INTERIM REPORT

for the project
Technical support to the Energy Community and its Secretariat to assess the candidate Projects of Energy Community Interest (PECI) and candidate Projects for Mutual Interest (PMI) in electricity, gas and oil infrastructure, and in smart grids development,
in line with the EU Regulation 347/2013 as adapted for the Energy Community

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1. INTRODUCTION

The Energy Community Secretariat has contracted a consortium of REKK and DNV GL to assist the Energy Community and its Groups to assess the candidate Projects of Energy Community Interest (PECI) and candidate Projects for Mutual Interest (PMI) in electricity, gas and oil infrastructure, and in smart grids development, in line with the EU Regulation 347/2013 adapted by Ministerial Council Decision 2015/09/MC EnC of 16 October 2015 by the Energy Community (referred to as *Adapted Regulation*).

The objective of the technical support is as follows

1. To use REKK electricity and gas market models and modify available electricity network model for the Energy Community Contracting Parties and use these in the assessment of PECI candidates;
2. To develop a multi criteria assessment methodology using the ENTSO-E and ENTSOG methodology for cost benefit analysis where applicable;
3. To assess the candidate projects for electricity, gas and oil infrastructure, as well as for smart grids, in order to be able to identify those which bring the greatest benefits for the Energy Community.

This assistance consists of four main tasks:

- Verification and classification of the submitted infrastructure projects
- Development of a project assessment methodology
- Evaluation of all submitted and eligible projects according to the criteria and the methodology
- Identification of Projects of Energy Community Interest as a result of the aforementioned tasks

The purpose of this interim report is to provide an overview of the submitted projects and to introduce the project assessment methodology that will be applied to each proposed investment project submitted by project promoters until 26.02.2016 or during the public consultation phase (which will follow the submission of this Interim Report). In doing so this interim report describes the steps that have already been carried out and outlines the steps which remain to be carried out within the parameters this project.

This interim report is therefore structured as follows. The following chapter describes the submitted projects and proposes a classification of these projects according to their eligibility and data verification. Chapter 3 provides an overview on the general approach which the consortium partners propose for the project assessment followed by a detailed description of the proposed project assessment methodology, which consists of an economic cost-benefit analysis and a set of additional criteria. This interim report closes (Chapter 4) looking ahead to the next steps that will be conducted by the consortium partners as part of this project. Furthermore three annexes are attached to this report, presenting a summary table with information on all submitted projects: (Annex 1) with an overview of the electricity and gas market models applied within the cost-benefit analysis; (Annex 2) describing the models; (Annex 3) presenting the input data to underpinning the modelling as agreed with the Contracting parties Representatives in the Groups.

1.1. STUDY BACKGROUND

The objective of the project is to assist the Energy Community Secretariat and the Group as defined by the Ministerial Council Decision (D/2015/09/MC-EnC on the implementation of regulation (EU) No 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure to implement the procedure and achieve the scope of the assignment, namely to propose a list of Projects of Energy Community Interest (PECI) and Projects of Mutual Interest (PMI) to the Ministerial Council for adoption in 2016. The proposed methodology should be in line with the EU 347/2013 Regulation as adapted for the Energy Community as far as possible.

In addition, the methodology applied to the latest selection of EU Projects of Common Interest (PCIs) under Regulation 347/2013 of the European Parliament and of the Council as well as the methodologies for the assessment of network infrastructure projects developed by ENTSOE and ENTSOG shall be taken into account.

The geographical scope of the assistance extends to the Contracting Parties of the Energy Community (Albania, Bosnia and Herzegovina, the Former Yugoslav Republic of Macedonia, Kosovo*[1], Moldova, Montenegro, Serbia and Ukraine). Nevertheless, projects may also be proposed to include EU Member States (MSs) when bordering a Contracting Party.

1.2. MAIN STEPS OF PROJECT ASSESSMENT

1. Questionnaires for the eligible project categories were developed by the consortium and presented to the Energy Community Secretariat in the Inception Report.

2. Eligibility criteria were verified for all projects based on the EU Regulation 347/2013 adapted by Ministerial Council Decision 2015/09/MC EnC of 16 October 2015 by the Energy Community.

3. Verification of submitted data was carried out for data consistency, by checking the relevant planning documents and for cost data using benchmarks.

