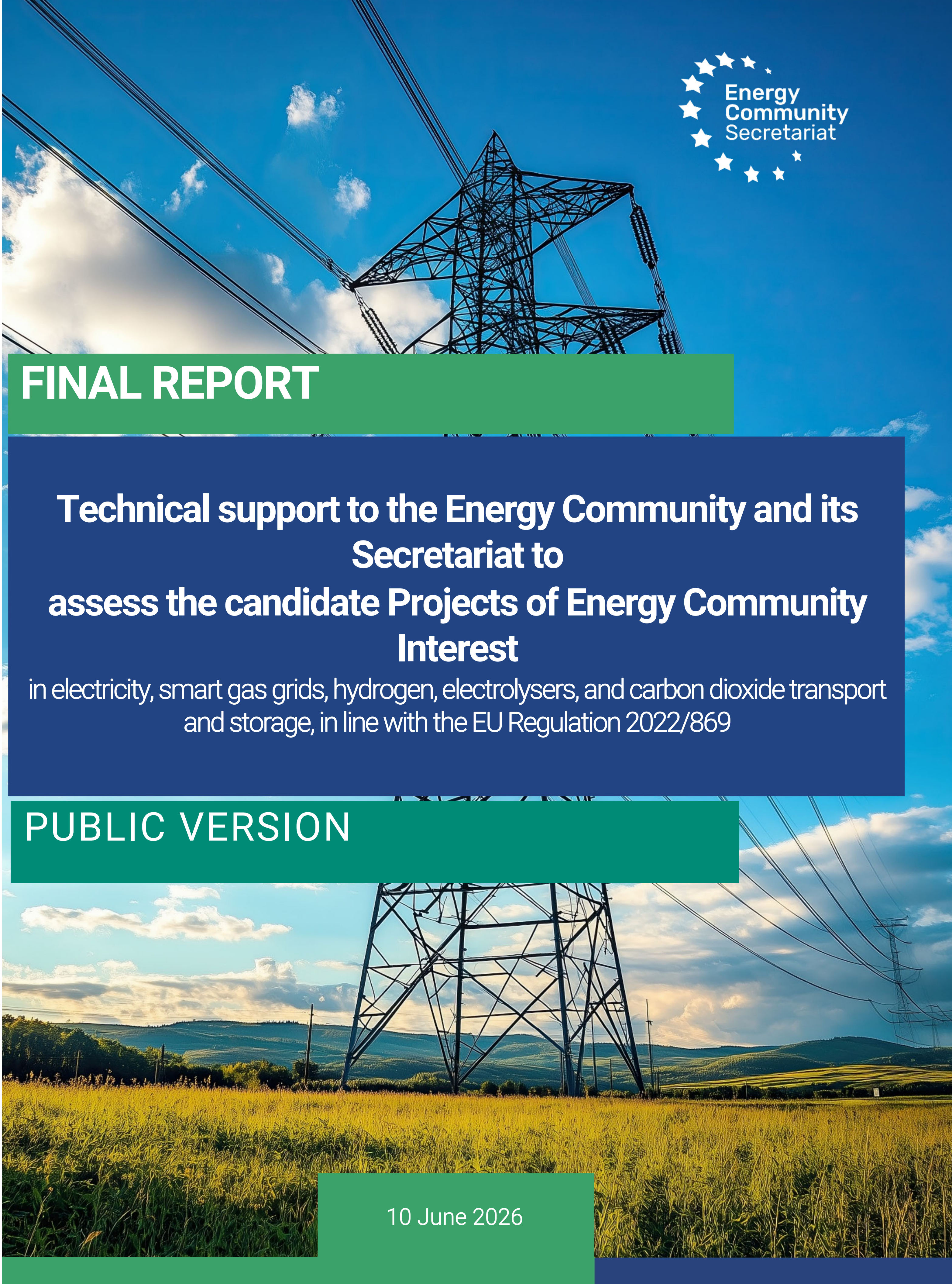

Energy Community Secretariat

FINAL REPORT

Technical support to the Energy Community and its Secretariat to assess the candidate Projects of Energy Community Interest

in electricity, smart gas grids, hydrogen, electrolysers, and carbon dioxide transport and storage, in line with the EU Regulation 2022/869

PUBLIC VERSION

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Impressum

TITLE: *Technical support to the Energy Community and its Secretariat to assess the candidate Projects of Energy Community Interest in electricity, smart gas grids, hydrogen, electrolysers, and carbon dioxide transport and storage, in line with the EU Regulation 2022/869*

FINAL REPORT

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Abbreviations and acronyms

aFRR	automatic Frequency Regulation Reserve
AL	Albania
BA	Bosnia and Herzegovina
B/C	Benefit-Cost
CAPEX	Capital Expenditures
CBA	Cost Benefit Analysis
CCS	Carbon Capture and Storage
CF	Cash Flow
CP	Contracting Party
EnC	Energy Community
ECS	Energy Community Secretariat
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emission Trading Scheme
EU	European Union
GE	Georgia
HPP	Hydro Power Plant
JRC	Joint Research Centre
MCA	Multi criteria analysis
MD	Moldova
ME	Montenegro
mFRR	manual Frequency Regulation Reserve
MK	North Macedonia
MS	Member State
NOSBiH	Independent System Operator in Bosnia and Herzegovina
NPP	Nuclear Power Plant

NPV	Net Present Value
NT	National Trends
OHL	Overhead Line
OPEX	Operating Expenditures
OT	Operational Technology
PECD	Pan European Climate Database
PECI	Projects of Energy Community Interest
PINT	Put In one at the Time
PECI	Projects of Mutual Interest
PSHPP	Pump Storage Hydro Power Plant
PSS/E	Power System Simulator for Engineering
RE	Renewable Energy
RES	Renewable Energy Sources
RO	Romania
RR	Replacement Reserve
RS	Serbia
SEW	Socio-economic Welfare
SK	Slovakia
SoS	Security of Supply
SS	Substation
TEN-E	Trans-European Networks for Energy
TOOT	Take Out One at a Time
TR	Turkey
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UA	Ukraine
VoLL	Value of Lost Load
XK	Kosovo*

Public version of the report – clarification

EIHP has been engaged in supporting the Energy Community Secretariat to assess the candidate Projects of Energy Community Interest (PECI) in electricity, smart gas grids, hydrogen, electrolysers, and carbon dioxide transport and storage, in line with the EU Regulation 2022/869, and with respect to the 2nd PECI selection process. The activities under this assignment have been caried out from November 2025 to June 2026, and resulted with several reports, as explained in Chapter 1.2.

The public version of the final report has been prepared in line with Regulation (EU) 2022/869, as adopted in the Energy Community (TEN-E Regulation), to inform the public about the selection process and to protect some data which are considered as confidential (for example TYNDP 2026 data delivered by ENTSO-E, and data on the Ukrainian power system). Furthermore, all content related to the projects ranking has been deleted from this version, in line with Article 4(5) of the TEN-E Regulation, defining that:

5) In order to facilitate the assessment of all projects that could be eligible as projects of Energy Community interest (PECI) and that could be included in a preliminary list, each Group shall assess each project's benefits in a transparent and objective manner. Each Group shall determine its assessment method on the basis of the aggregated contribution to the criteria referred to in paragraph 3. That assessment shall lead to a ranking of projects for internal use of the Group. Neither the preliminary list nor the Energy Community list shall contain any ranking, nor shall the ranking be used for any subsequent....

During the selection process the Secretariat have organised public consultations (16 March – 17 April 2026) and received three sets of comments from the following organisations:

Centre of Environmental Initiatives “Ecoaction" / Екодія

Citizens’ Initiative “Spasimo Brezna”

CEE Bankwatch Network

All received comments are published here, and the PECI electricity group members were informed about the outcomes of the public consultations:

https://www.energy-community.org/topics/infrastructure/2026/PC.html

EIHP was not included in the public consultations and was not responsible for taking any decision with respect to the outcomes of these consultations. It was a sole responsibility of the PECI electricity group members and the decision-making body of the group consisting of the representatives of the Energy Community Contracting Parties.

1 Project objectives and activities

In order to create conditions for an integrated energy market in the European Union (EU) and neighbouring countries, it is necessary to define an appropriate regulatory and market framework that would attract investments in energy infrastructure and enhance stability, sustainability and reliability of energy supply. Regulation (EU) 2022/869 (the revised TEN-E Regulation) identifies **eligible categories for energy infrastructure development projects** and promotes better cooperation between countries, with the main objective to ensure **market and system integration and competition** that benefits all EU Member States and Energy Community Contracting Parties (CPs).

The revised **TEN-E Regulation was adopted in the Energy Community** by the Ministerial Council Decision 2023/02/MC-EnC of 14 December 2023 (hereinafter referred to as: the Regulation). Eligible energy infrastructure categories, with respect to the EnC adaptation of the original regulation, may be divided into two broader categories, **electricity and gas related projects.**

The overall objective of the project is to enhance market integration, security of supply, sustainability and competition of the electricity and hydrogen/gas markets of the Energy Community Contracting Parties.

The new PECI selection process started in November 2025, under which the Consultant’s task was **to assist the Energy Community Secretariat (ECS) and the two groups (related to electricity and gas) in compiling the second PECI list to be approved by the Ministerial Council by the end of 2026**. Potential eligible projects are divided into two broader infrastructural categories, electricity and gas, and must include **at least two Energy Community Contracting Parties** or be located at the territory of one Energy Community Contracting Party **having a significant cross-border impact on another Energy Community Contracting Party**, while this impact on the EU Member State(s) is not observed[1].

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[1] It is preliminarily estimated that all EnC CPs may benefit from this condition except Georgia, especially regarding the electricity sector, due to its geographic isolation with respect to other EnC CPs.

1.1 Main project activities

- In order to achieve the final objective of the project, i.e. to prepare the draft preliminary PECI list, the Consultant carried out the following **tasks/activities**:
- **Defined methodological approach and assumptions** – preparation of the methodological and organizational framework for the entire assignment
- **Created candidate project questionnaires** – preparation of the project-specific questionnaires for collection of the relevant input data (technical, economic, status and progress) for candidate projects
- **Created country-specific questionnaires** – preparation of the country-specific data questionnaires for collection of the relevant country input data for Contracting Parties
- **Validated collected data** – validation of the collected input data in terms of techno-economic consistency
- **Carried-out a project eligibility verification** - project eligibility verification based on the criteria defined in the Regulation, prior to modelling activities
- **Applied ENTSO-E and ENTSOG scenarios using modelling tool/s** – development of electricity sector models and scenarios using appropriate modelling tools that enable project assessment considering regional market conditions and energy infrastructure of the CPs
- **Performed socio-economic cost-benefit analysis** – assessment of socio-economic monetary and non-monetary project benefits and costs, based on the methodologies defined in the Regulation
- **Assessed the individual project candidates and composed relative rankings** - individual project assessment for each of the eligible project categories based on the results under previous activity and creation of relative rankings of all eligible projects.

The flowchart of the aforementioned tasks/activities is depicted in the following figure.

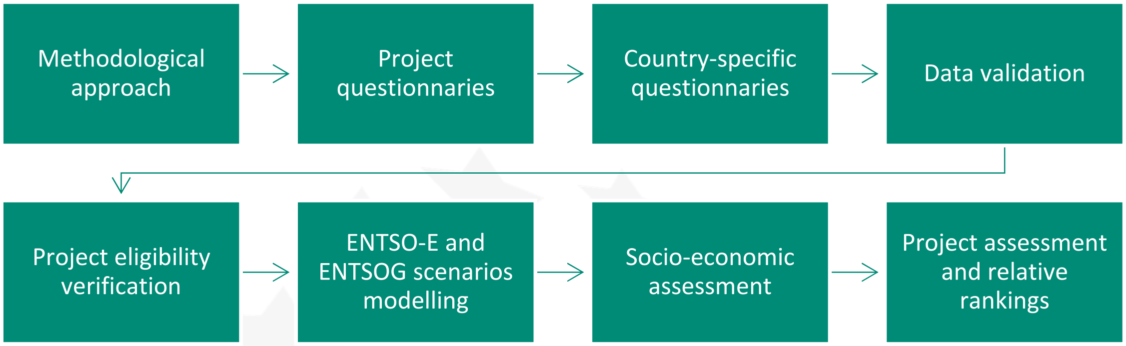

Figure 1: Activities carried out during the project implementation

1.2 Work plan and deliverables

The project started on the 10th of November 2025, with the planned finalization of all project activities for the 31st of May 2026. A kick-off meeting was held on 13th of November 2025, followed by the first Groups' meeting, i.e. projects' introductory meeting held on 17th of November 2025. The second and third Groups' meetings were held on 12th of February and 12th of March, while the fourth Groups' meeting was held on 19th of May 2026.

Creation of project questionnaires and country-specific questionnaires was implemented during the inception phase of the project. The questionnaires were used for the data collection process, which can be considered as the first phase of the project. The data collection process started 1st of December 2025 and lasted until 19thof January 2026 (for project data) and 30th of January 2026 (for country-specific data). Inception report was prepared and deliver by the Consultant on 10th of December 2025.

The second phase of the project is implemented after the data collection process. Initial data set for candidate projects and Contracting Parties was used for data validation and project eligibility pre-verification. Results of these activities are presented in the Data Validation and Scenario Report, which includes report on the collected project and country data, data validation process and compliance of the data with the proposed analysis, results of the project eligibility verification, and description of defined scenarios and assumptions.

After data clarification/revision, collecting feedback on methodology, scenarios, data and assumptions, the Analysis Techniques' Guidance Document is finalised containing final description of the data, scenarios, applied methodologies and techniques, sensitivities to be carried out, and structure of results and indicators. The report also concludes which nominated projects will be further analysed through the cost-benefit analyses and multi-criteria analysis, pre-eligible projects.

The third phase of the project is related to project assessment process. Based on the defined methodology, data, assumptions, scenarios and sensitivities, a project specific socio-economic assessment was made. In this phase, and for the purposes of projects' assessment, regional market and network models were developed using appropriate modelling tools. Project-specific, aggregated assessment results and sectoral relative rankings are presented to the Groups.

This document represents the Final Report of the entire project containing detailed description of the applied methodology, scenarios, data and assumptions and presentation and interpretation of the results for each analysed project in all scenarios and sensitivities.

It should be noted that the presented CBA results are based on the application of the relevant methodologies outlined in this report, using input data provided by the national authorities of the Contracting Parties for their respective power systems, as well as data submitted by project promoters for the candidate projects.

The project assessment was carried out with the objective of evaluating regional impacts and overall welfare within the Energy Community Contracting Parties region, rather than specific national benefits or benefits for individual project investors. Therefore, the outcomes of this assessment may differ from economic viability assessments performed by project investors or from assessments conducted at the national level.

It shall be also stressed that project benefits which were considered for the CBA are only those benefits appearing in the Energy Community Contracting Parties, excluding any benefits which may appear in the Member States of the European Union (in line with the TEN-E Regulation, as adopted in the Energy Community). By including possible benefits related to the EU MSs, some of the evaluated projects may show different results, including in the sensitivity analyses as well.

2 Projects' eligibility overview

In order for a project to be considered eligible, it must comply with the eligibility criteria defined in the TEN-E Regulation[2]. These criteria are grouped into three categories: general eligibility criteria, specific criteria, and technical criteria.

The results of the verification of the general, specific, and technical eligibility criteria for each nominated project, with the exception of the CBA assessment, which is performed in the subsequent phase of the evaluation process, are as shown in the following figure. Out of the 27 nominated projects (16 electricity-related and 11 gas-related projects), 8 projects were assessed as pre-eligible for the CBA phase. The pre-eligible project categories include seven electricity transmission overhead lines and one energy storage facility (PSHPP).

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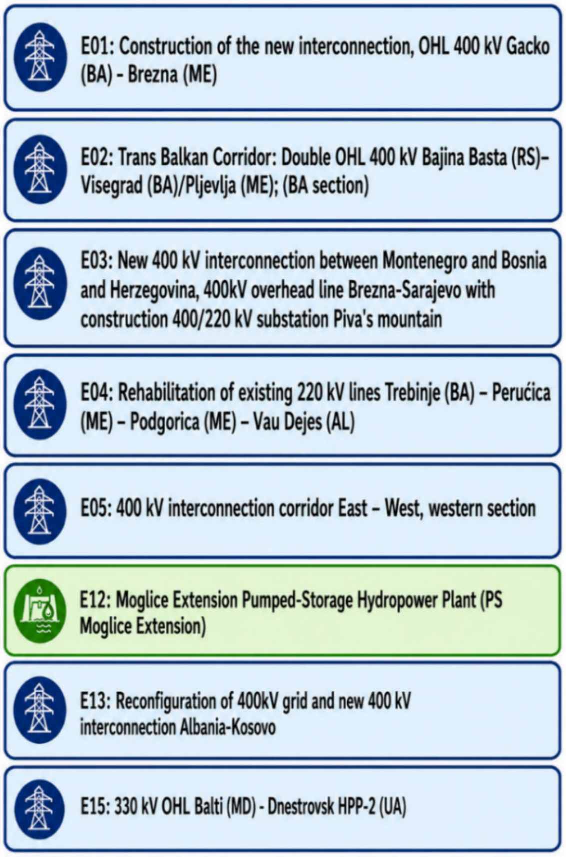
[2] https://www.energy-community.org/dam/jcr:4e6d1113-5894-4b78-a9cf-86d5e817731b/EnC%20REGULATION%20(EU)%202022869%20(002).pdf



E01: Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)

E02: Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS)-Visegrad (BA)/Pljevlja (ME); (BA section)

E03: New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400kV overhead line Brezna-Sarajevo with construction 400/220 kV substation Piva's mountain

E04: Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejes (AL)

E05: 400 kV interconnection corridor East – West, western section

E12: Moglice Extension Pumped-Storage Hydropower Plant (PS Moglice Extension)

E13: Reconfiguration of 400kV grid and new 400 kV interconnection Albania-Kosovo

E15: 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA)

Figure 2: Eligible projects for CBA and MCA analyses

3 Approach and methodologies for project assessment

A general approach for project assessment is presented in this section, with the focus on the relevant provisions of the TEN-E Regulation related to the project assessment and other relevant methodologies (published by ENTSO-E and European Commission) that were applied in the project assessment process, namely CBA and MCA analyses.

