Towards a Zero Emission Electricity Sector: A Pan-European Structural Electricity Integrated Model to assess Italian Power Generation and Transmission Expansion Pathways.

Annamaria Zaccaria[a*], Edoardo Somenzi[a], Giulia Iacovissi[a], Federico Pontoni[ab], Filippo del Grosso[a], Sara Zanini[ac]

[a] Fondazione Eni Enrico Mattei, Milan, Italy

[b] Bocconi University, Milan, Italy

[c] Ca' Foscari University, Department of Management, Venice, Italy

** corresponding author*

18th IAEE European Conference

Bocconi University

Milan, 24th-27th July 2023

Agenda

1. Introduction
2. Methodology
   2.1. Energy model
   2.2. Optimization model
   2.3. Granularity
3. Results
4. Discussion & conclusions

Annex

1. Introduction

Research question: ***How can the Italian electricity system be decarbonized through a holistic approach that considers renewables, innovative transition technologies and market integration while minimizing costs?***

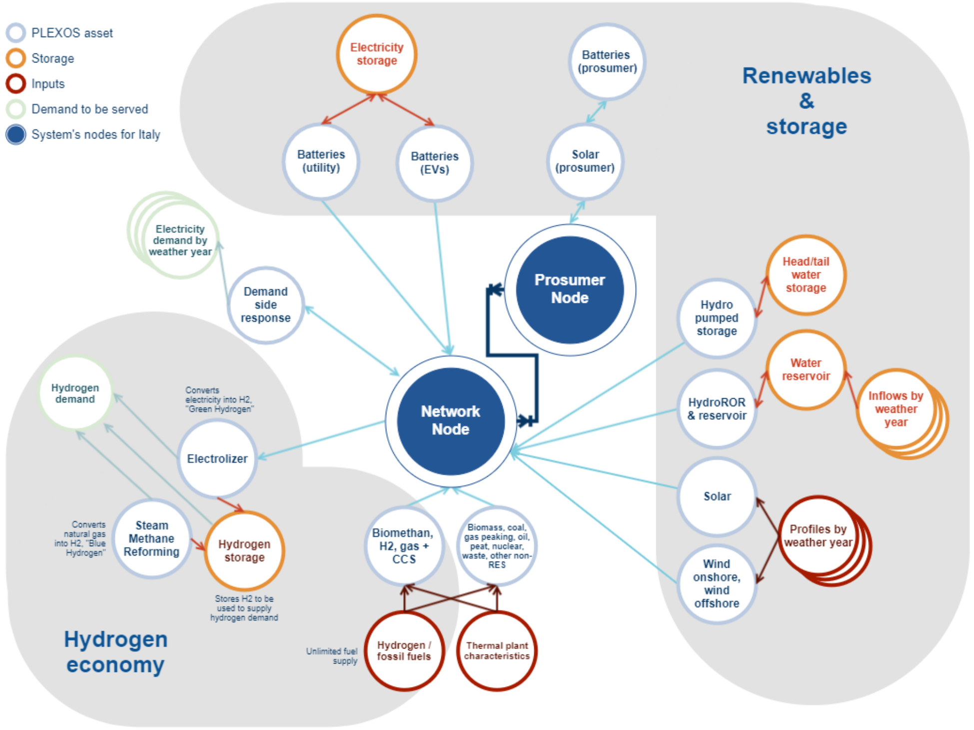
The FEEM project "Towards a Zero-Emission Electricity Market" presents a long-term optimization strategy to achieve full decarbonization of the electricity system by 2050, emphasizing cost minimization and acknowledging the 2030 targets as an intermediate step. The distinguishing feature of this model* is its emphasis on dynamic integration with other European countries. It considers how variations in a Country's generation portfolio can impact interregional electricity flow dynamics, recognizing the interconnected nature of electricity markets across Europe.

The achievement of ambitious objectives for decarbonization necessitates a **transformative overhaul of the power system** (Pastore et al., 2022). Careful planning is imperative, considering essential aspects such as **reliability, security and stability** (Bellocchi et al., 2020; Guandalini et al., 2017). Maintaining a delicate **balance between supply and demand** is vital to prevent blackouts and meet peak demand (Brouwer et al., 2014). Addressing the **intermittent nature of Variable Renewable Energy Sources** (VRES), **energy storage solutions** or **backup systems** are indispensable (Bertsch et al., 2012). Additionally, integrating energy-consuming sectors with power-producing sectors through **sector coupling** is vital (IRENA, 2022).

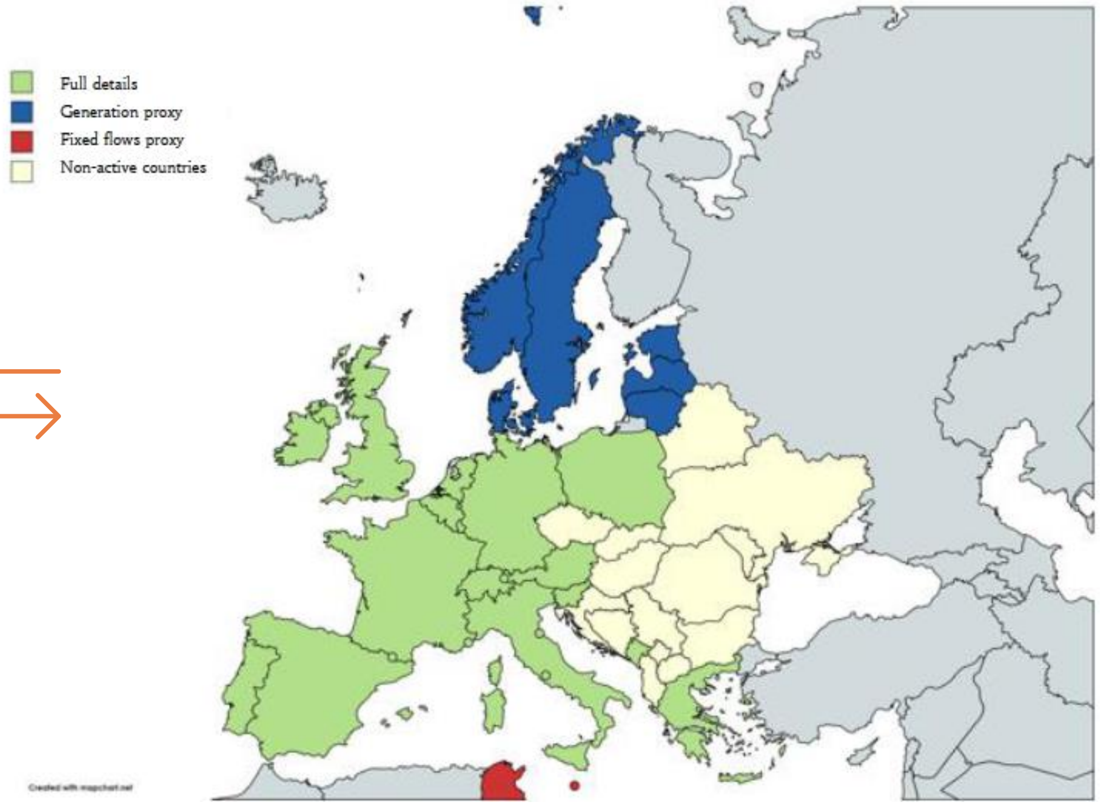
** This is an optimization model rather than a planning model, illustrating how the sector could evolve in the absence of financial and bureaucratic constraints.*

2.1. Methodology | Energy model

- Model with **very high technological, geographical, temporal granularity** and which simulates the different types of consumers.
- The model optimizes the system in the long-term, considering aspects such as **reliability, security and stability,** which are essential in long-term generation capacity and transmission expansion (Bellocchi et al., 2020; Guandalini et al., 2017).