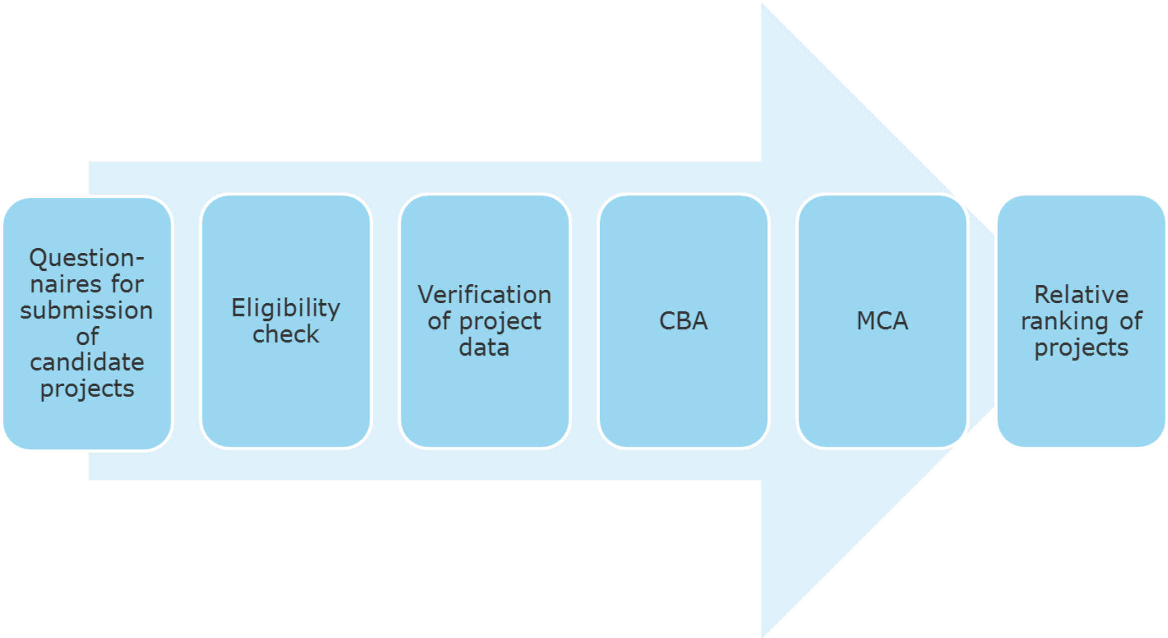
4. Modelling based cost-benefit analysis will aggregate all the potential monetized benefits of the proposed project into the calculation of a social NPV on the Energy Community level. All projects with a negative NPV will be reported to the Groups.

*This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.

5. Potential benefits that cannot be monetized in the framework of the CBA will be assessed with separate indicators for gas and for electricity. Weights are attached to all the indicators, and a scoring system will incorporate all results in a final score.

6. The scores of the multi criteria assessment will serve the Groups with a ranking of projects to assist the decision making process for PECI and PMI projects. The final list of projects will be proposed by the Groups to the Ministerial Council and will not include any ranking.

Figure 1. Workflow of the project



1.3. Outputs and Deliverables

The first output of the project was the Inception Report, which incorporated the final questionnaires, and was submitted to the Energy Community Secretariat 15 January 2016.

At the first Group meeting 26 February 2016 the assessment methodology was presented, models for the CBA were introduced, and the approach for a multi-criteria assessment capturing benefits outside of the CBA was approved. The Groups also agreed to the weights that are to be used for the different indicators.

Project proposals submitted by the project promoters were checked for eligibility and in the course of additional data submission the final data set for assessment was established. In the second meeting of the Groups on 08 April 2016 the results of the eligibility and data verification were presented and a decision on the main modelling assumptions was taken. The eligibility check and data verification results and the methodology that will be used for project assessment is presented in this Interim report.

The eligible projects will be assessed in May and the preliminary ranking of projects based on the methodology described in this report will be presented to the Groups on 29-30 June 2016 in Vienna.

The Final Report will contain the list of projects proposed for PECI and PMI status, as well as a detailed evaluation of all project submitted for the call and considered eligible. The final list of PECIs and PMIs will not provide a ranking of projects, but will list those projects which are found fit for the designation.

2. OVERVIEW OF SUBMITTED PROJECTS AND THEIR ELIGIBILITY

2.1. General Overview of Submitted Projects

In total, 33 project proposals were submitted to the Secretariat of the Energy Community. The Consortium screened all project submissions for eligibility based on the *Adapted Regulation* and presented its findings on eligibility to the Groups in the 08 April 2016 meeting. Investment cost for all submitted projects totalled 4,000 million €, with more than half of this sum planned for gas infrastructure. For comparison, in 2013 there were 85 projects submitted with a total CAPEX of ca. 25,000 million €. It is important to note that electricity generation-projects are not eligible in 2016, as opposed to 2013 (in 2013, 29 projects were electricity generation projects).

Table 1. Overview of the submitted projects

	Electricity trans-mission	Electricity storage	Gas trans-mission	Gas Storage	LNG	Smart Grid	Oil	Total
Submitted projects	13	0	16	0	1	2	1	33
Submitted investment cost	Ca.1200 million €		Ca. 2350 million €				490 million €	Ca.4040 million €

The geographical location of the proposed projects is shown on the following maps.

Figure 2. Location of submitted electricity projects

Source: REKK based on Project Promoters and ENTSO-E. The display of location is for illustration only.

Figure 3. Location of submitted gas projects

Source: REKK based on Project Promoters and ENTSOG. The display of location is for illustration only.

