand(r,f,l,fdt,y);
```

```
equation UD3_UnmetDemand (REGION,FUEL,FLEXIBLEDEMANDTYPE,YEAR);
UD3_UnmetDemand (r,f,fdt,y).. sum(l,UnmetDemand(r,f,l,fdt,y)) =e= UnmetDemandAnnual(r,f,fdt,y);
```

```
equation UD4_CostOfUnmetDemandSeasonal (REGION,SEASON,FLEXIBLEDEMANDTYPE,YEAR);
UD4_CostOfUnmetDemandSeasonal(r,ls,fdt,y)..sum((f,l),UnmetDemand(r,f,l,fdt,y)*PriceOfUnmetDemand(r,f,ls,fdt,y)*Conversionls(l,ls)) =e= CostOfUnmetDemandSeasonal(r,ls,fdt,y);
```

```
equation UD5_CostOfUnmetDemand (REGION,FLEXIBLEDEMANDTYPE,YEAR);
UD5_CostOfUnmetDemand(r,fdt,y)..sum(ls,CostOfUnmetDemandSeasonal(r,ls,fdt,y)) =e=
CostOfUnmetDemand(r,fdt,y);
```

```
equation UD6_DiscountedCostOfUnmetDemand (REGION,FLEXIBLEDEMANDTYPE,YEAR);
UD6_DiscountedCostOfUnmetDemand(r,fdt,y)..
CostOfUnmetDemand(r,fdt,y)/((1+DiscountRateDemand)**(y.val-smin(yy, yy.val)+0.5)) =e=
DiscountedCostOfUnmetDemand(r,fdt,y);
```

```
equation
DS1_RateOfNetCharge(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
DS1_RateOfNetCharge(r,f,ls,ld,lh,fdt,y).. RateOfNetChargeDelayed(r,f,ls,ld,lh,fdt,y) +
RateOfNetChargeAdvanced(r,f,ls,ld,lh,fdt,y) =e= RateOfNetCharge(r,f,ls,ld,lh,fdt,y);
```

```
equation
DS2_RateOfNetChargeDelayed(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
DS2_RateOfNetChargeDelayed(r,f,ls,ld,lh,fdt,y).. RateOfChargeDelayed(r,f,ls,ld,lh,fdt,y)-
RateOfDischargeDelayed(r,f,ls,ld,lh,fdt,y) =e= RateOfNetChargeDelayed(r,f,ls,ld,lh,fdt,y);
```

```
Equation
DS3_RateOfNetChargeAdvanced(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
```

DS3_RateOfNetChargeAdvanced(r,f,ls,ld,lh,fdt,y).. RateOfChargeAdvanced(r,f,ls,ld,lh,fdt,y)-
RateOfDischargeAdvanced(r,f,ls,ld,lh,fdt,y) =e= RateOfNetChargeAdvanced(r,f,ls,ld,lh,fdt,y);

equation
DS4_MaxShareConstraint(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMA
NDTYPE,YEAR);
DS4_MaxShareConstraint(r,f,ls,ld,lh,fdt,y)..
RateOfChargeDelayed(r,f,ls,ld,lh,fdt,y)+RateOfChargeAdvanced(r,f,ls,ld,lh,fdt,y) =l=
MaxShareShiftedDemand(r,f,fdt,y)*RateOfDailyFlexibleDemand(r,f,ls,ld,lh,fdt,y);

equation
DS5_DelayedLoadsDailyBalance(REGION,FUEL,SEASON,DAYTYPE,FLEXIBLEDEMANDTYPE,YEAR);
DS5_DelayedLoadsDailyBalance(r,f,ls,ld,fdt,y).. sum(lh,RateOfChargeDelayed(r,f,ls,ld,lh,fdt,y)*DaySplit(y,lh))
=l= sum(lh, RateOfDischargeDelayed(r,f,ls,ld,lh,fdt,y)*DaySplit(y,lh));

equation
DS6_DelayedLoadsStorageLevelGreaterZero(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,
FLEXIBLEDEMANDTYPE,YEAR);
DS6_DelayedLoadsStorageLevelGreaterZero(r,f,ls,ld,lh,fdt,y).. sum(lhlh$(ord(lh)-ord(lhlh) >=
0),RateOfChargeDelayed(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh)) =g= sum(lhlh$(ord(lh)-ord(lhlh) >=
0),RateOfDischargeDelayed(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh));

equation
DS7_DelayUpperLimit(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMAN
DTYPE,YEAR);
DS7_DelayUpperLimit(r,f,ls,ld,lh,fdt,y)$(lh.val<= (smax(lhlh,lhlh.val))- MaxDelay(fdt))..