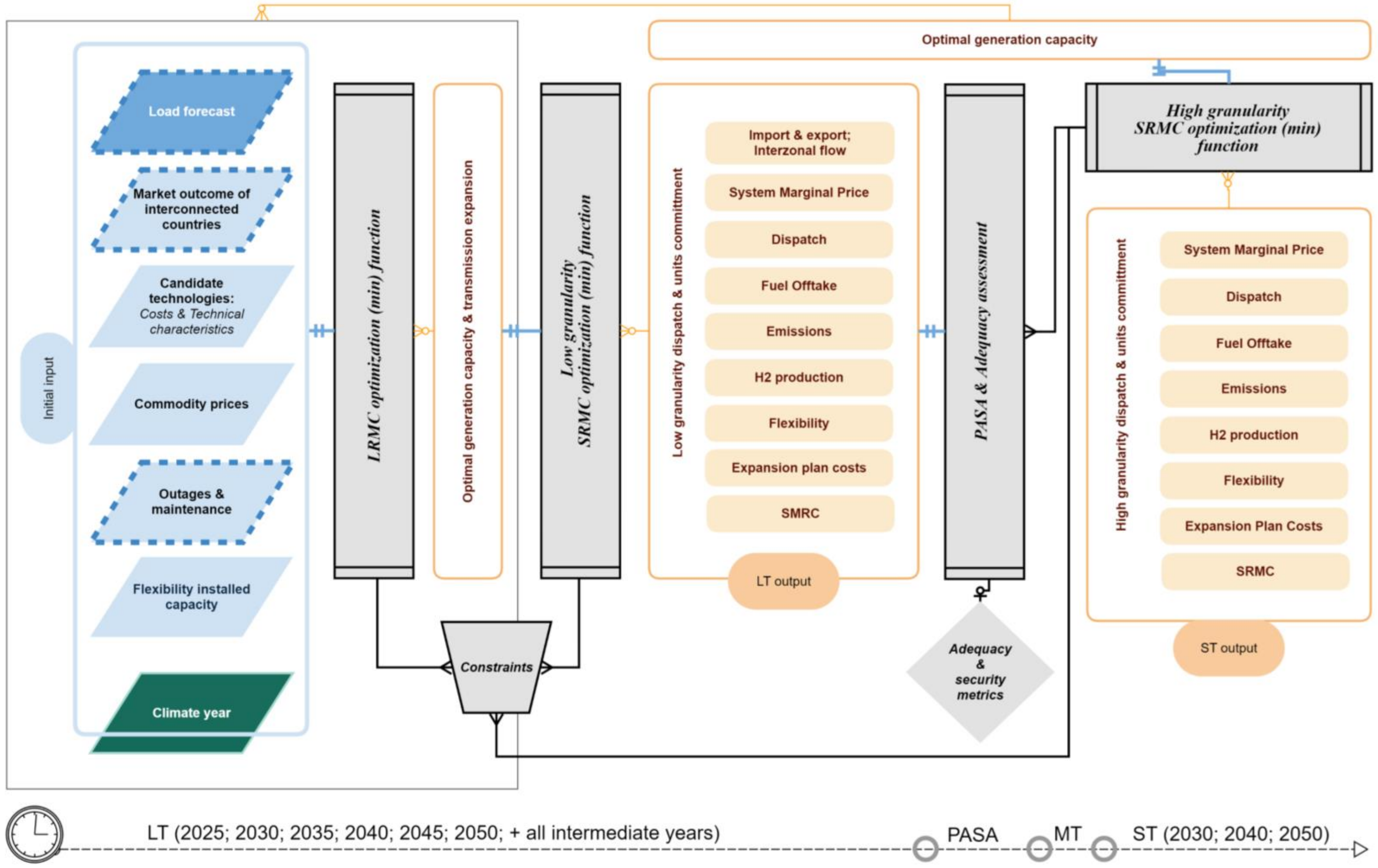


- The model is **integrated at the European level**, enabling Italy to optimize its decarbonization path while considering the efforts of other European countries (Energy Exemplar, 2023b).



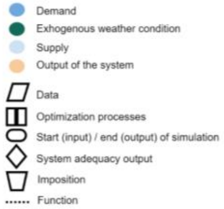
Fondazione Eni Enrico Mattei

2.2. Methodology | Optimization model



The electric power system database (Energy Exemplar, 2023b) contains hourly load data, generator details, prices, technologies, and interconnections for detailed simulation. PLEXOS handles long to short-term data combinations.

- **Long Term** (LT) plan uses Mixed Integer Programming to optimize 28-year costs and determines generation capacity, transmission capacity and storage capacity. It also provides a preliminary dispatch.
- **Projected Assessment of System Adequacy** (PASA) prepares maintenance events and computes reliability indexes at annual level.
- **Medium Term Schedule** (MT) defines optimal strategies for hydropower commitment at annual level.
- **Short Term Schedule** (ST) optimizes unit commitment, dispatch decisions and demand flexibility at hourly level, based on LT, PASA and MT decisions.



FONDAZIONE ENI ENRICO MATTEI

2.3. Methodology | Granularity

Simulation settings and runtime performance

	Phases' horizon	Unit Commitment Optimality	Chronology	Granularity	Dimension of the problem (non-zero values)	Run Time
Low granularity (LG)	LT (2023-2050)	Integer	Partial without Slicing Blocks	Quarterly (LDC: 5 blocks)	9,364,323	00:14:47
	ST (2030; 2040*; 2050)			Hourly	~ 1,300,000	~ 01:00:00
High granularity (HG)	LT (2023-2050)	Integer	Partial with Slicing Blocks	Monthly (LDC: 5 blocks)	26,946,420	11:03:54
	ST (2030; 2040*; 2050)			Hourly	~ 1,300,000	~ 01:00:00

*Results are only presented for 2030 and 2050 target years

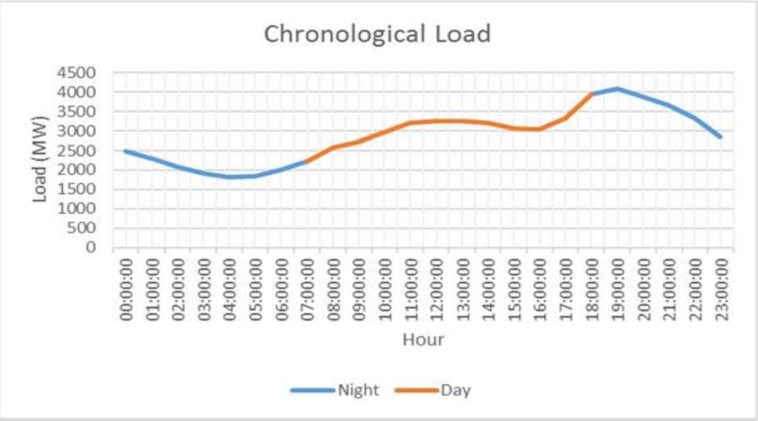
The optimization phases provide varying levels of insight into the electricity system's performance.

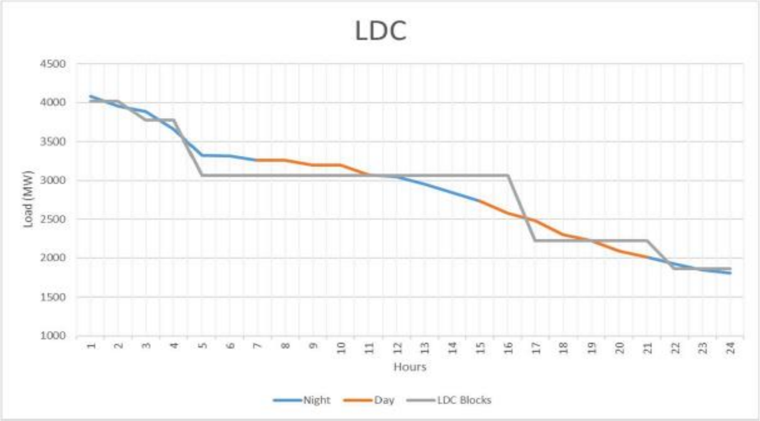
Finer granularity offers more accurate load forecasts, aiding in system adequacy assessment and identifying supply-demand balance issues (Nweke et al., 2012).

Load duration curve (LDC) approximation options are explored and compared. A **partial chronology approach simplifies LDC** (Energy Exemplar, 2023a) potentially leading to inaccuracies in VRES generation.

Two scenarios (HG and LG) with differing chronology are developed in this study.

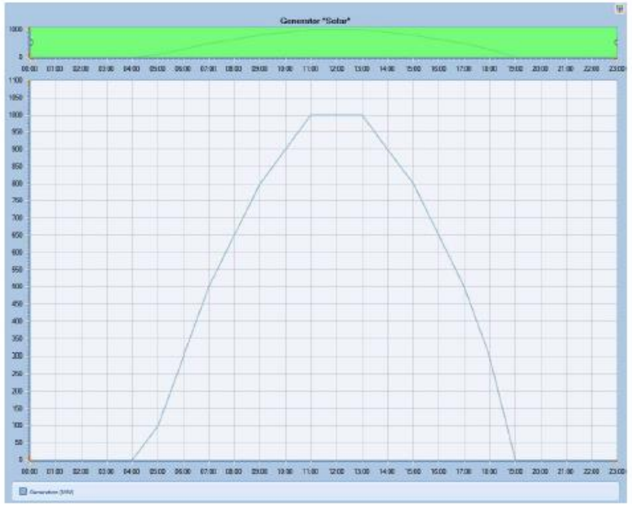
2.3. Methodology | Granularity





Source: Energy Exemplar

Partial Chronology can group day and night into same simulation block.



Solar PV generation (ST)

Solar PV generation (MT - Partial)

Source: Energy Exemplar

This issue can be fixed with Slicing Blocks that should be kept together when performing time slicing for partial chronology.

The "**Slicing Blocks**" technique is introduced to preserve meaningful temporal relationships and prevent data distortion, enhancing analysis accuracy.