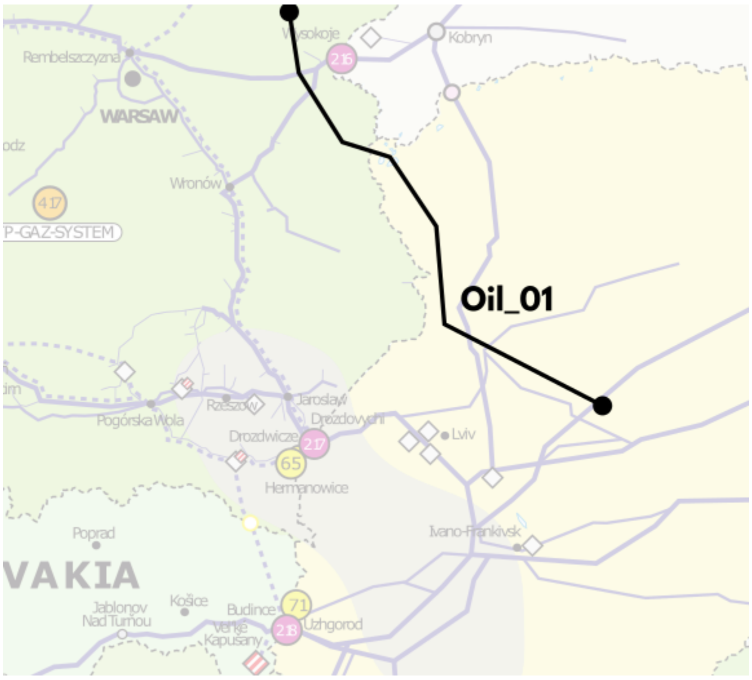


Figure 4. Location of the submitted oil project

Source: REKK based on Project Promoters and ENTSOG. The display of location is for illustration only.

In addition, two smart grid projects, one in Kosovo* and one in the FYR of Macedonia have been submitted.

2.2. Applied Approach for Eligibility Check and Data Verification

The eligibility of the proposed projects has been assessed on the basis of the information provided in the project questionnaires as well as any additional information provided by the project promoters throughout the process. The eligibility check follows the criteria specified in the *Adapted Regulation*. The accuracy of the submitted technical and commercial project data is further corroborated to the best possible extent in order to, before serving as the basis for the project assessment. This verified list of eligible projects is summarized in Table 13 showing the most important technical parameters that will be used as input data for the CBA modelling.

All proposed investment projects submitted by the project promoters until 26 February 2016 have been taken through the following pre-assessment steps. For the projects to be submitted during the public consultation the same procedure will apply.

- Eligibility check of the proposed projects applying the *Adapted Regulation*
- Verification of the submitted project data
- Identification of potential project overlaps, complementarities and competitiveness between the proposed projects,
- Possible clustering or division of project submissions for the sake of methodologically sound project evaluation

The following figure illustrates these first phase of the project evaluation.

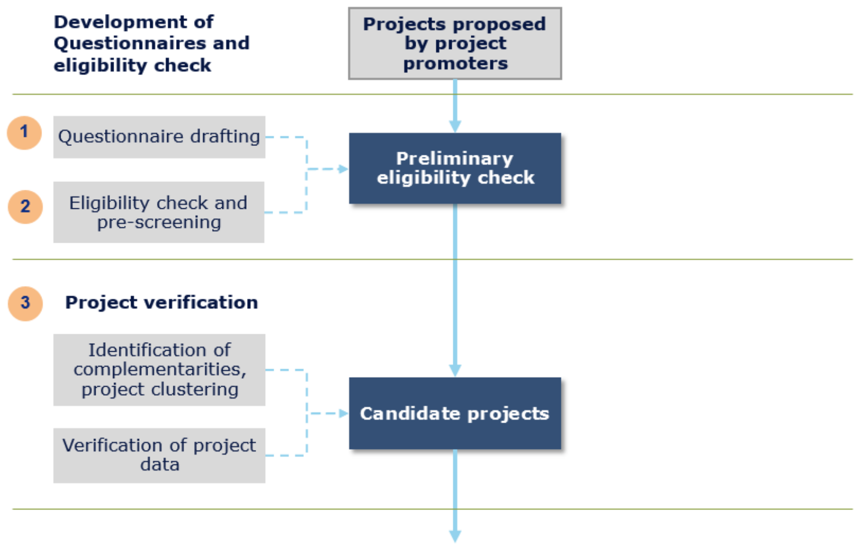


Figure 5. Pre-assessment phase of project evaluation

2.2.1. Eligibility Check

To be considered for the status of Project of Energy Community Interest a number of eligibility criteria are to be met as outlined in EU Regulation 347/2013 adapted by Ministerial Council Decision 2015/09/MC EnC of 16 October 2015 by the Energy Community (*Adapted Regulation*). **General criteria** for eligibility require that

1) the investment project falls in at least one of the energy infrastructure categories and areas as described in Annex I of the *Adapted Regulation*;
2) the potential overall benefits of the project outweigh its costs, including in the longer term;
3) the project involves at least two Contracting Parties or a Contracting Party and a Member State by directly crossing the border of two or more Contracting Parties, or of one Contracting Party and one or more Member States

   or

   the project is located on the territory of one Contracting Party and has a significant cross-border impact.

Please note, that whether the potential overall benefits of the project outweigh its costs, as well as whether a project has a significant cross-border impact, can only be assessed within the gas and electricity market modelling, the results of which will be presented in the CBA. Projects with a negative social NPV will be reported to the Group in the next meeting as projects that do not fulfil this criterion. For projects with a negative but close to zero NPV it is up to the Groups to decide whether the non monetized benefits would outweight the cost to arrive to a zero NPV. The multicriteria assessment will also include the other indicators to help the decision making.

For electricity, project submissions must fit into one of the following energy infrastructure categories:

a) high-voltage overhead transmission lines, if they have been designed for a voltage of 220 kV or more, and underground and submarine transmission cables, if they have been designed for a voltage of 150 kV or more;
b) electricity storage facilities used for storing electricity on a permanent or temporary basis in above-ground or underground infrastructure or geological sites, provided they are directly connected to high-voltage transmission lines designed for a voltage of 110 kV or more;
c) any equipment or installation essential for the systems defined in (a) and (b) to operate safely, securely and efficiently, including protection, monitoring and control systems at all voltage levels and substations.