3.1 Project assessment approach

A graphical presentation of the approach for project assessment is presented in Figure 3. After the data collection process during which the project-related data and country-specific data were collected, data validation and verification were carried out. Several iterations were made to clarify delivered data or to submit additional data by project promoters.

The next step was projects' eligibility verification which was made according to the general, specific and technical criteria. Eligibility verification resulted with the final list of eligible projects for further project assessment, i.e. CBA that includes modelling activities based on the relevant methodologies.

The input data for project assessment is primarily based on the collected data regarding candidate projects (delivered by the project promoters) and regarding country-specific data of the Contracting Parties. Country-specific data of the Contracting Parties were delivered by the ministries or TSOs, assuming that the data are in line with the TYNDP 2026 planning process. It should be noted that TYNDP 2026 has not yet been officially published at the time of data collection. Nevertheless, the data were requested and submitted in alignment with the TYNDP 2026 input data and planning framework. For countries that are not part of the Energy Community but are subject to modelling, the relevant input data in line with the TYNDP 2026 were provided by ENTSO-E.

In terms of the modelling phase and project assessment based on the modelling results, general approach consists of the following steps:

- Development of a reference scenario (without any of the candidate projects), against which all projects were assessed until 2050,
    - Each project is added to the reference scenario to determine its benefits (PINT, put-in-one-at-a-time modelling approach[3]),
- Determination of socio-economic monetary and non-monetary benefits and costs for each project (project-specific CBA and MCA),
- Comparison of individual project assessment results between projects in the same project category and proposition of relative project rankings.

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[3] Put IN one at the Time (PINT) is a methodology that considers each new investment/project on the given network structure one-by-one and evaluates the results with and without the examined network investment/project reinforcement.

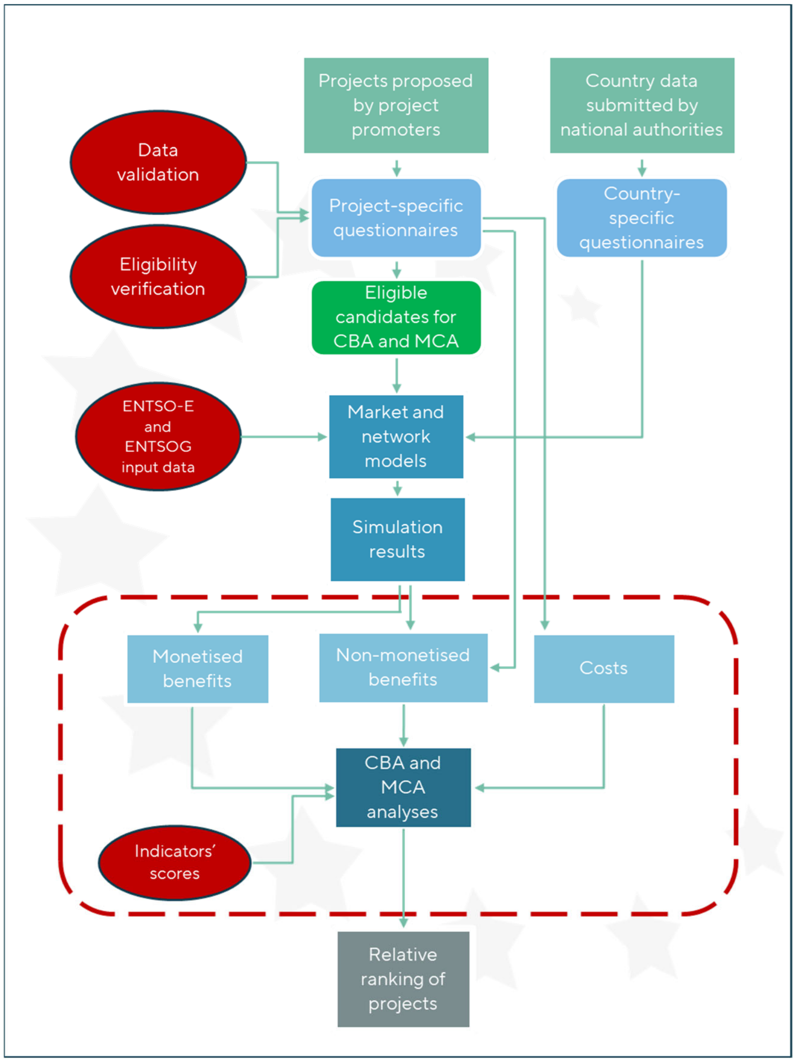

Figure 3: Project assessment approach

For possibly mutually competing projects, where the CBA result for two or more projects is positive, the TOOT (take-out-one-at-a-time) approach has been additionally applied to assess individual candidates in more detail and the interdependencies between these projects.

The main objective of the assessment is to determine if the potential overall benefits of the project outweigh its costs, which is one of the general eligibility criteria determined by the TEN-E Regulation.

In order to apply methodology for project assessment it is necessary to develop electricity sector model using appropriate modelling tools that enable project assessment considering regional market conditions and existing and future energy infrastructure of the Contracting Parties. In the eligibility verification process all the gas(es) candidate projects were declared as not eligible. Thus, only modelling of the electricity sector was considered in the modelling phase of the project. The Consultant developed a regional model of the electricity systems of CPs using PLEXOS Energy Modelling software[4] (further in text: PLEXOS).

PLEXOS enables modelling of many different parts of the energy sector, including electricity, gas, storages, hydrogen and other. The model simulates the behaviour of the system and market by trying to meet the demand at least cost over the planning horizon, respecting all the imposed constraints. In other words, the objective of the optimization function is to minimize the total system cost by taking into account various characteristics and constraints of the system and market.

To determine costs and benefits of the project, a reference case, i.e. reference scenario has to be established (against which all projects were assessed). Reference case assumes energy system without any of the project candidates, and simulation results for this case were used for comparison with scenario with each project, to calculate the benefits of adding a certain project into the system.

Reference scenario was made without including any nominated projects, even not the most mature ones, due to uncertainties related to all infrastructure projects in the Energy Community, where significant lags in projects realisation has been observed (for example, previous PECIs like Trans Balkan corridor and the OHL 400 kV Bitola – Elbasan). Furthermore, it was agreed that reference case may include just the projects for which construction works have been already started. Trans Balkan corridor (section 4), as the most mature project, was also not included in the reference case because of the following uncertainties:

- The project is lagging for more than 5 years with respect to the initial plans;
- The final commissioning date has been constantly changing and regularly postponed;
- Final project's realisation (section 4) depends on the HVDC link MONITA – 2nd phase, for which the final planned commissioning data has been also constantly changing;
- Construction works have not been initiated;

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[4] Detailed characteristics of all production units and fundamentals in the market can be modelled. The model accounts for both the technical and economic operation of the system characteristics. In addition to the techno-economic input data, energy demand forecasts, RE production profiles, fuel prices, etc. can also be provided as inputs to the model.

In addition to the PLEXOS model, for electricity sector candidates, PSS/E model that enables detailed electricity network modelling, was used to determine benefits such as impact of the project on network losses.

While some benefits of the projects were determined based on the modelling results, there are also benefits that were assessed based on the data sent by the project promoters, depending on specific assessment criteria set out in the respective methodologies. The methodologies that served as the basis for electricity project assessment are described in section 0.

Based on the results of quantitative as well as qualitative analysis, individual project assessment was made for each of the pre-eligible projects. Each benefit evaluated in a specific project category is scored based on the approach described in section 0. Based on the calculated total scores of each individual project a relative ranking of all eligible projects is provided as the final output of the assessment (not included in the public version of the final report as described in the introductory part).

The Consultant, in cooperation with the Energy Community Secretariat, also considered whether the energy efficiency first principle is applied as regards the establishment of the regional infrastructure needs and as regards each of the candidate projects.

3.2 Relevant methodologies

Projects that are preliminary found eligible according to the general, specific and technical criteria set out in the TEN-E Regulation, must be further assessed in line with appropriate methodologies. Methodologies for the assessment of benefits and costs of different categories of projects are written in line with the TEN-E Regulation, as adopted in the Energy Community.

Eligibility verification resulted with the projects for CBA analyses in the following electricity infrastructure categories:

- High and extra-high voltage overhead transmission lines,
- Energy storage.

Thus, the methodologies that will were applied in the project assessment phase are (according to Article 11(1) and Article 11(8) of the TEN-E Regulation as adopted in the Energy Community):

- 4th ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects, April 2024 (applied for the overhead transmission lines projects),
- Harmonised System Wide Cost-Benefit Analysis for Candidate Energy Storage Projects , May 2023 (applied to the energy storage project).

- The methodology which is also considered[5] in the PECI selection process is the one developed by the EU Commission and agreed/used by the respective groups in the 2025 PCI/PMI process at the EU level:
- Methodology for assessing the electricity and offshore infrastructure candidate PCI and PMI 2nd Union PCI-PMI list 2025.

The *4th ENTSO-E Guideline for the CBA of Grid Development Projects* prepared by ENTSO-E in compliance with the requirements of the TEN-E Regulation, was also used, together with the *TYNDP 2026 CBA Implementation Guidelines*[6] as an accompanying document of the *4th ENTSO-E CBA Guideline*.

One additional condition set out in the TEN-E Regulation that is common for all project categories is that in assessing projects, in order to ensure a consistent assessment approach among the projects, due consideration must be given to:

- the urgency and the contribution of each proposed project in order to meet the Energy Community 2030 targets for energy and climate and the 2050 climate neutrality objective, market integration, competition, sustainability, and security of supply,
- the complementarity of each proposed project with other proposed projects, including competing or potentially competing projects,
- for proposed projects that are, at the time of the assessment, projects on the Energy Community list, the progress of their implementation and their compliance with the reporting and transparency obligations.

The following two sections contain a summary of the relevant indicators for the two project categories, based on the previously listed methodologies and in correlation with the criteria set out in the TEN-E Regulation.

3.2.1 High and extra-high voltage overhead transmission lines

To determine whether each candidate project complies with the specific criteria defined in the TEN-E Regulation, the relevant indicators identified within the category of overhead transmission lines are presented below:

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[5] But not necessarily strictly followed.

[6] Implementation Guidelines for TYNDP 2026 based on 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, Draft version, December 2025

- Market integration: increase in Annual Socio-Economic Welfare (B1 ΔSEW indicator, M €/year)
- Sustainability: additional societal benefit due to CO_2 variation (B2 ΔCO_2 indicator, monetised by using societal costs of CO_2 (M €/year))
- Security of supply: adequacy to meet demand (B6 ΔSoS, M €/year) and system stability (B8 Stability (Transient, Voltage and Frequency Stability))
- Grid losses: (B5 ΔLosses indicator, M €/year).

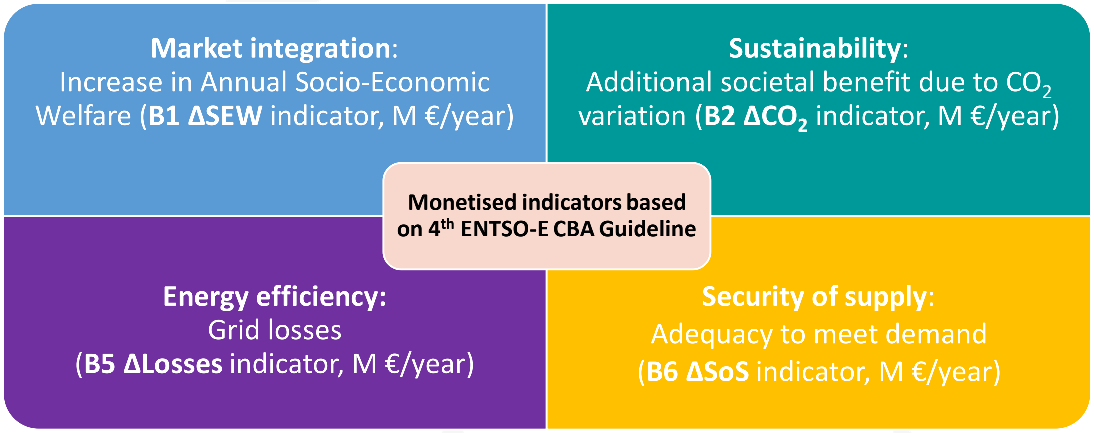

Figure 4 Monetised benefits for overhead transmission lines based on 4th ENTSO-E CBA Guidelines and in relation to eligibility criteria set out in the TEN-E Regulation

Table 1 summarizes monetised benefits that are calculated using market and network modelling results for the reference case and each candidate project separately.

Indicator	Where calculated	Monetisation
B1: Socio-economic welfare (SEW)	Market model: generation costs	Δ Generation Costs
Indicator	Where calculated	Monetisation
B1: Socio-economic welfare (SEW)	Market model: generation costs	Δ Generation Costs
B2: CO_2 variation	Market model: CO_2 emissions	CO_2 variation x (Societal Cost – ETS Price)
B5: Grid losses	Network model: grid losses Market model: marginal prices	Δ Losses x Marginal Electricity Price

B6: Security of supply (SoS)	Market model: unserved energy	Δ Unserved energy × Value of Lost Load (VoLL)

Table 1: Monetised CBA indicators based on market and network models for overhead transmission line projects

Socio-economic welfare (B1) is monetised through changes in total generation costs, while CO_2 variation (B2) is monetised using the difference between the societal cost of carbon[7] and the ETS price applied in the scenario.

Grid losses (B5) are monetised by combining network-modelled loss variations with electricity marginal prices obtained from the market model[8]. Security of Supply (B6/B8) is monetised through changes in Energy Not Supplied (ENS), multiplied by the assumed Value of Lost Load (VoLL)[9], reflecting the economic impact of non-supplied electricity.

Other benefits, such as System Stability (B8) are not monetised but qualitatively described and scored based on the approach described in the section 0. Figure 5 shows all benefits, monetised and non-monetised, that are evaluated for overhead transmission line projects.

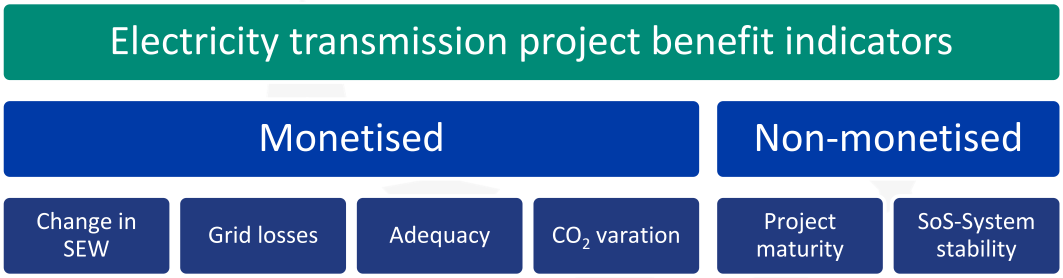

Figure 5: Monetised and non-monetised project assessment indicators for electricity transmission lines

3.2.2 Energy storage

To determine whether each candidate project complies with the specific criteria defined in the TEN-E Regulation, the relevant indicators identified within the category of energy storage projects are presented below:

- Market integration: increase in Annual Socio-Economic Welfare (B1 ΔSEW indicator,

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[7] CO_2 societal cost is assumed according to the high levels in the TYNDP 2024 (data for TYNDP 2026 were not determined during the modelling activities of the project): 189 EUR/t in 2030 and 498 EUR/t in 2040.

[8] Based on the Implementation Guidelines for TYNDP 2026, there is a cap for the monetisation of grid losses set to 212.86 EUR/MWh in 2030 and 236.04 EUR/MWh in 2040 and 2050 respectively.

[9] Based on the Implementation Guidelines for TYNDP 2026, the VoLL for all EnC Contracting Parties is 10,000 EUR/MWh.

M €/year)

- Sustainability: additional societal benefit due to CO_2 variation (B2 ΔCO_2 indicator, monetised by using societal costs of CO_2 (M €/year))
- Security of supply: adequacy to meet demand (B8 ΔSoS indicator, M €/year)
- Grid losses: (B5 ΔLosses indicator, M €/year).

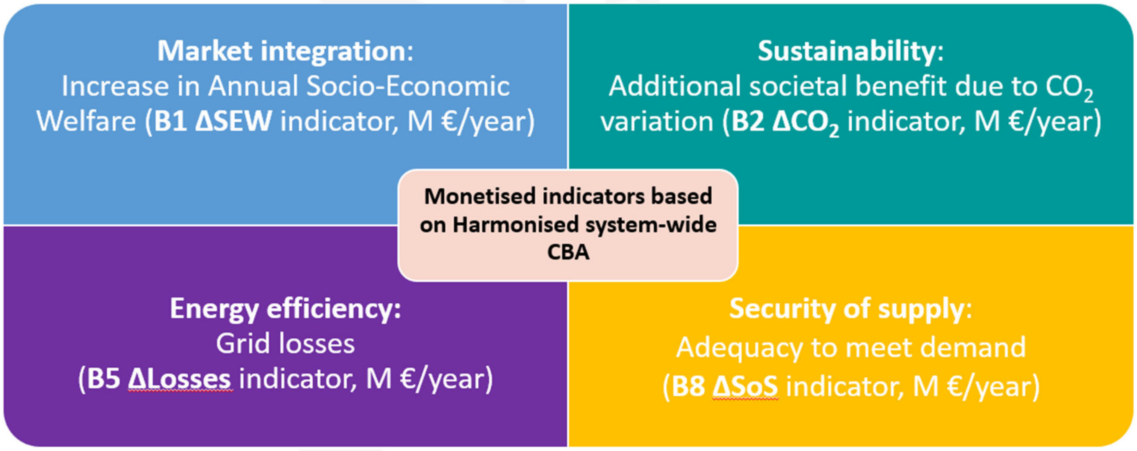

Figure 6: Monetised benefits for energy storage projects based on Harmonised system-wide CBA for candidate energy storage projects and in relation to eligibility criteria set out in the TEN-E Regulation

The following table summarises monetised benefits that are calculated using market and network modelling results for the reference case and for the case with candidate storage project.

