Energy Community

Assessment for the identification of candidate PECI projects in line with EU Regulation 2022/869 Final Report

Infrastructure

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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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Contents

Abbreviations and acronyms

aFRR	automatic Frequency Regulation Reserve
AL	Albania
AZ	Azerbaijan
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
DE	Distributed Energy
DSO	Distribution System Operator
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
GA	Global Ambition
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
PMI	Projects of Mutual Interest
PSHPP	Pump Storage Hydro Power Plant
RE	Renewable Energy
RES	Renewable Energy Sources
RO	Romania
RR	Replacement Reserve
RS	Serbia
RU	Russia
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*

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1 Project objectives and activities

In February 2024, Energy Community Secretariat (ECS) conducted a public procurement process for **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**, in order to ensure assistance in compiling the preliminary list of **Projects of Energy Community Interest (PECI)**, in line with the Regulation (EU) No 2022/869 (further in text: the Regulation), as adopted in the Energy Community.

The Regulation was adopted in June 2022 at the EU level and built upon the Regulation (EU) No 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure (adopted in 2013) and also known as the **Trans-European Networks for Energy (TEN-E)**. The new Regulation (also known as the revised TEN-E) identifies eligible categories for energy infrastructure development projects and promotes better cooperation between countries, with the main objective **to ensure market and system integration** that benefits EU Member States with respect to the original regulation and Energy Community Contracting Parties (CPs) with respect to the adopted version in the Energy Community. The same is valid for the Energy Community Contracting Parties (CPs), since revised TEN-E was adopted in the EnC by the Ministerial Council Decision 2023/02/MC-EnC of 14 December 2023.

Eligible energy infrastructure categories, with respect to the EnC adaptation of the original regulation, may be divided into two broader categories, **electricity-related and gas-related projects**, with the specific eligible sub-categories. Potential eligible projects must involve **at least two Energy Community Contracting Parties** by directly or indirectly crossing the border thereof or be located on the territory of one Energy Community Contracting Party (EnC CP) having a significant cross-border impact on at least another EnC CP.

Based on the public procurement process, the ECS contracted Energy Institute Hrvoje Požar (further in text: the Consultant) with the main task to assist ECS and the two Groups (related to electricity and gas(es)) in compiling the preliminary list of PECI projects to be approved by the Ministerial Council. The main output of the entire process is the list of PECI projects to be submitted to the Ministerial Council for adoption in December 2024.

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.

During the project implementation, the Consultant has developed **a project-assessment methodology** which was used to evaluate the impact of the proposed projects on the Contracting Parties and the Energy Community as a whole. The methodology consists of **cost-benefit analysis (CBA)** to assess socio-economic dimensions of the projects (monetisation) in line with the methodologies published by the European Network of Transmission System Operators (ENTSO) for Electricity and the ENTSO for Gas or developed by the European Commission, and of **multi-criteria analysis (MCA)** to evaluate other important contributions of the projects (non-monetary component) in line with the indicators defined in the Regulation and primarily used for projects prioritisation. Both analyses and project impacts evaluation cover a time horizon until 2050.

1.1 Main project activities

In order to reach the final goal of the technical support, namely to draft the list of PECI, the Consultant carried out the following **tasks/activities**:

1. **Creation of candidate project questionnaires:** preparation of the project-specific questionnaires for collection of the relevant input data (technical, economic, status and progress) for candidate projects;
2. **Creation of country-specific questionnaires:** preparation of the country-specific data questionnaires for collection of the relevant country input data for CPs;
3. **Validation of the collected data:** validation of the collected input data in terms of techno-economic consistency;
4. **Project eligibility verification:** project eligibility verification based on the criteria defined in the Regulation, prior to modelling activities;
5. **ENTSO-E and ENTSOG scenarios modelling using modelling tool/s:** development of electricity sector models and scenarios using appropriate modelling tools that enable project assessment considering regional market conditions and existing energy infrastructure of the CPs;
6. **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;
7. **Assessment of the individual project candidates and composition of 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.

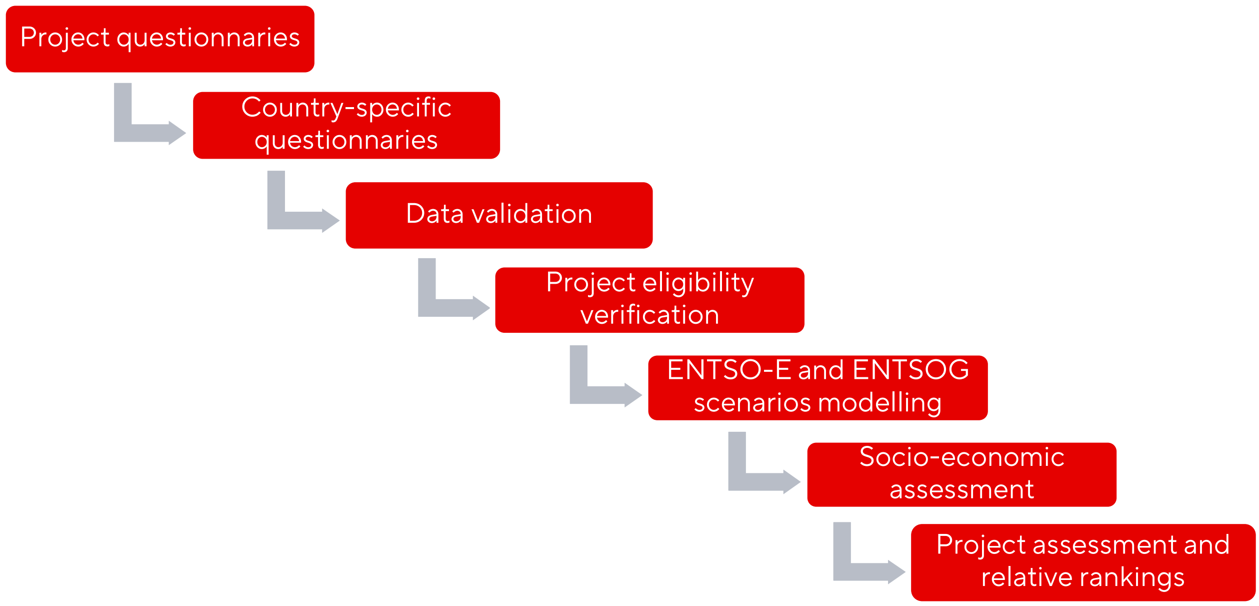

Figure 1. Activities carried out during the project implementation

1.2 Project meetings and deliverables

The project started 15th of February 2024 and the kick-of meeting was held on 16th of February 2024 when the Consultant presented their methodology for project execution to Energy Community Secretariat.

Inception report was prepared and delivered by the Consultant on 29th of February 2024. The 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**.

Public invitation for project promoters together with the project questionnaires for each of the eligible categories were published by the Energy Community Secretariat on 26th of February 2024. Promoters had a chance to submit their applications until the end of March 2024.

The first meeting of the electricity and gas(es) related Groups was held on 7th of March 2024. The Consultant presented approach, work plan and organization together with the project and country specific questionnaires.

Questionnaires for collection of country-specific data were created to collect input data for Energy Community Contracting Parties, i.e. the countries in which candidate projects should be located. Two separate country-specific template questionnaires were created for the electricity and gas sectors taking into account relevant market and infrastructural conditions in each country for the period until 2050. The relevant authorities had a chance to fill in the country-specific data until the 17th of April 2024. The second Groups' meeting was held on 18th of April 2024.

The **second phase of the project** was implemented after the data collection process. The initial data set for candidate projects and countries was used for **data validation and project eligibility verification**. The results of these activities are presented in ***Data Validation and Scenario Report*** which was delivered on 7th of May 2024.

After report delivery, the third Groups' meeting was held on 16th of May 2024. The members of the gas(es) related Group were not present at the third meeting because the data validation and eligibility verification process resulted with only electricity related projects for further assessment that includes modelling activities.

After data clarification/revision, collecting feedback on methodology, scenarios, data and assumptions, ***Analysis Techniques' Guidance Document*** containing a final description of the data, scenarios, applied methodologies and techniques, sensitivities to be carried out, and structure of the results and indicators was prepared in May 2024. Due to the comments of the European Commission and changes made upon the delivery of the report, the final version of the ***Analysis Techniques' Guidance Document*** was prepared and delivered in June 2024.

The **third and the last phase of the project** was the **project assessment** process. Based on the defined methodology, data, assumptions, scenarios and sensitivities, a project specific socio-economic assessment was made. Project assessment results were presented in 4th electricity related Group's meeting held on 19th of June 2024, together with the relative ranking of projects and preliminary PECI list.

This document presents the ***Final Report*** of the entire project containing a summary of the applied methodologies, 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 results of the CBA and MCA are based on application of relevant methodologies outlined in this report, utilizing input data provided by national authorities for the power systems of Contracting Parties and by project promoters regarding candidate projects.
The project assessment was made to evaluate regional impacts and welfare within the Energy Community Contracting Parties region, and not specific national benefits or benefits for individual project investors. Therefore, the outcomes of this assessment may differ in comparison to an economic viability assessment carried out by an investor or assessment carried on a national level.

2 Approach and methodologies for project assessment

2.1 Approach for project assessment

A graphical presentation of the approach for project assessment is presented in Figure 2. The **data collection process**, during which project-related data and country-specific data were collected, was finalized in early May 2024 when the last set of country data was received. After data collection, **data validation and verification** were carried out. Several iterations were made to clarify the delivered data or to submit additional data by project promoters and national authorities.

The next step was **projects' eligibility verification** which was made according to the general, specific and technical criteria that are in detail described and presented in the ***Data Validation and Scenario Report***. Eligibility verification resulted with the final list of eligible projects for further project assessment (presented in section 3), i.e. CBA and MCA that include modelling activities based on the relevant methodologies. Applied methodologies are described in section 2.2.

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

- **Development of the reference scenario (without any of the candidate projects)**, against which all projects are assessed,
    - Each project is added to the reference scenario to determine its benefits (*PINT modelling approach*[1]) until 2050,
- **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.**

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 revised TEN-E Regulation. The compliance with this criterion requires to apply project assessment methodology that considers the modelling of the system in which the new project should be incorporated[2].

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[1] *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.*

[2] *At the EU level this assessment is made by the ENTSO-E while preparing the TYNDPs, at the EnC level this is done separately by conducting market and network simulations for relevant scenarios and time frames.*

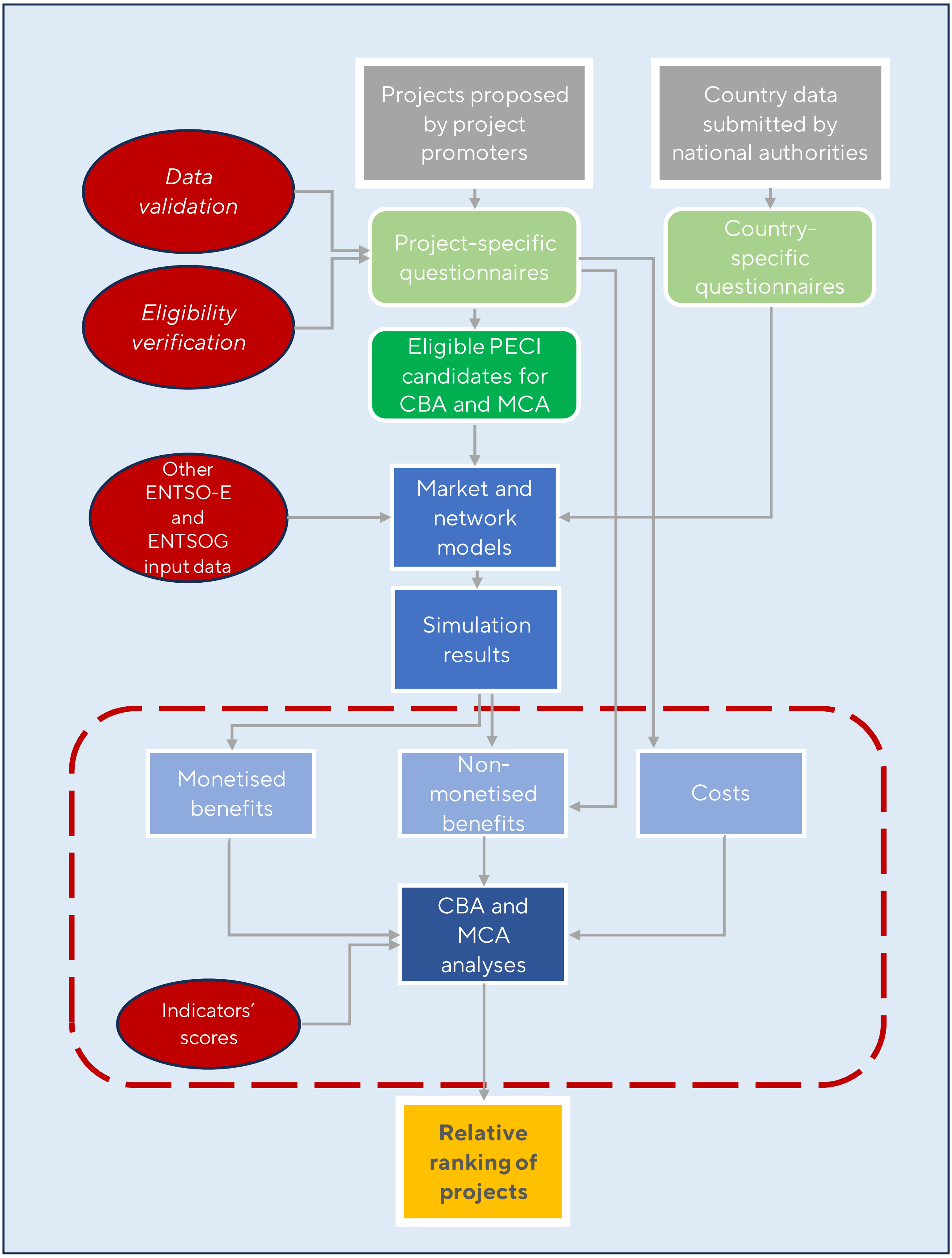

Figure 2. Project assessment approach

In order to apply methodology for project assessment electricity sector model was developed that enables project assessment considering **regional market conditions** and energy infrastructure of the Contracting Parties. In the eligibility verification process, all the gas(es) candidate projects were declared as not eligible[3]. 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 by minimizing costs over the planning horizon, and 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 been established (against which all projects are assessed). The reference case assumes energy system without any of the project candidates, and simulation results for this scenario are used to compare results for the scenario that includes the project under consideration and to calculate the benefits of adding a certain project into the system.

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 the impact of the project on network losses.

While some benefits of the projects are determined based on the modelling results, there are also benefits that are assessed based on the data sent by the project promoters, depending on specific assessment criteria set out in the respective methodologies.

Calculated monetised benefits and costs were used as inputs for the CBA of each project. In addition to the CBA, a multi-criteria analysis was conducted to address benefits that cannot be monetised. Based on the results of both quantitative and qualitative analyses, an individual project assessment was made for each eligible project. Evaluated benefits were scored according to the approach described in the section 2.3. The calculated total scores of each individual project were used to propose **a relative ranking of all eligible projects** as the final output of the assessment.

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. This is assessed by taking into account the Distributed Energy scenario in 2050 defined under TYNDP by the ENTSO-E, through the sensitivity analysis including -20% of the forecasted demand and by

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[3] More details available in Data Validation and Scenario Report.

[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.

calculating network losses for each eligible project (decrease of losses contributes to the energy efficiency).

2.2 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 also in line with the TEN-E Regulation, as adopted in the Energy Community, and are described in the following sections for each of the categories of projects that were found eligible.

Eligibility verification resulted with the projects for CBA and MCA analyses in the following electricity infrastructure categories (more details available in section 3):

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

Thus, the methodologies that 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):

- **CBA Methodology of the ENTSO-E** (applied for the overhead transmission lines projects)
    - 4th ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects*, April 2024.*

- **Methodology developed by the European Commission** (applied to the energy storage project)
    - Harmonised system-wide cost-benefit analysis for candidate energy storage projects*, May 2023.*

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 2023 PCI/PMI process at the EU level:

- *Methodology for assessing the electricity and offshore infrastructure candidate PCI and PMI 1st Union PCI-PMI list 2023, June 2023.*

The ***TYNDP-specific CBA Implementation Guidelines*** as an accompanying document of the *4th ENTSO-E CBA Guideline*, was also used for project assessment calculations.