For natural gas, project submissions must fit into one of the following energy infrastructure categories:

a) transmission pipelines for the transport of natural gas and bio gas that form part of a network which mainly contains high-pressure pipelines, excluding high-pressure pipelines used for upstream or local distribution of natural gas;
b) underground storage facilities connected to the above-mentioned high-pressure gas pipelines;
c) reception, storage and regasification or decompression facilities for liquefied natural gas (LNG) or compressed natural gas (CNG);
d) any equipment or installation essential for the system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations.

Smart grid projects should contribute to the adoption of smart grid technologies across the Energy Community to efficiently integrate the behaviour and actions of all users connected to the electricity network, in particular the generation of large amounts of electricity from renewable or distributed energy sources and demand response by consumers.

Project submissions in the area of oil must fit into one of the following energy infrastructure categories:

a) pipelines used to transport crude oil;
b) pumping stations and storage facilities necessary for the operation of crude oil pipelines;
c) any equipment or installation essential for the system in question to operate properly, securely and efficiently, including protection, monitoring and control systems and reverse-flow devices;

To assess whether an **electricity** transmission project has a significant cross-border impact (according to the Regulation), the implementation of the project needs to result in an increase of the grid transfer capacity, or the capacity available for commercial flows. This is to be measured at the border of that Contracting Party with one or several other Contracting Parties and/or Member States, or at any other relevant cross-section of the same transmission corridor having the effect of increasing this cross-border grid transfer capacity, by at least 500 MW compared to the situation without the commissioning of the project.

Significant cross-border impacts of **natural gas** transmission projects are measured (according to the Regulation) by the following criteria: when the project involves investment in reverse flow capacities or changes in the capability to transmit gas across the borders of the Contracting Parties and/or Member States concerned by at least 10% compared to the situation prior to the commissioning of the project; natural gas storage or liquefied/compressed natural gas needs to directly or indirectly supply at least two Contracting Parties and/or one or more Member State; fulfil the infrastructure standard (N-1 rule) at a regional level (in accordance with Article 6(3) of Regulation (EU) No 994/2010 of the European Parliament and of the Council).

For **smart grid** projects the following additional eligibility criteria are specified in Annex III.1(d) of Regulation 347/2013 as adapted for the Energy Community (Ministerial Council Decision 2015/09/MC-EnC of 16 October 2015):

- project designed for equipment and installations at high-voltage and medium-voltage level at 10kV or more

- project involves transmission and distribution system operators from at least two Contracting Parties

- covers at least 50,000 users that generate or consume electricity or do both in a consumption area of at least 300 GWh/year, of which at least 20 % originate from renewable resources that are variable in nature.

In addition to the general eligibility criteria, **oil** projects must also contribute significantly to all of the following specific criteria:

- security of supply reducing single supply source or route dependency;

- efficient and sustainable use of resources through mitigation of environmental risks;

- interoperability

2.2.2. Data Verification

To verify data submitted by project promoters, we have checked the following secondary sources:

- Previous submission of PECI candidates in 2013, where applicable;
- In case the project was also submitted as a PCI candidate, documentation related to the 2015 PCI application;
- Data about the projects published in the Ten Year Network Development Plans (TYNDP) of ENTSO-E and ENTSOG;

- Data published in national TYNDPs.

Apart from checking the consistency of data, we have assessed the investment cost of the project on the basis of ACER benchmarks[2] and using the expert judgement of DNV GL's local experts.

Figure 6. General steps performed to verify project data

Verification of technical data	• Length of project, diameter, capacity • Geographical match
Verification of mutual interest	• Letter of intent from the other hosting country in the project • Commissioning date and other technical characteristics are agreed upon with the other hosting countries
Verification of cost data	• Check if all parts of the projects are included • Benchmarking of total cost – within a reasonable range

2.3. Electricity Infrastructure Projects

2.3.1. Eligibility of Electricity Infrastructure Projects

As far as infrastructure categories are concerned, all submitted electricity projects fit into one of the infrastructure types specified in the *Adapted Regulation* for PECI or PMI status.

The second requirement of the *Adapted Regulation* stipulates that the infrastructure element crosses the border of at least two Contracting Parties or a Contracting Party and a Member State. In case of transformer stations, the infrastructure should be essential for such an investment to be realised. All but one project pass this criterion. El_11 (the 400/110 kV Substation Kumanovo) is the final element of a bigger project cluster: part of the 400 kV interconnection Štip (MK) – Nis (RS). However, this substation cannot be separately assessed as there is no NTC impact assigned to the substation.

[2] ACER (2015): Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure

The third requirement is to have a significant cross-border effect, which relates to a capacity increase of over 500 MW. To date we have not received sufficient information from the questionnaires to evaluate EL_02, EL_12 and EL_13, (see Table 2 for project names) and thus we have requested further information from the project promoters. Concerning project EL_13, the proposed project is part of the TYNDP project cluster 147, with NTC contributions of 600 and 1000 MW in two directions. Although the proposed sub-project has a NTC impact of 200-300 MW alone – which would be under the threshold specified in the Regulation – as part of a bigger project cluster our recommendations is to include it in the project assessment with its 200-300 MW NTC contribution, ensuring that the total NTC between the two countries is reflective of the whole cluster in the modelling.