sum(lhlh$(ord(lhlh)<=ord(lh)),RateOfChargeDelayed(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh)) =l=
sum(lhlh$(ord(lhlh)<=ord(lh)+MaxDelay(fdt)),RateOfDischargeDelayed(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh));

equation
DS8_AdvancedLoadsDailyBalance(REGION,FUEL,SEASON,DAYTYPE,FLEXIBLEDEMANDTYPE,YEAR
);
DS8_AdvancedLoadsDailyBalance(r,f,ls,ld,fdt,y).. sum(lh, RateOfChargeAdvanced(r,f,ls,ld,lh,fdt,y)*DaySplit(y,lh))
=l= sum(lh, RateOfDischargeAdvanced(r,f,ls,ld,lh,fdt,y)*DaySplit(y,lh));

equation DS9_AdvancedLoadsStorageLevelBelowMaximum
(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEMANDTYPE,YEAR);
DS9_AdvancedLoadsStorageLevelBelowMaximum(r,f,ls,ld,lh,fdt,y).. sum(lhlh$(ord(lh)-ord(lhlh) >= 0),
RateOfChargeAdvanced(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh)) =l= sum(lhlh$(ord(lh)-ord(lhlh) >= 0),
RateOfDischargeAdvanced(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh));

equation
DS10_AdvanceLowerLimit(REGION,FUEL,SEASON,DAYTYPE,DAILYTIMEBRACKET,FLEXIBLEDEM
ANDTYPE,YEAR);
DS10_AdvanceLowerLimit(r,f,ls,ld,lh,fdt,y)$(lh.val <= (smax(lhlh,lhlh.val)- MaxAdvance(fdt)))..
sum(lhlh$(ord(lhlh)<=(ord(lh)+MaxAdvance(fdt))), RateOfChargeAdvanced(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh))
=g= sum(lhlh$(ord(lhlh) <= ord(lh)), RateOfDischargeAdvanced(r,f,ls,ld,lhlh,fdt,y)*DaySplit(y,lhlh));

equation DS11_MinimiseDelay (REGION,FUEL,SEASON,DAYTYPE,FLEXIBLEDEMANDTYPE,YEAR);
DS11_MinimiseDelay(r,f,ls,ld,fdt,y).. sum(lhlh, DaySplit(y,lhlh)*365*24*sum(lh$(ord(lhlh)-ord(lh) >= 0),
(RateOfChargeDelayed(r,f,ls,ld,lh,fdt,y)- RateOfDischargeDelayed(r,f,ls,ld,lh,fdt,y))*DaySplit(y,lh)*365*24)) =e=
SumOfDailyNetChargeDelayed(r,f,ls,ld,fdt,y);

equation
DS12_MinimiseAdvance(REGION,FUEL,SEASON,DAYTYPE,FLEXIBLEDEMANDTYPE,YEAR);
DS12_MinimiseAdvance(r,f,ls,ld,fdt,y)..sum(lhlh, DaySplit(y,lhlh)*365*24*sum(lh$(ord(lhlh)-ord(lh) >=
0),(RateOfDischargeAdvanced(r,f,ls,ld,lh,fdt,y)-
RateOfChargeAdvanced(r,f,ls,ld,lh,fdt,y))*DaySplit(y,lh)*365*24))=e=SumOfDailyNetChargeAdvanced(r,f,ls,ld,fd
t,y);

equation DS13_CostOfShiftedDemand(REGION,FLEXIBLEDEMANDTYPE,YEAR);
DS13_CostOfShiftedDemand(r,fdt,y)..