Table 2: Monetised CBA indicators based on market and network models for energy storage projects

Indicator	Where calculated	Monetisation
B1: Socio-economic welfare (SEW)	Market model: generation costs	Δ Generation Costs
B2: CO_2 variation	Market model: CO_2 emissions	CO_2 variation x (Societal Cost – ETS Price)
B5: Grid losses	Network model: grid losses Market model: marginal prices	Δ Losses x Marginal Electricity Price
B6: Security of supply (SoS)	Market model: unserved energy	Δ Unserved energy x Value of Lost Load (VoLL)

The monetisation approach applied for energy storage projects is consistent with the methodology used for overhead transmission line projects, relying on synchronized market and network modelling results and the same assumptions regarding the VoLL, societal costs of emissions, and the electricity price cap used in the monetisation of grid losses.

Figure 7 shows all benefits, monetised and non-monetised, that are evaluated for energy storage projects.

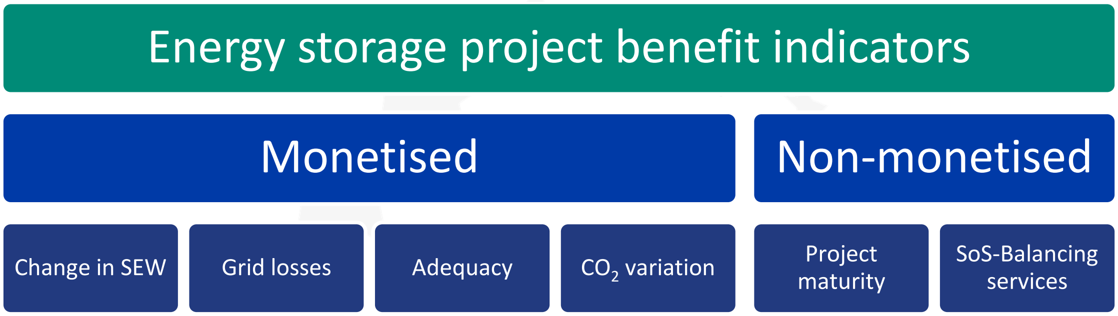

Figure 7: Monetised and non-monetised project assessment indicators for energy storage

All the monetised indicators (change in SEW, grid losses, CO_2 variation, adequacy) are the same as in the case of electricity transmission lines described in previous section. With regard to non-monetised indicators, project maturity is also determined in the same manner as for the transmission projects. The only difference in project assessment is the Security of Supply indicator which is measured for energy storage projects through provision of balancing services.

3.3 Structure of results

This section presents the main indicators determined within the CBA and MCA analyses for each PECI candidate project under the relevant infrastructure category, based on the methodologies described in the previous sections and on simulations carried out using market and network tolls together with the input data set described in Section 0.

3.3.1 Benefit/Cost ratio

The monetised part of the project assessment consists of all the monetised project benefits described in Section 0, together with project costs (CAPEX and OPEX). Monetised benefits (change in SEW, CO_2 variation, grid losses and SoS-adequacy) are determined for each project based on the comparison of modelling results for the reference scenario (without the project) and the scenario including the project. CAPEX and OPEX data had been provided by project promoters and verified by the Consultants. Although significant deviations in unit investment costs were found between projects, no crucial deviations from expected values were found, i.e., unit costs are within the expected range.

The monetised benefits and verified project costs serve as a basis for the calculation of the Net Present Value (NPV) and the **Benefit/Cost (B/C) ratio.** In general, the cost-benefit analysis selects the projects with the highest NPV or highest Benefit/Cost ratio.

The **B/C ratio** is calculated as the present value of all monetised benefits divided by the present value of all project costs. The present value of the monetised benefits and costs is calculated using the **discount rate of 4%,** in line with the ENTSO-E CBA 4.0 methodology. The higher the B/C ratio the larger the net benefit of an implementation of the individual project is expected to be. If the costs exceed associated project benefits, i.e. **the B/C ratio is lower than one, then the project is considered non-compliant** with the general eligibility criterion set out by the TEN-E Regulation, in line with the practice in the Energy Community during the previous PECI selection processes. A residual value of the project under consideration is considered zero after 25 years of exploitation, also in line with ENTSO-E CBA 4.0 methodology.

3.3.2 System stability

Overhead transmission lines

System stability refers to non-monetized indicator which shows quantitatively how much the project supports the voltage stability, transient stability and frequency stability. It is presented with the following values:

- ‘0’ – no change: the technology/project has no (or just marginal) impact on the respective indicator,
- ‘+’ - small to moderate improvement: the technology/project has only a small impact on the respective indicator,
- ‘++’ - significant improvement: the technology/project has a large impact on the respective indicator.

Project promoters had to fill in the specified data regarding the system stability for electricity transmission projects in project questionnaires. Where there is no change in the indicator, the points were not assigned. According to the *4^{th} ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects*, qualitative indicators specified for impact on system stability show that a maximum of five ‘+’ can be assigned to a certain technology. This indicator and the associated points served for the MCA only, which is not described in this public version of the final report.

Energy storage

The balancing services indicator shows welfare savings through the exchange of balancing energy and imbalance netting. Balancing energy refers to products such as Replacement Reserve

(RR), manual Frequency Regulation Reserve (mFRR), and automatic Frequency Regulation Reserve (aFRR). Another important indicator for system balancing is exchanging/sharing balancing capacity.

Indicators like the frequency support reserve (FCR), could be of major relevance for the assessment, since storage systems can be used for balancing the fluctuating feed-in from renewable energies and participate in the market for frequency support reserve (FCR). Furthermore, energy storage systems can participate in the frequency restoration process providing frequency restoration reserves (FRR) to the electricity balancing market.

Following the principles of the Implementation Guidelines for TYNDP 2026 based on 4th ENTSO-E guideline for cost benefit analysis of grid development projects, in which it is stated that for energy storage the benefit indicators remain analogous to the grid development benefit indicators, the balancing benefits are addressed by qualitative assessment with the use of the following unit of measure: 0/+/++ where:

- ‘0’ indicates that the project has marginal impact on the indicator.
- ‘+’ indicates that the project has only a small to moderate impact on the indicator.
- ‘++’ indicates that the project has significant impact on the indicator.

This indicator and the associated points served for the MCA only, which is not described in this public version of the final report.

3.3.3 Project maturity

Project maturity also contributes to the final scoring of each eligible project. The maturity level is assessed based on the status and completion of project development phases, as provided by project promoters through the project questionnaires. This indicator is intended to provide additional recognition and prioritisation to more mature projects compared to projects at earlier stages of development, but was used for the MCA only, which is not described in this public version of the final report.

3.4 Relative ranking of projects

Not contained in this public version of the report (according to article 4(5) of the TEN-E Regulation, as adopted in the Energy Community).

4 Input data and modelling assumptions

Figure 8 presents the main input data and respective data sources for modelling reference scenario based on which the projects are assessed for their benefits are presented. Input data are based on the collected country-specific data from national authorities and on the relevant TYNDP 2026 scenarios.

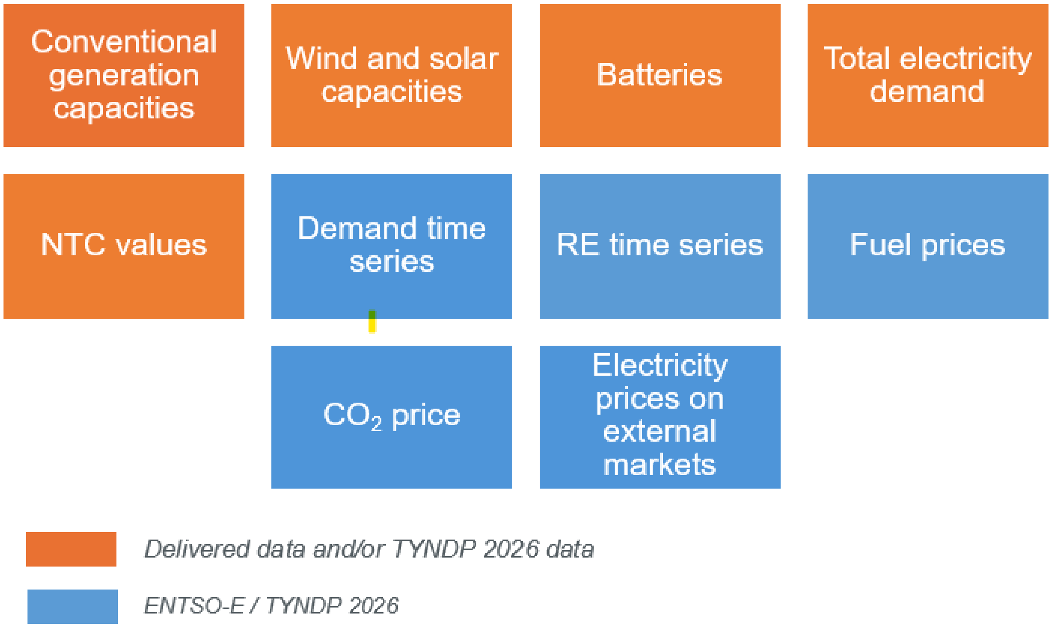

Figure 8: Input data categories and sources for model development

Detailed descriptions of the input data and modelling assumptions, such as generation capacities and electricity demand in CPs, NTC values, fuel and CO_2 prices, etc., were presented during the process to the PECI electricity group members, while the following sections provide a summary of several key assumptions relevant for understanding the analysis results presented in Section 5.

4.1 Modelling scenarios

Scenarios that are modelled using PLEXOS have to be in line with the latest joint ENTSO-E and ENTSOG scenarios prepared under TYNDP 2026. At the kick-off meeting held in November, it was agreed with the Energy Community Secretariat that TYNDP 2026 data will be used, which ENTSO-E will provide to the Energy Community Secretariat for the purposes of this analysis.

Under the TYNDP 2026 Scenarios Framework, the Central scenario (National Trends+) reflects latest updated national energy and climate plans (NECPs), national and EU policies. The Central scenario is available for 2030, 2035, 2040 and 2050 horizon.

For the project assessment purposes under the PECI process, the Central scenario (National Trends+) is modelled for the horizon until 2050. The NT+ scenario-related data for modelled countries that are considered in the model refer to: total conventional generation capacities per fuel/technology type, batteries capacities, total electricity demand and demand time series, NTC values between CPs and neighbouring countries, fuel and CO_2 prices.

Once the reference case is implemented based on the TYNDP 2026 scenario data, the PINT modelling approach is used to assess the impacts of each project on the system costs and benefits.

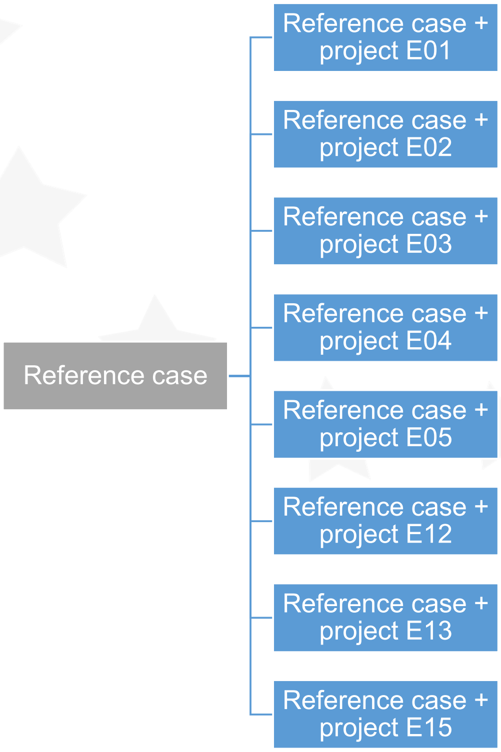

Figure 9: Modelling approach - the reference case for one target year without and with the projects

Additional scenarios may be analysed in the form of sensitivity analyses considering parameters such as demand, commodity prices, RE share etc. Sensitivity analyses and the uncertainties which are reflected are described in Section 0.

4.2 Geographical scope

The geographical scope of the regional market model developed in PLEXOS is presented in Figure 10.The market model includes systems of Contracting Parties: Albania, Bosnia and Herzegovina, Kosovo*, Moldova, Montenegro, North Macedonia, Serbia, and Ukraine. These countries were modelled on a detailed unit-by-unit level based on the collected input data through country-specific questionnaires and based on the previous experience of the Consultant in modelling these Contracting Parties.

In addition to the Contracting Parties, their neighbouring countries/markets were modelled based on the best available data (primarily ENTSO-E) and extensive experience of the Consultant in modelling these countries. Depending on the data availability, some countries are presented on a unit-by-unit level (e.g. Croatia, Bulgaria, Romania, Greece), while others are modelled on a technology level (e.g. Hungary, Italy, Slovakia and Poland).

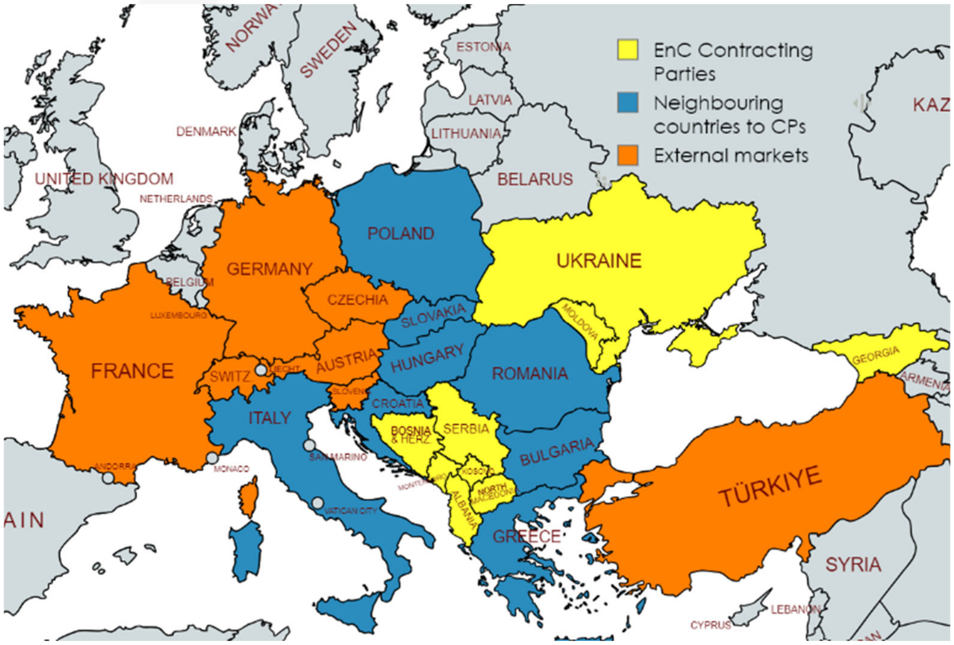

Figure 10: Geographical scope of regional market model in PLEXOS

Power systems of other countries, that have borders with neighbouring countries of CPs, such as Austria, are considered in regional PLEXOS model as spot markets. Hourly market prices, that are modelled in line with the TYNDP 2026 data (provided by the ENTSO-E), are assumed to be insensitive to price fluctuations within the CPs region and its neighbouring countries. Electricity exchange between external spot markets, the CPs region and their neighbouring market areas are modelled to be constrained with actual transmission capacities (also based on TYNDP 2026 reference grid data).

With regard to **power network model** in PSS/E, the geographical scope also includes systems of Albania, Bosnia and Herzegovina, Kosovo*, Moldova, Montenegro, North Macedonia, Serbia and Ukraine. These countries were modelled on a power transmission voltage level (400, 220 and 110 kV), including all transmission network elements (lines, transformers), with the generation on **power plant level**, for those connected to the transmission network, based on the previous experience of the Consultant in modelling these Contracting Parties.

4.3 Time horizon

The time horizon covers period until 2050, analysing in particular the following time-frames: **2030, 2035, 2040 and 2050**, in line with the TYNDP 2026. For the periods between selected years, **linear interpolation** is used for CBA.

4.4 Generation capacities

Data on generation capacities for CPs are collected from relevant authorities (ministries and TSOs). Given that there were some differences in the collected data and the data based on the TYNDP 2026 scenarios, it has been agreed between the Secretariat and the Consultant[10], that the data provided by relevant national authorities will be used in market model development. The modifications of the provided input data were made where necessary to assume **carbon neutrality in 2050** by decommissioning all coal-fired and lignite thermal power plants without any exception, and by eventually assuming the application of carbon capture technology on gas-fired power plants or their usage of clean gases[11].

Details on generation capacities in CPs for reference years were presented during the process to the PECI electricity group members.

4.5 Electricity demand

Data on electricity demand for CPs are also collected from relevant authorities. Given that there are some differences in the collected data and the data based on the TYNDP 2026 scenarios, it has been agreed between the Secretariat and the Consultant, that the data provided by relevant national authorities will be used in market model development. In cases where data were not provided, TYNDP 2026 data were used.

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[10] Confirmed by the electricity group at the meeting on 12 March 2026.

[11] Gas-fired power plants in some EnC CPs (Ukraine, Serbia, Albania, North Macedonia and Moldova) are assumed to be operational in 2050 but operating in line with the carbon neutrality target.

Details on electricity demand in CPs for reference years were presented during the process to the PECI electricity group members.

4.6 Weather years and climate assumptions

TYNDP 2026 introduces an improved approach to energy system modelling by combining historical weather data with future climate projections, to better capture the impacts of climate change on electricity demand and renewable energy generation. Since weather conditions directly affect both electricity consumption and renewable production, selecting representative weather years (weather scenarios) is important to ensure robust and future-oriented system planning, based on key climate variables relevant for power system modelling. The weather scenarios considered for TYNDP 2026 market are selected individually for each target year to achieve the best possible representation of the whole set of available weather scenarios.

The minimum requirement for project assessment is to use the most representative weather scenario of the three weather scenarios, based on the weighting factors presented in previous table. Weather scenarios used in TYNDP 2026 are derived from the Pan-European Climate Database (PECD) version 4.2 dataset, where each scenario corresponds to a specific combination of climate model and projection year. The selected WS scenarios therefore represent individual PECD climate-year time series (e.g. wind and solar) that are used as inputs for market model simulations.