Table 2. Eligibility check for submitted electricity projects

Project code	Project name	Infra-structure	Crossing border of two CPs or MSs	Capacity over 500 MW	Candidate for (PECI/PMI/NO)
EL_01	Transbalkan corridor phase 1	☑	☑	☑	PECI
EL_02	Transbalkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	☑	**?**	**?**	PECI
EL_03	TransBalkan Electricity Corridor, Grid Section in Montenegro	☑	☑	☑	PECI
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	☑	☑	☑	PMI
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	☑	☑	☑	PMI
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	☑	☑	☑	PMI
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	☑	☑	☑	PMI
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian el. network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	☑	☑	☑	PMI
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	☑	☑	☑	PMI
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	☑	☑	☑	PMI
EL_11	400/110 kV Substation Kumanovo	☑	✕	✕	Not eligible, Part of a larger cluster, not assessed in PECI
EL_12	400 kV interconnection Skopje 5 - New Kosovo	☑	☑	**?**	PECI
EL_13	400 kV Interconnection Bitola(MK)-Elbasan(AL)	☑	☑	200-300 MW?	**?**

2.3.2. Data Verification for Electricity Infrastructure Projects

Three areas have been verified for the electricity projects: technical data (including NTC values, length and voltage characteristics of the overhead lines (OHL) as well as capacity values for the substations), the existence of a letter of intent from the neighbouring TSOs and the project cost data.

The technical data could generally be verified for all submissions, with the exception of two projects, where missing/ambiguous data remains concerning the technical information (EL-02 and EL-12 projects). It is important to note, however, that these two projects have a commissioning date past 2026. It is possible to evaluate them, but consideration should be given to the fact that the PECI/PMI list will be updated every 2 years and projects beyond a 10-year horizon could be submitted at a later phase.

A Letter of consent from the other involved Contracting Parties and/or Member States is requested for all projects, except those that are already in the ENTSO-E, G TYNDP, or on the PCI list 2015; in these cases, there is already indication that the project is jointly promoted by the countries on both sides of a border. If the project is not in one of these exemptions, but the TYNDP of the counterpart country includes the specific project, it could also be regarded as a project of both parties' interest. For project El_08 we did not receive information on the planned commissioning year from the Polish side. For project El_10 no commissioning date was provided in the national TYNDPs of Romania or Moldova. In these two cases we have requested the Ukrainian project promoter to ask for the Letter of Consent from neighbouring TSOs confirming the application as of both parties's interest.

To verify the submitted cost data, we have used ACER's Infrastructure Unit Investment Cost Report[3] in order to judge if the project costs fall within the range of the covered project types. The report gives values on the electricity infrastructure elements (by kV level for OHL, underground, or subsea cables) and for substations, according to the ratings of the lines (e.g. in MVA).

[3] ACER: Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)

Table 3. Indicators for Unit Investment Costs for overhead lines (total cost per line length, €/Km)

	Mean (€)	Min-max interquartile range (€)	Median (€)
380-400 kV, 2 circuit	1 060 919	579 771 – 1 401 585	1 023 703
380-400 kV, 1 circuit	598 231	302 664 – 766 802	597 841
220-225 kV, 2 circuit	407 521	354 696 – 461 664	437 263
220-225 kV, 1 circuit	288 289	157 926 -298 247	218 738

Table 4. Indicators for Unit Investment Costs for Substations by ratings (€/MVA)

	Mean (€)	Min-max interquartile range (€)	Median (€)
Total cost per rating (per MVA)	38 725	26 436 – 52 078	35 500

We have used the reported min-max interquartile range for the comparison, which already filters out the outliers in the report. A challenge in this comparison is that the submitted electricity infrastructure projects include the construction of new lines as well as the refurbishment of existing lines. It is however very difficult to evaluate the unit cost of refurbishments. Most of the time, the refurbishment infers the installation of a new OHL, but uses existing routes without the need for land acquisition. However, refurbishments in many cases means that the old line is dismantled, and a new, higher capacity line is installed along the same route, which may cost the same as the installation of a new OHL. For this reason, we used the same benchmark investment cost.

The benchmarking was based on the data provided by the project promoters on the line length and the capacities of the substations. We found that project El_05 is above the reported interquartile range, but would fall within the absolute observed min-max range.

The table below summarises our findings on the verification of electricity projects.

Table 5. Verification of project data for submitted electricity projects (strikethrough projects are not eligible)

Project code	Project name	Technical data	From-to	Letter of consent or equivalent	Cost
EL_01	Transbalkan corridor phase 1	☑	RO-RS-BA-ME	☑	☑
EL_02	Transbalkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	**?**	RS	☑	☑
EL_03	TransBalkan Electricity Corridor, Grid Section in Montenegro	☑	RS-ME	☑	☑
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	☑	BA-HR	☑	☑
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	☑	MD-RO	☑	Above range
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	☑	MD-RO	☑	Not reported
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	☑	MD-RO	☑	Not reported
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian electricity network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	☑	UA-PL	**Not yet**	☑
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	☑	UA-SK	☑	☑
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	☑	UA-RO	**Not yet**	☑
~~**EL_11**~~	~~400/110 kV Substation Kumanovo~~	~~☑~~	~~MK~~	~~☑~~	~~☑~~
EL_12	400 kV interconnection Skopje 5 - New Kosovo	**?**	MK-KO	☑	☑
EL_13	400 kV Interconnection Bitola(MK)-Elbasan(AL)	☑	MK-AL	☑	☑

2.3.3. Project Clustering of Electricity Infrastructure Projects

Project EL_01 and EL_03 will be assessed together as they are complementary projects (the economic assessment is carried out for a merged project). This decision is supported by the project promoter, who indicated his agreement at the 8 April 2016 Group meeting.