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,

[5] *But not necessarily strictly followed.*

- 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 (not applicable at the moment since this is the 1st PECI selection process under the revised/new TEN-E Regulation).

2.2.1 High and extra-high voltage overhead transmission lines

According to the TEN-E Regulation, the PECI eligible candidates falling under electricity transmission, distribution and energy storage infrastructure categories shall contribute:

- **significantly to sustainability** through the integration of renewable energy into the grid, the transmission or distribution of renewable generation to major consumption centers and storage sites, and to reducing energy curtailment, where applicable,

and to **at least one** of the specific criteria:

- **market integration**, including through lifting the isolation of at least one CPs and reducing energy infrastructure bottlenecks, competition, interoperability and system flexibility,
- **security of supply**, including through interoperability, system flexibility, cybersecurity, appropriate connections and secure and reliable system operation.

According to the Annex IV in the TEN-E Regulation, these criteria must be measured in the following manner:

- **transmission of renewable energy generation** to major consumption centres and storage sites, by estimating the amount of generation capacity from renewable energy sources (by technology, in MW), which is connected and transmitted due to the project, compared to the amount of planned total generation capacity from those types of renewable energy sources without the project,
- **market integration, competition and system flexibility**, in particular by:
  - calculating, for cross-border projects, including reinvestment projects, the impact on the grid transfer capability in both power flow directions, measured in terms of amount of power (in MW), and their contribution to reaching the minimum 15 % interconnection target[6], and for projects with significant cross-border impact, the impact on grid transfer capability at borders between relevant Contracting Parties, and on demand-supply balancing and network operations in relevant Contracting Parties,
  - assessing the impact, in terms of energy system-wide generation and transmission costs and evolution and convergence of market prices provided by a project under various planning scenarios, in particular taking into account the variations induced on the merit order,

[6] *According to the EnC Secretariat's study "Electricity interconnection targets in the Energy Community Contracting parties" all EnC CPs satisfy 15% interconnection target except Ukraine.*

- **security of supply, interoperability and secure system operation**, in particular by assessing the impact of the project on the loss of load expectation in terms of generation and transmission adequacy for a set of characteristic load periods, taking into account expected changes in climate- related extreme weather events and their impact on infrastructure resilience. Where applicable, the impact of the project on independent and reliable control of system operation and services shall be measured.

In order to determine whether the abovementioned criteria are satisfied, specific methodologies have to be used for each project category. According to the TEN-E Regulation, the single sector draft methodologies published by the ENTSO-E and ENTSOG respectively under Article 11 of Regulation shall be applied to the projects of high and extra-high voltage overhead transmission lines. Since in this PECI process only electricity projects are eligible, that means that only ENTSO-E Methodology must be used.

The ***4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects*** defines nine categories of possible benefits that the construction of overhead transmission line can obtain. They are shown in Figure 3.

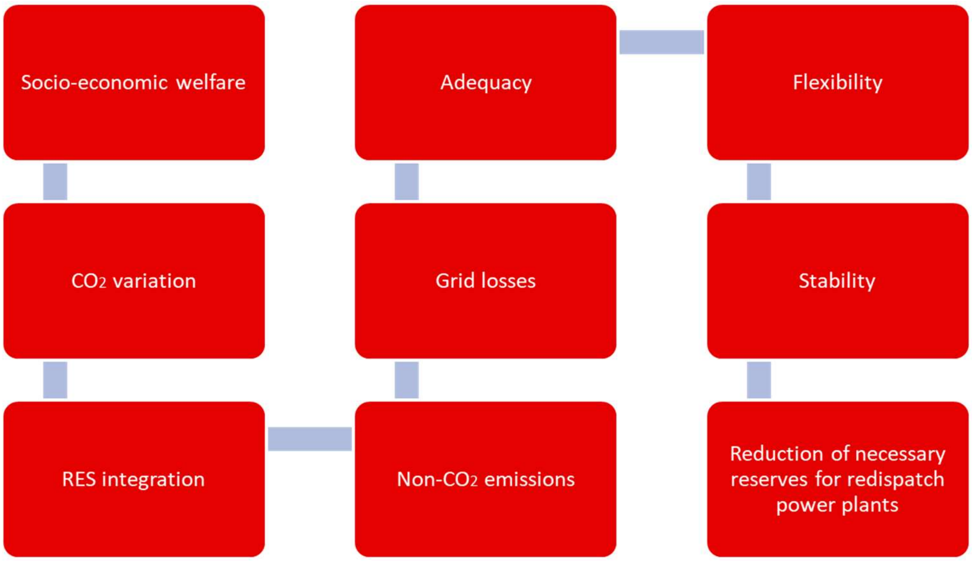

Figure 3. Project benefits for grid development projects

Out of these project benefits, some can be quantified and monetised, while others can only be qualitatively described. Through the use of synchronized market and network models, the following indicators were monetised:

- **Socio – economic welfare (SEW)** – this indicator reflects the contribution of the project in increasing transmission capacity(ies) over the borders of the EnC CPs (excluding the EU Member States), making an increase in commercial exchanges possible so that electricity markets can trade power in a more economically efficient manner. The monetisation of SEW is done in EUR/yr. For this indicator, **generation cost method is used to monetize the increase in SEW**, by determining a difference between the total generation costs in the power systems of EnC countries with and without the project, based on the PLEXOS market simulation results.
- **Additional Societal benefit due to CO_2 variation** – this indicator is used to properly reflect the EU objectives of CO_2 emissions reduction. To avoid double counting with

the CO_2 variation already monetised into the SEW (B1) and the losses (B5), changes in CO_2 emission (without and with a project) are multiplied by the difference between the CO_2 societal cost[7] and the ETS price used in the scenario.
- **Security of supply (SoS)** – this indicator is calculated in case there is an occurrence of unserved energy in the modelling results and is then monetised by multiplying that unserved energy with the value of lost load (VoLL)[8].
- **Grid losses** – this indicator is used to reflect the changes in transmission system losses that can be attributed to a project. The energy efficiency benefit of a project is measured through the change of thermal losses in the grid due to the project. For the grid losses calculation, both market and network models are used – in the network model the amount of losses (GWh) is calculated and then multiplied by marginal electricity prices acquired from the market model in order to fully monetize this benefit.

Described indicators serve to determine whether each project complies with the specific TEN-E Regulation criteria:

- **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).

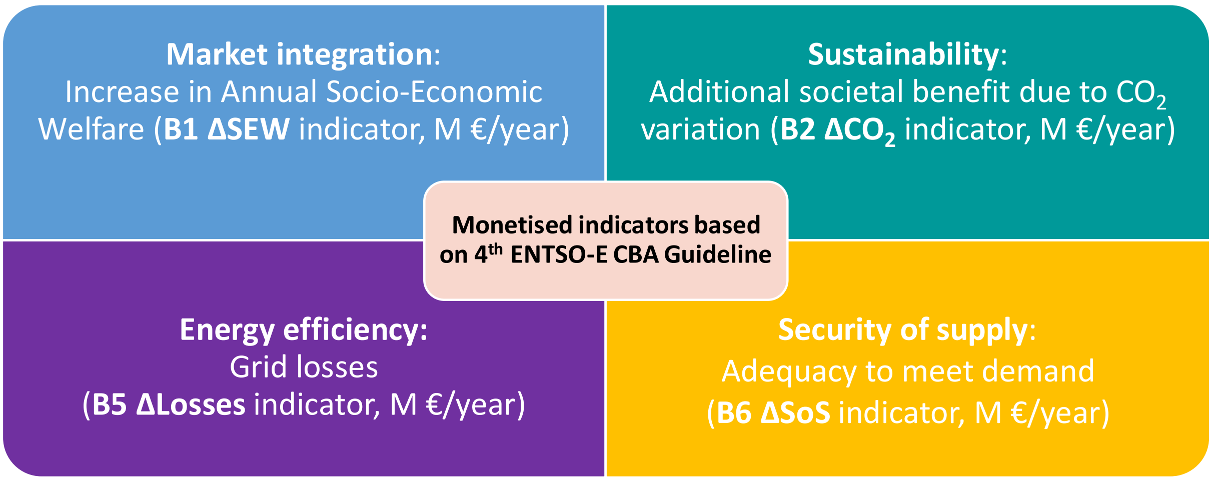

Figure 4. Monetised benefits for overhead transmission lines based on 4th ENTSO-E CBA Guidelines and in relation to eligibility criteria set out in the TEN-E Regulation

[7] *CO_2 societal cost is assumed according to the high levels in the TYNDP 2024: 189 EUR/t in 2030 and 498 EUR/t in 2040.*

[8] *VoLL used to monetise the SoS indicator is 3000 EUR/MWh.*

Other benefits were not monetized but qualitatively described and scored based on the approach described in section 2.3.

Figure 5 shows benefits that are evaluated for overhead transmission line projects, as well as the costs that are used to calculate benefit-cost ratio.

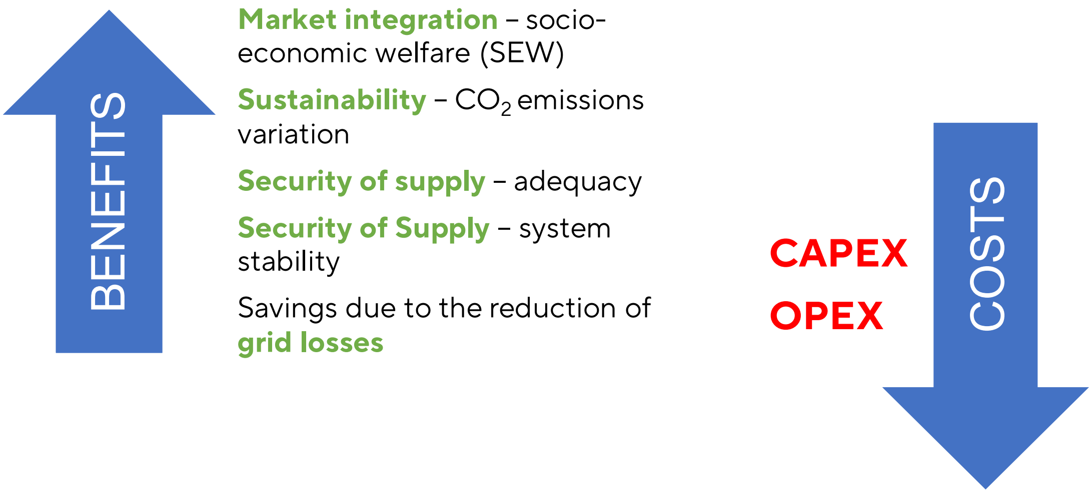

Figure 5. Benefits and costs for high and extra high voltage overhead transmission line projects according to the relevant methodologies

2.2.2 Energy storage

For energy storage projects, the TEN-E Regulation prescribes the same contributions as in the case of overhead transmission lines, i.e. the project must contribute:

- **significantly to sustainability** through the integration of renewable energy into the grid, the transmission or distribution of renewable generation to major consumption centers and storage sites, and to reducing energy curtailment, where applicable,

and to **at least one** of the specific criteria:

- **market integration**, including through lifting the isolation of at least one CPs and reducing energy infrastructure bottlenecks, competition, interoperability and system flexibility;
- **security of supply**, including through interoperability, system flexibility, cybersecurity, appropriate connections and secure and reliable system operation.

According to the Annex IV from the TEN-E Regulation, these criteria must be measured in the following manner:

- **transmission of renewable energy generation** to major consumption centres and storage sites, by comparing new capacity provided by the energy storage project with total existing capacity for the same storage technology in the area of the analysis,
- **market integration, competition and system flexibility**, in particular by:

  - calculating, for cross-border projects, including reinvestment projects, the impact on the grid transfer capability in both power flow directions, measured in terms of amount of power (in MW), and their contribution to reaching the minimum 15 % interconnection target, and for projects with significant cross-border impact, the impact on grid transfer capability at borders between relevant Contracting Parties, and on demand-supply balancing and network operations in relevant Contracting Parties,
  - assessing the impact, in terms of energy system-wide generation and transmission costs and evolution and convergence of market prices provided by a project under various planning scenarios, in particular taking into account the variations induced on the merit order,
- **security of supply, interoperability and secure system operation**, in particular by assessing the impact of the project on the loss of load expectation in terms of generation and transmission adequacy for a set of characteristic load periods, taking into account expected changes in climate- related extreme weather events and their impact on infrastructure resilience. Where applicable, the impact of the project on independent and reliable control of system operation and services shall be measured.

For energy storage projects, ***Harmonised system-wide cost-benefit analysis for candidate energy storage projects****, May 2023*, is applied in project assessment process. This methodology defines monetised, non-monetised (quantified) and qualitative benefits for energy storage projects.

CBA methodology for energy storage projects is similar to the ENTSO-E CBA methodology and recognises the following main benefits that must be calculated:

- **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 (**B8 ΔSoS** indicator, M €/year)
- **Grid losses:** (**B5 ΔLosses** indicator, M €/year).

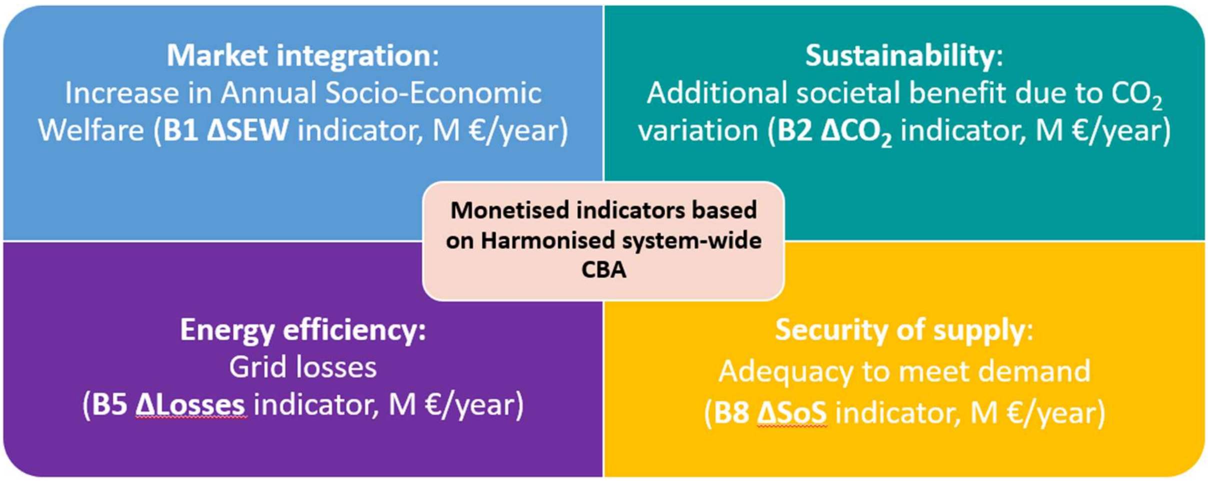

Figure 6. Monetised benefits for energy storage projects based on Harmonised system-wide CBA for candidate energy storage projects and in relation to eligibility criteria set out in the TEN-E Regulation

Along with these indicators, some indicators are given in the methodology as non-monetized that can be described qualitatively or quantified, or possibly monetised but under special conditions (available models and data) like RES integration (B3), Variation of non-CO_2 emissions (B4), Variation of electricity balancing markets services (B6), Variation in other ancillary services markets (B7), Generation capacity deferral (B8), Transmission capacity deferral (B10), and Variation of redispatch services (B11). These are described only if there is enough information in the project application on those indicators. Figure 7. shows the benefits and costs that were considered in the analysis of the energy storage project.