4.7 Fuel and CO_2 prices

Fuel and CO_2 prices are important input parameters in market models. These parameters have impact on marginal generation costs of thermal units and thus affect the optimal dispatch of all units in the system. They have impact on total generation costs, as well as on the level of CO_2 emissions, which are the parameters directly related to determination of socio-economic welfare in the project assessment process. Values for fuel and CO_2 prices were presented during the process to the PECI electricity group members, based on the publicly available TYNDP 2026 draft supply assumptions, as well as data provided by ENTSO-E.

4.8 NTC values

Data on NTC values between CPs and CPs and neighbouring countries are collected from relevant authorities and were presented during the process to the PECI electricity group members. Given that there were some differences in the collected data and the data based on the TYNDP 2026 scenarios, the final input data set regarding NTC values was determined by using the following principles:

- based on the data provided by relevant CPs authorities in cases where there are no differences between the provided data by the two national authorities for the same border,

- based on the TYNDP 2026 data if the provided data by relevant CPs authorities differs from each other and from the TYNDP 2026 data,
- in cases where TYNDP 2026 doesn't provide data for specific border, values provided by relevant CPs authorities are used. If values provided by relevant CPs authorities differ for the same border, a lower NTC value is used.

5 Results

For each of the pre-eligible projects (seven electricity transmission lines and one pumped-storage hydro power plant), the cost-benefit analysis was performed, that considers the following parameters:

01. The costs of the project, that were provided by the project promotors. Those costs consist of capital expenditures (CAPEX) and operation and maintenance costs (OPEX).
02. Benefits that may arise because of the commissioning of the project. Those benefits are calculated using complex market and network models that include the Energy Community Parties, as well as neighbouring countries and neighbouring markets.

Benefits that are valued through the cost-benefit analysis are defined in various cost-benefit analysis methodologies that are described in section 0. These methodologies prescribe in detail which are the possible benefits that a project of a certain infrastructure category can obtain and how it should be calculated. The methodologies exist for each of the infrastructure categories, however, since through the eligibility process only high and extra high overhead line projects and energy storage project were found eligible, only their corresponding methodologies were used for the determination and calculation of benefits.

The process of calculation of benefits is such that first, a reference scenario must be developed. The reference scenario presents the state in the models in which none of the nominated projects is commissioned. Instead, the energy systems are modelled according to assumptions and input data obtained from CPs and outside sources. Then, separate scenarios are developed for each of the projects in which one project is commissioned in the models at the time (PINT method). The benefits of a specific project are calculated as the difference in the value of a given indicator between the scenario including the project and the corresponding reference scenario without the project. The modelling results for CPs for the reference scenario in four target years are presented in the following section, while the rest of the sections describe the results of the cost-benefit analysis for each pre-eligible project.

The result of the cost-benefit analysis for each project is the benefit-cost ratio (B/C), which shows whether the benefits that arise because of the project are sufficient to cover the cost that the project generates. It is a profitability indicator used in cost-benefit analysis to determine the viability of cash flows generated from an asset or project. The B/C compares the present value of all benefits generated from a project/asset to the present value of all costs.

In order to determine that the societal impact of the project is positive, B/C must be higher than one. Formula for calculating B/C is the following:

$$\frac{B}{C} = \frac{\sum_{t=1}^{n} \frac{CF_t[Benefits]}{(1+i)^t}}{\sum_{t=1}^{n} \frac{CF_t[Costs]}{(1+i)^t}}$$

Where:

- CF=Cash Flow
- i=discount rate
- n=number of periods
- t=period when the cash flow occurs.

The discount rate that is used in the following calculations is the one that is advised by the CBA methodologies, 4%. The calculation horizon is 25 years, observed from a year of planned project commissioning.

In the following subchapters, individual indicators that participate in the B/C calculation, as well as B/C result, are described and valuated for the reference scenario as well as for each project scenario. In the sensitivity analysis, presented in Section 0, B/C is tested for the main scenario drivers to further examine the impact of them on each individual project.

5.1 Reference scenario

This section presents simulation results for the reference scenario in 2030, 2035, 2040 and 2050, which are relevant for determining the projects' benefits. The results cover the following categories:

- Electricity balance: shows generation, demand and net interchange in each Contracting Party identifying import-dependant countries and potential security of supply issues in case of unserved energy (related to the determination of Security of Supply indicator),
- Generation costs: show total generation costs in each, including fuel and CO_2 emission costs (related to the determination of the SEW indicator),
- CO_2 emissions: indicates the amount of CO_2 emissions in each Contracting Party (related to the determination of the CO2 variation indicator),
- Grid losses: shows the amount of grid losses in each Contracting Party (related to the Grid losses indicator),

- Electricity prices: show average annual electricity prices Contracting Parties (related to the monetisation of the Grid losses indicator).

5.1.1 Electricity balance

Figures 11 depict electricity generation, load, and net interchange in the Contracting Parties for the years 2030, 2035, 2040, and 2050 in the reference scenario, based on the PLEXOS simulation results. Total electricity load in each Contracting Party is input to market model, based on annual load projections provided by the relevant authorities for each Contracting Party through country-specific questionnaire. Generation in each country is based on the optimization results which are affected by available generation capacities in each year and their techno-economic characteristics. Net interchange reflects the difference between the total exports and imports; positive values indicate that a country is a net exporter, while negative values indicate a net importer status.

In 2030, Ukraine has the highest generation and load, followed by Serbia. Countries with smaller power systems, such as Kosovo* and Montenegro, show the lowest load and generation. Albania, Montenegro and Ukraine are net exporters, while Bosnia and Herzegovina, Kosovo*, North Macedonia, Moldova and Serbia are net importers. There is no security of supply issues regarding the occurrence of unserved energy.

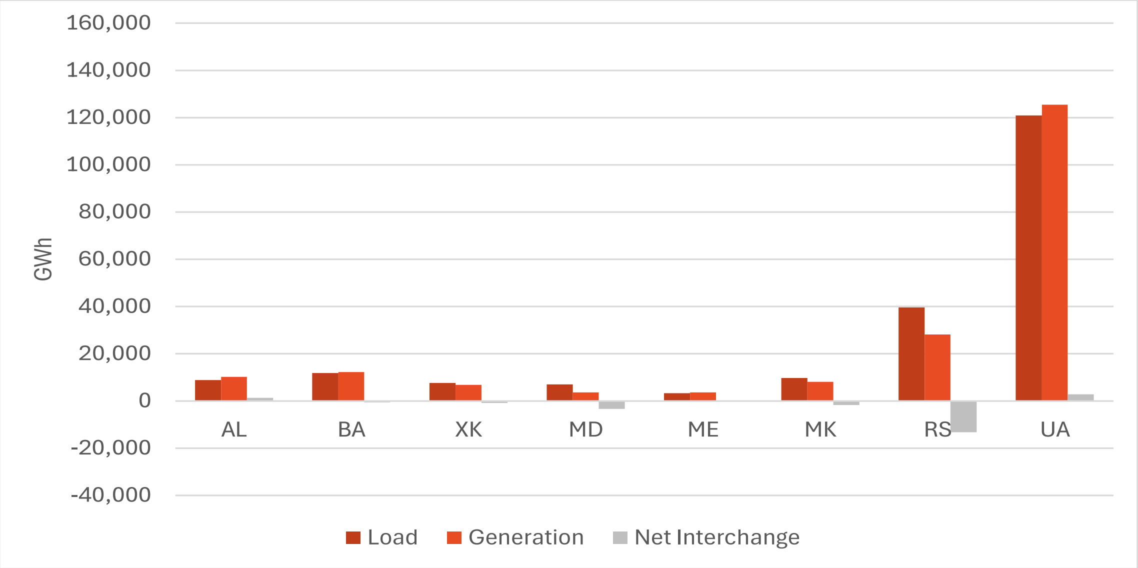

Figure 11: Electricity balance in CPs in 2030 (reference scenario)

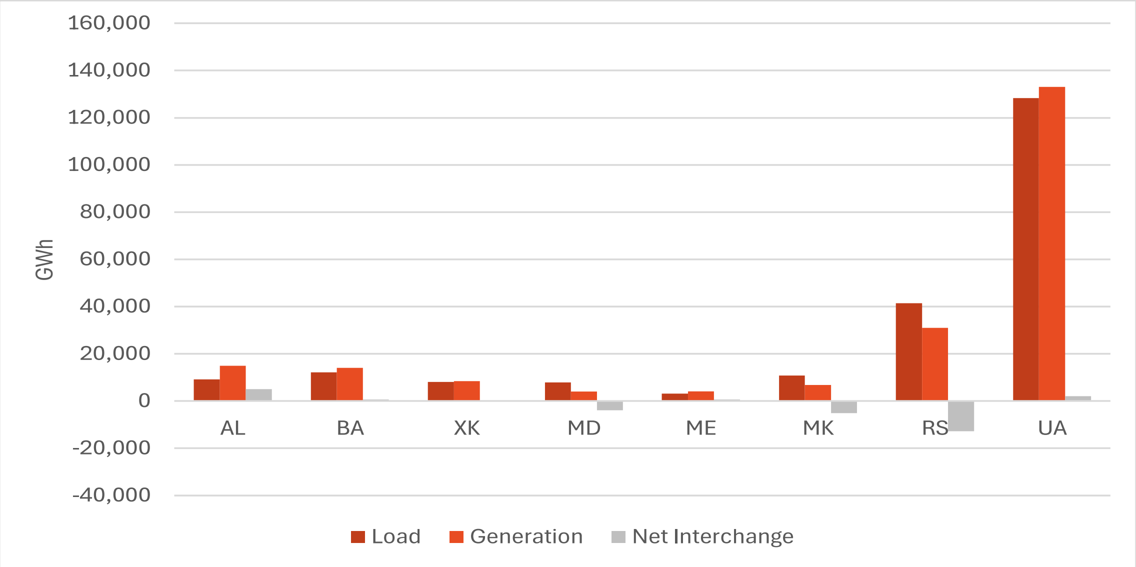

Figure 12: Electricity balance in CPs in 2035 (reference scenario)

In 2035, Albania, Bosnia and Herzegovina, Kosovo*, and Ukraine are net exporters, while Serbia, North Macedonia and Moldova are net importers of electricity. Compared to 2030 when Bosnia and Herzegovina and Kosovo* had a negative electricity balance, by 2035, both systems transition to net exporter status, primarily due to the growth of renewable energy generation. In Bosnia and Herzegovina, thermal power plants are no longer operating due to the high share of RE generation, while in Kosovo*, wind and solar generation increases but lignite-fired thermal power plants continue to play an important role in electricity production.

There is no security of supply issues regarding the occurrence of unserved energy in 2035 in any of the Contracting Parties.

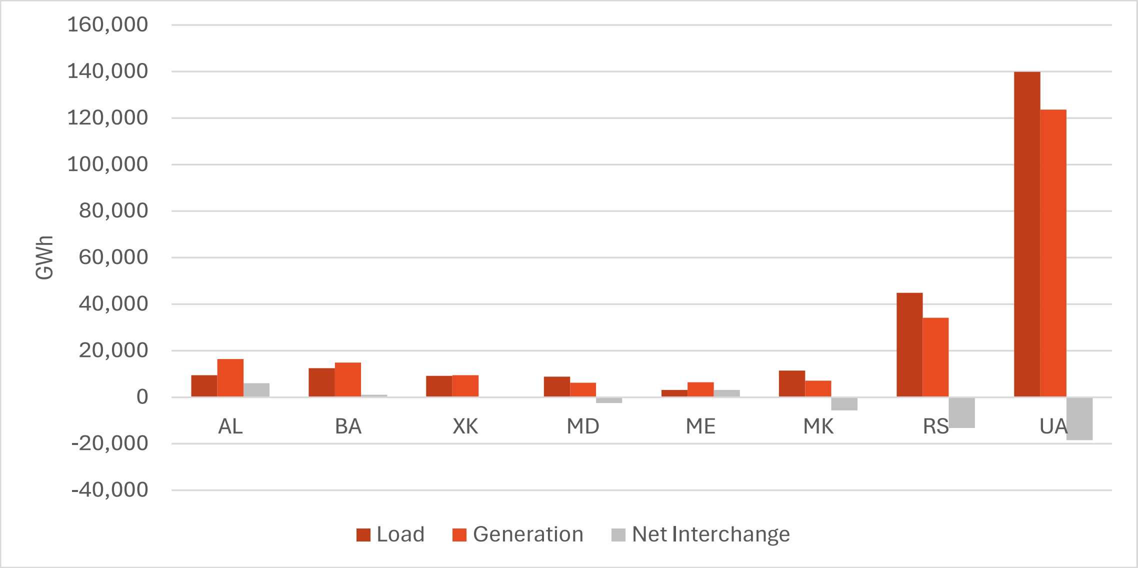

Figure 13: Electricity balance in CPs in 2040 (reference scenario)

In 2040, Albania, Bosnia and Herzegovina, Kosovo*, and Montenegro remain net electricity exporters, supported by the continued expansion of renewable energy generation, particularly wind and solar.

In contrast, Ukraine becomes a net importer due to increasing electricity demand combined with the gradual phase-out of all coal-fired power plants by 2040 and the retirement of a significant number of nuclear units. As a result**, the system faces security of supply challenges, leading to the occurrence of energy not supplied (ENS) amounting to 515 GWh.** The occurrence of ENS in any of the Contracting Parties affects the calculation of the Security of Supply (SoS) indicators in scenarios with the projects (as presented in section 0).

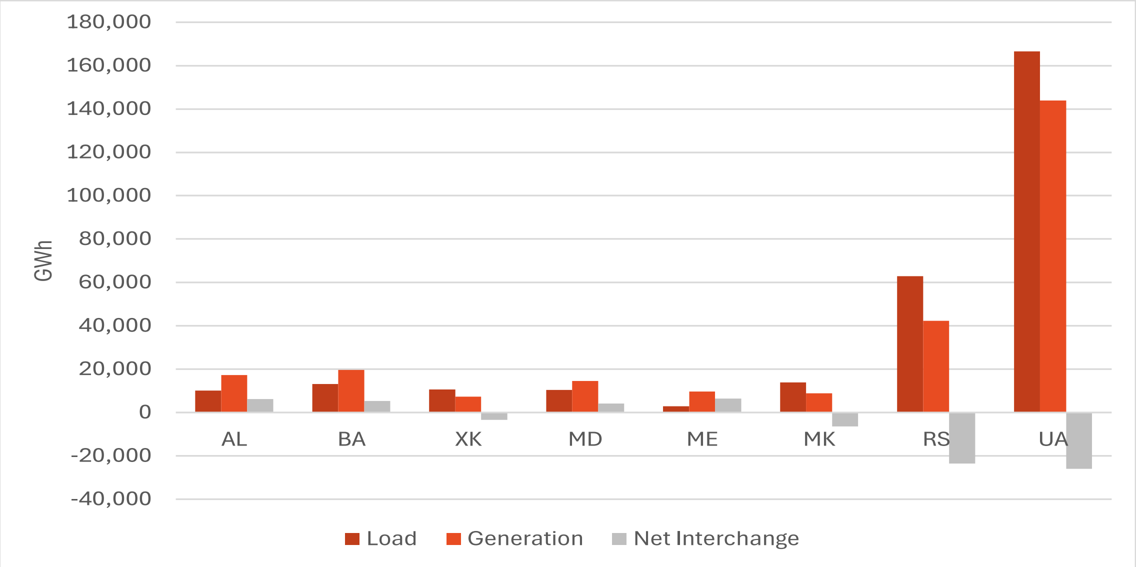

Figure 14: Electricity balance in CPs in 2050 (reference scenario)

In 2050, Albania, Bosnia and Herzegovina, and Montenegro remain net electricity exporters due to the high share of renewable generation in their power systems.

At the same time, ENS appears not only in Ukraine, where it increases significantly, but also in Moldova, Kosovo*, and Serbia. In Serbia, ENS is mainly driven by the phase-out of a large number of lignite-fired thermal power plants after 2040. In Kosovo*, lignite-fired generation is also assumed to be fully phased out by 2050 in line with the decarbonisation targets. In Ukraine, besides the retirement of large nuclear units, a significant share of gas-fired generation is also decommissioned by 2050 (based on the provided country-specific data). Based on the simulation results, around 4.8% of the projected electricity demand in 2050 could not be supplied, either from domestic generation or imports. Serbia, Kosovo* and Moldova are affected by ENS to a lesser extent relative to their annual electricity demand compared to Ukraine. As in the 2040 case, the occurrence of ENS across the region affects the calculation of SoS indicators in scenarios with projects.

More specifically, for the projects' CBA, amount of unserved energy in CPs was used for each project to determine the variation between the reference case and the cases with the projects, i.e. to calculate B6 (for OHLs) or B8 (for energy storage) ΔSoS indicator.

5.1.1.1 Generation by fuel/technology type

The following figure presents the electricity generation mix in the Energy Community Contracting Parties for the years 2030, 2035, 2040, and 2050, highlighting the transition towards renewable energy sources and the gradual phase-out of coal and lignite-based generation. Generation values are result of PLEXOS optimization in each year, based on available generation capacities delivered through country-specific questionnaires.

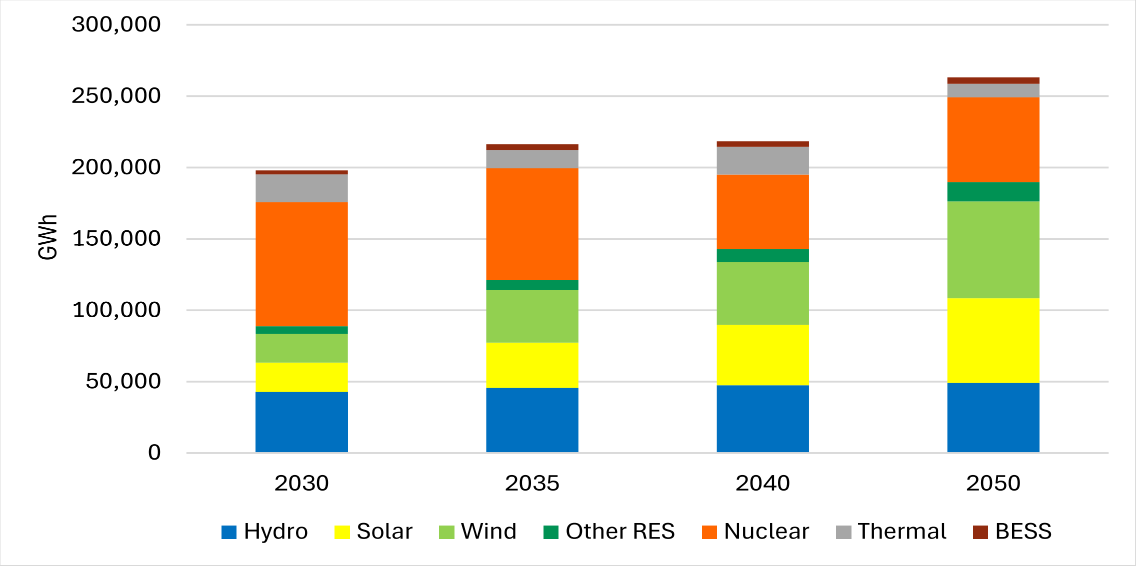

Figure 15: Generation by technology type in EnC CPs (reference scenario)

The generation mix in the Contracting Parties undergoes a significant transition between 2030 and 2050, characterised by a significant increase in renewable electricity generation, particularly from wind and solar power plants. Total electricity generation increases from around 198 TWh in 2030 to approximately 263 TWh in 2050, reflecting both growing electricity demand and the large-scale integration of renewable energy sources. By 2050, almost half of the total electricity generation in the region is provided by wind and solar technologies.