2.4. NATURAL GAS INFRASTRUCTURE PROJECTS

2.4.1. Eligibility of Natural Gas Projects

All gas transmission projects are cross-border projects so the criterion of affecting two Contracting Parties or a Contracting Party and a Member State is met. In case of the Eagle LNG terminal proposal, the terminal is planned to be located in Albania, which has no interconnection to any of the neighbouring countries yet. The project however includes an undersea pipeline to Italy, which allows for the inclusion of a neighbouring EU Member State.

Most of the pipeline projects are new infrastructures, typically creating new connections between countries. The 10% threshold in capacity increase was easily met by all projects. There is only one reverse flow project proposed: the development of firm capacity on the Hungary-Ukraine pipeline. This capacity is currently available only on an interruptible basis.

The following tables summarise the eligibility check for submitted natural gas infrastructure projects.

Table 6. Eligibility check for submitted natural gas projects

Project code	Project name	From country – to country	Infrastruc-ture type	Crossing border of two CPs + MSs	Reverse flow or capacity increase over 10%	Candidate for (PECI/ PMI/NO)
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	BA-HR	☑	☑	☑	PMI
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzacBosanska Krupa)	BA-HR	☑	☑	☑	PMI
GAS_03	Interconnection Pipeline BiH HR (PloceMostarSarajevo / Zagvozd-Posusje Travnik)	BA-HR	☑	☑	☑	PMI
GAS_04	Interconnector of Republic of Macedonia with Bulgaria and Greece	MK- BG MK -GR	☑	☑	☑	PMI
GAS_05	Interconnector of Republic of Macedonia with Kosovo*, Albania and Serbia	MK-KO* MK-RS MK-AL	☑ ☑ ☑	☑ ☑ ☑	☑ ☑ ☑	PECI
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar to Albanian border	AL-MK	☑	☑	☑	PECI
GAS_07	Macedonian part of TESLA project	GR -MK MK-RS RS-HU HU-AT	☑	☑	☑	PECI
GAS_08	Interconnector Serbia-Romania	RS-RO	☑	☑	☑	PMI
GAS_09	Gas Interconnector RS-BG - Section on the Serbian territory	BG-RS	☑	☑	☑	PECI
GAS_10	Gas Interconnector Serbia Croatia	RS - HR	☑	☑	☑	PMI
GAS_11	Gas Interconnector RS-MK Section on the Serbian territory	RS-MK	☑	☑	☑	PECI
GAS_12	Gas Interconnector RS-MK Section Nis (Doljevac) Pristina	RS-KO	☑	☑	☑	PECI
GAS_13	Albania-Kosovo Gas Pipeline (ALKOGAP)	AL-KO	☑	☑	☑	PECI
GAS_14	Gas Interconnection Poland Ukraine	PL-UA	☑	☑	☑	PMI
GAS_15	Development of the HU to UA firm capacity	HU-UA	☑	☑	☑	PMI
GAS_16	Ionian Adriatic Pipeline	AL-ME ME-HR	☑	☑	☑	PMI
GAS_ LNG_17	EAGLE LNG and Pipeline	FSRU-AL AL-IT	☑	☑	☑	PMI

2.4.2. Data Verification for Natural Gas Infrastructure Projects

Data verification of gas projects has been complicated by widespread absence of basic data (e.g. on capacity and cost), resulting in data requests sent to promoters. The majority of the interconnector projects were not accompanied with bordering connections, which means that there may be a risk of building pipelines on the project promoters' territories that are never connected or only commissioned in full after a long delay. Joint submissions were rare, but a few sterling examples included projects concerning Bosnia and Herzegovina and Croatia, the IAP, and Polish-Ukrainian reverse flow gas pipeline. In other cases we have accepted that there was a mutual interest if the counterparty provided a letter of consent , or if the project was included in that country's TYNDP. Also, we have accepted projects that have been assigned PCI status, such as the Serbia-Bulgaria gas interconnector, and the Macedonian segment of TESLA pipeline. To properly model TESLA pipeline, we chose to assess the entire project as it is included in the PCI list of 2015.

If the project was not submitted jointly by the connected or crossed Contracting Parties or Member States, or was not included in the respective TYNDPs, PCIs, CESEC lists, project promoters were requested to submit a letter of consent from their counterparty to the EnC Secretariat. Consultant and ECS required project promoters to submit the basic data for CBA assessment. If this was submitted, the technical data criterion was considered satisfied. We also checked whether the proposed project connects to an existing network point.

In the case of inconsistency between the neighbouring TSOs' capacity data, the lesser rule was applied; in a mismatch of commissioning years, the later date was applied. Lesser rule had to be applied for the Serbian-Bulgarian gas pipeline, where only the first stage of the project (39,44 GWh/day capacity) was submitted by Serbia.