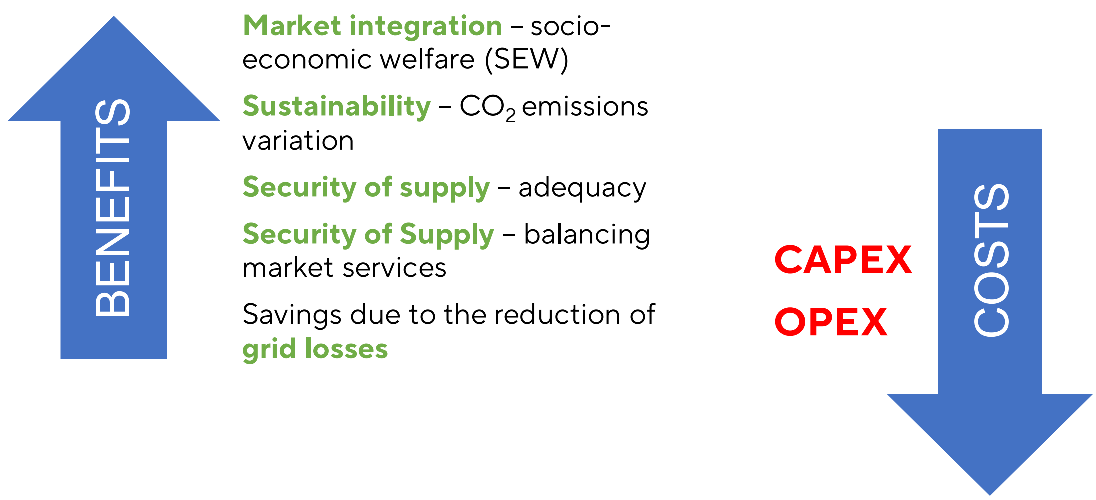

Figure 7. Benefits and costs for energy storage projects according to the relevant methodologies

2.3 Structure of results

This section represents the main indicators determined under the CBA and MCA analyses for each PECI candidate project within the relevant infrastructure category, based on the methodologies presented in the previous section, and simulations carried out using market and network tolls using the input data set described in section 4.

When determining the benefits of each candidate OHL project, market and network simulations were carried out with and without the proposed project. The impact of each proposed project was analysed within the benefits defined by the relevant methodologies as presented in the previous sections. The benefits, i.e. indicators that were calculated in the project assessment process refer to monetised, and non-monetised indicators.

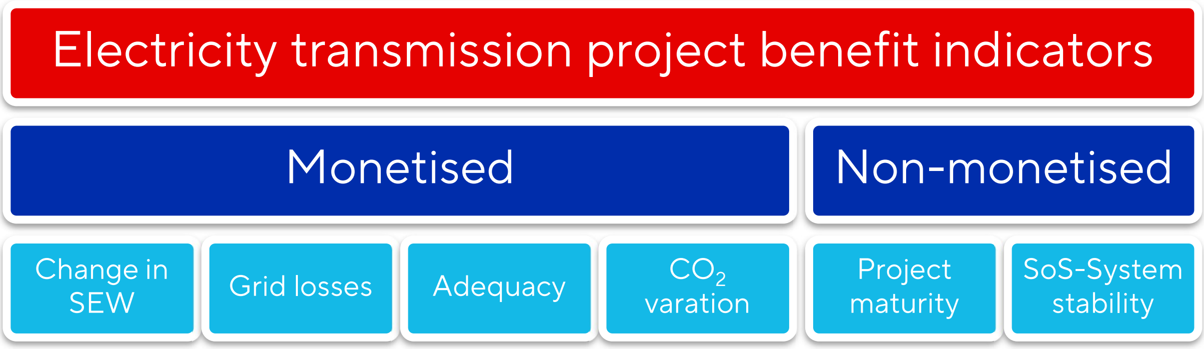

Figure 8. Monetised and non-monetised project assessment indicators – electricity transmission lines

The same approach was applied to determine the possible benefits of the energy storage project, i.e., market and network simulations were carried out with and without the proposed project. The benefits that were calculated refer to monetised, and non-monetised indicators presented in the following figure.

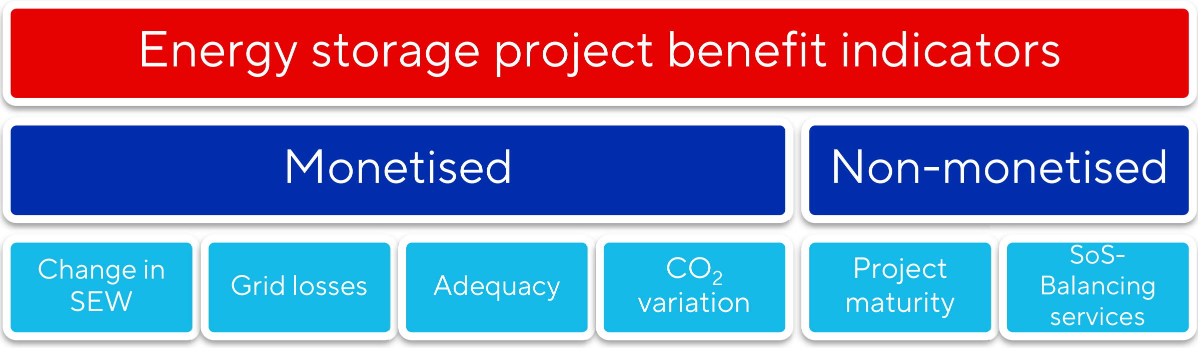

Figure 9. Monetised and non-monetised project assessment indicators – energy storage

All the monetised indicators (change in SEW, grid losses, CO_2 variation, adequacy) are the same as in the case of electricity transmission lines.

Non-monetised indicators refer to **project maturity and Security of Supply (SoS)** for both project categories. However, the SoS indicator is measured differently: it is assessed through system stability for overhead transmission lines and through the provision of balancing services for energy storage projects. The following paragraphs describe the scoring approach of each indicator, both monetized and non-monetized, to enable the relative ranking of projects based on their total score.

2.3.1 Benefit/Cost ratio

The monetised part of the project assessment is composed of all the monetised project benefits and project costs (CAPEX and OPEX). Monetised benefits (change in SEW, CO_2 variation, grid losses and adequacy) for each project are determined based on the comparison of modelling results for the reference scenario (without the project) and for the scenario with the project. Data on CAPEX and OPEX were delivered by project promoters and verified by the Consultants. Although significant deviations in unit investment costs were found between different projects, no crucial deviations from expected values were found, i.e., unit costs are within the expected range.

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

The **B/C ratio** is determined as the present value of all monetised benefits divided by the present value of all 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.

For projects **with B/C ratio higher than one**, points are allocated to enable project ranking under the same infrastructure category. Namely, it is anticipated that only projects with a B/C ratio above one (or a positive NPV) will generate a net benefit for the CPs. The maximum points that a project can receive based on **the B/C ratio is 20**, as presented in the table below.

Table 1. Possible points for B/C ratio of the project

Range of B/C ratio value	Points
1	10
1-2	11
2-3	12
3-4	13
4-5	14
5-6	15
6-7	16
7-8	17
8-9	18
9-10	19
>10	20

2.3.2 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 *4th 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. Thus, for small to moderate impact on system's stability ('+'), 0.4 points is assigned, and for significant impact ('++'), 0.8. points are assigned. Thus, theoretically, a project that has a maximum impact of 5 '+' can be assigned with maximum of **2 points** (5*0.4).

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 2022 (ENTSO-E 2022), 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.

In the MCA, for small to moderate impact on system's stability ('+'), 0.4 points is assigned, and for significant impact ('++'), 0.8. points are assigned. Thus, theoretically, a project that has a maximum impact of 5 '+' can be assigned with maximum of **2 points** (5*0.4).

2.3.3 Project maturity

Project maturity also contributes to the final scoring of each eligible project. It is determined based on data regarding the status/completion of project development phases provided by project promoters through project questionnaires. All project development phases are presented in Table 2. For the completion of each project development phase a score of 0.5 point is assigned. **A maximum of 5 points** can be received for completion of all project phases before the construction. This indicator serves the more mature projects to be additionally awarded and prioritised comparing with less mature projects.

Table 2. Project development phases and possible points based on the phase completion

Project development phase	Possible points for phase completion
Prefeasibility study	0.5
Technical feasibility study	0.5
Economic feasibility study (Cost-benefit analysis)	0.5
Environmental impact assessment	0.5
Detailed design study	0.5
Resloved financing	0.5
Obtained approvals/permits	0.5
Approval by regulatory authority	0.5
Final investment decision	0.5
Tendering procedure	0.5

2.4 Relative ranking of projects

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 (section 5.2.3). Projects are ranked if it is determined that their overall benefits outweigh their costs. For electricity transmission overhead lines and energy storage projects, a maximum of **27 points** can be assigned based on the indicator scoring presented in previous sections and summarized in Table 3.

The projects are ranked from highest to lowest total score, ranging from 27 points down to 10 points (which represents the threshold for a project to be economically viable, i.e., having a B/C ratio > 1). The ranking should be done separately for the transmission and storage projects. However, only one energy storage project is eligible for CBA and MCA; therefore, scores are assigned to this project but no ranking is provided in this infrastructure category.

Table 3. Maximum points per each benefit indicator for ranking of electricity transmission and energy storage projects

Indicator	Maximum points
B/C ratio	20
SoS - System stability (OHL) or Balancing services (Storage)	2
Project maturity	5
TOTAL	**27**

3 Projects' eligibility overview

In this section general and specific eligibility criteria for candidate projects are presented, followed by projects' overview and their compliance with the listed criteria.

3.1 Eligibility assessment criteria

In order for a project to be found eligible, it must comply with the eligibility criteria described in the TEN-E Regulation. There are several categories of criteria that are mentioned in the TEN-E Regulation. The first category that projects must comply with in order to be further assessed is the following **general eligibility criteria**:

- the project falls in at least one of the **energy infrastructure priority interconnection corridors** and areas set out in Annex I of the TEN-E Regulation;
- the potential **overall benefits of the project outweigh its costs**, including in the longer term (will be calculated later through the CBA);
- the project meets any of the following criteria:
  - o it involves at least two Contracting Parties by directly or indirectly, via interconnection with a third country, crossing the border of two or more Contracting Parties;
  - o it is located on the territory of one Contracting Parties, either inland or offshore, including islands, and has a significant cross-border impact.

The following specific criteria apply to PECI falling within **specific energy infrastructure categories**:

(a) **for electricity transmission**, distribution and storage projects the project contributes significantly to sustainability through the integration of renewable energy into the grid, the transmission or distribution of renewable generation to major consumption centres and storage sites, and to reducing energy curtailment, where applicable, and contributes to at least one of the following specific criteria:

(i) market integration, including through lifting the energy isolation of at least one Contracting Party and reducing energy infrastructure bottlenecks, competition, interoperability and system flexibility;

(ii) security of supply, including through interoperability, system flexibility, cybersecurity, appropriate connections and secure and reliable system operation;

(b) **for smart electricity grid projects**, the project contributes significantly to sustainability through the integration of renewable energy into the grid, and contributes to at least two of the following specific criteria:

(i) security of supply, including through efficiency and interoperability of electricity transmission and distribution in day-to-day network operation, avoidance of congestion, and integration and involvement of network users;

(ii) market integration, including through efficient system operation and use of interconnectors;

(iii) network security, flexibility and quality of supply, including through higher uptake of innovation in balancing, flexibility markets, cybersecurity, monitoring, system control and error correction;

(iv) smart sector integration, either in the energy system through linking various energy carriers and sectors, or in a wider way, favouring synergies and coordination between the energy, transport and telecommunication sectors;

(c) **for carbon dioxide transport and storage projects** the project contributes significantly to sustainability through the reduction of carbon dioxide emissions in the connected industrial installations and contributes to all of the following specific criteria:

(i) avoiding carbon dioxide emissions while maintaining security of supply;

(ii) increasing the resilience and security of transport and storage of carbon dioxide;

(iii) the efficient use of resources, by enabling the connection of multiple carbon dioxide sources and storage sites via common infrastructure and minimising environmental burden and risks;

(d) **for hydrogen**, the project contributes significantly to sustainability, including by reducing greenhouse gas emissions, by enhancing the deployment of renewable or low carbon hydrogen, with an emphasis on hydrogen from renewable sources in particular in end-use applications, such as hard-to-abate sectors, in which more energy efficient solutions are not feasible, and supporting variable renewable power generation by offering flexibility, storage solutions, or both, and the project contributes significantly to at least one of the following specific criteria:

(i) market integration, including by connecting existing or emerging hydrogen networks of Contracting Parties, or otherwise contributing to the emergence of an Energy Community-wide network for the transport and storage of hydrogen, and ensuring interoperability of connected systems;

(ii) security of supply and flexibility, including through appropriate connections and facilitating secure and reliable system operation;

(iii) competition, including by allowing access to multiple supply sources and network users on a transparent and non-discriminatory basis;

(e) **for electrolysers**, the project contributes significantly to all of the following specific criteria:

(i) sustainability, including by reducing greenhouse gas emissions and enhancing the deployment of renewable or low-carbon hydrogen in particular from renewable sources, as well as synthetic fuels of those origins;

(ii) security of supply, including by contributing to secure, efficient and reliable system operation, or by offering storage, flexibility solutions, or both, such as demand side response and balancing services;

(iii) enabling flexibility services such as demand response and storage by facilitating smart energy sector integration through the creation of links to other energy carriers and sectors;

(f) **for smart gas grid projects**, the project contributes significantly to sustainability by ensuring the integration of a plurality of low-carbon and particularly renewable gases, including where they are locally sourced, such as biomethane or renewable hydrogen, into the gas transmission, distribution or storage systems in order to reduce greenhouse gas emissions, and that project contributes significantly to at least one of the following specific criteria:

(i) network security and quality of supply by improving the efficiency and interoperability of gas transmission, distribution or storage systems in day-to-day network operation by, inter alia, addressing challenges arising from the injection of gases of various qualities;

(ii) market functioning and customer services;

(iii) facilitating smart energy sector integration through the creation of links to other energy carriers and sectors and enabling demand response.

The projects that satisfy general and specific eligibility criteria can then be further assessed for **additional specific (technical) criteria** per different energy infrastructure categories based on the TEN-E Regulation:

- for **electricity transmission**: the project increases the grid transfer capacity, or the capacity available for commercial flows, at the border of that CP with one or several other CPs, or at any other relevant cross-section of the same transmission corridor having the effect of increasing this cross-border net transfer capacity, by at least 500 MW compared to the situation without commissioning of the project;
- for **electricity storage**: the project provides at least 225 MW installed capacity and has a storage capacity that allows a net annual electricity generation of 250 GWh/year;
- for **smart electricity grids**: the project is designed for equipment and installations at high-voltage and medium voltage level, and involves TSOs, TSOs and DSOs, or DSOs from at least two CPs; the project should satisfy at least two of the following criteria: it involves 50 000 users, generators, consumers or prosumers of electricity, it captures a consumption area of at least 300 GW hours/year, at least 20% of the electricity consumption linked to the project originates from variable renewable resources, or it decreases energy isolation of non-interconnected systems in one or more CPs;
- for **smart gas grids**: the project involves TSOs, TSOs and DSOs, or DSOs from at least two CPs. DSOs may be involved, but only with the support of the TSOs of at least two CPs that are closely associated to the project and ensure interoperability;
- for **hydrogen**: hydrogen transmission - the project enables the transmission of hydrogen across the borders of the CPs concerned, or increases existing cross-border hydrogen transport capacity at a border between two CPs by at least 10% compared to the situation prior to the commissioning of the project, and the project sufficiently demonstrates that it is an essential part of a planned cross-border hydrogen network and provides sufficient proof of existing plans and cooperation with neighbouring countries and network operators or, for projects decreasing energy isolation of non-interconnected systems in one or more CPs, the project aims to supply, directly or indirectly, at least two CPs; hydrogen storage or hydrogen reception facilities - the project aims to supply, directly or indirectly, at least two CPs;
- for **electrolysers**: the project provides at least 50 MW installed capacity provided by a single electrolyser or by a set of electrolysers that form a single, coordinated project and brings benefits directly or indirectly to at least two CPs,
- for **carbon dioxide** projects: the project is used to transport and, where applicable, store anthropogenic carbon dioxide originating from at least two CPs.

3.2 Projects' overview

As a first step in the eligibility process, all data related to the nominated projects were analysed. In total, there were 17 nominated projects. A list of all the projects nominated for this PECI cycle, with involved CPs, is shown in Figure 10.