Hydropower continues to play an important role throughout the analysed period; however, its overall generation remains relatively stable, with no major increase by 2050 due to the limited potential for additional large hydropower development. At the same time, thermal generation based on lignite and hard coal is gradually phased out and fully decommissioned by 2050, in line with decarbonisation objectives and emission reduction targets. Consequently, the remaining thermal generation in 2050 mainly refers to gas-fired units equipped with carbon capture and storage (CCS) technology. In addition, the generation contribution of battery energy storage systems (BESS) is also included in the results, based on the development plans submitted by the Contracting Parties.

5.1.2 Generation costs

Total generation costs in Contracting Parties based on PLEXOS simulation results are presented in Table 3. These costs include fuel costs, variable operation and maintenance costs, start and shutdown costs and CO2 emissions costs. The total generation costs are largely influenced by CO_2 emission costs in Contracting Parties where thermal power plants are in operation, particularly due to the high CO_2 emission prices used as input assumptions in the modelling process.

Country	2030	2035	2040	2050
AL	44.4	47.0	45.4	57.2
BA	36.7	37.8	38.8	42.3
XK	546.2	976.8	1,425.6	1.2
MD	273.9	197.4	433.9	1303.6
ME	8.3	10.3	10.3	10.8
MK	286.0	41.3	56.1	143.6
RS	1,488.2	1,866.8	2,685.6	144.9
UA	1,426.4	1,288.2	2,938.3	1,363.3
TOTAL	4,110.2	4,466.6	7,634.9	3,067.8

Table 3: Total generation costs in reference scenario in 2030, 2035, 2040 and 2050 (in mil. EUR)

In Contracting Parties that mostly rely on renewable electricity generation throughout the analyzed period, total generation costs remain relatively stable (e.g. Albania, Bosnia and Herzegovina, and Montenegro). This is primarily due to the dominant share of hydropower and other renewable energy sources in the generation mix, meaning that costs are largely related to operation and maintenance expenditures, with limited or no exposure to fuel costs and CO_2 emission costs associated with increasing CO_2 emission prices.

In Contracting Parties with significant thermal power generation, total generation costs are strongly influenced by CO_2 emission costs due to increasing CO_2 emission prices (e.g. Kosovo* and Serbia). Costs increase until 2040 as lignite-fired generation remains an important part of the electricity mix while CO_2 emission price continues to rise. By 2050, however, total generation costs decrease sharply following the complete phase-out of lignite-fired thermal power plants. The reduction is particularly notable in Kosovo*, where generation in 2050 was assumed to be based entirely on solar, wind and hydropower generation (although delivered country-specific data still contained coal-fired TPP units in 2050). In Serbia, although lignite-fired units are also decommissioned, part of the remaining thermal generation is provided by gas-fired units (with CCS), resulting in lower decrease of generation costs compared to 2040.

In Ukraine, total generation costs in 2030 and 2035 remain relatively moderate due to the dominant share of nuclear and renewable electricity generation in the system. However, in 2040, a significant number of nuclear units are assumed to be decommissioned, leading to increased utilisation of gas-fired power plants to maintain system adequacy. Combined with higher fuel prices and CO_2 emission costs, this results in a substantial increase in total generation costs compared to 2035. By 2050, generation costs decrease again as a large share of gas-fired generation is also phased out, reducing the overall fuel and CO_2-related costs, despite the increasing adequacy challenges and occurrence of ENS in the system.

In Moldova, generation costs are mainly associated with gas-fired generation and renewable energy sources throughout the analysed period. While costs remain relatively moderate up to 2040, a noticeable increase occurs in 2050 due to the significantly higher utilisation of gas-fired power plants. This is primarily driven by energy shortages in Ukraine, which increase the need for electricity support from neighbouring systems and consequently lead to higher dispatch levels of generation units in Moldova and other surrounding countries.

Considering all Energy Community Contracting Parties, total generation costs reach their highest levels in 2040 (around 7.6 billion EUR).

Figure 16 shows a significant increase in the share of CO_2 emission costs within total generation costs in the Contracting Parties between 2030 and 2040. The share of emission-related costs rises from approximately 41% of total generation costs in 2030 to around 68% in 2040. This trend is primarily driven by the substantial increase in CO_2 price applied in the modelling assumptions, rising from 97.5 EUR/tCO_2 in 2030 to 297.5 EUR/tCO_2 in 2040. As thermal power plants, particularly lignite- and coal-fired units, remain in operation in several Contracting Parties during this period, the higher carbon prices significantly increase overall generation costs.

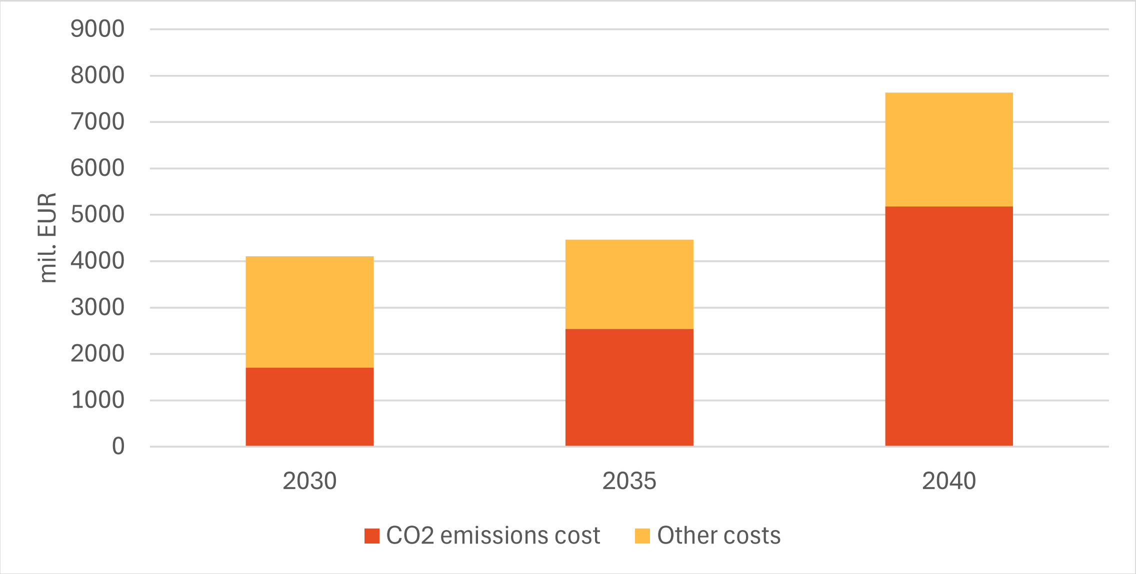

Figure 16: Total generation costs in EnC Contracting Parties in 2030, 2035 and 2040

After 2040, total generation costs decrease significantly (by 60% compared to 2040), as renewable energy sources become dominant in the regional generation mix and coal and lignite-fired generation is gradually phased out by 2050.

For the projects' CBA, total generation costs in all CPs were used for each project to determine the variation between the reference case and the cases with the projects, i.e. to calculate B1 ΔSEW indicator.

5.1.3 CO2 emissions

Amount of CO_2 emissions from electricity generation in the Contracting Parties is presented for 2030, 2035 and 2040 in reference scenario, due to assumed carbon neutrality in 2050.

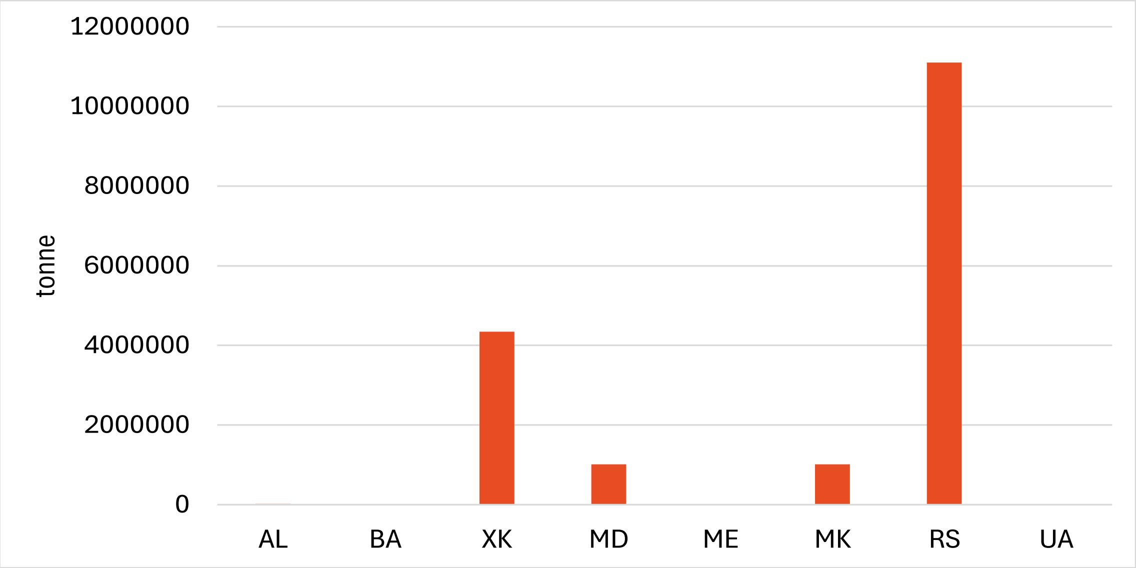

Figure 17: CO_2 emissions in CPs in 2030 (reference scenario)

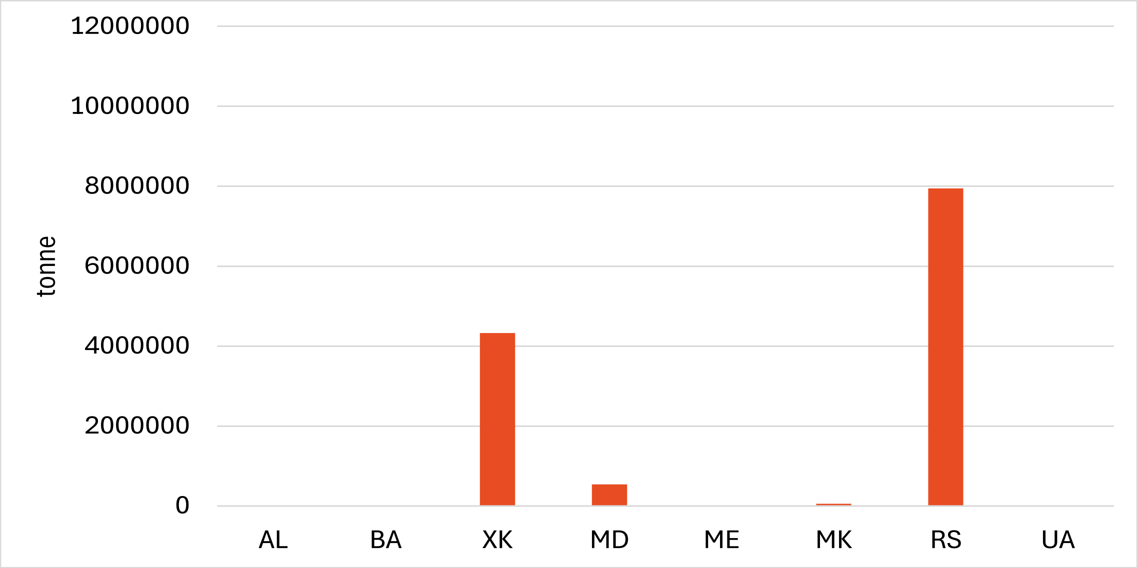

Figure 18: CO_2 emissions in CPs in 2035 (reference scenario)

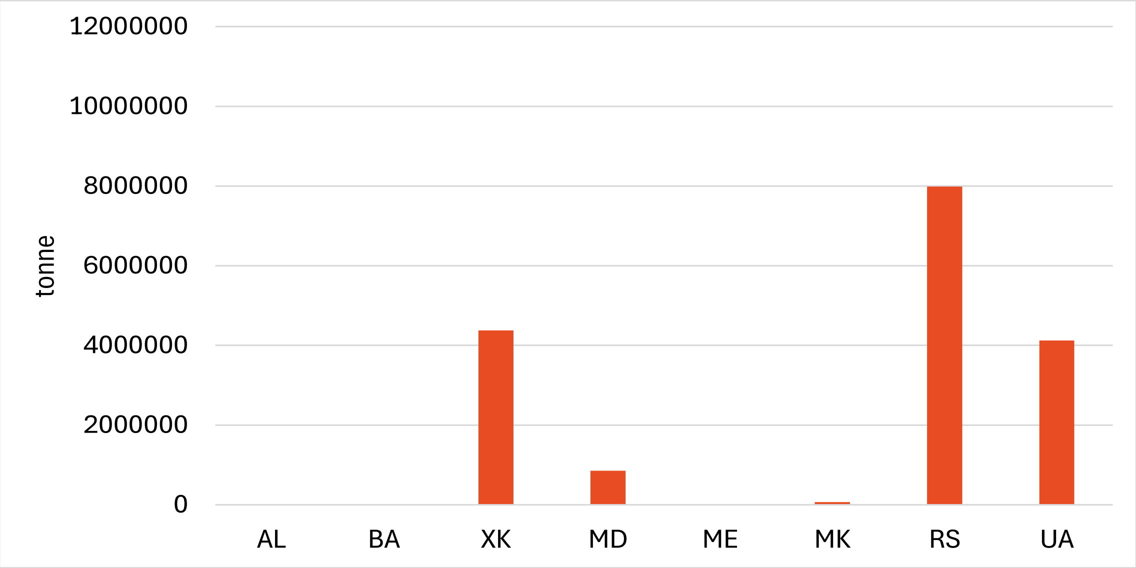

Figure 19: CO_2 emissions in CPs in 2040 (reference scenario)

The results indicate that CO_2 emissions are highest in systems with significant lignite-based electricity generation, particularly in Serbia and Kosovo*, where lignite-fired thermal power plants continue to represent an important share of the generation mix during most of the analysed period.

Between 2030 and 2035, total emissions decrease in several Contracting Parties (e.g. Serbia, North Macedonia) due to the increasing integration of renewable energy sources and reduced utilisation of thermal power plants. However, in 2040, emissions increase again in some systems due to higher utilisation of gas-fired generation required to maintain adequacy and security of supply. This is especially visible in Ukraine, where the partial retirement of nuclear generation capacity compared to 2035 results in increased dispatch of gas-fired units and consequently higher CO_2 emissions.

On the other hand, Contracting Parties with generation mixes largely based on renewable energy sources, such as Albania, Bosnia and Herzegovina, Montenegro, and North Macedonia, show very low or no CO_2 emissions throughout the analysed period. This is also consistent with the relatively stable generation costs observed in these systems, as they are less exposed to fuel costs and emission costs compared to the systems relying on thermal generation. as presented in previous section.

The following table presents total CO_2 emissions from electricity generation in CPs for the three reference years.

Table 4: CO_2 emissions from electricity generation in CPs (in tonnes)

2030	2035	2040
17,497,004	12,870,429	17,412,307

Total CO_2 emissions from electricity generation decrease from approximately 17.5 million tonnes in 2030 to 12.9 million tonnes in 2035, mainly due to the increasing share of renewable energy generation and reduced utilisation of coal-fired thermal power plants. However, emissions increase again in 2040, reaching around 17.4 million tonnes. This increase is primarily driven by higher CO_2 emissions in Ukraine, where the partial retirement of nuclear generation capacity leads to increased utilisation of gas-fired generation units to maintain adequacy and security of supply.

For the projects' CBA, amount of CO_2 emissions from electricity generation in CPs was used for each project to determine the variation between the reference case and the cases with the projects, i.e. to calculate B2 ΔCO_2 indicator.

5.1.4 Grid losses

Grid losses given in this subchapter are detected in the reference scenario, without candidate projects. Transmission network losses for the region were calculated using verified PSS/E network models for the target years 2030, 2035, and 2040. The simulations accounted for projected generation, load profiles, network topology, and planned reinforcements in each country, ensuring a high level of fidelity to expected system conditions.

The results indicate that annual transmission losses are expected to range approximately 4.550–6.459 GWh/year, depending on the year and scenario assumptions.

Losses increase slightly over time due to projected load growth and network expansion, with modelled values of 4,550 GWh (2030), 5,150 GWh (2035), and 5,808 GWh (2040), 6,459 GWh (2050), while the corresponding loss share relative to total supply remains within 1.5–2.5 %, reflecting improvements in network efficiency and reinforcement measures. These results are consistent with current regional loss percentages reported in national TSOs' and regulators' annual energy balances, confirming that transmission losses are a relatively small but significant component of overall system efficiency.

Annual grid losses without candidate projects in the whole region are given in the following table for four analysed years.

Table 5: Annual grid losses in CPs in reference scenario

Grid losses (GWh)	
2030	4,550
2035	5,150
2040	5,808
2050	6,459

5.1.5 Electricity prices

In PLEXOS, the electricity market price in each hour in a country is determined by the marginal cost of generation, meaning the system marginal price is set by the operating cost of the most expensive unit online during a given period. If there is electricity import from other countries, this import is treated as extra generation capacity, and its price is also considered in determining the most expensive unit. If unserved energy occurs in a certain hour, then the model uses the VoLL as the price for that hour.