FONDAZIONE ENI ENRICO MATTEI

3.1. Results | Load composi

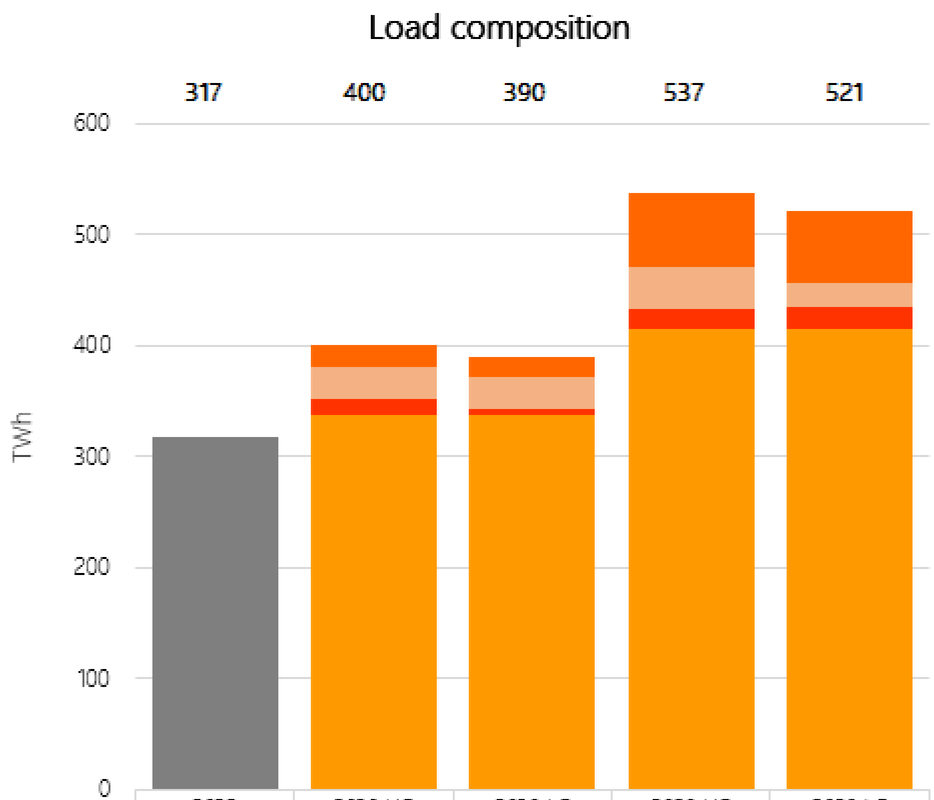
The demand for electricity is higher in the HG scenario, (+2,8% in 2030 and +3,1% in 2050): LG simulations can lead to an underestimation, in Short Term run, of peak electricity demand, resulting in potentially reduced requirements for storage solutions.

In HG scenario the **total demand for electricity in 2030** will be equal to 400 TWh**:**

- Electrolyzers consumption 19 TWh
- Storage 45 TWh (+30% vs LG scenario)
- Native Load 337 TWh

In HG scenario the **total demand for electricity in 2050** will be equal to 537 TWh**:**

- Electrolyzers consumption 67 TWh
- Storage 55 TWh (+36% vs LG scenario)
- Native Load 415 TWh



	2022	2030 HG	2030 LG	2050 HG	2050 LG
Electrolyzers electrical usage	0	19	19	67	65
Withdrawal for hydraulic storage network services	0	30	27	37	20
Withdrawal for batteries network services	0	15	7	18	20
Native load	317	337	337	415	415

Since the current availability and efficiency of Italian storage solutions remain limited (IEA, 2022), a contribution to potential unbalances may arise both if the expansion of RES capacity occurs rapidly without the corresponding establishment of adequate storage infrastructure, and also if unbalances between their demand (i.e. withdrawal for network services) and supply verifies.

3.2. Results | Installed capacity

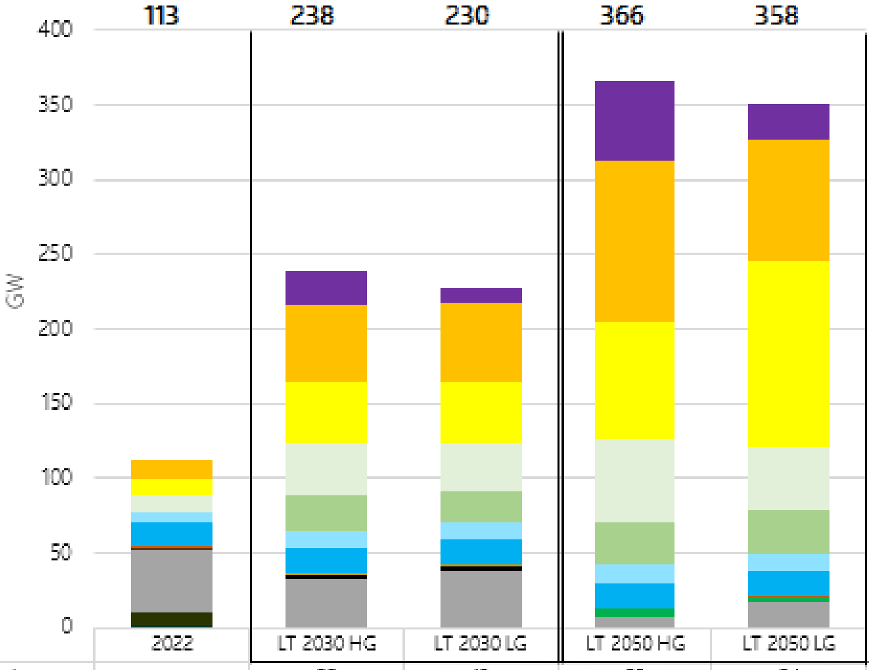
In order to achieve the targets established for the year 2030, HG simulation signals that it is necessary to **increase the generation capacity by 125 GW.**

HG Main drivers of growth in 2030 vs 2022:
- Solar +67 GW (59% utility);
- Wind +48 GW;
- Batteries +22 GW (the intermittent nature of VRES necessitates the implementation of energy storage solutions or backup systems to ensure the continuous supply of energy (Bertsch et al., 2012).

In 2050 the installed capacity reaches 366 GW in HG:
- The model, for reasons of backup capacity and base load needs, installs 5 GW of fourth generation nuclear and 4 GW of biomethane;
- All CCS is retired by 2040.

Comparing the LG scenario with the HG scenario (-5% and -2% in the 2030 and 2050 on total installed capacity):
- Limited reliance on electrochemical storage (in 2050 -56% LG vs HG),
- Gas (including decarbonized one) emerges as a viable solution to meet the load (in 2050 +137% LG vs HG),
- Higher generation capacity to meet the overestimated load curve of LT,
- Excessive rooftop installation which leads to 113 TWh of energy curtailment in 2050.

Comparison of LT installed capacity (2030 & 2050) between HG and LG



	2022	LT 2030 HG	LT 2030 LG	LT 2050 HG	LT 2050 LG
Batteries	-	22	10	53	24
Solar (Utility)	13	53	53	108	82
Solar (Rooftop)	12	40	41	77	125
Wind onshore	11	35	32	57	41
Wind offshore	-	23	21	28	29
Hydro pumped	7	12	12	12	12
Hydro	15	16	16	17	17
Geothermal	1	1	1	1	1
Other	1	0	0	-	-
Waste	0	0	0	-	-
Biomass	2	1	1	-	-
Nuclear 4g	-	-	-	5	3
CCS	-	2	3	-	-
Gas*	42	33	38	7	17
Coal	8	-	-	-	-
Oil	1	-	-	-	-

** Possibility of blending gas /biomethane*

Fondazione Eni Enrico Mattei

3.3. Results | Generation

The renewable generation capacity achieves a remarkable milestone, surpassing the original target of **65%** and reaching **90%** by the year 2030. High price of gas and CO2 lead the simulation to rapidly install renewables:

- **Natural gas represents a minimal share, 6%** of the total (vs 47% in 2022). The overall production of fossil sources is equal to less than 20 TWh, of which almost 4 from CCS
- **Solar and wind grow by 433% and 950% respectively**