The table below summarises our findings on the verification of natural gas projects.

Table 7. Verification of project data for submitted natural gas projects

Project code	Project name	Technical data	From-to	Letter of intent	Cost
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	☑	BA-HR	☑	☑
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzac-Bosanska Krupa)	☑	BA-HR	☑	☑
GAS_03	Interconnection Pipeline BiH HR (PloceMostarSarajevo / ZagvozdPosusje Travnik)	☑	BA-HR	☑	☑
GAS_04	Interconnector of the FYR of Macedonia with Bulgaria and Greece	☑	MK-BG	tbc BG	☑
			MK-GR	tbc GR	☑
GAS_05	Interconnector of of the FYR of Macedonia with Kosovo, Albania and Serbia	☑	MK-KO*	tbc Kosovo* d	no cost
			MK-RS	☑	no cost
			MK-AL	tbc AL	no cost
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border	☑	AL-MK	tcb AL	Only MK cost submitted
GAS_07	Macedonian part of TESLA project	☑	MK-GR MK-RS RS-HU HU-AT	☑	Only MK cost submitted
GAS_08	Interconnector Serbia-Romania	☑	RS-RO	tbc RO	Only RS cost submitted
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	☑	RS-BG	☑	Only RS cost submitted
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	☑	RS-HR	☑	☑
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia Section on the Serbian territory	☑	RS-MK	tbc MK	Only RS cost submitted
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo) Section Nis (Doljevac) Pristina	Capacity data missing	RS-KO*	tbc Kosovo*	Only RS cost submitted
GAS_13	AlbaniaKosovo Gas Pipeline (ALKOGAP)	☑	AL-KO*	☑	☑
GAS_14	Gas Interconnection Poland Ukraine	☑	UA-PL	☑	☑
GAS_15	Development of the HU to UA firm capacity	☑	UA-HU	☑	☑
GAS_16	Ionian Adriatic Pipeline	☑	AL-ME ME-HR	☑	Above range
GAS_ LNG_17	EAGLE LNG and Pipeline	☑	LNG_AL AL-IT	☑	only the pipeline part was included into the cost the terminal is planned to be chartered

Cost verification

Submitted CAPEX figures by project promoters were also cross-checked against ACER's benchmarks. We have found that these figures were generally in line with ACER's cost data, although some clarifications are needed. To this end project promoters have been contacted and will be dealt with individually. Cost data will not presented in this report for confidentiality reasons.

Table 8. 2015 indexed unit investment cost of transmission pipelines commissioned in 2014 (average values)

Pipeline diameter	<16"	16-27"	28-35"	36-47"	48-57"
Average unit cost, real 2015 €/km	643 936	746 801	847 966	1 427 041	2 098 567

Source: ACER Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)

The Eagle LNG terminal did not submit cost data for the undersea pipeline section (AL-IT), hence the cost of the project could not be verified. The project promoter has been contacted to submit additional data.

For projects that were not jointly submitted, secondary sources were used to estimate the cost of the additional part of the project. First, if submitted, a letter of intent from the other hosting party was used as a data source for cost, capacity and planned year of commissioning.

Second, if no letter of intent was provided, the TYNDP of the neighbouring country was consulted for cost, capacity and planned year of commissioning.

In case no additional cost data was provided from either source, the cost for the other part of the project was estimated according to ACER's benchmark and the length and the diameter of the pipeline.

Indication of mutual interest

A significant problem common among gas projects was that projects were submitted only up to the border and did not appear to connect to any existing or planned pipeline. Therefore, a proof of mutual interest of the directly connected or crossed country was deemed necessary.

Table 9. Indication of mutual interest (as of 25.04.2016)

Project code	Project name	Source	Letter of intent
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	Letter of support from Plinacro	☑
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzacBosanska Krupa)	Letter of support from Plinacro	☑
GAS_03	Interconnection Pipeline BiH HR (PloceMostarSarajevo / Zagvozd-Posusje Travnik)	Letter of support from Plinacro	☑
GAS_04	Interconnector of of the FYR of Macedonia with Bulgaria and Greece	Not in TYNDP 2015	tbc BG tbc GR
GAS_05	Interconnector of of the FYR of Macedonia with Kosovo, Albania and Serbia	Kosovo*does not support	tbc Kosovo* ☑ tbc AL
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border	**?**	tcb AL
GAS_07	Macedonian part of TESLA project	PCI 2015	☑
GAS_08	Interconnector Serbia-Romania	Not in RO TYNDP	tbc RO
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	PCI 2015	☑
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	in HR TYNDP	☑
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia Section on the Serbian territory	GAS_05a submitted separetely	☑
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) Section Nis (Doljevac) Pristina	Kosovo* does not support	tbc Kosovo*
GAS_13	AlbaniaKosovo Gas Pipeline (ALKOGAP)	Letter of support	☑
GAS_14	Gas Interconnection Poland Ukraine	Submitted for TYNDP 2017(?)	☑
GAS_15	Development of the HU to UA firm capacity	Not in TYNDP 2015 nor in HU TYNDP, submitted for TYNDP2017(?)	☑
GAS_16	Ionian Adriatic Pipeline	Letter of intent from Montenegro, Albania TYNDP, ENTSOG TYNDP	☑
GAS_ LNG_17	EAGLE LNG and Pipeline	ENTSOG TYNDP	☑

2.4.3. Project Clustering of Natural Gas Infrastructure Projects

As agreed at the Group meeting on 8 April 2016, Gas_05a (Interconnector the FYR of Macedonia-Albania) will be analysed as a standalone project. The interconnector Serbia – the FYR of Macedonia was submitted by both hosting countries up to their borders. The proposal of joining the previous Gas_05b with Gas_11 (Interconnector Serbia-the FYR of Macedonia) was approved by both hosting countries, so the interconnector will be assessed as a joint project under the number of Gas_11.