Average annual electricity prices in all CPs for four analysed years in the reference scenario are presented in the following table.

Table 6: Average annual electricity prices in CPs in reference scenario

Electricity price (EUR/MWh)	
2030	74.1
2035	37.1
2040	86.6
2050	382.0

The average electricity prices in the EnC Contracting Parties show significant variations throughout the analysed period, reflecting changes in the generation mix, CO_2 emission costs, and overall security of supply issues. In 2030, the average electricity price amounts to 74.1 EUR/MWh, while in 2035 it decreases to 37.1 EUR/MWh. This reduction is primarily driven by the increased integration of renewable energy sources and reduced dependence on thermal power generation, leading to lower generation costs and reduced fuel and CO_2 emission costs.

In 2040, average electricity prices increase to 86.6 EUR/MWh. This trend is consistent with the previously observed increase in total generation costs and CO_2 emissions. Higher utilisation of thermal and gas-fired generation, combined with significantly higher CO_2 emission prices, results in increased marginal generation costs across the region. In addition, reduced nuclear generation availability in Ukraine leads to higher operation of gas-fired units and contributes to the occurrence of Energy Not Supplied (ENS), further increasing electricity prices.

By 2050, average electricity prices rise to 382 EUR/MWh. Although the generation mix becomes largely decarbonised and dominated by renewable energy sources, the very high prices are linked to reduced system adequacy and the occurrence of significant ENS levels in several Contracting Parties, but primarily in Ukraine. In this context, electricity prices are strongly influenced by the assumed Value of Lost Load (VoLL), which sets very high price levels during periods of non-served energy and in the system.

For the projects' CBA, electricity prices in CPs in scenarios with the projects were used to monetise B5 ΔLosses indicator.

It is important to note that, in cases of very high electricity prices caused by the occurrence of ENS, a cap price was applied in the monetisation process in accordance with the Implementation Guidelines for TYNDP 2026, in order to avoid unrealistically high monetised values of grid losses.

5.2 Scenarios with the projects

In this section, market and network simulation results are presented for each candidate project relevant for the calculation of the CBA indicators. More specifically, the analysis evaluates the impact of each project on total generation costs, total CO_2 emissions, grid losses and energy not supplied (ENS). It is important to emphasize that results are analysed at the aggregated level of all Energy Community Contracting Parties, allowing assessment of the overall regional impact of the considered projects on sustainability, market integration, energy efficiency and system stability.

5.2.1 E01

For the E01 project - Construction of the new interconnection, OHL 400 kV Gacko (BA) – Brezna (ME), the increase in NTC after project commissioning in 2035 is estimated at:

BA→ME 1650 MW,

ME→BA 550 MW.

Since the project is not expected to be commissioned by 2030, the analysis of project impacts was performed for the reference years 2035, 2040, and 2050.

Table 7 presents the changes in relevant simulation results in scenarios with the E01 project compared to the reference scenario for the years 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E01 project and the corresponding reference scenario without the project. Positive values indicate an increase of the analysed indicator due to the project implementation, while negative values indicate a decrease compared to the reference case.

Table 7: Change in simulation results in scenarios with E01 project compared to the reference scenario

	2035	2040	2050
Δ Total generation costs (mil. EUR)	+11.03	-18.04	+2.02
Δ Total CO_2 emissions (tonnes)	+32,785	-42,517	-
Δ Grid losses (GWh)	-22.79	-23.92	-26.43
Δ Security of Supply (GWh)	-	-0.80	-10.22

The results show that the project affects total generation costs, CO_2 emissions, and security of supply indicators differently across the three analysed years. Although generation costs generally decrease in Bosnia and Herzegovina, with a smaller impact in Montenegro, the aggregated results at the level of all Energy Community Contracting Parties show both increases and decreases in total costs. This is mainly a consequence of changed regional dispatch patterns and modified power flows caused by the new interconnection, which affect generation utilisation differently across neighbouring systems. Although the project-induced changes in total generation costs amount to several million EUR, their impact becomes relatively small when compared to the overall generation costs presented in Table 3. In 2035, total generation costs increase by around 0.25% compared to the reference scenario, while in 2040 they decrease by approximately 0.24%. In 2050, the impact is almost negligible, with a slight increase of around 0.07%.

With regard to CO_2 emissions, in 2035, emissions slightly increase, while in 2040 they decrease, reflecting the varying utilisation of thermal and renewable generation technologies under the changed network conditions. The project contributes positively to the SoS indicator in 2040 and 2050, where the reduction of ENS demonstrates the beneficial effect of improved interconnection capacity and stronger regional integration of the electricity market.

In terms of project's impact of losses variation, the highest impact is on losses variation in Bosnia and Herzegovina, while aggregated annual decrease for all CPs amounts 22.8 GWh in 2030 to 26.4 GWh in 2050.

5.2.2 E02

For the E02 project - TransBalkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA) / Pljevlja (ME), the increase in NTC after project commissioning in 2028 is estimated at:

- BA→RS 1055 MW,
- RS→BA 475 MW,
- ME→RS 300 MW,
- RS→ME 300 MW.

Since the project was expected to be commissioned in 2028, the analysis of project impacts was performed for the reference years 2030, 2035, 2040, and 2050.

Table 8 presents the changes in relevant simulation results in scenarios with the E02 project compared to the reference scenario for the years 2030, 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E02 project and the corresponding reference scenario without the project.

Table 8: Change in simulation results in scenarios with E02 project compared to the reference scenario

	2030	2035	2040	2050
Δ Total generation costs (mil. EUR)	-5.45	+0.44	-34.73	-0.019
Δ Total CO_2 emissions (tonnes)	+26,480	+2,974	-75,706	-
Δ Grid losses (GWh)	-28.78	-30.28	-31.79	-35.11
Δ Security of Supply (GWh)	-	-	-23.77	-54.28

Table 9 presents the changes in relevant simulation results in scenarios with the E03 project compared to the reference scenario for the years 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E03 project and the corresponding reference scenario without the project.

According to the simulation results, total generation costs in CPs are decreasing in all years, except in 2035, in which a slight cost increase appears. Since the indicators are analysed at the aggregated level of all EnC Contracting Parties, the modified regional dispatch and cross-border power flows may simultaneously lead to increased generation costs in some neighbouring systems, resulting in slight increases of aggregated regional costs in certain years. The project has the strongest impact on the reduction of generation costs in Serbia, while a significant decrease of generation costs is also observed in Bosnia and Herzegovina in 2035.

A similar effect can also be observed for CO_2 emissions, where changes in regional generation dispatch influence the utilisation of thermal and renewable generation technologies differently across the region. The project effect on emission reduction is particularly visible in 2040, which is also the year with the highest CO_2 emissions and emission-related generation costs at the regional level. The project also contributes positively to SoS issues in 2040 and 2050, through the reduction of ENS enabling stronger regional interconnection capacity and improved electricity exchange possibilities between neighbouring systems.

The highest impact on losses variation is also in Serbia, but grid losses are also significantly decreased in Bosnia and Herzegovina and Montenegro. The highest decrease in grid losses in all CPs in expected in 2050, amounting to 35.1 GWh.

5.2.3 E03

For the E03 project - New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain, the increase in NTC after project commissioning in 2032 is estimated at:

- BA→ME 340 MW,
- ME→BA 690 MW.

Table 9: Change in simulation results in scenarios with E03 project compared to the reference scenario

	2035	2040	2050
∆ Total generation costs (mil. EUR)	+5.30	-4.31	-2.11
∆ Total CO_2 emissions (tonnes)	+3,951	-9,820	-
∆ Grid losses (GWh)	-31.34	-32.90	-36.34
∆ Security of Supply (GWh)	-	-0.86	-0.60

Since the project is expected to be commissioned in 2032, the analysis of project impacts was performed for the reference years 2035, 2040, and 2050.

According to the simulation results, the project generally contributes to a reduction in regional generation costs, with a higher impact in Bosnia and Herzegovina than in Montenegro. However, similarly to the previous projects, the aggregated regional results for all CPs may show cost and emissions increase in some years, such as 2035, due to changes in dispatch and in cross-border electricity flows across the wider regional system of CPs. In 2035, CO_2 emissions increase in line with the increased generation costs, while in 2040 the E03 project contributes to a reduction of regional CO_2 emissions. In addition, the project positively affects the SoS indicator through the reduction of ENS in 2040 and 2050.

The simulation results further indicate that the project has the most significant impact on grid loss variations in Bosnia and Herzegovina due to the changed regional power flow patterns after project commissioning. The highest decrease in grid losses in all CPs in expected in 2050, amounting to 36.3 GWh.

5.2.4 E04

For the E04 project - Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL), the increase in NTC after project commissioning in 2030 is estimated at:

- BA→ME 125 MW,
- ME→BA 250 MW,
- ME→AL 125 MW,
- AL→ME 250 MW.

Since the project is expected to be commissioned in 2030, the analysis of project impacts was performed for the reference years 2030, 2035, 2040, and 2050.

Table 10 presents the changes in relevant simulation results in scenarios with the E04 project compared to the reference scenario for the years 2030, 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E04 project and the corresponding reference scenario without the project.

Table 10: Change in simulation results in scenarios with E04 project compared to the reference scenario

	2030	2035	2040	2050
Δ Total generation costs (mil. EUR)	-12.37	+6.44	-50.76	+12.87
Δ Total CO_2 emissions (tonnes)	-3,449	+6 130	-113,996	-
Δ Grid losses (GWh)	-29.46	-31.00	-32.54	-35.94
Δ Security of Supply (GWh)	-	-	-24.40	-52.73

According to the simulation results, total generation costs in CPs are decreasing in 2030 and in 2050, while in 2035 and 2050 a cost increase appears. The highest impact of E4 project is on generation costs in Bosnia and Herzegovina, compared to other countries connected by this line.

The reduction of CO_2 emissions is especially pronounced in 2040, which is also the year with the highest regional emission levels and emission-related generation costs. The reinforcement of the AL–ME and BA–ME interconnections enables higher renewable electricity generation in Albania, Bosnia and Herzegovina, and Montenegro in 2040, while lignite-based generation in Serbia decreases, confirming the project's role in supporting RES integration and reducing regional CO_2 emissions. In addition, a slight reduction in gas-fired generation in Ukraine is also observed, further contributing to lower regional emissions and generation costs.

Simulation results also show notable contribution to ENS decrease in 2040 and 2050. This effect becomes especially important in 2050, when very high ENS levels are observed in the reference scenario across several Energy Community Contracting Parties.

Loss decrease is expected in all analysed years, with a minimum value of 29.5 GWh in 2030, and 35.6 GWh in 2050. The highest impact on grid losses variation is expected in Bosnia and Herzegovina.

5.2.5 E05

For the **E05 project - 400 kV interconnection corridor East – West, western section,** the increase in NTC after project commissioning in 2030 is estimated at:

- MK→XK 500 MW,
- XK→MK 500 MW.

Since the project is expected to be commissioned in 2030, the analysis of project impacts was performed for the reference years 2030, 2035, 2040, and 2050.

Table 11 presents the changes in relevant simulation results in scenarios with the E05 project compared to the reference scenario for the years 2030, 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E045 project and the corresponding reference scenario without the project.

Table 11: Change in simulation results in scenarios with E05 project compared to the reference scenario

	2030	2035	2040	2050
Δ Total generation costs (mil. EUR)	-6.49	+8.01	-21.97	+5.55
Δ Total CO_2 emissions (tonnes)	-8 526	+32,332	-51,246	-
Δ Grid losses (GWh)	-2.90	-3.05	-3.20	-3.53
Δ Security of Supply (GWh)	-	-	-1.13	-72.33

According to the simulation results, the E05 project has a particularly important impact on security of supply, especially in 2050, when it leads to the complete elimination of ENS that appears in Kosovo* in the reference scenario. This confirms the project's contribution to regional adequacy and cross-border support in periods of reduced system flexibility.

Regarding the total generation costs, the project leads to both increases and decreases depending on the analysed year due to changes in regional dispatch and electricity flows. However, the overall effect is generally beneficial, with the most pronounced impact observed in Kosovo*, particularly in 2030. The project also contributes to reduced generation costs in Serbia, mainly through lower utilisation of lignite-fired generation units. Consequently, CO_2 emissions are also reduced in 2030 and 2040.

Overall, the project demonstrates value in reducing generation costs especially in systems relying on lignite-based electricity generation, such as Kosovo* and Serbia, while simultaneously improving regional SoS and supporting more efficient utilisation of available generation resources across the interconnected systems.

With regard to grid losses, the decrease in grid losses is similar in Kosovo* and North Macedonia in all years. In total, variation in grid losses is lower compared to other candidate projects.

5.2.6 E12

For the Moglice Extension Pumped-Storage Hydropower Plant (PSHPP Moglice Extension), a new PSHPP of 1,620 MW is expected to be in operation from 2033. Since the project is expected to be commissioned in 2033, the analysis of project impacts was performed for the reference years 2035, 2040, and 2050.

Table 12 presents the changes in relevant simulation results in scenarios with the E12 project compared to the reference scenario for the years 2030, 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E12 project and the corresponding reference scenario without the project.

Table 12: Change in simulation results in scenarios with E12 project compared to the reference scenario

	2035	2040	2050
Δ Total generation costs (mil. EUR)	+40.28	-23.36	-13.65
Δ Total CO_2 emissions (tonnes)	+184,867	-37,067	-
Δ Grid losses (GWh)	-43.83	-24.66	-24.74
Δ Security of Supply (GWh)	-	+6.11	-63.05

According to the simulation results, the E12 project (PSHPP Moglice) increases total generation costs and CO_2 emissions at the regional level in 2035. This is mainly related to a slight increase in lignite-fired generation in Serbia caused by modified regional dispatch patterns after project commissioning. Consequently, higher utilisation of thermal generation also leads to increased CO_2 emissions in that year.

In the later years, however, the project contributes to a reduction in total regional generation costs, reflecting the positive role of pumped-storage hydropower in system flexibility and renewable energy integration. Since the project is located in Albania, the most significant impacts on generation patterns and generation costs are observed in the Albanian power system. The PSHPP operates in average around 4,000 hours annually and contributes to reducing renewable energy curtailment in Albania, which becomes increasingly important with the growing share of variable renewable energy sources in the system.

The project also has a significant positive impact on security of supply, particularly in 2050, when ENS is reduced by approximately 63 GWh. This confirms the important role of storage facilities in supporting adequacy and flexibility, and integration of high shares of renewable electricity generation in the regional power system.

The project also affects variation in grid losses. According to the simulation results, total grid losses in the Contracting Parties are expected to decrease by approximately 43.8 GWh in 2030, with the lower and comparable reduction in 2040 and 2050 at about 24 GWh.

5.2.7 E13

For the E13 project - Reconfiguration of 400 kV grid and new 400 kV interconnection Albania-Kosovo*, the increase in NTC after project commissioning in 2029 is estimated at:

- AL→XK 500 MW,
- KS→AL 500 MW.

Since the project is expected to be commissioned in 2029, the analysis of project impacts was performed for the reference years 2030, 2035, 2040, and 2050.

Table 13 presents the changes in relevant simulation results in scenarios with the E13 project compared to the reference scenario for the years 2030, 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E13 project and the corresponding reference scenario without the project.

Table 13: Change in simulation results in scenarios with E13 project compared to the reference scenario

	2030	2035	2040	2050
Δ Total generation costs (mil. EUR)	-9.07	+13.98	-18.87	+0,99
Δ Total CO_2 emissions (tonnes)	-9,777	+30,274	-47,405	-
Δ Grid losses (GWh)	-16.43	-17.29	-18.15	-20.05
Δ Security of Supply (GWh)	-	-	+2.64	-53.58

According to the simulation results, the E13 project leads to both increases and decreases in total generation costs depending on the analysed year, reflecting changes in regional dispatch patterns and cross-border electricity flows. However, the most significant reduction in total generation costs is observed in 2040, which is also the year with the highest generation costs and CO_2 emissions at the regional level. The project therefore demonstrates particular value in periods with high thermal generation utilisation and higher CO_2 emission costs.

Similarly as E05, the project has a more pronounced impact on systems relying on lignite-based electricity generation, particularly Kosovo* and Serbia, where it contributes to lower utilisation of thermal generation and consequently lower generation costs and CO_2 emissions. On the other hand, the impact is less significant in systems such as Albania, where electricity generation is already predominantly based on hydropower and renewable energy sources.

While the impact on total generation costs in 2050 is relatively limited, the project shows a significant positive effect on SoS. In particular, it contributes to a substantial reduction of ENS, completely eliminating it in Serbia and Kosovo*, while also reducing ENS levels in Moldova and Ukraine.

The project also affects variation in grid losses. According to the simulation results, total grid losses in the Contracting Parties are expected to decrease by approximately 16.4 GWh in 2030, with the reduction further increasing to around 20 GWh by 2050.

5.2.8 E15

For the **E15 project - 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA),** the increase in NTC after project commissioning in 2032 is estimated at:

- UA→MD 500 MW,
- MD→UA 500 MW.

Since the project is expected to be commissioned in 2032, the analysis of project impacts was performed for the reference years 2035, 2040, and 2050.

Table 14 presents the changes in relevant simulation results in scenarios with the E15 project compared to the reference scenario for the years 2035, 2040, and 2050. The presented values represent the difference (Δ) between the scenario including the E15 project and the corresponding reference scenario without the project.

Table 14: Change in simulation results in scenarios with E15 project compared to the reference scenario

	2035	2040	2050
Δ Total generation costs (mil. EUR)	-7.17	-97.58	-15.01
Δ Total CO_2 emissions (tonnes)	-145,294	-206,317	-
Δ Grid losses (GWh)	-22.93	-24.06	-26.06
Δ Security of Supply (GWh)	-	-205.12	-62.49

According to the simulation results, the E15 interconnection project between Moldova and Ukraine has a positive impact on all analysed indicators throughout the entire analysed period. The project contributes to reductions in total generation costs, CO_2 emissions, grid losses, and

ENS, confirming its importance for regional integration and adequacy support between the two neighbouring systems.