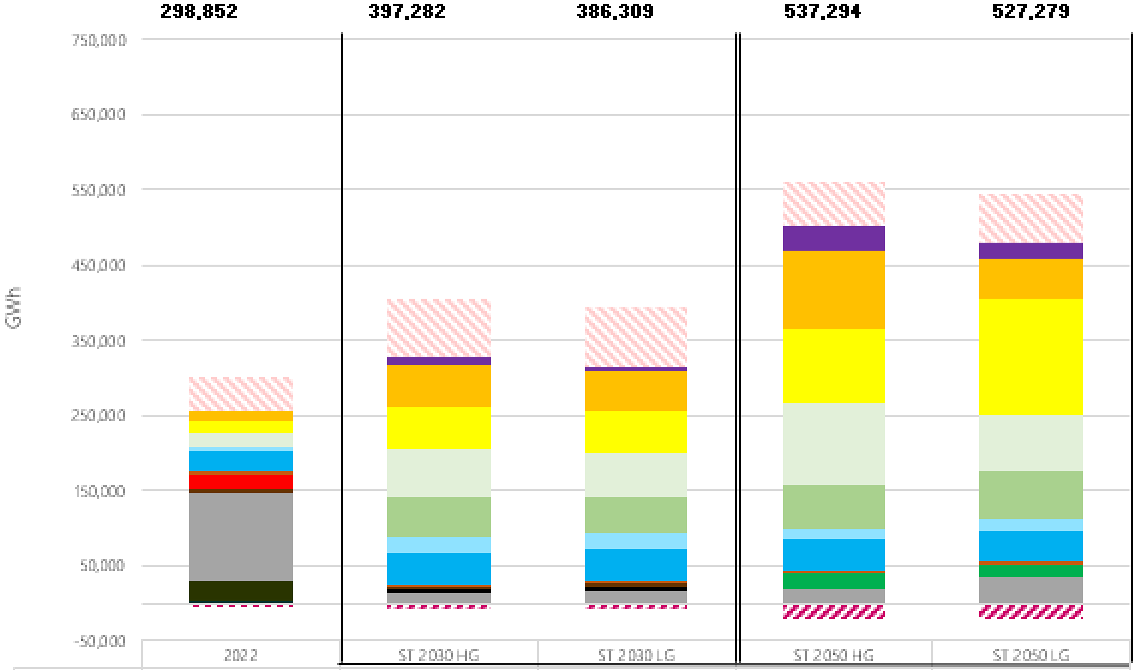
In 2050 the entire generation is decarbonized:

- **Solar accounts for almost 205 TWh (*utility scale*** and ***prosumer)***
- **Wind onshore 90 TWh** and **offshore 42 TWh**
- **Nuclear 21 TWh**
- Biomethane and other renewable gases will be useful for managing flexibility (Synchronous generation for adequacy purposes)

From 2030 to 2050, HG results, compared to LG scenario ones, show:

- **Higher Solar Utility Penetration (+89%);**
- **Reduced Reliance on Imports (-7%);**
- **Higher batteries contribution (+46%)**

Comparison of LT and ST annual generation (2030 & 2050) between HG and LG



	2022	ST 2030 HG	ST 2030 LG	ST 2050 HG	ST 2050 LG
Export	-3,781	-8,247	-7,369	-21,857	-20,174
Import	46,571	76,490	78,506	57,654	62,052
Batteries	-	12,209	6,593	33,034	22,646
Solar (Utility)	13,938	56,022	52,842	101,848	53,867
Solar (Rooftop)	14,183	54,095	54,791	100,656	153,189
Wind onshore	20,103	65,167	59,174	108,766	76,060
Wind offshore	-	52,480	49,092	59,155	62,855
Hydro pumped	5,503	22,516	20,468	13,439	15,201
Hydro	26,362	40,827	41,719	41,240	41,285
Geothermal	5,445	4,007	4,340	3,304	3,552
Other	17,999	196	256	-	-
Waste	289	2	4	-	-
Biomass	5,553	2,660	2,873	-	-
Nuclear 4g	-	-	-	21,042	17,356
CCS	-	4,308	7,404	-	-
Gas *	117,337	14,552	15,617	19,012	35,129
Coal	26,933	-	-	-	-
Oil	2,417	-	-	-	-

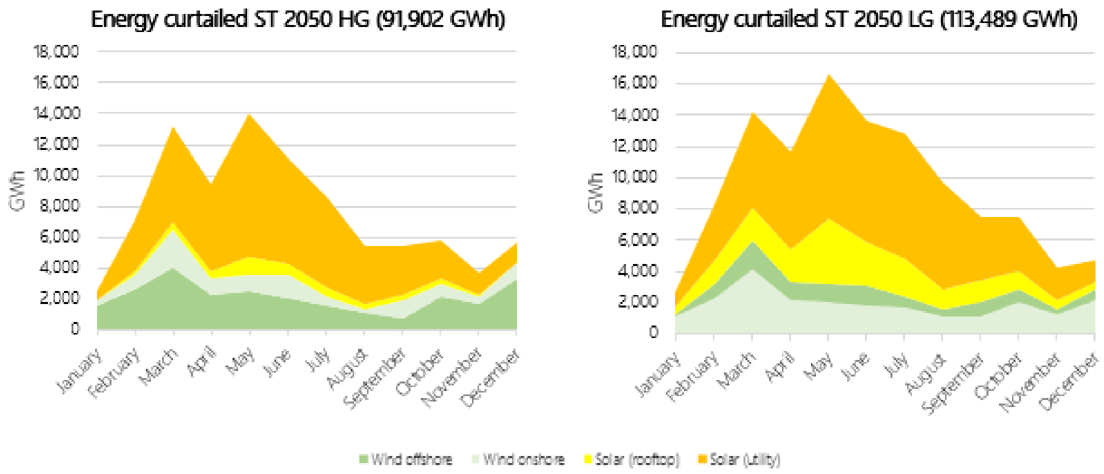
** Possibility of blending gas /biomethane*

Fondazione Eni Enrico Mattei

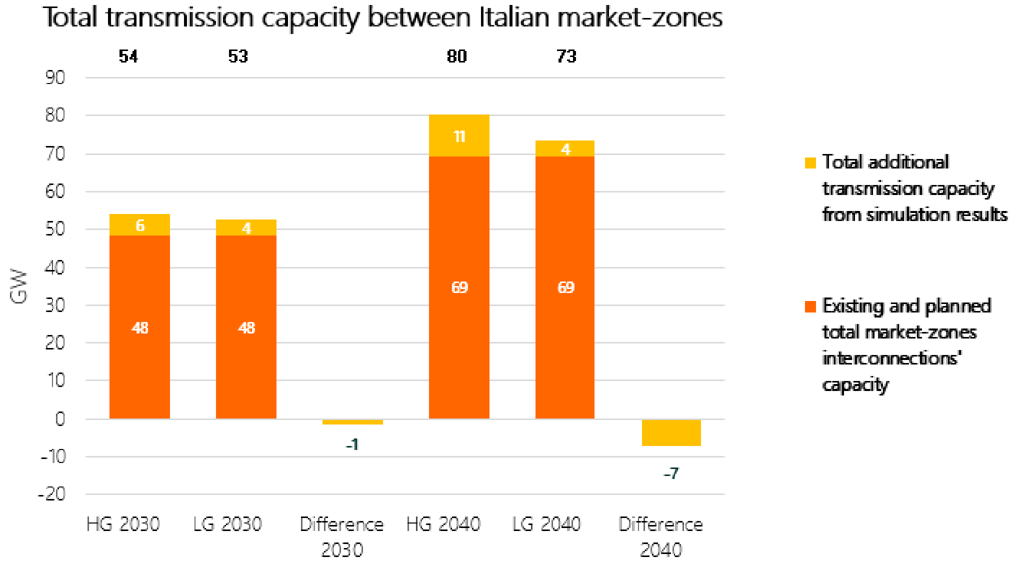
3.4. Results | VRES role

A higher contribution of VRES to total generation is expected by the HG optimization (72% in 2030 and 79% in 2050) than the LG exercise (70% in 2030 and 75% in 2050). The integration of additional renewable capacity poses challenges to the reliability and security of the electricity system (Li et al., 2018; Alizadeh et al., 2016).

- Performed optimization highlights the risks of oversizing the installed generation capacity and underutilize planned investments (i.e. stranded assets) too.
- **For LG simulation, by 2050, there is a significant proliferation of solar rooftop panels, which results in a substantial amount of energy curtailed** (113 TWh, +23% vs HG) **in comparison with HG case.**



- **Intermittent renewables have a specific geographical distribution**, with the southern regions and islands dominating in utility-scale solar and wind energy.
- **PLEXOS detects more intraregional flows in the HG optimization than in the LG.** The development of RES capacity necessitates the upgrading of T&D networks to facilitate the efficient distribution of the generated power (Terna, 2023b).