CostFactorShiftedDemand(fdt)*sum((f,l,ls,ld,lh),((SumOfDailyNetChargeDelayed(r,f,ls,ld,fdt,y)+SumOfDailyNet

ChargeAdvanced(r,f,ls,ld,fdt,y))* DaysInDayType(y,ls,ld))*YearSplit(l,y)*Conversionls(l,ls)*Conversionld(l,ld)*Conversionlh(l,lh)*52) =e= CostOfShiftedDemand(r,fdt,y);
equation DS14_DiscountedCostOfShiftedDemand(REGION,FLEXIBLEDEMANDTYPE, YEAR); DS14_DiscountedCostOfShiftedDemand(r,fdt,y).. CostOfShiftedDemand(r,fdt,y)/((1+DiscountRateDemand)**(y.val-smin(yy, yy.val)+0.5)) =e= DiscountedCostOfShiftedDemand(r,fdt,y);

Annex B – Input data used for the case study

Annex B.1 – Techno-economic data for 2018 [311,374–376] .

Technologies	CAPEX (US$/kW)	Fixed Costs (US$/kW)	Variable Costs (US$/ GJ)	Expected Lifetime (years)	Capacity Factor	Efficiency (%)
Biomass	1905	13	0.50	25	0.75[a]	35
Coal	3927	33	1.29	40	0.85	45
Fuel Oil	1400	25	1.70	25	0.85	35
Natural Gas	1051	12	0.83	30	0.85	38
Nuclear	6151	99	0.63	40	0.90	35
Large Hydro	2627	45	0.00	60	0.43[a]	100
Small Hydro	3080	35	0.00	60	0.43[a]	100
Wind	1558	51	0.00	25	0.37	100
PV Distributed	2726	16	0.00	25	0.15	100
PV Utilities	1678	25	0.00	25	0.17	100
Concentrated Solar Power	5767	67	1.12	40	0.40	100
Transmission (N-SE,N-S)	486	0	0.00	60	-	93
Transmission (NE-SE, N-NE)	378	0	0.00	60	-	93
Transmission (SE-S)	216	0	0.00	60	-	93
Transmission (International)	305	0	0.00	60	-	93

[a] This is the average value for the entire year. However, the capacity factor for hydropower and biomass varies across the year (i.e., between seasons and subsystems).

Annex B.2 – Other parameters of the model [56,311,374–378].

Parameter	Value	Parameter	Value
Discount Rate (%)	9	Demand NE - 2018 (TWh)	99.26
Reserve Margin (%)	30	Demand NO - 2018 (TWh)	50.83
Minimum Target for Thermal (%)	10	Demand SE - 2018 (TWh)	325.45
Number of Time-Slices	96	Demand SE - 2018 (TWh)	106.67
Cost of Imported Electricity (US$/MWh)	70	Demand growth 2017-2022 - NE (%)	4.0
Fuel Cost (US$/GJ) - Uranium	2.88	Demand growth 2023-2030- NE (%)	3.8
Fuel Cost (US$/GJ) - Fuel Oil	17.03	Demand growth 2031-2040 - NE (%)	3.1
Fuel Cost (US$/GJ) - Coal	4.60	Demand growth 2017-2022 - NO (%)	5.5
Fuel Cost (US$/GJ) - Natural Gas	9.50	Demand growth 2023-2030- NO (%)	3.5
Fuel Cost (US$/GJ) - Biomass	1.50	Demand growth 2031-2040 - NO (%)	3.1
Emission Factor - Fuel Oil ($MtCO_2$/TWh)	0.67	Demand growth 2017-2022 - SE (%)	3.5
Emission Factor - Coal ($MtCO_2$/TWh)	1.04	Demand growth 2023-2030- SE (%)	3.3
Emission Factor - Natural Gas ($MtCO_2$/TWh)	0.38	Demand growth 2031-2040 - SE (%)	3.1
Emissions Penalty - 2019 (US$/ tons of CO_2)	20.00	Demand growth 2017-2022 - SO (%)	3.4
Emissions Penalty - 2040 (US$/ tons of CO_2)	61.50	Demand growth 2023-2030- SO (%)	3.4
		Demand growth 2031-2040 - SO (%)	3.1

Annex B.3a – Load profiles for each sector (1 – 12h).