The most significant impact on generation costs and CO_2 emissions is observed in Moldova and Ukraine, which is expected considering the direct connection between the two systems. The effect is particularly pronounced in Moldova in 2035 and 2050, while in 2040 both countries experience substantial benefits due to the increased need for regional support and cross-border electricity exchange. Similarly to several previously analysed projects, the strongest regional benefits are observed in 2040, which is also the year with the highest aggregated generation costs and CO_2 emissions in the CPs region.

The project has a particularly important role in improving security of supply in 2040, when approximately 515 GWh of ENS occurs in Ukraine in the reference scenario. The E15 project reduces ENS by around 205 GWh, corresponding to a reduction of almost 40%, demonstrating the strong contribution of the interconnection to regional adequacy support. In 2050, the project continues to positively affect security of supply, although the impact is somewhat lower compared to 2040.

In addition, the project contributes to continuous reductions in grid losses across all analysed years, indicating more efficient regional power flows and improved utilisation of the transmission network. According to the simulation results, total grid losses in the Contracting Parties are expected to decrease by approximately 22.9 GWh in 2030, with the reduction further increasing to around 26 GWh by 2050.

5.3 Cost-benefit analysis

As described earlier, several benefits were calculated to determine B/C ratio based on the comparison with the reference scenario. Those monetised benefits include:

- B1 – Socio-economic welfare (SEW)
- B2 - Additional societal benefit due to CO_2 variation
- B5 - Variation in Grid Losses
- B6/B8 - Security of Supply: Adequacy

Costs that they were put in opposition to are:

- C1 – Capital expenditures (CAPEX)
- C2 – Operation costs (OPEX)

The results are presented for each project in great detail in the following chapters. There are some differences in the benefit cost ratio calculation compared to the previous PECI process in 2024. Those are the following:

01. The calculation of benefits and costs is prolonged to the full 25 years from the commissioning of the project, as opposed to the last PECI process when all the projects were evaluated until 2050, no matter when their commissioning date was. Since 2050 is the last modelling year in PLEXOS, all project benefits after 2050 are assumed to remain constant and are therefore replicated for each year until the 25th year of project operation. The same assumption is applied for OPEX values.
02. As it was previously mentioned, there was a cap for the monetisation of grid losses as to avoid the overinflation of the grid losses benefit. This was done according to the Implementation Guidelines for TYNDP 2026 based on 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, and the cap was set to 212.86 EUR/MWh in 2030 and 236.04 EUR/MWh in 2040 and 2050 respectively.
03. Another change that was done according to the ENTSO-E Guidelines is the Value of Lost Load that is used for the monetisation of the Security of Supply benefit. In previous cycle it was set to 3,000 EUR/MWh, and in this cycle a value of 10,000 EUR/MWh was used. In the ENTSO-E Guidelines this value is recommended for all the countries for which the VoLL is not calculated, and that is the case for all the Energy Community CPs.

It is also noteworthy that the modelling is done for four target years, 2030, 2035, 2040 and 2050, while the results for the cost-benefit analysis for the remaining years are interpolated based on the modelling results for target years.

5.3.1 E01

The first project, construction of a new 400 kV OHL between Bosnia and Herzegovina and Montenegro, is supposed to be commissioned in 2035. The investment is planned from 2030 and is supposed to last until 2035, until the commissioning. Projects costs that were provided by the project promoters are presented in the following table.

Table 15: Project costs (E01)

mil. EUR	2030	2031	2032	2033	2034	2035	2036	2037	2038-
CAPEX	1.03	1.03	1.13	4.60	13.58	8.65			
OPEX							0.053	0.053	0.148

The total investment cost of E01 amounts to 30 million EUR. The observed horizon for the benefit cost ratio calculation is from 2035 to 2060.

The sum of discounted project benefits is presented in Figure 20.

Figure 20: Discounted project benefits (E01)

The highest impact on the benefit cost ratio is from the decrease in unsupplied energy that this project provides to the Energy Community CPs, while the lowest impact (although still positive), is from the increase of the socio-economic welfare for the Energy Community CPs.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in the figure below. It shows what the primary benefits of the implementation of the project are.

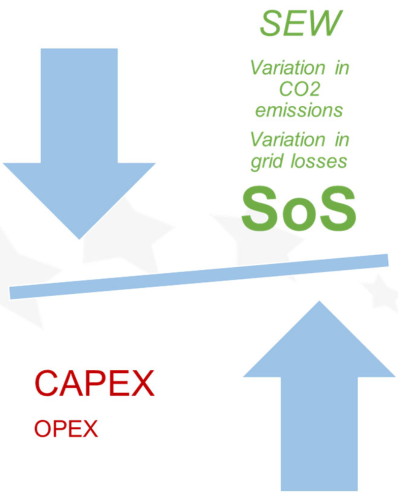

Figure 21: Impact on the benefit cost ratio (E01)

The benefit cost ratio of this project is quite high and amounts to 28.39, with an NPV value of 620.44 million EUR. The high B/C and NPV are a direct result of an overwhelming positive change in the benefits in the scenario when the project is implemented, which provide the sufficient cash flows to cover the project investment and operation costs.

5.3.2 E02

The second project is Trans Balkan Corridor, which is the only project of all the nominated projects that is already in the implementation stage (actually section 3, which is a precondition for the section 4, which is analysed here). It consists of a double 400 kV OHL connecting Serbia with Bosnia and Herzegovina and Montenegro. Its commissioning date is in 2028, while the investments started in 2025 and are supposed to last until the commissioning.

Projects costs that were provided by the project promoters are presented in Table 16.

Table 16: Project costs (E02)

mil. EUR	2025	2026	2027	2028	2029	2030-
CAPEX	1.60	1.58	11.95	8.98		
OPEX[12]					0.025	0.027

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[12] OPEX for E02 increases until the end of the observed horizon, 5-10% yearly.

The total CAPEX of E02 is 24.13 million EUR. The observed horizon for the benefit cost ratio calculation is from 2028 to 2053. The sum of discounted project benefits is presented in the figure below.

Figure 22: Discounted project benefits (E02)

The absolute highest positive impact of the TransBalkan corridor is in the decrease of unsupplied energy it brings to the Energy Community CPs. The increase in socio-economic welfare is also substantial, while the decrease of grid losses and CO_2 emissions are in the same ballpark.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in Figure 23. It shows what the primary benefits of the implementation of the project are.

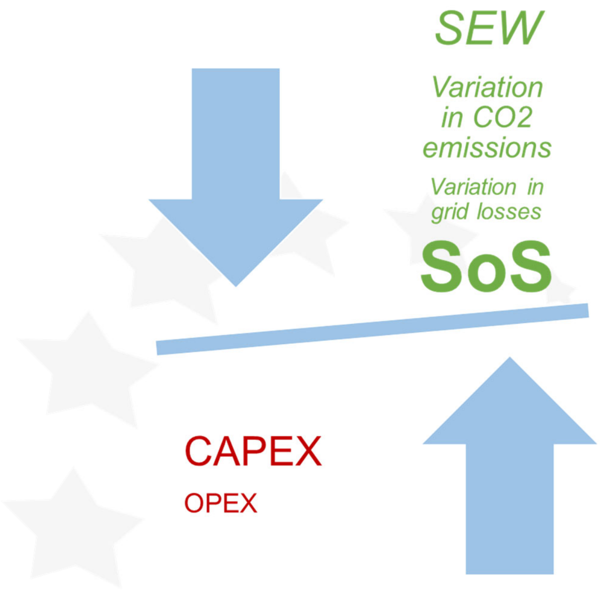

Figure 23: Impact on the benefit cost ratio (E02)

The benefit cost ratio is very high for this project also, 47.46. Net present value is over one billion EUR, i.e. 1,16 million EUR. The high benefits that present with this project, as opposed to the scenario without the project, are the main cause of this result.

5.3.3 E03

The third project is also between Bosnia and Herzegovina and Montenegro which includes a construction of a new substation in Montenegro, Piva's mountain. The line commissioning date is in 2032, while some of the investments are already underway and will continue until the commissioning.

Projects costs that were provided by the project promoters are presented in the following table.

Table 17: Project costs (E03)

mil. EUR	2026	2027	2028	2029	2030	2031	2032	2033
CAPEX	1.05	1.35	1.35	17.09	17.09	19.43	19.43	
OPEX								0.42

The total investment cost of E03 amounts to 76.76 million EUR. The observed horizon for the benefit cost ratio calculation is from 2032 to 2057. The sum of discounted project benefits is presented in Figure 24.

Figure 24: Discounted project benefits (E03)

For this project, the sum of discounted benefits is positive, however it is slightly smaller compared to the first two projects. The reduction of total generation costs that this project brings to the EC CPs is similar in value as the reduction of CO_2 emissions (around 5% in the share of total benefits), while the reduction of grid losses and increased security of supply are present in higher values. The highest share, of almost 60% in the total discounted sum of benefits, is taken by the increased security of supply.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in the figure below.

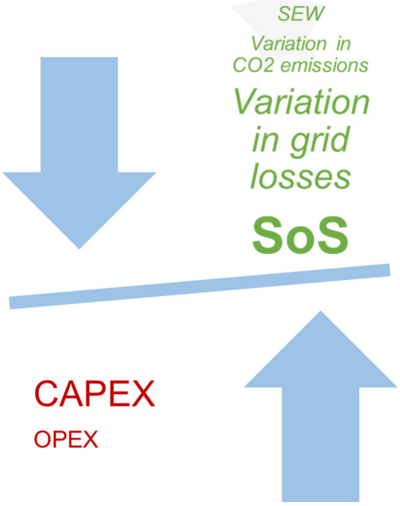

Figure 25: Impact on the benefit cost ratio (E03)

For this project, the benefit cost ratio is only slightly higher than 1, which is still a positive outcome of the benefit cost analysis. The B/C is 1.69, while NPV is 46.05 million EUR.

5.3.4 E04

The fourth project is the only project in the category of overhead lines that does not include a construction of a new line. This project is aimed at the rehabilitation of the existing 220 kV lines that connect Bosnia and Herzegovina to Montenegro and then to Albania. The commissioning date for this project is in 2030, with investments starting from 2026.

Projects costs that were provided by the project promoters are presented in Table 18.

Table 18: Project costs (E04)

mil. EUR	2026	2027	2028	2029	2030	2031	2032	2033-
CAPEX	1.32	5.46	9.95	5.03	2.45			
OPEX						0.08	0.08	0.19

The total investment cost for this project is 24.20 million EUR, which is quite lower compared to other projects that are a part of this analysis. However, this is expected since the investment does not envision a construction of a new line, only the rehabilitation of an existing one. The observed horizon for the benefit cost ratio calculation is from 2030 to 2055. The sum of discounted project benefits is presented in the figure below.

Figure 26: Discounted project benefits (E04)

This project brings a prevailing benefit to the EC CPs in the reduction of unsupplied energy and that benefit makes over 90% of the total discounted sum of benefits of this project. It is important to keep in mind that this is not only a consequence of the fact that the project is beneficial in terms of reducing the unsupplied energy, but also the consequence of the VoLL amount with which this benefit in GWh is monetised. Since VoLL for EC CPs is very high, it inflates the benefit, making it this substantial.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in Figure 27.

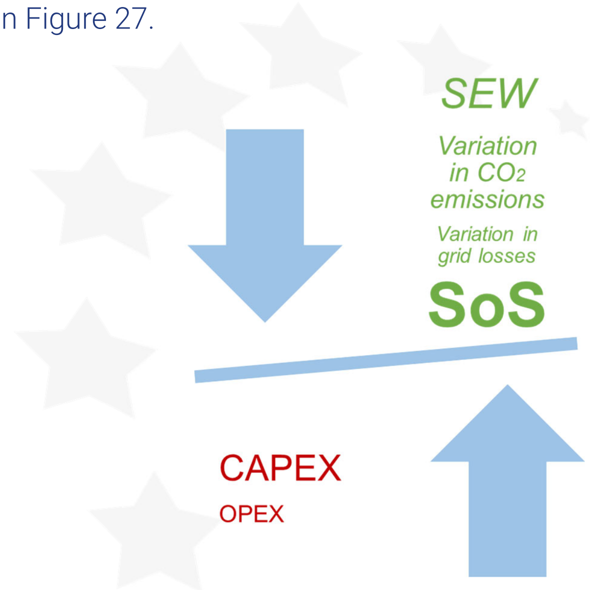

Figure 27: Impact on the benefit cost ratio (E04)

In both previous figures it is visible that, while security of supply benefit is predominant for this project, the increase in socio-economic welfare is also quite high. All of these facts, along with the fact that this project has a very low investment cost, result in a benefit cost ratio of 135.39 and net present value of 3,172 million EUR.

5.3.5 E05

The fifth project will be commissioned in 2030. The investments for this project should start in 2026, and the observing horizon for the analysis is from 2030 to 2055.

Projects costs that were submitted by the project promotors are presented in the following table.

Table 19: Project costs (E05)

mil. EUR	2026	2027	2028	2029	2030-
CAPEX	5.50	15.60	15.60	116.60	
OPEX					4.15

The total CAPEX for this project is 153.30 million EUR. The sum of discounted project benefits that result because of this new line are presented in Figure 28.

Figure 28: Discounted project benefits (E05)

Similarly to the previous project, the predominant impact of this project is in the increase of security of supply. More specifically, this project eliminates the unsupplied energy that appears in Kosovo* in 2050 because of the shutdown of coal fired power plants. This result is to be expected since the modelling methodology prescribes that all coal fired thermal power plants must be inactive in 2050, and there is no replacement of this energy. This is why new overhead lines bring that much benefit in 2050 specifically; they mitigate the problem that arises because of this approach. The lowest positive impact this project brings is in the decrease of grid losses, only 0.15%.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in the figure below.

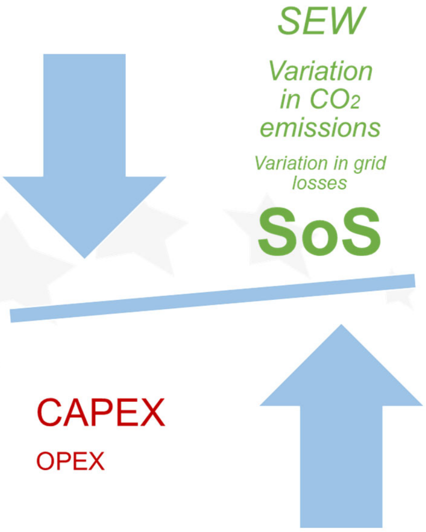

Figure 29: Impact on the benefit cost ratio (E05)

Even though the monetised SoS benefit is very high and similar to the previous project, because of the difference in the investment costs, i.e. this project is quite capitally intensive, the benefit cost ratio is lower compared to E04, and it is 14.57, while NPV is 2,607 million EUR.

5.3.6 E12

This project is the only project in the energy storage category that passed the preliminary eligibility check. It is a project of a 1620 MW pumped storage hydro power plant in Albania, i.e. an extension of the existing Moglice HPP that will use the existing Moglice reservoir as its lower reservoir. The commissioning is supposed to be in 2033, with investments starting in 2027.

Projects costs that were submitted by the project promotors are presented in the following table.

Table 20: Project costs (E12)

mil. EUR	2027	2028	2029	2030	2031	2032	2033	2034	2035-
CAPEX	107	161	214	357	411	268	179	89	
OPEX								9.7	9.7

The total investment cost for this PSHPP is 1,79 billion EUR, which is in line with the expected unit cost of a pumped storage hydro power plant. This is the project with the highest investment and operating costs out of all the analysed projects. The calculation is from 2033 to 2058.

The sum of discounted project benefits that result because of this new line are presented in Figure 30.

Figure 30: Discounted project benefits (E12)

This is the first project that presents with a negative benefit, which means that, specifically in this case, the amount of CO_2 emissions has become higher when this project was implemented in the PLEXOS model, as opposed to the situation as it was without this project. Since the methodology for determining which projects are in all of Energy Community's interests takes into account the changes in all the EC CPs, it is to be expected that for certain projects the result might become less favourable. This is especially the case for projects like energy storage projects that are located at the territory of only one Contracting Party and therefore have a lower impact on other CPs. This does not eliminate the positive impact that the project might have on its domestic country. Specifically, this PSHPP completely replaces the generation from Vlora thermal power plant, which is run on natural gas, substituting it with hydro energy. While this is quite an important impact on the Albanian energy system, when observing all CPs it is visible that some of the thermal power plant in Serbia generate more, at the same times as the pumping of PSHPP, which causes the increase of CO_2 emissions.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in the figure below.

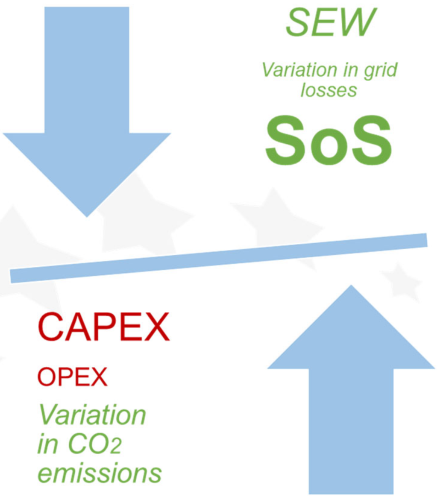

Figure 31: Impact on the benefit cost ratio (E12)

Even with the increase in CO_2 emissions that presents with the implementation of this project, the benefit cost ratio is still positive, 1.52, while NPV is 818.80 million EUR.

5.3.7 E13

This project is a reconfiguration of 400 kV grid and a construction of new 400 kV interconnection between Albania and Kosovo* that will be commissioned in 2029. The investments should begin this year.

Projects costs that were provided by the project promotors are presented in the following table.

Table 21: Project costs (E13)

mil. EUR	2026	2027	2028	2029	2030-
CAPEX	3.50	5.50	25.35	59.05	
OPEX					0.63

The total amount of investment for this project is 93.40 million EUR. The sum of discounted project benefits that result because of this new line are presented in the figure below.