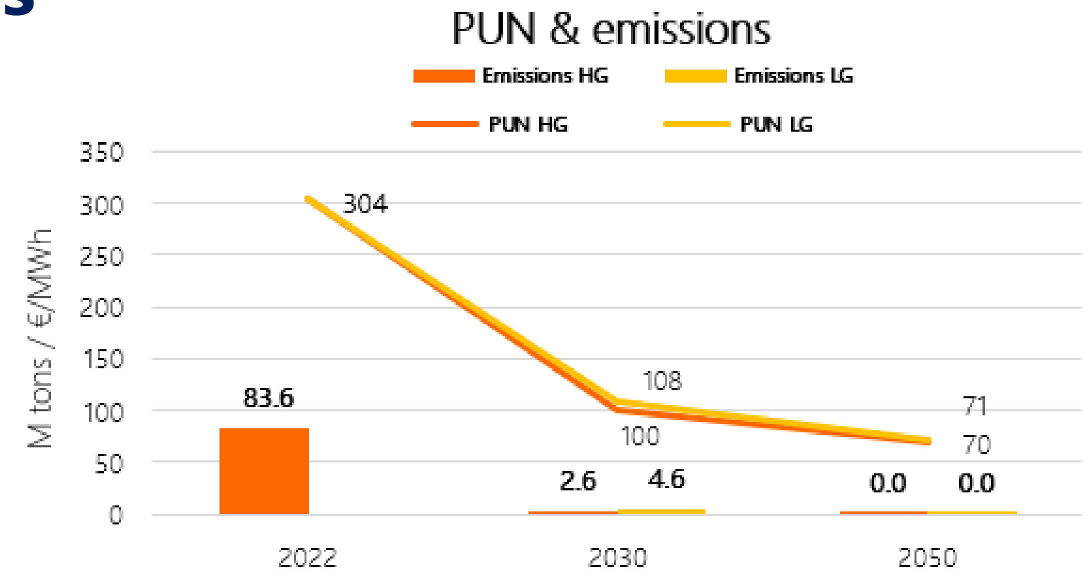
3.5. Results | PUN & emissions

The optimization efforts lead to **almost zero emissions from the electric system as early as 2030**. This is done to prevent the Prezzo Unico Nazionale (PUN) from being influenced by the expected price of the Emission Trading System (ETS), which is anticipated to reach nearly €110/ton by 2030.

HG and LG optimizations differ, with LG showing higher prices and emissions. However, as zero marginal cost generation increases, hourly price differences between HG and LG decrease.

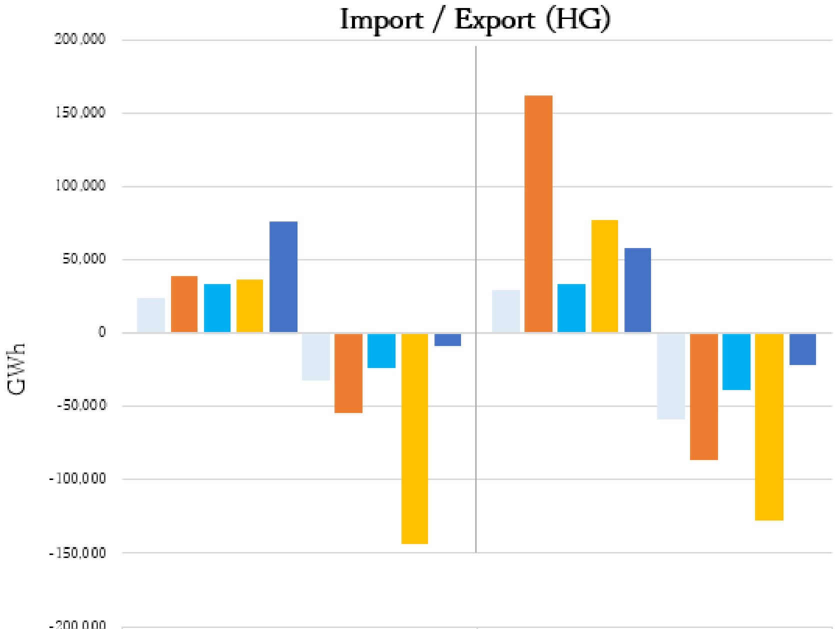
Zonal prices are misaligned: the increase in generation capacity from renewable sources leads to a substantial reduction in zonal electricity prices which leads to greater competition in the Italian electricity market and a higher penetration of storage technologies.

Zonal prices differences between the simulations performed at different granularity levels persist with almost always higher prices in the LG case.
On average HG prices are 16% lower in 2030 and 4% lower in 2050.

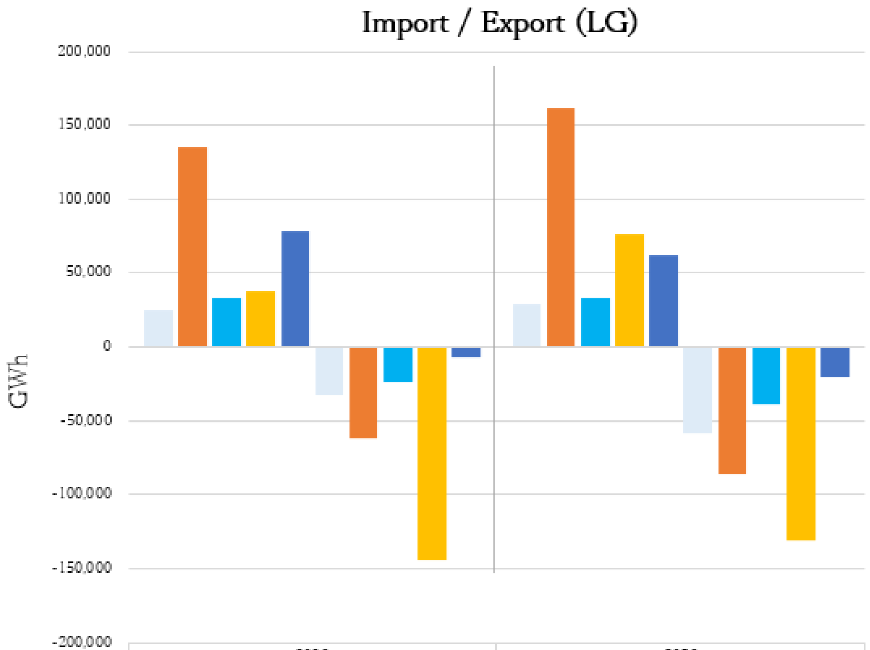


	ST 2030 HG	ST 2030 LG	ST 2050 HG	ST 2050 LG	Unit
Calabria	48.50	56.55	48.38	50.12	€/MWh
Centre North	76.12	87.27	59.20	55.04	€/MWh
Centre South	77.09	88.81	52.67	54.01	€/MWh
North	132.72	138.67	89.84	92.13	€/MWh
South	51.94	60.69	47.80	50.43	€/MWh
Sardinia	41.88	54.37	40.77	46.20	€/MWh
Sicily	57.73	66.84	47.95	52.05	€/MWh

3.6. Results | Import & export EU



	2030	2050
Import Austria	24,578	28,996
Import Germany	39,276	161,845
Import Spain	33,590	33,391
Import France	37,416	77,687
Import Italy	76,490	57,654
Export Austria	-32,472	-58,972
Export Germany	-54,934	-85,882
Export Spain	-23,796	-38,900
Export France	-144,109	-127,741
Export Italy	-8,247	-21,857

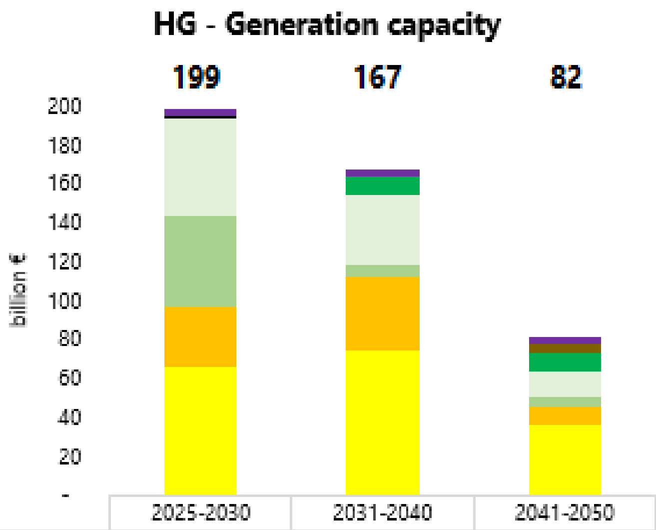


	2030	2050
Import Austria	24,447	29,043
Import Germany	135,826	161,630
Import Spain	33,203	33,222
Import France	37,366	76,280
Import Italy	78,506	62,052
Export Austria	-32,469	-58,958
Export Germany	-61,568	-86,172
Export Spain	-23,884	-39,112
Export France	-144,641	-130,639
Export Italy	-7,369	-20,174

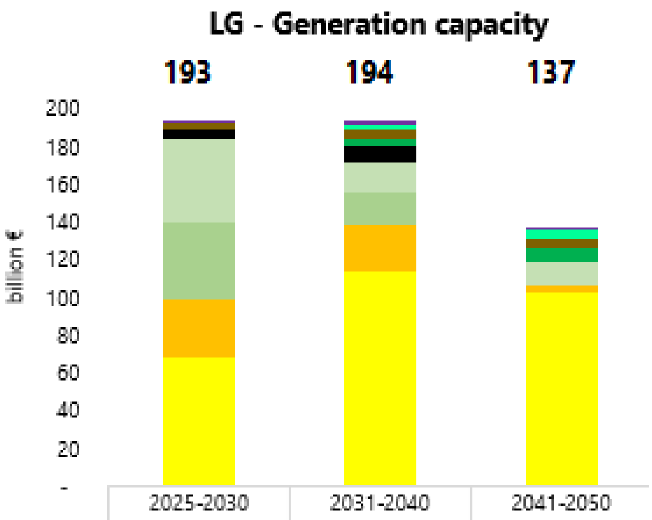
The simulation, taking into account operational foreign markets, also optimizes with respect to import and export opportunities. In both scenarios, Italy remains a net importer, but only in the HG simulation, its balance with Europe improves considerably. Specifically:

- In the HG scenario, Italy's net import decreases by 16% compared to 2022, indicating a substantial improvement in its trade balance with Europe.
- In the LG scenario, Italy's net import decreases by 2% compared to 2022, indicating a more modest improvement in its trade balance with Europe.