Residential													
Region	**Appliance/Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
NE	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	0%	0%	0%	0%	0%	0%	27%	65%	100%	81%	52%	4%
	Tumble Dryers	0%	0%	0%	0%	0%	0%	8%	25%	42%	67%	75%	67%
	Dish Washers	1%	2%	0%	0%	0%	0%	33%	30%	33%	17%	57%	27%
	Air Conditioning	95%	95%	92%	88%	70%	47%	29%	8%	2%	2%	1%	2%
NO	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	0%	0%	0%	0%	0%	0%	49%	100%	84%	65%	39%	14%
	Tumble Dryers	0%	0%	0%	0%	0%	0%	8%	25%	42%	67%	75%	67%
	Dish Washers	1%	2%	0%	0%	0%	0%	33%	30%	33%	17%	57%	27%
	Air Conditioning	98%	88%	76%	69%	66%	57%	37%	18%	3%	6%	4%	3%
SE	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	0%	0%	0%	0%	0%	0%	57%	100%	85%	59%	35%	15%
	Tumble Dryers	0%	0%	0%	0%	0%	0%	8%	25%	42%	67%	75%	67%
	Dish Washers	1%	2%	0%	0%	0%	0%	33%	30%	33%	17%	57%	27%
	Air Conditioning	69%	65%	58%	52%	48%	46%	38%	12%	5%	3%	3%	3%
SO	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	0%	0%	0%	0%	0%	0%	57%	100%	85%	59%	35%	15%
	Tumble Dryers	0%	0%	0%	0%	0%	0%	8%	25%	42%	67%	75%	67%
	Dish Washers	1%	2%	0%	0%	0%	0%	33%	30%	33%	17%	57%	27%
	Air Conditioning	99%	94%	86%	74%	63%	54%	34%	0%	0%	0%	0%	2%
Commercial													
	Process/Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
All	Ar-conditioning/ cooling	11%	9%	8%	8%	9%	11%	18%	48%	75%	84%	82%	79%
	Heating	11%	9%	8%	8%	9%	11%	18%	48%	75%	84%	82%	79%
Industrial													
All	**Process/Hour**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	All Processes	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Annex B.3b – Load profiles for each sector (12 – 24h).

Residential													
Region	**Appliance/Hour**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
NE	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	13%	19%	24%	16%	11%	8%	3%	14%	16%	19%	3%	3%
	Tumble Dryers	59%	100%	67%	33%	17%	25%	59%	42%	8%	17%	17%	8%
	Dish Washers	33%	67%	100%	67%	50%	33%	50%	100%	83%	33%	17%	3%
	Air Conditioning	4%	8%	4%	2%	2%	3%	7%	11%	31%	100%	20%	92%
NO	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	22%	25%	17%	11%	9%	4%	16%	17%	18%	18%	4%	4%
	Tumble Dryers	59%	100%	67%	33%	17%	25%	59%	42%	8%	17%	17%	8%
	Dish Washers	33%	67%	100%	67%	50%	33%	50%	100%	83%	33%	17%	3%
	Air Conditioning	7%	3%	5%	5%	5%	11%	20%	39%	69%	94%	98%	100%
SE	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	20%	24%	16%	11%	8%	3%	14%	17%	17%	19%	3%	3%
	Tumble Dryers	59%	100%	67%	33%	17%	25%	59%	42%	8%	17%	17%	8%
	Dish Washers	33%	67%	100%	67%	50%	33%	50%	100%	83%	33%	17%	3%
	Air Conditioning	8%	8%	8%	6%	7%	10%	25%	43%	67%	90%	100%	75%
SO	Freezer	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Refrigerator	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Washing Machine	20%	24%	16%	11%	8%	3%	14%	17%	17%	19%	3%	3%
	Tumble Dryers	59%	100%	67%	33%	17%	25%	59%	42%	8%	17%	17%	8%
	Dish Washers	33%	67%	100%	67%	50%	33%	50%	100%	83%	33%	17%	3%
	Air Conditioning	2%	0%	0%	0%	1%	2%	11%	16%	47%	98%	99%	100%
Commercial													
	Process/Hour	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
All	Ar-conditioning/ cooling	80%	82%	85%	86%	100%	94%	74%	53%	41%	31%	21%	15%
	Heating	80%	82%	85%	86%	100%	94%	74%	53%	41%	31%	21%	15%
Industrial													
All	**Process/Hour**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	All Processes	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Annex B.4 – Technical and economic scenario assumptions for implementing DR.