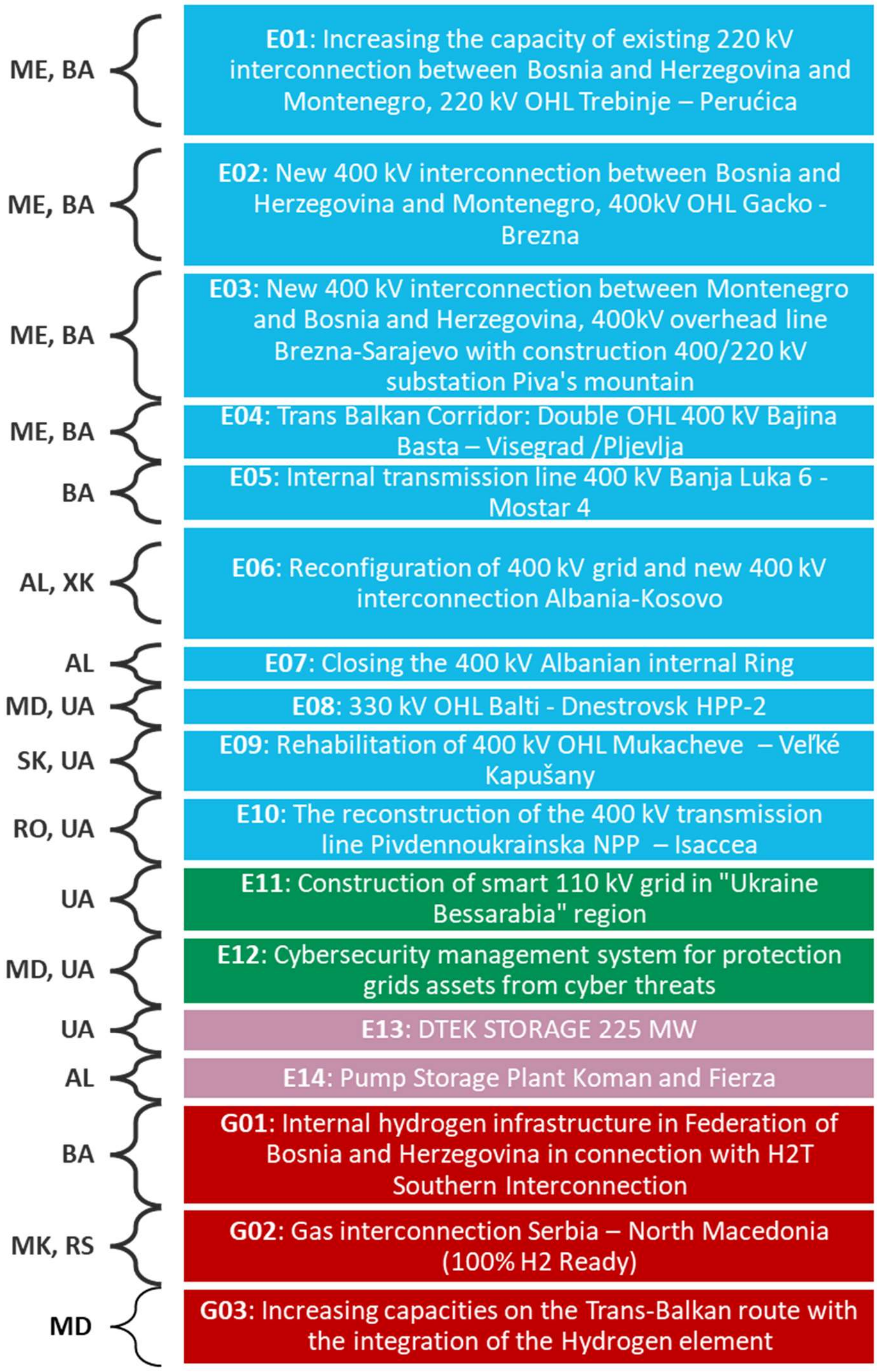

Figure 10. List of nominated projects (blue-OHLs, green-smart electricity grids, purple-electricity storage, red-gas(es))

In the electricity infrastructure category there were 14 nominated projects - ten of those nominated projects were high and extra high transmission lines and pertaining equipment, two projects were in the category of smart electricity grids and two projects were related to the energy storage facilities category. In the gas(es) eligible energy infrastructure category according to the TEN-E Regulation there were three nominated projects – two of those were nominated as hydrogen systems, including hydrogen pipelines, and one nominated project was a smart gas grid.

Through the analysis of the nominated projects in order to determine which ones are eligible, several criteria were examined. Namely, in order to find a project as eligible, it must comply with the general, specific and technical criteria as set out in the TEN-E Regulation. The details on how the project complies with the general, specific and technical criteria outlined in the TEN-E Regulation can be found in the ***Data Validation and Scenario Report***, along with specific descriptions provided for each project regarding its compliance with the eligibility criteria.

A brief summary of eligibility check and technical data verification is given in the table below.

Table 4. Summary of eligibility check and technical data verification

Project code	General criteria compliance	Specific criteria compliance	Technical data verification	Investment cost verification	Eligibility
E01	✓	✓	✓	✓	✓
E02	✓	✓	✓	✓	✓
E03	✓	✓	✓	✓	✓
E04	✓	✓	✓	✓	✓
E05	✓	✓	✓	✓	✓
E06	✓	✓	✓	✓	✓
E07	✓	✓	✓	✓	✓
E08	✓	✓	✓	✓	✓
E09	✗				✗
E10	✗				✗
E11	✓	✗			✗
E12	✓	✗			✗
E13	✓	✓	✓	✓	✓
E14	✓	✓	✗	✓	✗
G01	✓				✗
G02	✓				✗
G03	✓				✗

In the process of eligibility verification, it was found that out of 17 nominated projects, only nine complies fully to the general and specific criteria that they must comply with in order to go into the next stage of the analysis, which is the cost-benefit analysis and multi-criteria analysis. Those nine projects are listed below.

E01: Increasing the capacity of existing 220 kV interconnection between Bosnia and Herzegovina and Montenegro, 220 kV OHL Trebinje – Perućica

E02: New 400 kV interconnection between Bosnia and Herzegovina and Montenegro, 400 kV OHL Gacko – Brezna

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: Trans Balkan Corridor: Double OHL 400 kV Bajina Basta – Visegrad/Pljevlja (BA and ME section)

E05: Internal transmission line 400 kV Banja Luka 6 - Mostar 4

E06: Reconfiguration of 400 kV grid and new 400 kV interconnection Albania-Kosovo

E07: Closing the 400 kV Albanian internal ring

E08: 330 kV OHL Balti - Dnestrovsk HPP-2

E13: DTEK STORAGE 225 MW

Figure 11. List of eligible projects for CBA and MCA analysis[9]

From these nine projects, eight are in the electricity category of high and extra high overhead lines, while one is in the electricity category of energy storage facilities. Short descriptions and locations of the eligible projects are presented hereinafter.

[9] *Since there are three potentially competing projects over the same border ME-BA (E01, E02, E03) there is a large probability that the realisation of one project may influence the economic viability of the other two projects. Since two projects were found to have B/C < 1, such risk was not analysed.*

E01: Increasing the capacity of existing 220 kV interconnection between Bosnia and Herzegovina and Montenegro, 220 kV OHL Trebinje – Perućica

Project promoter(s): CGES (ME), NOSBiH/Elektroprijenos BiH (BA)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2028

ΔNTC increase: ME-BA 500 MW, BA-ME 500 MW, as declared and verified by the project promoters.

Project description (as defined by the project promoters):

Benefits include resolving existing congestions between Bosnia and Herzegovina and Montenegro, enabling and supporting integration of a large number of RES in Bosnia and Herzegovina (region of East Herzegovina) and Montenegro (southwest region), increasing net transfer capacity (NTC) of energy from Bosnia and Herzegovina to Montenegro and Montenegro to Bosnia and Herzegovina and further development and integration of the market, security of supply, elimination of perceived insecurities in the past period.

Figure 12. Location of E01

E02: New 400 kV interconnection between Bosnia and Herzegovina and Montenegro, 400 kV OHL Gacko - Brezna

Project promoter(s): CGES (ME), NOSBiH/Elektroprijenos BiH (BA)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2035

ΔNTC increase: ME-BA 876 MW, 567 MW BA-ME, as declared and verified by the project promoters.

Project description (by project promoters): New 400 kV interconnection between Bosnia and Herzegovina and Montenegro will connect SS Gacko (BA) with SS Brezna (ME), total length about 51 km. Benefits include enabling and supporting integration of a large number of RES in Bosnia and Herzegovina (region of East Herzegovina) and Montenegro (west region), enabling the transfer of energy from Bosnia and Herzegovina to Montenegro and avoiding existing congestions between Bosnia and Herzegovina and Montenegro, further development and integration of the market and security of supply. Reduction of losses about 5 GWh (-4%) in Montenegro and Bosnia and Herzegovina 6.4 GWh (-1.5%).

Figure 13. Location of E02

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

Project promoter(s): CGES (ME), NOSBiH/Elektroprijenos BiH (BA)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2033

ΔNTC increase: ME-BA 725 MW, BA-ME 584 MW, as declared and verified by the project promoters.

Project description (by project promoters): The new 400 kV interconnection between Montenegro and Bosnia and Herzegovina would connect 400/110/35 kV substation Brezna in Montenegro with 400/220/110/x substation Sarajevo 20 in Bosnia and Herzegovina with construction of substation 400/220 kV Piva's mountain. New 400 kV interconnection transmission overhead line with the construction of new 400/220 kV SS Piva's mountain and establishment of a connection between HPP Piva and new SS Piva's mountain is analysed within two phases of construction. Expected benefits from the project are: reduction of losses in the transmission system, security of supply, connection of renewable energy sources to the transmission system, the new connection between Montenegro and Bosnia and Herzegovina will eliminate the possibility of congestion with increase of the NTC at this border and electricity market integration.

Figure 14. Location of E03

E04: Trans Balkan Corridor: Double OHL 400 kV Bajina Bašta (RS) – Višegrad (BA)/Pljevlja (ME) (BA and ME section)

Project promoter(s): NOSBiH/Elektroprijenos BiH (BA), CGES (ME)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2027

ΔNTC increase: ME-RS 600 MW, ME-RS 600 MW, and BA-RS 300 MW and RS-BA 500 MW, as declared by the project promoters

Project description (by project promoters): Increasing NTC between Serbia and Bosnia and Herzegovina, enabling full capacity production of HPP Višegrad (N-1 criteria), and increasing and support to RES integration.

Figure 15. Location of E04

E05: Internal transmission line 400 kV Banja Luka 6 - Mostar 4

Project promoter(s): NOSBiH/Elektroprijenos BiH (BA)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2034

ΔNTC increase: BA-ME 400 MW, ME-BA 350 MW, BA-RS 200 MW, RS-BA 200 MW, as declared by the project promoters.

Project description (by project promoters): Enabling and supporting integration of a large number of RES, enabling the transfer of energy through Bosnia and Herzegovina power system and avoiding possible congestion in the transmission network, further development and integration of the market.

Figure 16. Location of E05

E06: Reconfiguration of 400 kV grid and new 400 kV interconnection Albania-Kosovo*

Project promoter(s): KOSTT (XK), OST(AL)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2030

ΔNTC increase: AL-XK 500 MW, XK-AL 500 MW, as declared by the project promoters.

Project description (by project promoters):

The project consists of the extension of SS Fierza to 400 kV level and construction of a new 400 kV interconnection between Albania and Kosovo. It also consists of the extension of SS Prizreni 2 (actual voltage 220/110 kV) to Prizreni-4, 400 kV level

Figure 17. Location of E06

E07: Closing the 400 kV Albanian internal ring

Project promoter(s): OST(AL)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2030

ΔNTC increase: AL-ME 50 MW, AL-XK 100 MW, AL-MK 100 MW, as declared and verified by the project promoters[10].

Project description (by project promoter): The project consists of closing the 400 kV internal transmission lines in a ring topology through the construction of new 400 kV transmission line between substations Fier-Rrashbull and further to Tirana-2.

Figure 18. Location of E07

E08: 330 kV OHL Balti (MD) - Dnestrovsk HPP-2 (UA)

Project promoter(s): Moldelectrica (MD), Ukrenergo (UA)

Infrastructure category: High and extra high voltage overhead transmission lines

Commissioning year: 2032

ΔNTC increase: UA-MD 500 MW, MD-UA 500 MW, as declared by the project promoters.

[10] *The initial change in NTCs that the project promoters delivered amounted to 500 MW on all borders and this was accepted by the Consultant. However, upon further inspection it was noticed that the initial NTCs before the project commissioning did not match the TYNDP NTCs. Therefore, the initial values were changed, which also changed the final ΔNTC values.*

Project description (by project promoter): Strengthening the electricity interconnection between Republic of Moldova and Ukraine. Increasing the security of supply.

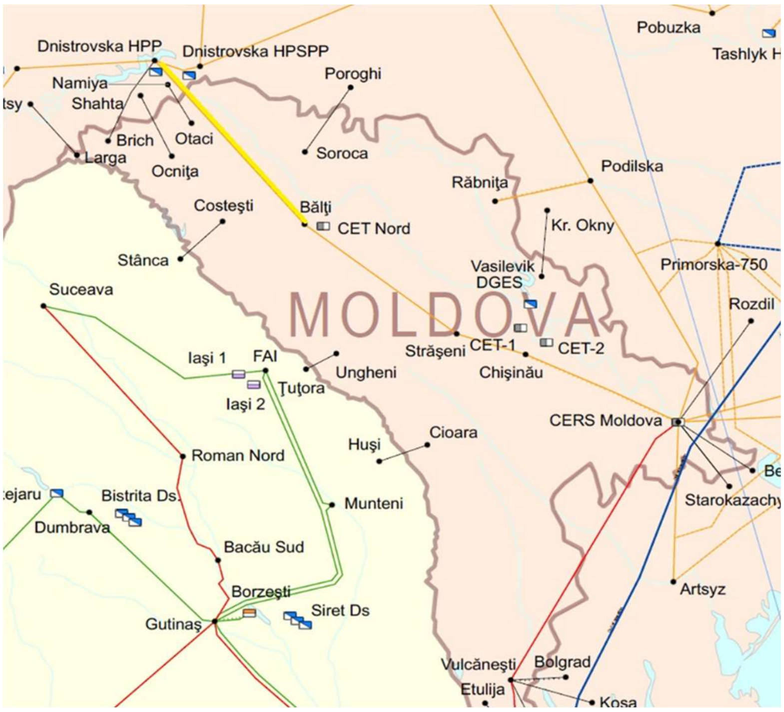

Figure 19. Location of E08

E13: DTEK STORAGE 225 MW

Project promoter(s): JSC DTEK WESTENERGY (UA)

Infrastructure category: Electricity storage

Commissioning year: 2025-2028

Project description (by project promoter): DTEK intends to develop, build and operate 225 MW / 450 MWh battery sites located in several locations in Western and Central Ukraine with a single control centre to ensure the power oscillation damping (POD) control and to provide ancillary services (FCR, aFRR) to the power grids of Ukraine and Moldova (UA/MD).

Figure 20. Location of E13

4 Input data and modelling assumptions

This section presents the input data and main modelling assumptions used for modelling the **reference scenario**, based on which the projects are assessed for their benefits.

The input data for modelling reference scenario is primarily based on the collected 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 2030 energy and climate targets for the EnC CPs[11]. For other input data, ENTSO-E and ENTSOG TYNDP 2022 data are primarily used as the relevant source because data for TYNDP 2024 were not available at the time when modelling activities were initiated. However, since TYNDP 2024 scenario report was published in the second half of May 2024[12], some data important for the analyses are used from this plan. Data categories with used sources for modelling are presented in Figure 21.

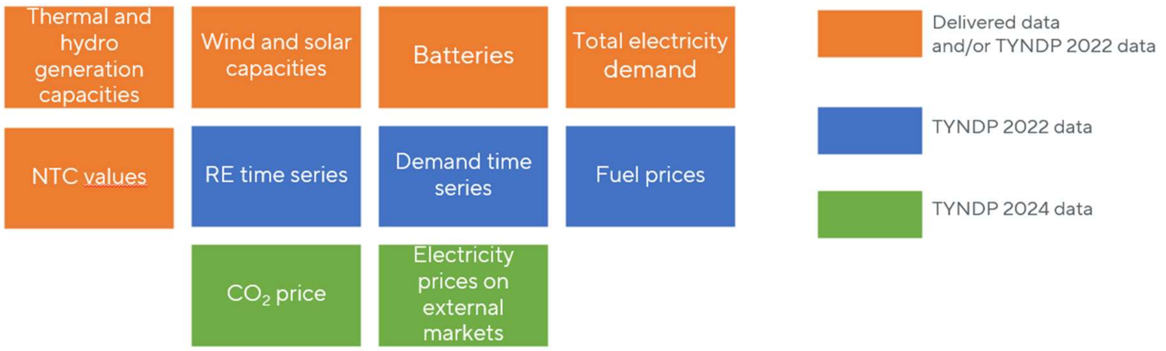

Figure 21. Sources for input data used for modelling reference scenario

Input data are presented in the following sections, together with the main modelling assumptions such as geographical scope, modelling scenarios and time horizon.