3.7. Results | Investments



	2025-2030	2031-2040	2041-2050
Batteries	4	4	4
BioMethane	-	-	4
Nuclear	-	9	10
Gas CCS	2	-	-
Wind Onshore	50	36	13
Wind Offshore	47	6	4
Solar (Utility)	30	38	10
Solar (Rooftop)	66	74	35



	2025-2030	2031-2040	2041-2050
Batteries	1	1	1
Hydrogen	-	3	5
BioMethane	3	5	5
Nuclear	-	3	8
Gas CCS	6	8	-
Wind Onshore	44	16	12
Wind Offshore	41	17	-
Solar (Utility)	31	24	5
Solar (Rooftop)	68	114	102

Overall investments exhibit higher magnitudes in the LG scenario (+17% vs HG).

Factors contributing to the cost increase in LG:

- Load profile approximation results in an overestimation of the load to be met in Long Term run;
- Higher installed generation capacity occurs in LG due to its failure to account for demand peaks;
- When LG completely phases out fossil thermal capacity, it excessively installs solar rooftop to balance the demand.

HG reaches an *optimum* more cost competitive than LG.

4.1. Discussion & conclusions

Comparison between High Granularity (HG) and Low Granularity (LG) Scenarios for Effective Planning:

1.Enhanced Precision for Accurate Decisions

- High granularity allows for a comprehensive analysis of data and information, leading to more accurate decisions on generation capacity, energy sources, and necessary investments to maintain supply-demand balance.
- In contrast, the LG scenario lacks detailed information, resulting in underutilization of various forms of flexibility and increasing dependence on foreign imports (2050 net-import +17% vs HG scenario).

2. System Security through Energy Diversity

- The HG scenario emphasizes diverse energy sources, including Variable Renewable Energy Sources (VRES), to ensure electricity system security. A prosumer approach to a diversified generation portfolio is critical for effective utilization of renewable sources and avoiding capacity oversizing.
- In the LG scenario, excessive rooftop solar causes significant energy curtailment (114 TWh), prioritizing thermal capacity over flexibility, hampering optimization.

3. Flexibility: A Key to System Security

- HG scenario incorporates flexibility options like hydrogen production and electrochemical storage, crucial for ensuring efficient VRES penetration and system stability.
- LG scenario's underestimation of demand peaks impacts energy storage investments, potentially leading to inadequate capacity during peak demand periods.

4.2. Discussion & conclusions

The advantages of an HG simulation for effective and efficient investment planning are demonstrated by the results and have multiple impacts.

Policy implications:

- Demand-balancing with Appropriate Technologies;
- Right balance between VREs and Batteries;
- Avoided overinstallation.

Strenghts and future research

- Generator-by-generator modeling;
- Hourly data details;
- Integration of European countries;
- Various consumer types;
- Sensitivity analyses on different climat years.

Limitations

- No financial or bureaucratic factors considered;
- Capacity Market not taken into account;
- Extensive computational resources for detailed simulations.

FONDAZIONE ENI ENRICO MATTEI

Thank you!

Annamaria Zaccaria

annamaria.zaccaria@feem.it

Supporting literature | I

Alizadeh, M. I., Moghaddam, M. P., Amjady, N., Siano, P., & Sheikh-El-Eslami, M. K. (2016). Flexibility in future power systems with high renewable penetration: A review. Renewable and Sustainable Energy Reviews, 57, 1186-1193.

Bain, D., & Acker, T. (2020). Cost implications of increased solar penetration and time-of-use rate interactions. Clean Energy, 4(3), 247-269.

Bellocchi, S., Manno, M., Noussan, M., Prina, M. G., & Vellini, M. (2020). Electrification of transport and residential heating sectors in support of renewable penetration: Scenarios for the Italian energy system. Energy, 196, 117062.

Bertsch, J., Growitsch, C., Lorenczik, S., & Nagl, S. (2016). Flexibility in Europe's power sector—An additional requirement or an automatic complement? Energy Economics, 53, 118-131.

BloombergNEF (2022). Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh. Available at: https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/ (accessed March, 2023)

Brinkerink, M., Gallachóir, B. Ó., & Deane, P. (2021). Building and calibrating a country-level detailed global electricity model based on public data. Energy Strategy Reviews, 33, 100592.

Brouwer, A. S., Van Den Broek, M., Seebregts, A., & Faaij, A. (2014). Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modeled. Renewable and Sustainable Energy Reviews, 33, 443-466.

Brouwer, A. S., van den Broek, M., Zappa, W., Turkenburg, W. C., & Faaij, A. (2016). Least-cost options for integrating intermittent renewables in low-carbon power systems. Applied Energy, 161, 48-74.

Cleary, B., Duffy, A., O'Connor, A., & Conlon, M. (2015). Assessing the future economic performance of wind generation in conjunction with compressed air energy storage in the new proposed Irish electricity market. Economics and Business Letters, 4(3), 87-97.

Cole, W., Greer, D., Ho, J., & Margolis, R. (2020). Considerations for maintaining resource adequacy of electricity systems with high penetrations of PV and storage. Applied Energy, 279, 115795.

Confindustria Energia (2023). Personal communication. June 15, 2023.

Deane, J. P., Gracceva, F., Chiodi, A., Gargiulo, M., & Gallachoir, B. P. (2015). Assessing power system security. A framework and a multi model approach. International Journal of Electrical Power & Energy Systems, 73, 283-297.

Department for Energy Security and Net Zero and Department for Business, Energy & Industrial Strategy (2016). BEIS Electricity Generation Costs (November 2016). Documentation available at: https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016 (accessed March, 2023).

Fondazione Eni Enrico Mattei

Supporting literature | II

Department for Energy Security and Net Zero and Department for Business, Energy & Industrial Strategy (2020). BEIS Electricity Generation Costs (2020). Documentation available at: https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020 (accessed March, 2023).

EC (2021) Fit-for-55. Available at: https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/#:~:text=The%20European%20climate%20law%20makes,EU%20climate%2Dneutral%20by%202050 (accessed April, 2023).

EC (2022). Piano REPowerEU. Available at: https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0023.02/DOC_1&format=PDF (accessed April, 2023).

EC (2023). National energy and climate plans. Available at: https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en (accessed April, 2023)

Edmunds, R., Davies, L., Deane, P., & Pourkashanian, M. (2015). Thermal power plant operating regimes in future British power systems with increasing variable renewable penetration. Energy Conversion and Management, 105, 977-985.

EEE (2023). Natural Gas. Available at: https://www.eex.com/en/market-data/natural-gas (accessed March, 2023).

EIRP (2018). What will advanced nuclear power plants cost? A Standardized Cost Analysis of Advanced Nuclear Technologies in Commercial Development. https://www.innovationreform.org/wp-content/uploads/2018/01/Advanced-Nuclear-Reactors-Cost-Study.pdf (accessed March, 2023).

Energy Exemplar (2023a). PLEXOS Integrated Energy Model 2019. https://energyexemplar.com/solutions/PLEXOS/ (accessed April, 2023).

Energy Exemplar (2023b). Central & Western European Dataset. https://energyexemplar.com/?view=datasets (accessed February, 2023).

ENTSO-E (2019). Mid-term Adequacy Forecast 2019. Documentation available at: https://www.entsoe.eu/outlooks/midterm (accessed February, 2023).

ENTSO-E, ENTSOG (2021). TYNDP 2022. Scenario Report. Version, October 2021. Available at: https://2022.entsos-tyndp-scenarios.eu/ (accessed February, 2023).

ENTSO-E, ENTSOG (2022). TYNDP 2022. Scenario Report. Version, April, 2022. Available at: https://2022.entsos-tyndp-scenarios.eu/ (accessed February, 2023).

ETN Global (2022). Hydrogen deployment in centralised power generation. A techno-economic case study. Available at: https://etn.global/wp-content/uploads/2022/06/H2-deployment-in-centralised-power-generation-techno-economic-study-April2022.pdf (accessed March, 2023).