	Parameter/Scenario		Scenario 3 and 4	Scenario 5 and 6	Scenario 7 and 8	Scenario 9 and 10
Load Shedding	Maximum Share of Unmet Demand (%)		100	100	100	100
	Discount Rate (%)		-	9	9	9
	Price of Unmet Demand (US$/MWh)	NE - Summer	0	104.99	104.99	9.21
		NO - Summer	0	104.33	104.33	8.92
		SE - Summer	0	104.99	104.99	8.96
		SO - Summer	0	53.36	104.99	8.16
		NE - Fall	0	67.20	103.80	5.58
		NO - Fall	0	57.66	55.19	5.58
		SE - Fall	0	80.73	103.80	5.60
		SO - Fall	0	80.73	103.80	5.60
		NE - Winter	0	134.43	60.77	5.78
		NO - Winter	0	134.49	60.55	5.78
		SE - Winter	0	134.43	60.45	5.77
		SO - Winter	0	134.43	57.86	5.06
		NE - Spring	0	44.48	69.16	10.95
		NO - Spring	0	42.68	59.97	10.95
		SE - Spring	0	44.48	51.50	11.47
		SO - Spring	0	44.48	49.34	11.45
Load Shifting[91]	Maximum Share of Shifted Demand (%)		100	100		100
	Maximum Delay - Industry (hours)		24	24		24
	Maximum Delay – Residential (hours)		2	2		2
	Maximum Delay – Commercial (hours)		2	2		2
	Minimum Advance - Industry (hours)		24	24		24
	Minimum Advance - Residential (hours)		2	2		2
	Minimum Advance – Commercial (hours)		2	2		2
	Price of Shifted Demand (US$/MWh per hour)		0	10		10
	Discount Rate (%)		-	9		9

[91] Load shifting is considered across all sectors (i.e., industrial, residential and commercial) with different time delay and advance for each sector, based in Ref. [243].

Annex C – Simulation results

Annex C.1 – Simulation results for the new installed capacity (2018-2040) in GW

Source/Scenario	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10
Biomass	8.4	8.3	8.3	8.3	8.4	8.3	8.5	8.4	8.4	8.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	41.7	32.9	23.1	19.8	32.9	26.4	38.9	30.7	33.7	29.3
Nuclear	10.2	9.3	11.4	10.6	10.0	9.3	11.0	9.9	9.8	9.0
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	6.5	3.2	4.1	3.0	3.2	1.7	5.9	2.2	3.5	2.1
Wind	26.5	23.8	23.2	21.7	24.4	22.1	25.4	23.0	24.1	22.1
Solar DG	49.4	49.4	49.4	49.4	49.4	49.4	49.4	49.4	49.4	49.4
Solar Utility	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
CSP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LH - Run-of-River	51.5	46.9	46.6	37.9	50.5	44.1	53.1	48.3	46.9	38.0
Total	**212.3**	**191.8**	**184.1**	**168.7**	**196.9**	**179.4**	**210.1**	**190.0**	**193.7**	**176.1**

Annex C.2 – Simulation results for the electricity generation share of each power source in 2040 (%)

Source/Scenario	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10
Biomass	9.1%	9.5%	9.9%	10.4%	9.5%	10.0%	9.2%	9.6%	9.6%	10.0%
Coal	0.5%	0.5%	0.4%	0.4%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%
Fuel Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural Gas	2.4%	2.4%	0.7%	0.6%	2.0%	1.9%	2.0%	2.0%	2.1%	2.0%
Nuclear	8.2%	8.1%	9.7%	9.7%	8.5%	8.5%	8.6%	8.5%	8.4%	8.4%
Large Hydro	7.3%	7.7%	7.7%	8.1%	7.5%	7.9%	7.3%	7.7%	7.7%	8.4%
Small Hydro	5.9%	4.6%	5.0%	4.8%	4.6%	4.1%	5.7%	4.1%	4.7%	4.3%
Wind	11.6%	11.3%	11.0%	11.3%	11.1%	10.9%	11.2%	11.1%	11.3%	11.0%
Solar DG	6.3%	6.5%	6.5%	6.8%	6.4%	6.5%	6.3%	6.6%	6.6%	7.0%
Solar Utility	3.0%	3.1%	3.0%	2.8%	3.0%	3.2%	2.9%	3.0%	3.0%	3.2%
CSP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LH - Run-of-River	45.9%	46.4%	46.1%	45.0%	46.8%	46.6%	46.4%	47.0%	46.2%	45.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%