4.1 Geographical scope

The geographical scope of the regional market model developed in PLEXOS is presented in the following figure. The developed market model includes power systems of Contracting Parties: Albania, Bosnia and Herzegovina, Georgia, Kosovo*, Moldova, Montenegro, North Macedonia, Serbia and Ukraine, and neighbouring countries/markets.

The approach for modelling generation systems can be **unit-by-unit,** meaning that each power plant is modelled separately, or generation capacities can be clustered on a

[11] https://www.energy-community.org/implementation/package/CEP.html

[12] https://2024.entsos-tyndp-scenarios.eu/

fuel/technology level. Based on the available data collected during the data collection process, all power systems of all CPs are modelled on a unit-by-unit level.

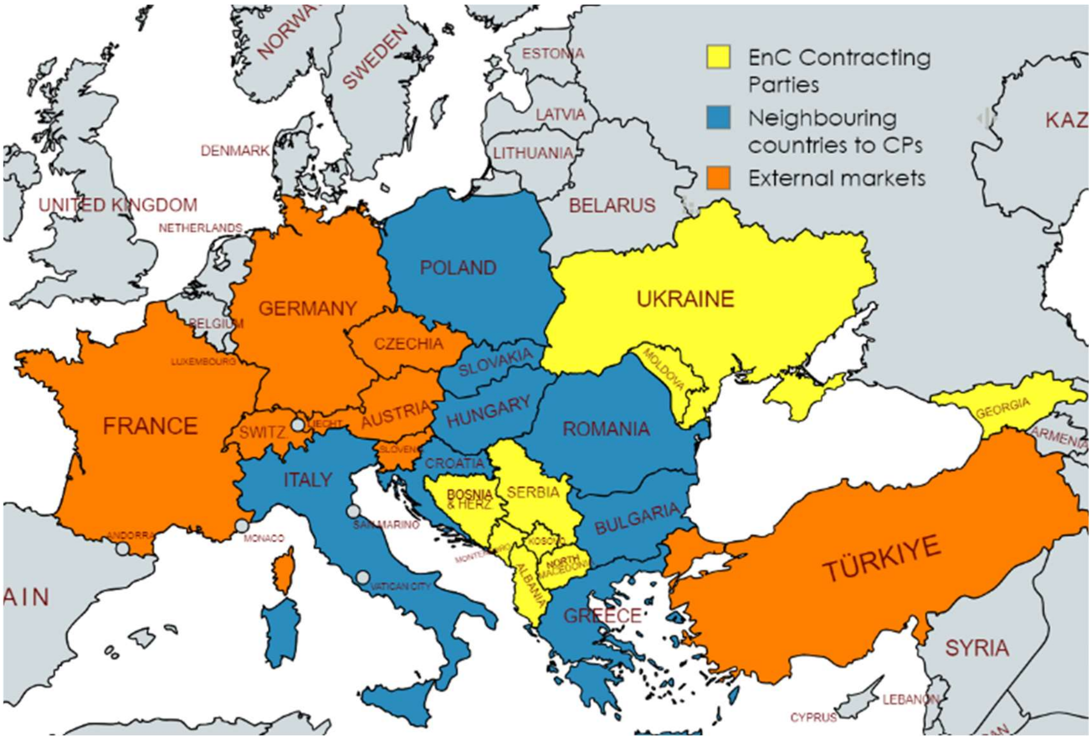

Figure 22. Geographical scope of regional market model in PLEXOS

In addition to the Contracting Parties, their neighbouring countries/markets (as presented in figure Figure 22above) are modelled based on the TYNDP data and the 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).

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 are supposed to be insensitive to price fluctuations in the CPs region and its neighbouring countries. Electricity exchanges between external spot markets and the CPs region and their neighbouring market areas are modelled to be constrained with transmission capacities based on the NTC values in TYNDP 2022.

4.2 Modelling scenarios

Modelled scenarios had to be in line with the latest joint ENTSO-E and ENTSOG scenarios developed under Ten Year Network Development Plan 2024 or 2022 (depending on the data availability of TYNDP 2024). Given that final report and datasets for the TYNDP 2024 have not been published during the first and the second phase of the project, the data from the **TYNDP 2022 is mostly used**. This primarily refers to the scenarios that are modelled as the reference cases for the period until 2050. Exceptions are CO_2 prices and wholesale electricity prices on the distant spot markets in relation to the EnC CPs which were taken from the latest TYNDP 2024 Draft Scenarios Report that was published in May 2024[13].

Under the TYNDP 2022, the **National Trends (NT)** scenario reflects national energy and climate policies (NECPs, national long-term strategies, hydrogen strategies…) based on the joint European targets. NT scenario is used for modelling of 2030 and 2040 time horizons (agreed at the 1st joint meeting of the Electricity and Gases Groups on 7th of March 2024), while for the later period, i.e. 2050, **Distributed Energy (DE)**[14] scenario is used to properly reflect EnC Contracting Parties dedication to fully decarbonise until 2050, as is defined in the core of the revised TEN-E Regulation. The decision to use National Trends scenarios for 2030 and 2040 is mainly based on the present conditions in the Energy Community CPs, especially by taking into account their distribution networks which are in general not ready to accept distributed energy sources on a large scale, which makes Distributed Energy scenarios for 2030 and 2040 practically not feasible for CPs due to their general lagging to the EU MSs in a technical, economic, regulatory and policy aspects. This assumption is also in line with the study made for the Energy Community Secretariat "Modernization, Decarbonization and Resilience - A Regional Transition Roadmap for the Western Balkans Study" (E3modelling, 2024), proposing gradual carbon pricing implementation with free allowances in the CPs to achieve carbon neutrality until 2050.

Country-specific data collected in the period from March 2024 until May 2024 are adjusted to the analysed scenarios, assumed to be in line with the Clean Energy Package targets, adopted in the Energy Community by the Ministerial Council Decision 2022/02/MC-EnC. This decision does not define specific electricity-related targets but just the sectorial ones (electricity, heating and cooling and transport) regarding greenhouse gas emissions, renewable energy and energy efficiency in relation to 1990 emissions, share of RES in gross final consumption of energy, and headline targets for energy efficiency. However, based on data delivered by the EnC CPs ministries and TSOs with respect to total installed capacities of hydro power plants, wind and solar power plants, and other RES, it was roughly estimated that delivered data is largely adjusted with the legally binding energy and climate targets[15].

Once the **reference case/scenario** is implemented for the three years (2030, 2040 and 2050) based on the delivered data, and TYNDP scenarios, the PINT modelling approach is used to assess the impacts of each project to the system costs and benefits. Given that there were 9 projects eligible for project assessment based on modelling activities, it was necessary to analyse impact of each of these projects to reference case in the three respective years, which resulted in total of 30 different modelling scenarios, as presented in the following figure.

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[13] Since the PECI selection process is not fully synchronised with the ENTSO-E TYNDP process (the newest TYNDP data lag to PECI process), the Energy Community Secretariat expresses its request to synchronise better with the ENTSO-E and TYNDP process in the next rounds of PECI selection processes (2026, 2028…).

[14] DE is the top-down scenario under the TYNDP 2022, that pictures a pathway achieving EU-27 carbon neutrality by 2050 and at least 55 % emission reduction in 2030.

[15] There were few countries which delivered data not fully in line with decarbonisation targets, regarding operation of coal-fired and gas-fired power plants in 2050 and this was adjusted by correcting the data by assuming phase-out of coal-fired power plants and possible operation of gas-fired ones but only equipped with Carbon Capture Storage (CCS).

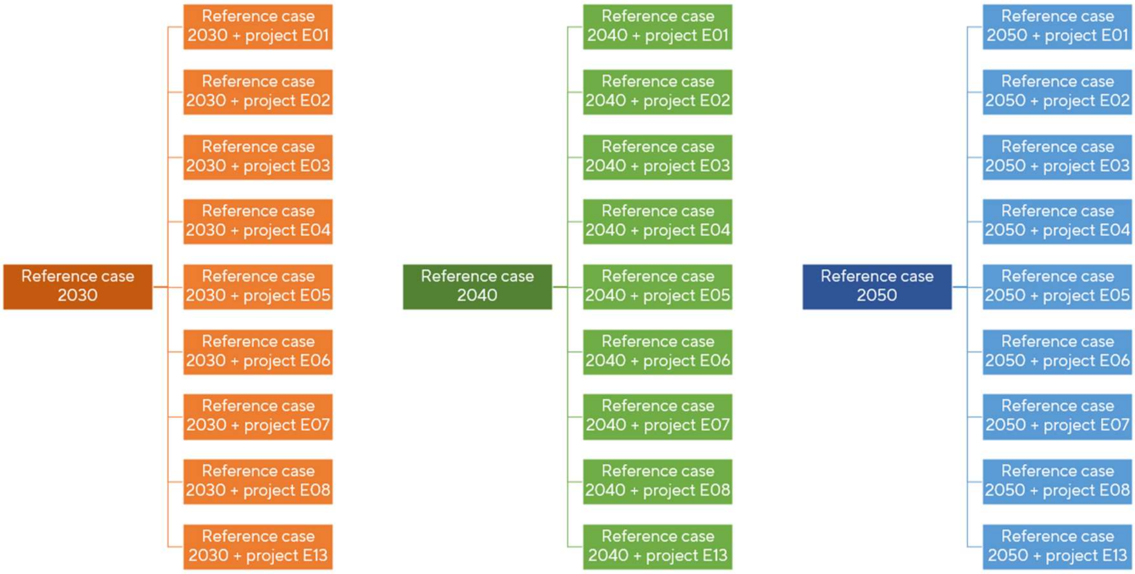

Figure 23. Modelling approach - the reference case without and with the projects

4.3 Time horizon

The time horizon covers the period until 2050, analysing in particular three time-frames: 2030, 2040 and 2050. As described in the previous section, for 2030 and 2040, the NT scenario is used, and for 2050 DE scenario.

For the periods between the selected years, linear interpolation is used for cost-benefit analysis.

4.4 Generation capacities

Data on generation capacities for CPs are collected from relevant authorities (ministries and TSOs). Given that there are some differences in the collected data and the data based on the TYNDP 2022 scenarios, it has been agreed between the Secretariat and the Consultant[16], that the data provided by relevant national authorities will be used in market model development. The modifications of the provided input data are made where necessary to assume carbon neutrality in 2050 (DE scenario) by decommissioning all coal-fired 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[17].

The following tables contain data on generation capacities in CPs based on the collected data in the three years, 2030, 2040 and 2050. Cells marked in green signify the data that is taken

[16] *Confirmed by the electricity group at the meeting on 16 May 2024.*

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

from TYNDP 2022 since no other data has been provided/revised from the initial TYNDP 2022 data set, while the rest of the data is provided by the national authorities.

Table 5. Generation capacities in 2030 in Contracting Parties (MW)

Country	Nuclear	Thermal-gas	Thermal-lignite/coal	Hydro	Wind	Solar	Batteries
AL	-	300	-	2533	300	700	-
BA	-	-	1418	2323.8	798	1514	50
GE	-	1598.2	22.3	4065	750	700	200
XK	-	-	904	100.7	677	550	170
MD	-	1720	47.2[18]	64.5	442	470	10
ME	-	49[19]	225	961.4	250	750	28
MK	-	760	31[20]	938.1	443	580	-
RS	-	400.9	4584	3244.2	3844	235	-
UA	13 940	2833.3	18 444	9172	580	7350	258

Table 6. Generation capacities in 2040 in Contracting Parties (MW)

Country	Nuclear	Thermal-gas	Thermal-lignite/coal	Hydro	Wind	Solar	Batteries
AL	-	300	-	2633	700	1300	-
BA	-	-	1418	2480.3	1500	3000	381
GE	-	1598.2	22.3	5805	1700	1650	200
XK	-	-	904	100.7	1275	1340	170
MD	-	1720	47.2	64.5	960	750	10
ME	-	49	225	961.4	600	2400	28
MK	-	-	31	1480.5	723	998	-
RS	-	400.9	3899	3848.3	3246	950	-
UA	13 940	2833.3	18 444	9172	2580	11 120	258

[18] *In Moldova thermal is not lignite/coal but other non-renewable thermal capacity*

[19] *In Montenegro thermal is not natural gas but other renewable thermal capacity*

[20] *In North Macedonia thermal is not natural gas but other renewable thermal capacity*

Table 7. Generation capacities in 2050 in Contracting Parties (MW)

Country	Nuclear	Thermal-gas*	Thermal-lignite/coal	Hydro	Wind	Solar	Batteries
AL	-	300	-	2633	1650	1650	-
BA	-	-	-	2480.3	2500	5000	500
GE	-	1598.2	-	8350	2900	2600	200
XK	-	-	-	100.7	1873	1938	170
MD	-	1720	-	64.5	1120	880	10
ME	-	-	-	961.4	700	4300	28
MK	-	-	-	1480.5	605	11553	105
RS	-	400.9	-	3848.3	2968	725	-
UA	13 940	2833.3	-	9172	6750	21220	258

* CCS applied

Based on the collected data, the total electricity generation capacity in CPs will amount to 92 GW in 2030, with coal/lignite thermal power plants still having a dominant share of 28%. This share is expected to decrease to 23% by 2040, with the complete decommissioning of coal/lignite-fired power plants assumed by 2050. By 2050, total electricity generation capacity in CPs will reach 122 GW, with solar power plants having the highest share at 41%. Wind capacity will increase from 8 GW in 2030 to 21 GW in 2050, and hydro power plants will have a total capacity of around 29 GW in 2050, corresponding to a share of 24%.

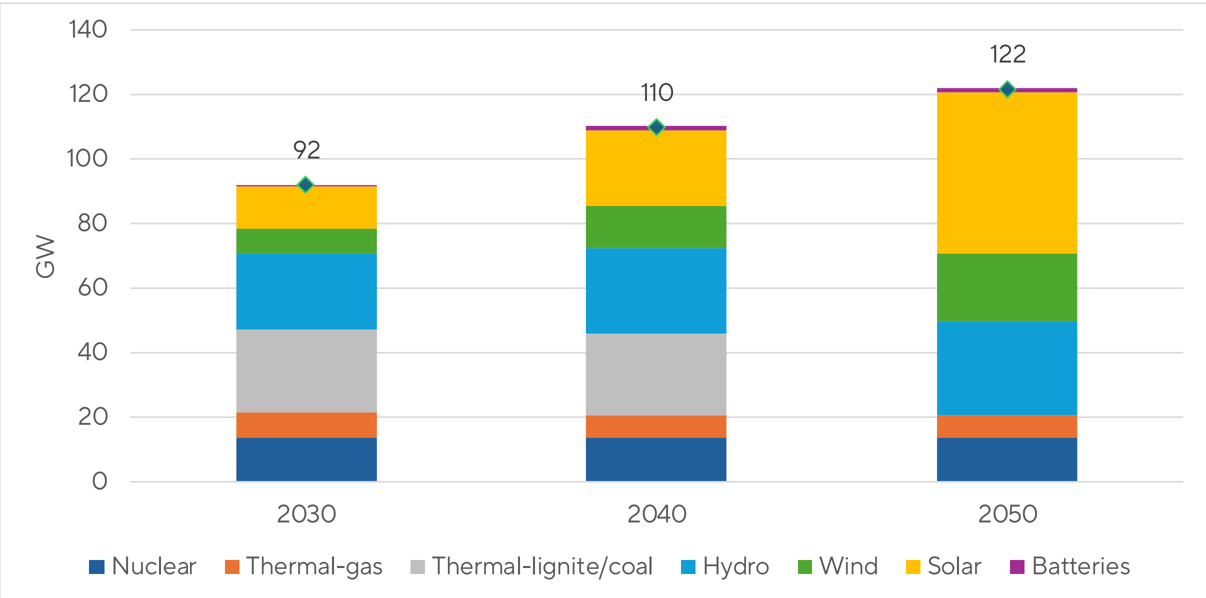

Figure 24. Generation capacities in Contracting Parties in 2030, 2040 and 2050

4.5 Electricity demand

Data on electricity demand for CPs are collected from relevant authorities. Given that there were some differences in the collected data and the data based on the TYNDP 2022 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 2022 data is used. Cells marked green indicate that the data is sourced from TYNDP since no other data has been provided by the authorities. This applies to demand data for all years in Serbia[21] and for North Macedonia in 2050.