E13	
B1	52.45 mil. EUR
B2	-49.07 mil. EUR
B5	23.55 mil. EUR
B6	1,703.34 mil. EUR

Figure 32: Discounted project benefits (E13)

This project, similarly, to E05, eliminates unsupplied energy that appears in Kosovo* in 2050 because of the imposed shutdown of coal fired thermal power plants. This is manifested through a very high security of supply benefit, which makes 98% of total monetised benefits. This project also manifests with negative variation in CO_2 emissions, meaning that the sum of CO_2 emissions in all EC CPs increases with this project.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in the figure below.

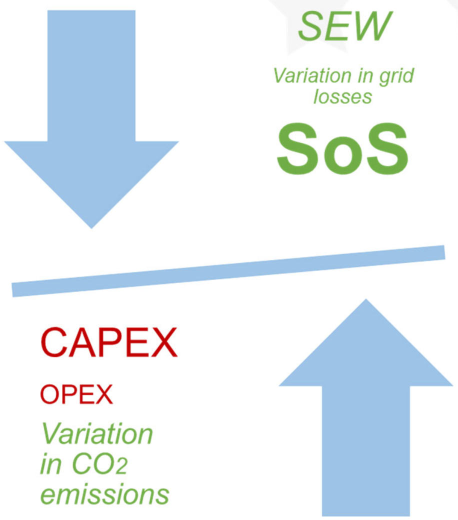

Figure 33: Impact on the benefit cost ratio (E13)

The CO_2 increase that happens with this project is a direct result of increased generation of thermal power plants in Albania and Kosovo* because of a higher transfer capacity between them enabling a higher interchange of energy. Even with this negative benefit, the benefit cost ratio remains higher than 1, i.e. 19.13, while net present value is 1,616 million EUR.

5.3.8 E15

The last analysed project in PECI 2026 cycle is a 330 kV line between Moldova and Ukraine, which was also a part of the previous PECI cycle. The commissioning date for this project is in 2032, while the investment is supposed to start in 2026.

Projects costs that were provided by the project promoters are presented in the following table.

Table 22: Project costs (E15)

mil. EUR	2026	2027	2028	2029	2030	2031	2032	2033-
CAPEX	0.80	0.60	0.60	13	13	13	13	
OPEX								0.15

The total CAPEX for E15 is 54 million EUR. The sum of discounted project benefits that result because of this new line are presented in the figure below.

Figure 34: Discounted project benefits (E15)

This project highly decreases the large amounts of unsupplied energy that appear in both Ukraine and Moldova in 2040 and 2050, mostly because of shutdowns of many conventional power plants in Ukraine. However, the increase of SEW and decrease of CO_2 emissions are also quite substantial with this project compared to the situation without the project.

The illustrative depiction of the impacts that project costs and benefits have on the benefit cost ratio is presented in the figure below.

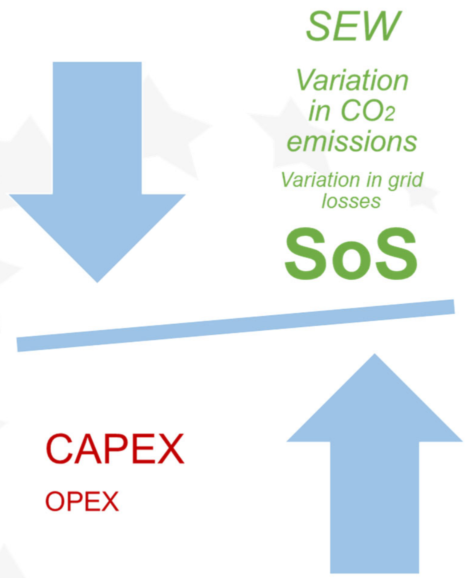

Figure 35: Impact on the benefit cost ratio (E15)

Since the results of modelling show a high positive impact of this project, the results of benefit cost analysis are expected, with the benefit cost ratio of 252.62 and NPV od 11,427 million EUR.

5.4 Multi-criteria analysis

This part is not included in the public version of the final report, in line with article 4(5) of the TEN-E Regulation, as adopted in the Energy Community.

5.5 Ranking of the projects

This part is not included in the public version of the final report, in line with article 4(5) of the TEN-E Regulation, as adopted in the Energy Community.

5.6 TOOT analysis of potentially mutually competing projects

The TOOT (Take Out One at a Time) method is a core analytical framework within the ENTSO- E TYNDP methodology used to assess the individual contribution of each transmission asset to the overall system. In a TOOT analysis, as opposed to the PINT analysis, the reference case represents the grid with all the analysed projects implemented and then each project is removed from the grid, one at a time, while the other lines remain in place, and the resulting change in monetised benefits is measured. This counterfactual approach isolated the marginal value of each asset by quantifying what the system would lose in its absence, capturing benefits such as lower generation costs, enhanced security of supply, etc. This approach was taken for three projects that share the same cross-border corridor. These projects include the same borders but still each delivers its own distinct contribution to the system and are not contingent on the construction or operation of other two projects. This cross-check is done to test the robustness of the project results in the PINT scenario. The projects that were a part of the TOOT analysis are the following:

- E01: Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)
- E03: New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain
- E04: Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)

These projects were chosen because they will increase the net transfer capacity on the same border, between Bosnia and Herzegovina and Montenegro, and the goal was to determine whether the implementation of any two projects would exclude the third one by making it less cost-efficient. Table 23 shows the comparison between cost benefit results for both approaches.

Table 23: Comparison of PINT and TOOT results

Code	Name of the Project	PINT		TOOT	
		B/C	NPV (MEUR)	B/C	NPV (MEUR)
E01	Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)	28.39	620.44	8.99	180.97
E03	New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain	1.69	46.05	1.05	3.28
E04	Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)	135.39	3,172.03	14.27	260.79

As it is to be expected, the PINT results consistently yield higher B/C ratios and NPV values than the TOOT results across all three projects, since PINT captures the project's benefit in a network where no reinforcements have yet been made, while it is presumed that the base network is more congested and the marginal value of a new asset greater.

On the other hand, TOOT removes a project from a fully reinforced network, so it captures the project's marginal contribution in an already upgraded system, therefore yielding lower benefits because the other investments have already relieved much of the congestion. Project E04 stands out as the highest performing asset under both methodologies, therefore reflecting the significant system value of rehabilitating this existing multi-border corridor. Project E01 also demonstrates strong performance, confirming its standalone contribution to the system. The lowest results are present for project E03, which returns the most modest results, though B/C higher than 1 and positive NPV still confirms a net positive contribution to Energy Community welfare, justifying its inclusion in the investment plan. However, since summarised delta NTC values between Montenegro and Bosnia and Herzegovina are extremely high when implementing all three projects (several times greater than the possible production in Montenegro), it is uncertain whether the economic justification of the project E03 is accurate enough based on applied assumptions on the possible NTC increase due to all three projects.

5.7 Sensitivity analyses

According to the TEN-E Regulation, each cost-benefit analysis shall include **sensitivity analyses concerning the input data set**, possibly related to the cost of generation and greenhouse gases as well as the expected development of demand and supply, expected development of renewable energy sources, and including the flexibility of both, and the availability of storage, the commissioning date of various projects in the same area of analysis, climate impacts and other relevant parameters.

4th ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects also points out the importance of conducting sensitivity analysis in the CBA, in order to increase the validity of the CBA results.

Sensitivity analysis can be performed to observe how the variation of parameters, either one parameter or a set of interlinked parameters, affects the model results, whereas aim is not to define complete new sets of scenarios but quick insights in the system behaviour with respect to single (few) changes in specific parameters.

In general, a sensitivity analysis **must be performed on a uniform level**, i.e. the sensitivity needs to be applied to all projects under assessment in the respective study. Some of the sensitivities conducted under the previous TYNDP processes are related to: fuel and CO_2 price, long-term societal cost of CO_2 emissions, climate year, load, technology phase-out/phase-in, must-run, installed generation capacity (including storage and RES), flexibility of demand and generation, availability of storage and the commissioning date of various projects.

Under the CBA of the ongoing PECI process, the Consultant proposed the following parameters to be variated in the sensitivity analysis:

- **Load** – it is expected that an increasing number of applications and different sectors like transport and heating will be electrified in the future (e.g. e-mobility, heat pumps, etc.), which would cause an increase in load and the necessary generation and therefore possibly affect several CBA indicators such as SEW. On the other hand, energy efficiency measures will lead to decreasing load.
- **RES** – amendments to the national RES goals, which could occur frequently in the observed horizon, could lead to dominant impacts on the results of the CBA assessment.

It was agreed that the Consultant will **increase load by 20%, and increase solar capacity by 20%** for each of the analysed years in the horizon. These proposed variations have been applied to the reference scenario without and with each of the analysed projects, as graphically represented in the following figure, resulting in more than 60 additional simulations in comparison to the base project assessment.

Figure 36: Performed sensitivities under the PECI project assessment process

Additional analyses were also performed regarding the sensitivities related to input data. All the sensitivities are described in the chapters below.

5.7.1 Sensitivity analysis +20% load

To assess the robustness of the project benefits under alternative future conditions, a sensitivity analysis was performed assuming a 20% increase in load across the Energy Community countries. The Energy Community is committed to integrating with the European internal energy market, and as such it represents a region with significant growth potential in electricity demand driven by economic development, electrification of end-use sectors, and population dynamics. A higher load scenario in these countries places additional stress on the existing and planned transmission infrastructure, increasing the pressure on cross-border interconnections and potentially amplifying the value of transmission investments. This sensitivity therefore tests whether the projects maintain their positive benefit cost ratios under a more demanding operational context and provides insight into how sensitive the project economics are to demand-side uncertainty.

The results of the sensitivity analysis have confirmed the importance of additional investments into the transmission network, especially under the higher load conditions. All the benefit cost ratios and NPV values resulted in higher values in this sensitivity.

5.7.2 Sensitivity analysis +20% solar

The increased solar penetration scenario produces more varied results across the project portfolio. While the majority of projects continue to record benefit cost ratios higher than 1, three projects (E01, E03 and E12) show negative NPV values and benefit cost ratios in this scenario. This outcome, while counterintuitive at first glance, reflects a structural shift in generation dispatch patterns driven by high solar penetration. When solar capacity is increased by 20%, large volumes of low-cost electricity are generated simultaneously across the region, particularly during daylight hours. This reduces the need for more expensive thermal generation, which in turn lowers the overall price differences between zones. These price differences between zones are the ones that create the economic case for new transmission capacities, i.e. with abundant solar generation, the system is already partially self- balancing and the congestion that a new transmission line was designed to relieve is less severe and therefore the measurable economic benefit of building that line is reduced. It is important to note that this does not indicate that these projects become detrimental to the system, it rather reflects a scenario in which the stress on the system that these projects were designed to address is partially alleviated by the generation mix itself.

5.7.3 Methodological sensitivities and sensitivities related to input data

The reference CBA was performed for each pre-eligible infrastructure project based on the methodology defined by the TEN-E Regulation and using country-specific input data collected from each Energy Community Contracting Party.

As indicated by the results of the reference case for the 2050-time horizon, energy not supplied (ENS) appears in Kosovo*, Moldova, Serbia, and Ukraine. This is a direct consequence of the long-term generation adequacy assessment, which appears unfavourable in these countries with respect to the full decarbonisation envisaged for this period. Due to limited domestic generation capacities and restricted NTCs at the borders of these countries, ENS occurs during hours when domestic generation and imports are insufficient to fully meet domestic demand.

This long-term system adequacy issue could be addressed either by constructing additional generation capacities or by increasing electricity import capabilities (i.e. expanding NTCs). However, both options introduce additional uncertainty regarding how adequacy challenges will ultimately be resolved by the target decarbonisation year.

New interconnections may represent a possible solution for reducing ENS by increasing NTC values in the import direction. Under the applied CBA methodology, changes in ENS values (due to project commissioning) are multiplied by the Value of Lost Load (VoLL) of 10,000 EUR/MWh in order to estimate the SoS adequacy benefit. This may result in exceptionally high benefits for certain projects appearing in the long-term frame, potentially dominating the overall project benefits over the analysed period of 25 years following project commissioning, despite the application of discounting to present value.

In other words, high ENS values in the target time horizon may directly determine the economic viability of certain projects, although such results are based on uncertain assumptions and input data. Furthermore, assessing the economic viability of new interconnectors primarily on the basis of delta SoS adequacy benefits may be misleading, as it neglects the possibility that ENS could be reduced or eliminated through the development of additional renewable generation capacities and energy storage facilities, which could significantly decrease the SoS benefit attributed to the electricity infrastructure project under consideration.

Due to these methodological uncertainties, as well as uncertainties and sensitivities related to long-term input data, two additional sets of CBAs were performed for each pre-eligible project under the following assumptions:

i. SoS adequacy benefits calculated for 2050 are excluded (i.e. set to zero), while SoS adequacy benefits identified in 2040 are assumed to continue until 2049; and
ii. instead of using benefits calculated for 2050, all benefits identified in 2040 are extended over the full assessment period (from 2040 until up to 25 years after project commissioning).

The first assumption provides an indication of the influence of the 2050 SoS adequacy benefit on a project's economic viability, as well as the associated risk in the event that adequacy levels in 2050 become satisfactory across all EnC CPs (i.e. ENS equal or close to zero). The second assumption eliminates uncertainties related to the long-term estimation of project economic viability by limiting the assessment horizon to 2040 conditions.

The following table shows the CBA results, for each pre-eligible project, depending on the analysed scenario.

For the scenario in which SoS adequacy benefits in 2050 and beyond are excluded, projects E05, E12 and E13 show negative CBA results (B/C < 1 and NPV < 0). This indicates that their economic viability is highly dependent on how the Contracting Parties (or some of them) will achieve the desired level of power system adequacy (ENS equal or close to zero) by the target decarbonisation year. It also implies that the current estimation of their economic viability is subject to significant uncertainty, due to the high level of risk associated with energy not supplied in the long-term time horizon.

Under the scenario in which all benefits identified in 2040 are extended until the end of the 25-year project operational period, while benefits calculated for 2050 are disregarded due to the high uncertainty of the underlying input data (although similar uncertainties also exist for the 2040 horizon, to a lesser extent), projects E05, E12 and E13 also show negative CBA results. This indicates that these projects are highly sensitive to assumptions related to the final decarbonisation year.

Considering both sensitivity analyses presented in this chapter, 5 projects can be considered sufficiently robust, as their economic viability does not depend significantly on assumptions related to the final decarbonisation year. Consequently, the risks associated with their implementation are substantially lower than those related to other projects that demonstrate high sensitivity to the assumptions discussed in this chapter. These projects are:

- E01: Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)
- E02: Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA)/Pljevlja (MN) – BA and MN sections
- E03: New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain
- E04: Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)
- E15: 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA).

Table 24: Results of CBA for the basic scenario and two scenarios related to input data sensitivity

Code	Name of the Project	Scenario 1: All benefits for 2050 included		Scenario 2: SoS benefit for 2050 and beyond set to 0 EUR		Scenario 3: All benefits for 2050 and beyond set to be the same as respective benefits in 2040	
		B/C	NPV (MEUR)	B/C	NPV (MEUR)	B/C	NPV (MEUR)
E01	Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)	28.39	620.44	5.29	97.09	7.10	138.06
E02	Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA)/Pljevlja (MN) – BA and MN sections	47.46	1,157.67	9.91	2.22	47.40	1,156.02
E03	New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain	1.69	46.05	1.30	20.26	1.86	57.23
E04	Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)	135.39	3,172.03	52.88	1,224.54	91.06	2,125.71
E05	400 kV interconnection corridor East – West, Western section	14.57	2,607.82	0.67	-63.55	0.89	-21.82
E12	Moglice Extension Pumped-Storage Hydropower Plant (PS Moglice Extension)	1.52	818.80	0.33	-2,081.92	0.50	-2,347.21
E13	Reconfiguration of 400 kV grid and new 400 kV interconnection Albania-Kosovo*	19.13	1,639.81	0.85	-167.27	0.54	-256.30
E15	330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA)	252.62	11,462.36	193.66	8,776.48	387.20	17,592.73

6 Conclusions

The complete PECI 2026 selection process is described through the set of reports, delivered by the consultants, as well through the minutes of the meetings of the PECI groups (electricity and gas). This document contains the most important part of the projects evaluation, describing the results of market and network simulations, feeding the CBA results, while other documents serve the PECI groups members to fully understand these results, explaining initial assumptions, data sets, and applied methodologies.

Calculations were done by strictly applying relevant methodologies from the TEN-Regulation, and by using input data provided by the Contracting Parties and ENTSO-E. However, significant uncertainties have been noticed in the input data, and consequently in the results, mainly with respect to the following:

- Economic viability of some projects is highly dependent on the assumptions for 2050, when large amounts of ENS appear in the model regarding the referent case;
- Some projects are also sensitive to the level of solar power plants integration.

Due to these reasons, we suggest that the Secretariat and the PECI electricity group consider three potential lists, among which only one shall be suggested as the draft preliminary PECI list, based on the decision of the Secretariat and the PECI electricity group.

The first list is based on direct application of all relevant methodologies and input data as delivered by the Contracting Parties, neglecting any sensitivities:

List 1 includes the following projects:

- E01: Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)
- E02: Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA)/Pljevlja (MN) – BA and MN sections
- E03: New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain
- E04: Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)
- E05: 400 kV interconnection corridor East-West, western section

- E12: Moglice Extension Pumped-Storage Hydropower Plant (PS Moglice Extension)
- E13: Reconfiguration of 400 kV grid and new 400 kV interconnection Albania – Kosovo
- E15: 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA).
- The second list is made by eliminating the projects showing high sensitivities on input data in 2050.

List 2 includes the following projects:

- E01: Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)
- E02: Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA)/Pljevlja (MN) – BA and MN sections
- E03: New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo 20 with construction 400/220 kV substation Piva's mountain
- E04: Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)
- E15: 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA).

The third list is made by eliminating the projects showing high sensitivities on input data in 2050, as well by eliminating other uncertainties (for example delta NTC values by applying PINT and TOOT method, solar PV integration level, unclear support from relevant ministry and regulatory authority).

List 3 includes the following projects:

- E01: Construction of the new interconnection, OHL 400 kV Gacko (BA) - Brezna (ME)
- E02: Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad
- E04: Rehabilitation of existing 220 kV lines Trebinje (BA) – Perućica (ME) – Podgorica (ME) – Vau Dejës (AL)
- E15: 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA).

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