Feijoo, F., Pfeifer, A., Herc, L., Groppi, D., & Duić, N. (2022). A long-term capacity investment and operational energy planning model with power-to-X and flexibility technologies. Renewable and Sustainable Energy Reviews, 167, 112781.

Foley, A. M., Gallachóir, B. Ó., Hur, J., Baldick, R., & McKeogh, E. J. (2010). A strategic review of electricity systems models. Energy, 35(12), 4522-4530.

Supporting literature | III

Gil, E., Aravena, I., & Cárdenas, R. (2014). Generation capacity expansion planning under hydro uncertainty using stochastic mixed integer programming and scenario reduction. IEEE Transactions on Power Systems, 30(4), 1838-1847.

GME (2019). EUPHEMIA Public Description Single Price Coupling Algorithm. Available at: https://www.mercatoelettrico.org/en/MenuBiblioteca/Documenti/20181212EuphemiaPublicDescription.pdf (accessed May, 2023).

GME (2023a). Available at: https://www.mercatoelettrico.org/it/ (accessed March, 2023).

GME (2023b). Futures prezzo gas GME

Gross, R., Heptonstall, P., Anderson, D., Green, T., Leach, M., & Skea, J. (2006). The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network. London: UKERC; 2006.

Guandalini, G., Robinius, M., Grube, T., Campanari, S., & Stolten, D. (2017). Long-term power-to-gas potential from wind and solar power: A country analysis for Italy. International Journal of Hydrogen Energy, 42(19), 13389-13406.

IEA (2011). Cost and Performance of Carbon Dioxide Capture from Power Generation. Available at: https://www.osti.gov/etdeweb/servlets/purl/21467305 (accessed March, 2023).

IEA (2020a). Power Systems in Transition Challenges and opportunities ahead for electricity security. Available at: https://www.iea.org/reports/power-systems-in-transition (accessed May, 2023).

IEA (2020b). Projected Costs of Generating Electricity. Available at: https://iea.blob.core.windows.net/assets/ae17da3d-e8a5-4163-a3ec-2e6fb0b5677d/Projected-Costs-of-Generating-Electricity-2020.pdf (accessed March, 2023).

IEA (2022). Italy Electricity Security Policy. Available at: https://www.iea.org/articles/italy-electricity-security-policy (accessed May, 2023).

Impram, S., Nese, S. V., & Oral, B. (2020). Challenges of renewable energy penetration on power system flexibility: A survey. Energy Strategy Reviews, 31, 100539.

IRENA (2022). Sector coupling. A key concept for accelerating the energy transformation. Available at: https://www.irena.org/Publications/2022/Dec/Sector-coupling-A-key-concept-for-accelerating-the-energy-transformation (accessed May, 2023).

Jeong, W. C., Lee, D. H., Roh, J. H., & Park, J. B. (2022). Scenario Analysis of the GHG Emissions in the Electricity Sector through 2030 in South Korea Considering Updated NDC. Energies, 15(9), 3310.

Li, J., Liu, F., Li, Z., Shao, C., & Liu, X. (2018). Grid-side flexibility of power systems in integrating large-scale renewable generations: A critical review on concepts, formulations and solution approaches. Renewable and Sustainable Energy Reviews, 93, 272-284.

Fondazione Eni Enrico Mattei

Supporting literature | IV

Lund, P. D., Lindgren, J., Mikkola, J., & Salpakari, J. (2015). Review of energy system flexibility measures to enable high levels of variable renewable electricity. Renewable and sustainable energy reviews, 45, 785-807.

Ministeri dello Sviluppo Economico, dell'Ambiente e della Tutela del Territorio e del Mare, delle Infrastrutture e dei Trasporti (2019). Piano nazionale integrato per l'energia e il clima. Available at: https://www.mise.gov.it/images/stories/documenti/PNIEC_finale_17012020.pdf (accessed May, 2023).

National Grid ESO (2021). Future Energy Scenarios. Available at: https://www.nationalgrideso.com/document/202851/download (accessed March, 2023).

Nweke, C. I., Leanez, F., Drayton, G. R., & Kolhe, M. (2012). Benefits of chronological optimization in capacity planning for electricity markets. In 2012 IEEE international conference on power system technology (POWERCON) (pp. 1-6). IEEE.

Pastore, L. M., Basso, G. L., Cristiani, L., & de Santoli, L. (2022). Rising targets to 55% GHG emissions reduction–The smart energy systems approach for improving the Italian energy strategy. Energy, 259, 125049.

Qualenergia (2023). Avviate le autorizzazioni per il nuovo elettrodotto Adriatic Link di Terna. Available at: https://www.qualenergia.it/articoli/avviate-autorizzazioni-nuovo-elettrodotto-terna-adriatic-link/ (accessed March, 2023).

Senatla, M., Nchake, M., Taele, B. M., & Hapazari, I. (2018). Electricity capacity expansion plan for Lesotho–implications on energy policy. Energy Policy, 120, 622-634.

Snam, Terna (2022). Documento di descrizione degli scenari 2022. Available at: https://download.terna.it/terna/Documento_Descrizione_Scenari_2022_8da74044f6ee28d.pdf (accessed February, 2023).

Terna (2021a). The new electricity market zones: what you need to know. Available at: https://lightbox.terna.it/en/insight/new-electricity-market-zones (accessed May, 2023).

Terna (2021b). Terna: 170 milioni di euro per la nuova linea elettrica Colunga Calenzano tra Emilia-Romagna e Toscana. Available at: https://www.terna.it/it/media/comunicati-stampa/dettaglio/Terna--170-milioni-di-euro-per-la-nuova-linea-elettrica-Colunga-Calenzano-tra-Emilia-Romagna-e-Toscana (accessed March, 2023).

Terna (2021c). Terna avvia l'Adriatic Link: oltre 1 miliardo di euro di investimenti per il nuovo cavo sottomarino tra Abruzzo e Marche. Available at: https://www.terna.it/it/media/comunicati-stampa/dettaglio/Terna-avvia-l-Adriatic-Link--oltre-1-miliardo-di-euro-di-investimenti-per-il-nuovo-cavo-sottomarino-tra-Abruzzo-e-Marche (accessed March, 2023).

Terna (2023a). Total load. Available at: https://www.terna.it/it/sistema-elettrico/transparency-report/total-load (accessed April, 2023).

Terna (2023b). Piano di Sviluppo. Available at: https://www.terna.it/it/sistema-elettrico/rete/piano-sviluppo-rete (accessed March, 2023).

Fondazione Eni Enrico Mattei

Supporting literature | V

Terna (2023c). Adequacy. Available at: https://www.terna.it/en/electric-system/dispatching/adequacy (accessed June, 2023).

Ventosa, M., Baıllo, A., Ramos, A., & Rivier, M. (2005). Electricity market modeling trends. Energy policy, 33(7), 897-913.

Vithayasrichareon P., Lozanov, T., Riesz, J., MacGill, I. (2015). Impact of operational constraints on generation portfolio planning with renewables. IEEE Power & Energy Society General Meeting, Denver, CO, USA, 2015, pp. 1-5.

Zafeiratou, E., & Spataru, C. (2018). Sustainable island power system–Scenario analysis for Crete under the energy trilemma index. Sustainable Cities and Society, 41, 378-391.

Annex

Fondazione Eni Enrico Mattei

CAPEX

Table 3 – CAPEX

Technology	Unit		Value	Source
Overhead cable	€	400 MW	170,000,000	Terna (2021b); Terna (2023b)
Subsea cable	€	1000 MW	1,000,000,000	Qualenergia (2023); Terna (2021c)
Solar (prosumer)	€/kW		2.275	IEA (2020b)
Solar (utility scale)	€/kW		728	IEA (2020b)
Wind onshore	€/kW		1,737	IEA (2020b)
Wind offshore	€/kW		2,019	IEA (2020b)
Nuclear 4G	€/kW		3,782	EIRP (2018)
Gas CCS (New plant + CCS)	€/kW		1882	IEA (2011); IEA (2020b); Confindustria Energia (2023)
CCS	€/kW		848	IEA (2011); IEA (2020b); Confindustria Energia (2023)
Gas / biomethane (dual fuel)	€/kW		1034	IEA (2020b); Confindustria Energia (2023)
New gas (CCGT)	€/kW		1034	IEA (2020b); Confindustria Energia (2023)
New gas (OCGT)	€/kW		570	IEA (2020b); Confindustria Energia (2023)
Hydrogen H2	€/kW		1100	ETN Global (2022); Confindustria Energia (2023)
*Batteries (utility scale)**	€/kW		396-179	IEA (2020b)
*Batteries (prosumer)**	€/kW		496-224	BloombergNEF (2022)