Table 8. Electricity demand in Contracting Parties (GWh)

Country	2030	2040	2050
AL	8900	9400	12 116
BA	11 158	12 681	13 457
GE	19 111	23 907	29 071
XK	6802	7998	10 180
MD	7002	8417	9993
ME	4539	5534	6281
MK	8879	10 147	10 759
RS	36 498	37 240	37 218
UA	151 840	208 500	296 600

According to the data presented in table above, an increase in total electricity demand is expected in all countries from 2030 to 2050. The highest increase during this period is anticipated in Ukraine, where demand is projected to nearly double by 2050 compared to 2030 (from 151.8 TWh to 296.6 TWh). Regarding other countries, the highest demand increases are expected in Georgia and Kosovo*.

Total electricity demand in Contracting Parties is projected to increase from 255 TWh in 2030, to about 426 TWh, marking a growth of around 67%. Ukraine holds the highest share of total demand among Contracting Parties.

[21] *Determined based on TYNDP 2022 data.*

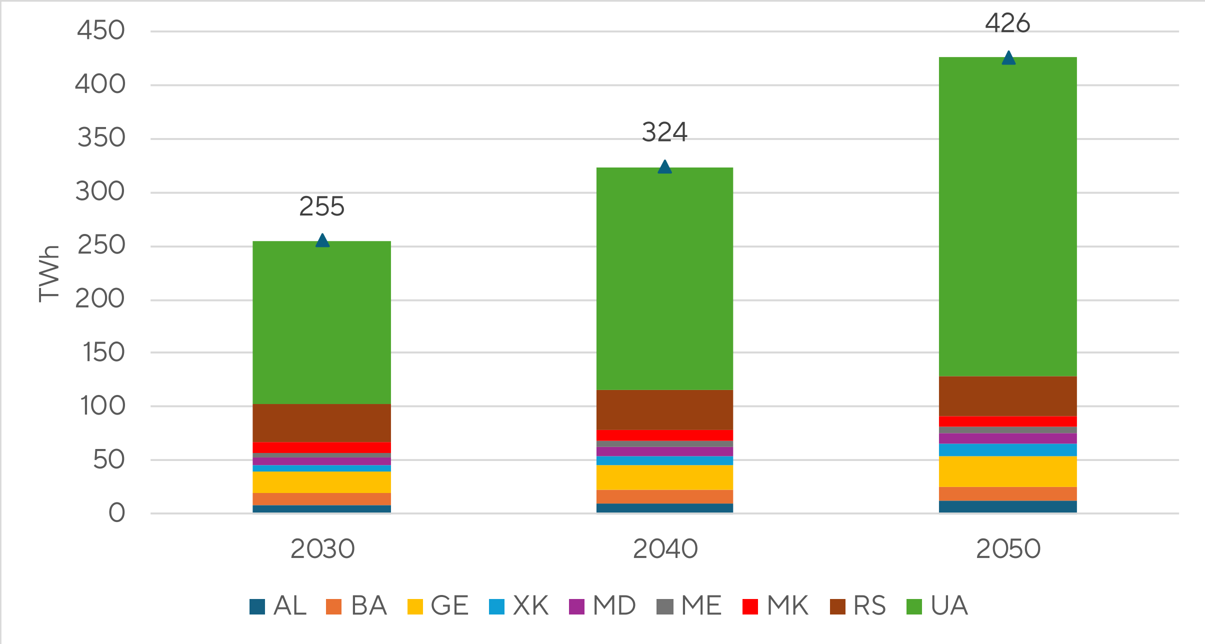

Figure 25. Electricity demand in CPs based on the collected data and TYNDP 2022 data

4.6 Fuel and CO_2 prices

Fuel and CO_2 prices are important input parameters in market models. These parameters have impact on the 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.

For the reference case, TYNDP 2022 values for fuel prices are used, as presented in the following tables, i.e. values for NT scenario in 2030 and 2040, and values for DE scenario in 2050. During the project execution, TYNDP 2024 was published (mid May 2024) and it was agreed with the EnC Secretariat to use the CO_2 prices based on the new available data in the TYNDP 2024 report. This also includes wholesale electricity prices for the spot markets outside of EnC CPs and their neighbouring EU MS.

Table 9. Fuel prices common to all scenarios in TYNDP 2022

€/GJ	2030	2040	2050
Nuclear	0.47		
Biomethane	20.74	16.94	13.97
Shale Oil	1.86	2.71	3.93
Lignite:			
- Group 1 (BG, MK and CZ)	1.40		N.a.
- Group 2 (SK, DE, RS, PL, ME, UK, IE and BA)	1.80		N.a.
- Group 3 (SI, RO and HU)	2.37		N.a.
- Group 4 (GR and TR)	3.10		N.a.

Source: TYNDP Scenario Building Guidelines, April 2022

Table 10. Fuel prices in TYNDP 2022 and CO_2 prices in TYNDP 2024 per scenarios and horizons

	Unit	Scenarios	2030	2040	2050
CO_2	€/tonne	**-**	**113.4**	**147.0**	**168.0**
Hard coal	€/GJ	**NT**	**2.48**	**2.41**	N.a.
		DE and GA[22]	1.97	1.92	**1.87**
Light oil		**NT**	**13.78**	**15.41**	N.a.
		DE and GA	10.09	9.61	**9.12**
Natural gas		**NT**	**6.23**	**6.90**	N.a.
		DE and GA	**4.02**	**4.07**	**4.07**
Biomethane		**NT**	20.74	16.94	N.a.
		DE and GA	**20.74**	**16.94**	**13.97**
Synthetic methane		**NT**	28.09	23.35	N.a.
		DE and GA	**28.96**	**23.35**	**18.09**
Renewable H2 imports		**NT**	20.25	16.08	N.a.
		DE and GA	**20.63**	**16.08**	**12.52**
Decarbonised H2 imports		**NT**	20.25	16.08	N.a.
		DE and GA	**17.11**	**17.55**	**17.91**

Source: TYNDP Scenario Building Guidelines, April 2022; TYNDP 2024 Scenarios Methodology Report, May 2024

[22] *Global Ambition – another ENTSO-E scenario in 2050 that was not analysed.*

4.7 Selection of climatic year

Annual electricity demand in CPs is used based on the data presented in section 4.5. In addition to annual demand projections, hourly load profiles for each country are used as input parameters to model demand in each analysed year. In the TYNDP 2022, hourly demand profiles are available for 35 climatic years (from 1982 to 2016). Given that the **year 2009** is selected as the most representative year in TYNDP 2022, the Consultant proposed using load profiles from this year.

The same year is proposed for the hourly profiles of RES generation, available in the Pan European Climate Database (PECD), which are also used as input data in the PLEXOS model for wind and solar power plants.

4.8 NTC values

Data on NTC values between CPs and CPs and neighbouring countries are collected from relevant authorities and initially presented in *Data Validation and Scenario Report*. Given that there were some differences in the collected data and the data based on the TYNDP 2022 scenarios, the final input data set regarding NTC values is 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 2022 data if the provided data by relevant CPs' authorities differs from each other and from the TYNDP 2022 data,
- in cases where TYNDP 2022 doesn't provide data for specific border (e.g. RS-XK), 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.

Regarding the MONITA HVDC link between Montenegro and Italy, NTC value of 1200 MW will be finally applied starting from 2030 according to confirmation received by TERNA about their intentions to have the second cable operational until this time frame.

Table 11. NTC values between CPs and CPs and neighbouring countries

<table>
<tr><th colspan="6">Final NTCs for the model</th></tr>
<tr><th>Interconnection</th><th>From:</th><th>To:</th><th>Year</th><th>NTC (MW)</th><th>Remark</th></tr>
<tr><td rowspan="6">AL00-GR00</td><td rowspan="3">AL00</td><td rowspan="3">GR00</td><td>2030</td><td>400</td><td rowspan="6">Data provided by AL and TYNDP 2022 differ. TYNDP 2022 data are used.</td></tr>
<tr><td>2040</td><td>400</td></tr>
<tr><td>2050</td><td>400</td></tr>
<tr><td rowspan="3">GR00</td><td rowspan="3">AL00</td><td>2030</td><td>400</td></tr>
<tr><td>2040</td><td>400</td></tr>
<tr><td>2050</td><td>400</td></tr>
</table>

Final NTCs for the model					
Interconnection	**From:**	**To:**	**Year**	**NTC (MW)**	**Remark**
AL00-ME00	AL00	ME00	2030	**350**	Data provided by AL and ME differ from each other and from TYNDP 2022 data. Data from TYNDP 2022 are used.
			2040	**350**	
			2050	**350**	
	ME00	AL00	2030	**350**	
			2040	**350**	
			2050	**350**	
AL00-MK00	AL00	MK00	2030	**500**	Data provided by AL and MK are the same as in TYNDP 2022.
			2040	**500**	
			2050	**500**	
	MK00	AL00	2030	**500**	
			2040	**500**	
			2050	**500**	
AL00-XK00	AL00	XK00	2030	**400**	Data provided by AL and XK differ in 2040 and 2050. TYNDP 2022 doesn't provide data for this border. The latest data provided by AL are used.
			2040	**400**	
			2050	**400**	
	XK00	AL00	2030	**400**	
			2040	**400**	
			2050	**400**	
BA00-HR00	BA00	HR00	2030	**750**	Data provided by BA are the same as in TYNDP 2022.
			2040	**750**	
			2050	**750**	
	HR00	BA00	2030	**700**	
			2040	**700**	
			2050	**700**	

<table>
<tr><th colspan="6">Final NTCs for the model</th></tr>
<tr><th>Interconnection</th><th>From:</th><th>To:</th><th>Year</th><th>NTC (MW)</th><th>Remark</th></tr>
<tr><td rowspan="6">BA00-ME00</td><td rowspan="3">BA00</td><td rowspan="3">ME00</td><td>2030</td><td>800</td><td rowspan="6">Data provided by BA and ME differ. Data provided by BA will be used as it is the same as the data in TYNDP 2022.</td></tr>
<tr><td>2040</td><td>800</td></tr>
<tr><td>2050</td><td>800</td></tr>
<tr><td rowspan="3">ME00</td><td rowspan="3">BA00</td><td>2030</td><td>750</td></tr>
<tr><td>2040</td><td>750</td></tr>
<tr><td>2050</td><td>750</td></tr>
<tr><td rowspan="6">BA00-RS00</td><td rowspan="3">BA00</td><td rowspan="3">RS00</td><td>2030</td><td>530</td><td rowspan="6">Data provided by BA is the same as in TYNDP 2022.</td></tr>
<tr><td>2040</td><td>530</td></tr>
<tr><td>2050</td><td>530</td></tr>
<tr><td rowspan="3">RS00</td><td rowspan="3">BA00</td><td>2030</td><td>510</td></tr>
<tr><td>2040</td><td>510</td></tr>
<tr><td>2050</td><td>510</td></tr>
<tr><td rowspan="6">ME00-IT00</td><td rowspan="3">ME00</td><td rowspan="3">IT00</td><td>2030</td><td>1200</td><td rowspan="6">Based on data provided by ME and TERNA for 2030.</td></tr>
<tr><td>2040</td><td>1200</td></tr>
<tr><td>2050</td><td>1200</td></tr>
<tr><td rowspan="3">IT00</td><td rowspan="3">ME00</td><td>2030</td><td>1200</td></tr>
<tr><td>2040</td><td>1200</td></tr>
<tr><td>2050</td><td>1200</td></tr>
<tr><td rowspan="6">ME00-RS00</td><td rowspan="3">ME00</td><td rowspan="3">RS00</td><td>2030</td><td>580</td><td rowspan="6">Data provided by ME and TYNDP 2022 differ. EMS did not provide data. Data from TYNDP 2022 are used.</td></tr>
<tr><td>2040</td><td>580</td></tr>
<tr><td>2050</td><td>580</td></tr>
<tr><td rowspan="3">RS00</td><td rowspan="3">ME00</td><td>2030</td><td>550</td></tr>
<tr><td>2040</td><td>550</td></tr>
<tr><td>2050</td><td>550</td></tr>
<tr><td rowspan="3">ME00-XK00</td><td rowspan="3">ME00</td><td rowspan="3">XK00</td><td>2030</td><td>300</td><td rowspan="3">Based on the data</td></tr>
<tr><td>2040</td><td>300</td></tr>
<tr><td>2050</td><td>300</td></tr>
</table>

Final NTCs for the model					
Interconnection	**From:**	**To:**	**Year**	**NTC (MW)**	**Remark**
	XK00	ME00	2030	**300**	provided by XK and ME.
			2040	**300**	
			2050	**300**	
GE00-AZ00	GE00	AZ00	2030	**2000**	Based on data provided by GE.
			2040	**2000**	
			2050	**2000**	
	AZ00	GE00	2030	**2000**	
			2040	**2000**	
			2050	**2000**	
GE00-TR00	GE00	TR00	2030	**1050**	
			2040	**1050**	
			2050	**1050**	
	TR00	GE00	2030	**1050**	
			2040	**1050**	
			2050	**1050**	
GE00-ARM00	GE00	ARM00	2030	**700**	
			2040	**700**	
			2050	**700**	
	ARM00	GE00	2030	**700**	
			2040	**700**	
			2050	**700**	
GE00-RU00	GE00	RU00	2030	**1600**	
			2040	**1600**	
			2050	**1600**	
	RU00	GE00	2030	**1600**	
			2040	**1600**	
			2050	**1600**	
GE00-ROM00	GE00	ROM00	2030	**1300**	
			2040	**1300**	
			2050	**1300**	
	ROM00	GE00	2030	**1300**	
			2040	**1300**	

Final NTCs for the model					
Interconnection	**From:**	**To:**	**Year**	**NTC (MW)**	**Remark**
			2050	**1300**	
MK00-BG00	MK00	BG00	2030	**400**	Data provided by MK are the same as in TYNDP 2022.
			2040	**400**	
			2050	**400**	
	BG00	MK00	2030	**500**	
			2040	**500**	
			2050	**500**	
MK00-GR00	MK00	GR00	2030	**850**	Data provided by MK are the same as in TYNDP 2022.
			2040	**850**	
			2050	**850**	
	GR00	MK00	2030	**1100**	
			2040	**1100**	
			2050	**1100**	
MK00-RS00	MK00	RS00	2030	**450**	Data provided by MK and TYNDP 2022 differ. EMS did not provide data. Data from TYNDP 2022 are used.
			2040	**450**	
			2050	**450**	
	RS00	MK00	2030	**540**	
			2040	**540**	
			2050	**540**	
MK00-XK00	MK00	XK00	2030	**270**	Data provided by MK and XK differ in all years. TYNDP 2022 doesn't provide data for this border. Lower values are used.
			2040	**270**	
			2050	**270**	
	XK00	MK00	2030	**300**	
			2040	**300**	
			2050	**300**	

Final NTCs for the model					
Interconnection	**From:**	**To:**	**Year**	**NTC (MW)**	**Remark**
XK00-RS00	XK00	RS00	2030	**400**	Based on data provided by XK. EMS did not provide data. TYNDP 2022 does not recognise this border. At the moment, there is no capacity allocation because NTC has not been defined and agreed between EMS and KOSTT.
			2040	**400**	
			2050	**400**	
	RS00	XK00	2030	**400**	
			2040	**400**	
			2050	**400**	
UA00-HU00	HU00	UA00	2030	**1420**	Based on data provided by UA. TYNDP 2022 does not recognise these borders.
			2040	**1420**	
			2050	**1420**	
	UA00	HU00	2030	**1420**	
			2040	**1420**	
			2050	**1420**	
UA00-SK00	SK00	UA00	2030	**1000**	
			2040	**1000**	
			2050	**1000**	
	UA00	SK00	2030	**1000**	
			2040	**1000**	
			2050	**1000**	
UA00-'RO00	RO00	UA00	2030	**1740**	
			2040	**1740**	
			2050	**1740**	
	UA00	RO00	2030	**1740**	

Final NTCs for the model					
Interconnection	**From:**	**To:**	**Year**	**NTC (MW)**	**Remark**
			2040	**1740**	
			2050	**1740**	
UA00-'PL00	PL00	UA00	2030	**600**	
			2040	**600**	
			2050	**600**	
	UA00	PL00	2030	**820**	
			2040	**820**	
			2050	**820**	
UA00-MD00	MD00	UA00	2030	**600**	Based on data provided by UA and MD. TYNDP 2022 does not recognise this border.
			2040	**1100**	
			2050	**1600**	
	UA00	MD00	2030	**600**	
			2040	**1100**	
			2050	**1600**	
MD00-RO00	MD00	RO00	2030	**300**	Based on data provided by MD. TYNDP 2022 does not recognise this border.
			2040	**750**	
			2050	**1600**	
	RO00	MD00	2030	**450**	
			2040	**750**	
			2050	**1600**	

5 Results

For each of the eligible projects, the cost-benefit analysis and multi-criteria analysis were performed. The cost-benefit analysis takes into account the following parameters:

1. 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).
2. 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 2.2 and in the previous report, the ***Analysis Techniques' Guidance Document***. 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, described in more detail in previous chapters and previous reports). The benefits for a specific project are then calculated as a difference of a certain indicator in scenario with the project as opposed to the reference scenario. **The modelling results for CPs for the reference scenario are presented in the following section, while the rest of the sections describe the results of the cost-benefit and multi-criteria analysis.**

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.

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 chapter 5.3, 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, 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 country 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 country, 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 country (related to the determination of the CO_2 variation indicator),
- **Electricity prices**: show average annual electricity prices in each country (related to the monetisation of the Grid losses indicator).

5.1.1 Electricity balance

Figures 26-28 depict electricity generation, load, and net interchange in Contracting Parties for the years 2030, 2040, and 2050 in the reference scenario based on the PLEXOS simulation results. Total electricity load includes pump load and battery load where pump-storage hydro power plants and batteries are operational. Net interchange reflects the difference between 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 and Georgia. Countries with smaller power systems, such as Kosovo* and Montenegro, show the lowest load and generation. Albania, Georgia and North Macedonia are net exporters, while the remaining Contracting Parties are net importers. There are no security of supply issues regarding the occurrence of unserved energy.

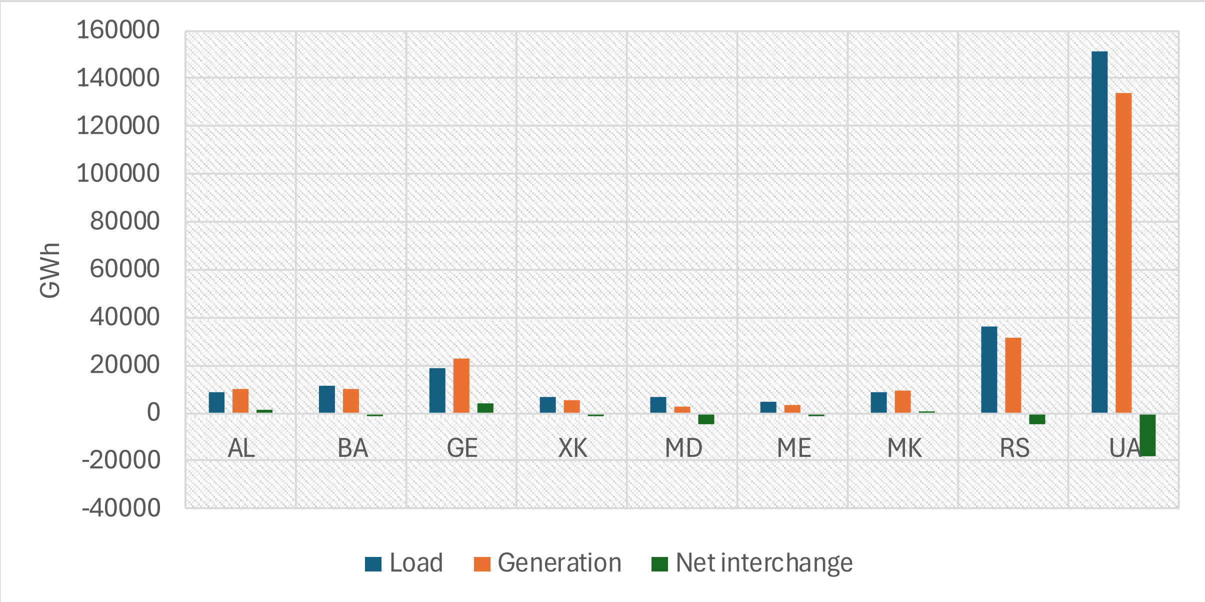

Figure 26. Electricity balance in CPs in 2030

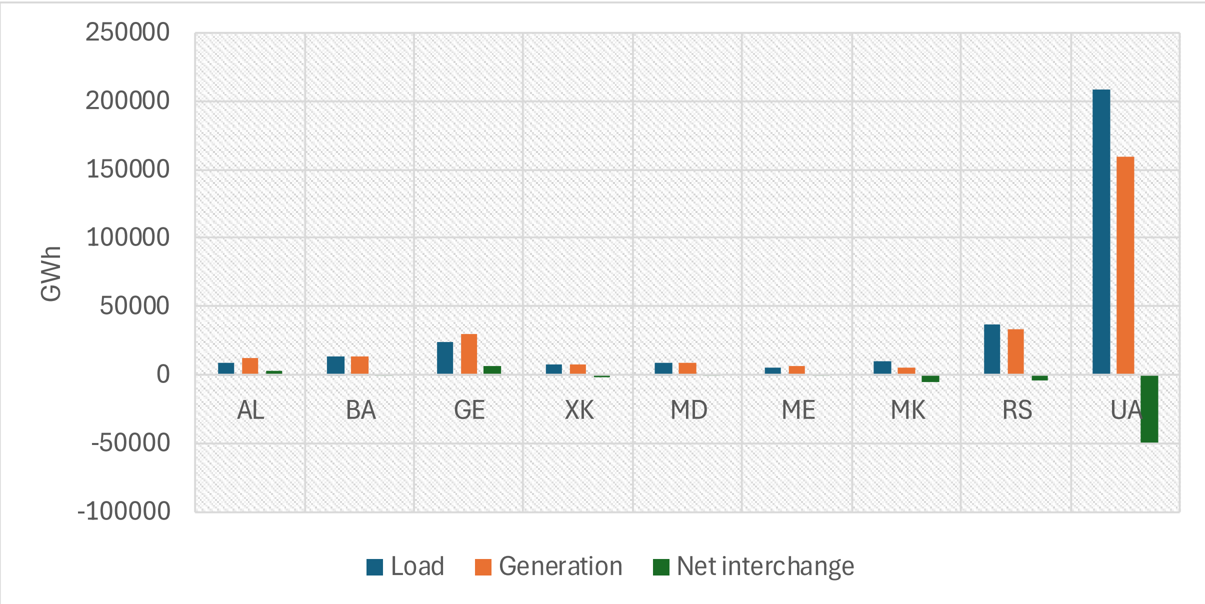

Figure 27. Electricity balance in CPs in 2040

In 2040, Albania, Bosnia and Herzegovina, Georgia, Montenegro and Moldova are net exporters, while Serbia, Kosovo, North Macedonia and Ukraine are net importers of electricity. Compared to 2030 when North Macedonia had a slightly positive electricity balance, by 2040, all thermal capacities are expected to be decommissioned, resulting in import dependency.

In 2040, unserved energy appears in Moldova and Ukraine, impacting the calculation of SoS indicator in scenarios with the projects (as presented in section 5.2.1).

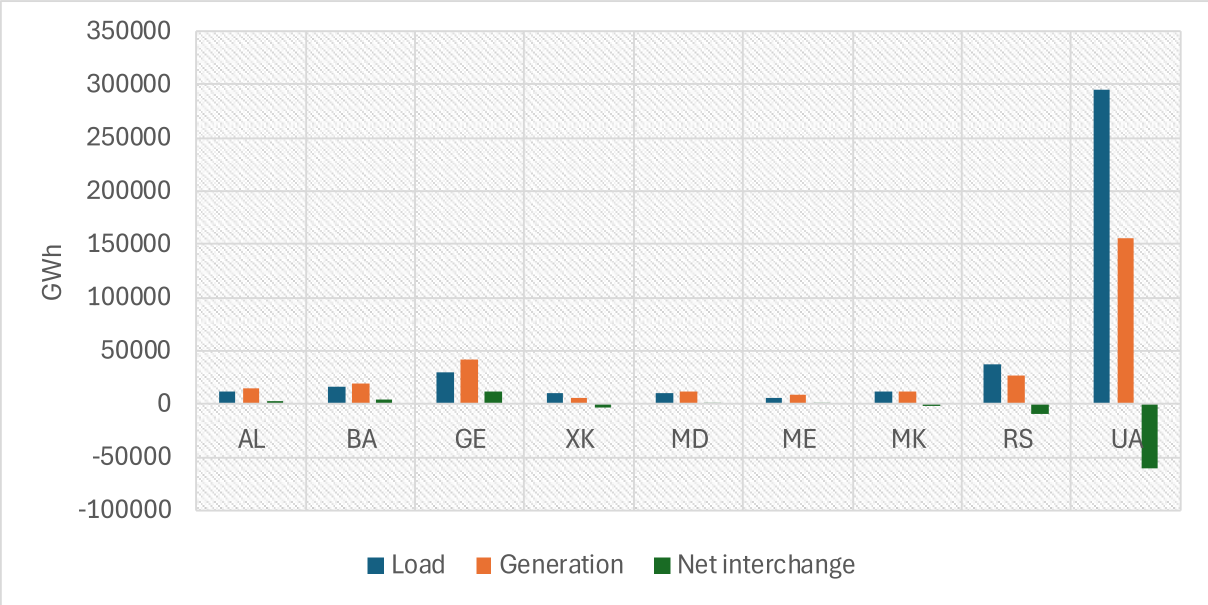

Figure 28. Electricity balance in CPs in 2050

In 2050, the problem of security of supply will be even more present, due to a significant amount of unserved energy in Ukraine. Based on the simulation results, nearly 27% of the projected electricity demand in 2050 could not be supplied, either from generation or imports, primarily due to the assumed decommissioning of all lignite/coal fired power plants with no alternative generation capacities provided in the collected country-specific data for Ukraine. In addition to Ukraine, problem of unserved energy affects also other CPs, such as Serbia, Kosovo and Moldova, but to a lesser extent relative to their annual electricity demand.

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.

5.1.2 Generation costs

Total generation costs in Contracting Parties based on PLEXOS simulation results are presented in Table 12. These costs include fuel costs, variable operations and maintenance costs, start and shutdown costs and CO_2 emissions costs. Ukraine has the highest costs in all years due to the size of its power system and available generation capacities.

Total costs in CPs are highest in 2040; increasing load, continued operation of the majority of thermal power plants, and higher CO_2 emission price, result in the highest generation costs. In general, countries that rely mostly on thermal power plants in their generation mix (e.g. XK and RS), have higher generation costs in 2030 and 2040, with a decrease in 2050 due to decommissioning of coal/lignite power plants.

For the projects' CBA, total generation costs in 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.

Table 12. Total generation costs in reference scenario in 2030, 2040 and 2050 (in mil. EUR)

Country	2030	2040	2050
AL	112.5	100.9	69.1
BA	33.1	33.7	40.8
GE	400.4	479.9	315.7
XK	402.1	501.5	1.2
MD	106.7	886.4	415.7
ME	8.5	10.4	11.9
MK	410.2	17.2	20.5
RS	1376.0	1354.0	170.5
UA	3033.3	6536.1	1043.7

5.1.3 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, which is set to 3000 EUR/MWh. Average annual prices in CPs for the three analysed years in the reference scenario are presented in following figure.

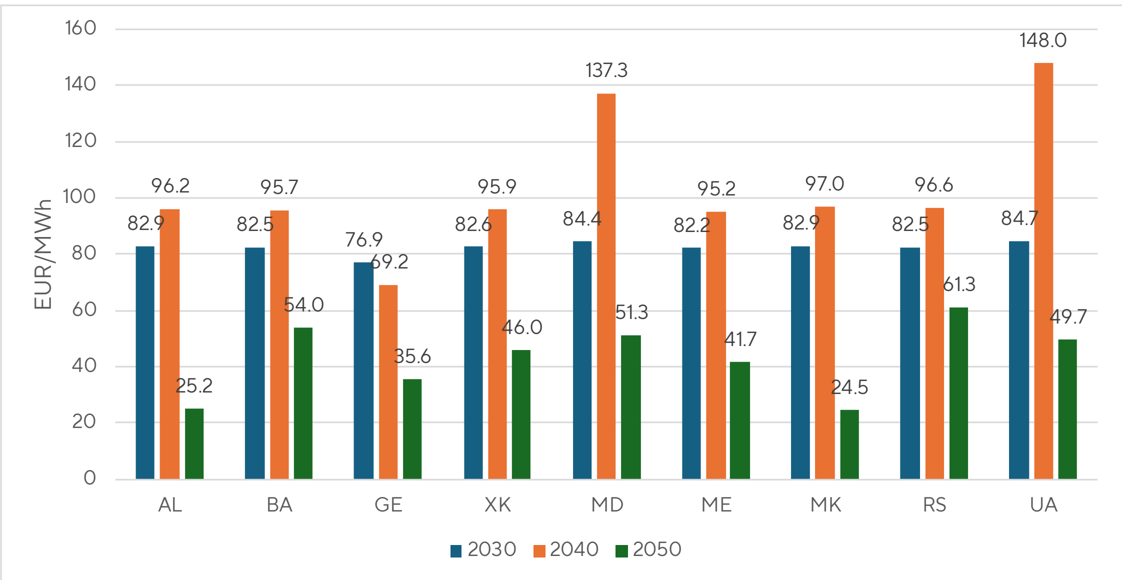

Figure 29. Average annual electricity prices in CPs in 2030, 2040 and 2050 (reference scenario)

In 2030, average electricity prices are uniform across CPs, with an average value of 84.4 EUR/MWh. The average price in 2040 is higher compared to 2030, amounting to 103.5 EUR/MWh. The increase in CO_2 emission price in 2040 affects the marginal costs of thermal units, and consequently, electricity prices. Some thermal units have high operating, start and shutdown costs, which also impact marginal costs and electricity prices. This is the case with Moldova and Ukraine in 2040, where their thermal units' high generation costs increase average electricity prices. Additionally, unserved energy appears in Moldova and Ukraine in 2040.

In 2050, average electricity prices are the lowest due to the decommissioning of coal/lignite power plants and the increased share of solar and wind power plants. The average price in 2050 across CPs amounts to 43.2 EUR/MWh. The lowest prices are in countries that rely entirely on hydro, wind, and solar generation, such as North Macedonia and Albania.

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

5.1.4 CO_2 emissions

Amount of CO_2 emissions is presented for 2030 and 2040 in reference scenario, due to assumed carbon neutrality in 2050.