** Only for batteries, a decreasing cost curve has been computed. Values for both categories refer to 2030 and 2050.*

OPEX

Table S3 – OPEX

Technology		OPEX component	Units	Value		Source	
Biomass / Waste		Variable	€/MWh	3.3		ENTSO-E (2019)	
		Fixed	€/kW	-		-	
Gas		Variable	€/MWh	1.1	1.6	ENTSO-E (2019)	
		Fixed	€/kW	13.0	25.0	BEIS (2020)	BEIS (2016)
Coal		Variable	€/MWh	3.3		ENTSO-E (2019)	
		Fixed	€/kW	35.0	40.0	BEIS (2020)	BEIS (2016)
Oil / Geothermal / Other		Variable	€/MWh	1.1		ENTSO-E (2019)	
		Fixed	€/kW	-		-	
CCS		Variable	€/MWh	3.2		ENTSO-E (2019)	
		Fixed	€/kW	51.8		BEIS (2020)	BEIS (2016)
Nuclear		Variable	€/MWh	9		ENTSO-E (2019)	
		Fixed	€/kW	25		BEIS (2020)	BEIS (2016)
Gas / biomethan (dual fuel) / Hydrogen / New gas (CCGT)		Variable	€/MWh	1.6		ENTSO-E (2019)	
		Fixed	€/kW	40		BEIS (2020)	BEIS (2016)
New gas (OCGT)		Variable	€/MWh	1.6		ENTSO-E (2019)	
		Fixed	€/kW	36		BEIS (2020)	BEIS (2016)
Batteries (EV)		Variable	€/MWh	30		ENTSO-E, ENTSOG (2022)	
		Fixed	€/kW	-		-	
Batteries (prosumer) / Batteries (utility scale)		Variabile	€/MWh	0.3		ENTSO-E, ENTSOG (2021)	
	2025	Fissa	€/kW	23.5		ENTSO-E, ENTSOG (2021)	
	2030			15.0			
	2035			14.5			
	2040			14.1			
	2045			13.6			
	2050			13.1			

Fondazione Eni Enrico Mattei

Prices of commodities

Table 4 – Prices of Commodities

Fuel/greenhouse gas	Unit	2030	2040	2050	Source
Biomass	€/MWh	27.4	34.6	41.8	ENTSO-E, ENTSOG (2022); GME (2023b)
Coal		7.1	6.9	6.7	
Lignite		6.5	6.5	6.5	
Gas		14.5	14.7	14.7	
Oil		36.3	34.6	32.8	
Biomethane		74.7	61	50.3	
Hydrogen		61.6	63.2	64.5	
Other		0	0	0	
Waste		0	0	0	
CO2	€/tonne	108	123	168	

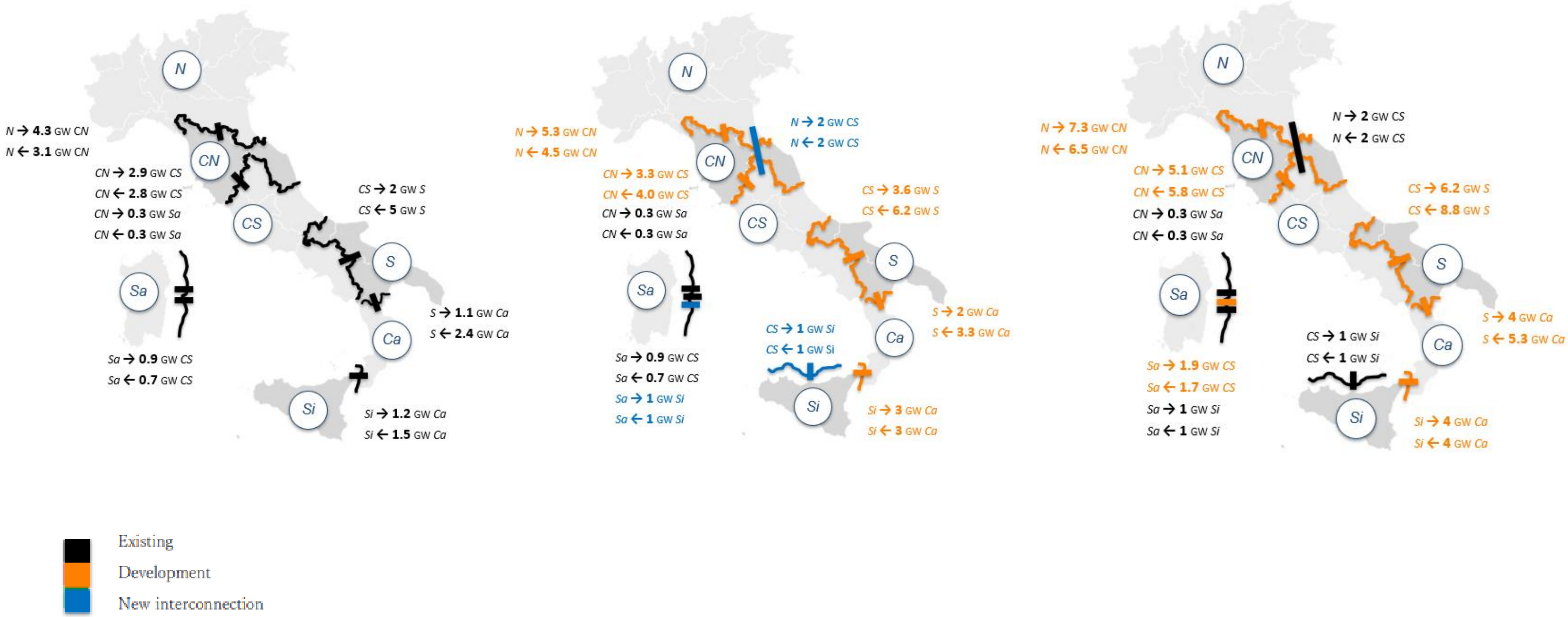
Fondazione Eni Enrico Mattei

Interregional interconnections

Table S1 – Interregional interconnections (GW)

		2030	2040	2050
AT-ITN	>	0.36	0.36	0.36
	<	0.15	0.15	0.15
CH-ITN	>	4.51	4.51	4.51
	<	1.91	1.91	1.91
FR-ITN	>	4.10	5.10	5.10
	<	2.00	3.00	3.00
GR-ITS	>	0.50	0.50	0.50
	<	0.50	0.50	0.50
ITSi-MT	>	0.22	0.22	0.22
	<	0.13	0.13	0.13
ME-ITCS	>	0.60	0.60	0.60
	<	0.60	0.60	0.60
SI-ITN	>	0.66	0.95	0.95
	<	0.65	0.95	0.95
TN-ITSi	>	0.60	0.60	0.60
	<	0.60	0.60	0.60

Intraregional interconnections



Fondazione Eni Enrico Mattei

New intraregional interconnections by market-zone

Interconnection		HG from 2040 (GW)	LG from 2040 (GW)
ITCa-ITS	>	0.4	
	<	0.4	
ITCa-ITSi	>		
	<		
ITCS-ITCN	>	0.4	
	<	0.4	
ITCS-ITN	>		
	<		
ITCS-ITS	>	0.8	1.4
	<	0.8	1.4
ITN-ITCN	>	3.2	1.4
	<	3.2	1.4
ITSa-ITCS	>		
	<		
ITSa-ITSi	>		
	<		
ITSi-ITCS	>		
	<		
ITCS-ITCa	>	0.8	1.4
	<	0.8	1.4
ITCN-ITSa	>		
	<		

Flexibility options

Flexibility:

The first flexibility solution is **batteries (electrochemical storage) and pumped storage (hydraulic storage)** the latter having no candidates in the long-term generation expansion but only existing fleets. Electrochemical storage includes utility scale batteries, connected to the network node, prosumer batteries, connected to the prosumer node, and electric vehicles (Evs). The latter are modelled as batteries capable of releasing energy to the grid when needed. The installed capacity of EVs is 11 percent of the fleet currently available (National Grid ESO, 2021).

Given the necessity of providing flexibility solutions to support VRES penetration, electrochemical storage – whose new installed capacity does not depend on hindering conditions such as territorial specificities, as instead is the case for hydraulic storage **– is allowed to be a candidate technology for the expansion plan.**

H2

The second solution is defined by the **hydrogen sector and its storage capacity** in salt caverns. Once H2 demand is met, the model may decide to produce surplus hydrogen and store it to meet hydrogen demand during periods of high system stress in a way that significantly reduces the electrical load on the electrolysers.

DSR

The last flexibility option is **Demand Side Response (DSR)**, which are dummy generators with a stepped supply curve and high electricity price levels that simulate the planned disconnection of large electricity consumers during high system stress (where, due to combined issues of adverse weather conditions, severe peak demand, and forced capacity outages, generation and imports are unable to cover the load) with a role of peak shaving.

Constraints:

a) **in 2030** Italy is expected to reach **65% of generation from renewable sources** (Italian constraint);

b) in **2050** the electricity system needs to reach **carbon neutrality**;

c) **reserve margin is set at 20%** capacity above peak demand;

d) **10% of generation must be provided by rotating synchronous plants**