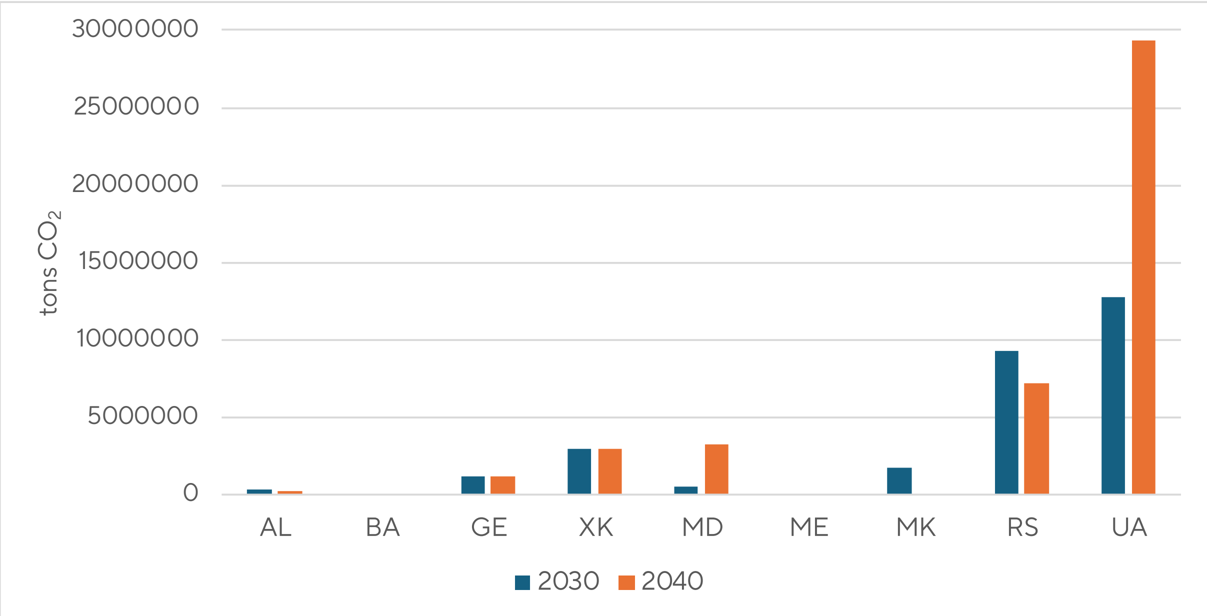

Figure 30. CO_2 emissions in CPs in 2030 and 2040 (reference scenario)

The total amount of CO_2 emissions in CPs in 2040 is higher compared to 2030. This correlates with higher generation costs, as presented in section 5.1.2. While some countries, such as North Macedonia and Serbia, have the CO_2 emissions decrease due to lower thermal generation, Moldova and Ukraine increase their thermal generation, resulting in higher CO_2 emissions.

For the projects' CBA, amount of CO_2 emissions 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.

5.2 Scenarios with the projects

5.2.1 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 CO2 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)

Table 1313 shows the summary of the abovementioned costs and benefits. It is important to mention that discounted values are presented for all indicators. It is also important to keep in mind that through models, three values for benefits were calculated directly, values for 2030, 2040 and 2050. For the years in between, **interpolation was done to obtain yearly values**. If a project is supposed to be commissioned before 2030, benefits of 2030 were duplicated up to the commissioning year. While the modelling was done for a wider geographical scope, only the results for EnC CPs are taken into account and summed up to provide inputs for the cost-benefit analysis.

Table 13. Summary of socio-economic assessment of eligible projects

No	CAPEX (*mil. EUR*)	OPEX (*mil. EUR*)	SEW (*mil. EUR*)	Variation in grid losses (*mil. EUR*)	Variation in CO_2 emissions (*mil. EUR*)	SoS (*mil. EUR*)	B/C
E01	-14.00	-1.24	-14.89	2.57	-25.47	198.34	**10.53**
E02	-21.04	-1.49	10.59	17.18	-1.04	-130.07	**0.16**
E03	-62.21	-4.92	19.82	21.75	11.43	-172.81	**0.28**
E04	-18.40	-3.16	99.75	41.53	76.69	-136.46	**3.78**
E05	-120.62	-11.25	-16.87	12.04	-17.33	-102.24	**0.02**
E06	-72.81	-0.90	1.50	16.50	-14.34	296.07	**4.07**
E07	-27.20	-0.35	-32.02	8.79	-56.54	284.54	**7.43**
E08	-43.82	-1.44	-115.91	25.38	-213.10	25,145.78	**548.89**
E13	-258.54	-65.68	263.60	3.97	378.03	18.15	**2.05**

It is visible from the table that six of the eligible projects have the B/C ratio above one, making them economically viable and profitable. The remaining three projects have a B/C below one and therefore are not deemed economically profitable.

Project **E01** presents with a negative summary discounted value of SEW, as well as of variation in CO_2 emissions. This occurs because in 2040, there is a slight increase in total generation costs in the scenario with project E01, as well as a slight increase of CO_2 emissions. The market model through which the results were obtained is a complex model involving detailed power systems of not just CPs, but SEE region also, as well as other countries modelled on technology basis, and external power markets. Because of this, it can occur that at a certain point in time, there is a slight decrease of benefits that a project would cause, if only one region is considered in benefit calculations (CPs region)[23]. However, since in this modelling process the Consultant has modelled three target years, if the project overall socio-economic impact is positive, it will be visible throughout that modelling horizon. Such is the case for E01, on which the slight decreases of SEW and increases of CO_2 emissions do not have a prevailing negative impact. On the contrary, the total socio-economic impact of E01 is overall positive, with resulting benefit-cost ratio of 10.53 and an NPV of over 145 mil. EUR.

E02 results with a benefit-cost ratio below one, proving it to be economically non-viable. Part of the reasoning for this result can be found in the negative impact of Security of Supply benefit, but the most important reason is the late commissioning date of this project. E02 is planned for commissioning in 2036, which means that it does not provide any benefits before that.

For project **E03**, the situation is similar. The commissioning of this project is in 2033. Additionally, investment costs for E02 are quite higher comparing to the first two projects. Benefit-cost ratio is 0.28 for E03, making it economically non-viable.

Project **E04**, the Trans Balkan Corridor, shows mostly positive benefit categories and is economically viable, with the benefit-cost ratio of 3.78.

The opposite is the case for project **E05**, which is an internal line in Bosnia and Herzegovina, making it different from the other, cross-border projects. This line is also significantly longer than the rest of the overhead lines that are being analysed, with the total length of 230 km. The discounted sum of all benefits except for the variation in grid losses is negative for this line, which proves that in this analysis, with this methodology, this project did not show a positive socio-economic impact. This is also shown in the benefit-cost ratio of 0.02.

The new 400 kV overhead line connecting Albania and Kosovo*, project **E06**, brings an overall positive SEW, as well as most other benefits, with the biggest positive impact being on the improvement of the security of supply. Its benefit-cost ratio is 4.07, making it economically viable.

Same is the case for **E07**, which has a benefit-cost ratio of 7.43, which is even higher that the previous result. This is also a direct consequence of not just positive benefits, but also of a lower investment cost for this specific project.

[23] *PLEXOS optimizes simulation results to minimize the total system costs across all systems/markets in the model. Consequently, while some countries may experience an increase in total costs, others observe lower costs, and leading to reduced overall system costs in the entire model.*

Project **E08**, which present an overhead line connecting Moldova and Ukraine, appears to be somewhat of an outlier in these results. Its benefit-cost ratio is significantly higher than the rest. When taking a detailed look at the rest of the results, it can be observed that the positive impact this project has on security of supply is much higher when comparing it to the other projects. While this might seem peculiar at first, the reasoning behind this is quite simple – in the market model, that has been observed by 2050, there is a large amount of unsupplied energy in 2050 in Energy Community CPs, especially in Ukraine. This is because by 2050, it is expected that Europe will be climate neutral and that all countries will have to decommission their fossil fuel plants, mainly coal and lignite plants. Power plants that have run on natural gas before will have to apply carbon capture and storage technology or to use clean gases. For the Energy Community CPs, this presents quite a challenge since many of these countries rely predominantly on fossil fuel generation and have presented with no plans for 2050 for replacing it and minimising the blow that the decommissioning of this plants will bring on their power systems. This is why, for many of these projects, in 2050 the biggest impact they present is on the security of supply. For E08, this impact is even greater since the input data that has been provided for Ukraine was incomplete, due to their current political situation and confidentiality of data, which might have made this impact even greater than expected. However, this does not put in question the reliability of this result since the supply of energy in CPs by 2050 is a realistic problem and will have to be analysed thoroughly in the future in order to find a solution to this overarching problem.

The only energy storage project that was found eligible, **E13**, the battery energy storage system in Ukraine, is also economically viable. It has a benefit-cost ratio of 2.05 and an overall positive impact on all the analysed benefits. While this project is planned to be built and commissioned in multiple stages, the last stage is planned for commissioning in 2028, and in line with the TEN-E Regulation, the cost-benefit analysis was performed from that year, so that only the benefits of the completely built system that follows the rule of minimum of 225 MW are taken into account.

5.2.2 Multi-criteria analysis

After the cost-benefit analysis was completed, a multi-criteria analysis was done in order to take into account the possible benefits that a certain project has that cannot be monetised. This is also important to be able to have a complete ranking list.

The projects that were not found economically viable did not go into the further process for the multi-criteria analysis, since the TEN-E Regulation specifically states that in order to rank the projects, one must be also economically, as well as it should comply with the general and specific criteria of eligibility, described beforehand.

For the multi-criteria analysis, aside from the **benefit-cost ratio**, two additional criteria were taken into account:

- **Project maturity**

- **SoS system stability/balancing**[24].

In the project application questionnaires, the project promoters were provided with several questions aimed at determining the possible impact that the project might have of system stability/balancing, as well as given multiple choices of project development stages to provide more detailed data of how far along their project development has come. These two criteria are quite important in the analysis of a certain project, since they prove either additional technical impact on the overall system, and therefore a positive impact on the society, or the higher probability of project completion, in case several stages of project development have been completed.

The structure of awarding points for each multi-criteria analysis category is explained in section 2.3. The following table shows the results of the multi-criteria analysis according to the above-mentioned criteria, and the total score for all the projects.

Table 14. Multi-criteria analysis results for eligible projects

No	Name	B/C	System stability	Project maturity	TOTAL
E01	**Increasing the capacity of existing 220 kV interconnection between Bosnia and Herzegovina and Montenegro, 220 kV OHL Trebinje – Perućica**	20	0.4	0.5	20.9
E02	*New 400 kV interconnection between Bosnia and Herzegovina and Montenegro, 400 kV OHL Gacko - Brezna*				
E03	*New 400 kV interconnection between Montenegro and Bosnia and Herzegovina, 400 kV overhead line Brezna-Sarajevo with construction 400/220 kV substation Piva's mountain*				
E04	**Trans Balkan Corridor: Double OHL 400 kV Bajina Basta – Višegrad/Pljevlja (BA & ME sections)**	13	0	2.5	15.5
E05	*Internal transmission line 400 kV Banja Luka 6 - Mostar 4*				
E06	**Reconfiguration of 400 kV grid and new 400 kV interconnection Albania-Kosovo**	14	1.2	0	15.2
E07	**Closing the 400 kV Albanian internal ring**	17	1.2	0	18.2
E08	**330 kV OHL Balti - Dnestrovsk HPP-2**	20	0	0	20
E13	**DTEK STORAGE 225 MW**	12	2	1.2	15.2

[24] The system stability criteria was analysed for high and extra high overhead lines infrastructure category, while system balancing was analysed for energy storage infrastructure category.

5.2.3 Ranking of the projects

According to the total score of the multi-criteria analysis, ranking was done for all the economically viable projects. The ranking is differentiated according to the infrastructure category of the eligible projects, i.e. OHLs are ranked together, while the energy storage project should be ranked separately. Since the energy storage project is the only one in its category, there is no need for ranking it. The result of the ranking of high and extra high overhead lines is shown in Table 15.

Table 15. High and extra high overhead lines final ranking

Rank	No	Name	B/C	System stability	Project maturity	TOTAL
1	E01	Increasing the capacity of existing 220 kV interconnection between Bosnia and Herzegovina and Montenegro, 220 kV OHL Trebinje – Perućica	20	0.4	0.5	20.9
2	E08	330 kV OHL Balti - Dnestrovsk HPP-2	20	0	0	20
3	E07	Closing the 400 kV Albanian internal ring	17	1.2	0	18.2
4	E04	Trans Balkan Corridor: Double OHL 400 kV Bajina Basta – Visegrad /Pljevlja (BA & ME sections)	13	0	2.5	15.5
5	E06	Reconfiguration of 400 kV grid and new 400 kV interconnection Albania-Kosovo	14	1.2	0	15.2

5.3 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 and decrease 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 90 additional simulations in comparison to the base project assessment.

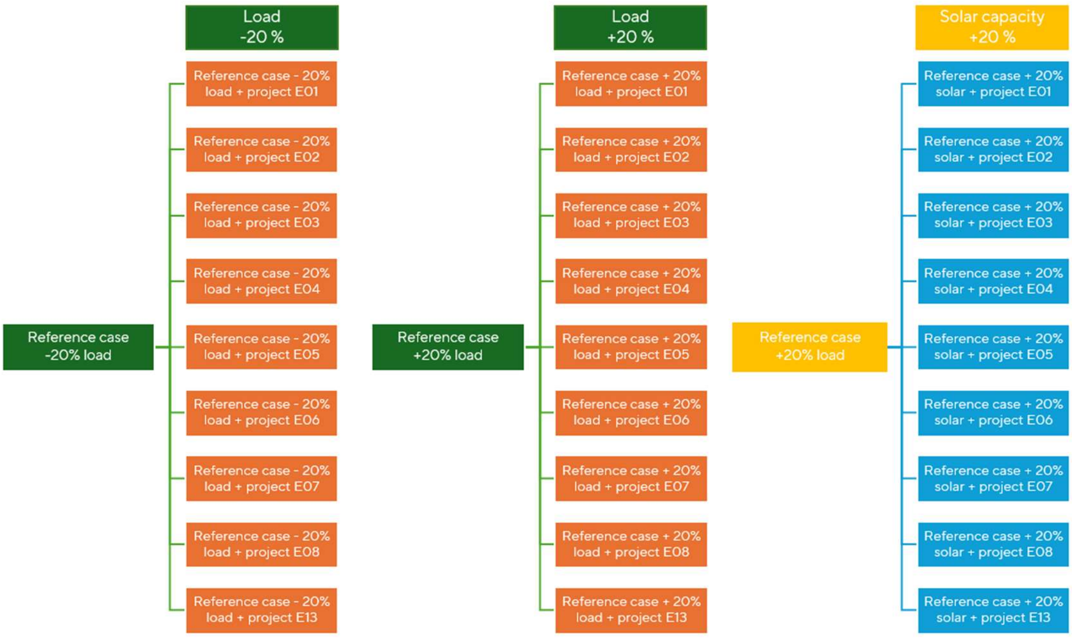

Figure 31. Performed sensitivities under the PECI project assessment process

The increase in solar capacity in CPs and other countries in the model led to a decrease in total generation costs, CO_2 emissions, and average electricity prices in all years in reference scenarios. Regarding the increase in load by 20%, the effects were opposite: higher demand resulted in increased generation and higher generation costs, leading to higher CO_2 emissions and electricity prices. The amount of unserved energy was significantly higher in comparison to the base simulations, occurring across all CPs in 2050. In Table 16 the results of the sensitivity analyses are shown. Along with the benefit-cost ratios for each sensitivity for each project, it is stated whether the results mark a change compared to the initial cost-benefit analysis.

Table 16. Results (B/C ratio) of the sensitivity analyses for all projects

No	Load +20%	*Change*	Load -20%	*Change*	Solar +20%	*Change*
E01	38.31		0.22		20.50	
E02	34.83		4.20		0.02	
E03	9.55		1.28		2.04	
E04	118.61		8.90		4.93	
E05	5.57		0.77		0.38	
E06	0.56		0.16		0.62	
E07	7.88		9.51		9.07	
E08	513.93		433.11		533.30	
E13	6.53		3.72		2.58	

While some changes can be observed, an analysis of their causes reveals that they are not surprising. The highest amount of economic viability result changes is present with the load variations. As was explained earlier, throughout the modelling process it was discovered that the biggest issue that will be present in the future for EnC CPs is the security of supply, i.e. the amount of unsupplied energy. Since that was already proven to be a problem in the base model, it is expected that this problem would be heightened with the increase of load, which would increase the amount of energy that had to be supplied to consumers. The projects that prove to have a positive socio-economic impact despite this issue are E01, E04, E07, E08 and E13, while E02, E03 and E05 would become more important in the case of such high increase of load comparing to the base case scenario.

With the load decrease of 20%, there are some changes also. The E05 result of the cost-benefit analysis proves to be robust, as well as E04, E07, E08 and E13, as before. For the first three projects, all involving the connection of Bosnia and Herzegovina and Montenegro, the load variations seem to be quite impactful, with the changes in economic viability for all projects. This can be attributed to the different points of connections of each of these lines and therefore diverging impacts on the security of supply.

The change, i.e. increase in solar capacity, does not cause a dramatic change in the economic viability of results, reversing the results for two projects, E03 and E06. This proves that these projects are more sensitive to generation type variation and that the increase in a renewable generation might have an impact on the cost-benefit analysis for these projects.

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