2.5. SMART GRID PROJECTS

For smart grid projects falling under the energy infrastructure category set out in Annex I.1(d) of Regulation 347/2013 as adapted for the Energy Community (Ministerial Council Decision 2015/09/MC-EnC of 16 October 2015) in the 2016 selection PECIs, two projects were submitted:

- SM_01 *Reduction of grid losses* of EVN Macedonia AD
- SM_02 *Kosovo Smart Meter Project* of Kosovo Electricity Distribution and Supply Company J.S.C

Based on the information within the questionnaires as well as additional data/information requested and provided by the project promoters **both of these projects were found not to meet the eligibility criteria specified in section 2.2.1; they are therefore not further considered within the assessment conducted by the Consultant under the PECI 2016 selection.** The table below summarises the information with regard to the eligibility criteria for both projects. Neither project reaches the minimum capacity network threshold of 20% originating from non-dispatchable renewable resources or the requirement to involve TSOs and DSOs from at least two Contracting Parties of the Energy Community. The Kosovo Smart Meter project also involves a consumption level below the threshold of 300 GWh/year required by Regulation 347/2013 as adapted for the Energy Community. In the case of the Smart Grid project in the FYR of Macedonia – given that the project does not meet the above mentioned eligibility criteria – it has not been verified whether the figures provided for the number of involved users and the consumption level are indeed referring only to the area of the Smart Grid project and a voltage level above 10kV.

Table 10. Eligibility criteria assessed for submitted projects under the category of Smart Grids

Eligibility Criteria	**SM_01** (Reduction of Grid Losses EVN Macedonia)	3. **SM_02** (Kosovo* Smart Meter Project)
Voltage level(s) (kV) above 10kV	*Mostly 10kV*	35kV and 10(20)kV
Number of users involved more than 50,000	*100,000*	400,000
Consumption level in the project area equals at least 300 GWh/year	*666 GWh/year*	4,676 GWh/Year
In terms of capacity, share (%) of energy supplied by non-dispatchable resources levels above 20%	N/A	N/A
Involvement of TSOs / DSOs from at least two Contracting Parties	N/A	N/A

3.1. Oil Projects

For oil projects falling under the energy infrastructure category set out in Annex I.(3) of *Adapted Regulation* in the 2016 selection PECIs, only one project – the Brody Adamowo pipeline – has been submitted.

Based on the questionnaire submitted by the promoter, it is acknowledged that the delivery of Caspian and Central Asian crude oil through the Brody Adamowo pipeline will increase security of oil transportation by serving to diversify supply routes to the EU and Poland. The project contributes to protecting and improving the condition of the natural environment and health by avoiding shipping risks and emissions arising from tanker traffic, which would be the transport alternative in case the pipeline was not realized.

As far as interoperability is concerned, the Brody Adamowo oil pipeline would ensure continuous oil flows to the dependent refineries in case of a supply disruption along the conventional supply route. The project will provide for the integration of the Ukrainian oil transportation system with that of Poland and Europe. It also creates the opportunity to transport crude oil in reverse from the Baltic Sea to consumers in Ukraine, Slovakia and the Czech Republic.

In summary, all eligibility criteria are met by the proposed oil infrastructure project "Construction of the Brody Adamowo oil pipeline".

Table 11. Eligibility check for submitted oil project

Project code	Project name	Crossing border of two CPs + MSs	Reducing single source dependency (SOS)	Environmental risk mitigation	Interoperability	Lifetime (Years)	Letter of intent?
Oil_01	Construction of the Brody Adamowo oil pipeline	☑	☑	☑	☑	20	Joint submission

Technical and cost data of the Brody-Adamowo oil pipeline had been verified during the process leading up to the 2013 PECI list. The project is part of both PCI and PECI lists. In the current submission, CAPEX was increased by approximately 10%.

3.2. LIST OF ELIGIBLE PROJECTS AS THEY WILL BE MODELLED

The following tables provide an overview on the electricity transmission, natural gas transmission and LNG projects that will be evaluated by the assessment methodology described in the following chapter, including the clustering and division of submitted projects as agreed with the promoters.

Table 12. List of eligible electricity projects to be modelled and evaluated (strikethrough projects are not eligible)

Code	project name	NTC increase		Capacity	Commissioning date
		Country A	Country B		
el_01	Transbalkan corridor phase 1	RO	RS	750	2018
		RS	RO	450	2018
		RS	ME	500	2023
		ME	RS	500	2023
		RS	BA	600	2023
		BA	RS	500	2023
el_02	Transbalkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	RS	RS	?	2027
el_03	TransBalkan Electricity Corridor, Grid Section in Montenegro	ME	RS	1000	2020
	TransBalkan Electricity Corridor, Grid Section in Montenegro	RS	ME	1100	2020
el_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	BA	HR	504	2030
el_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	MD	RO	500	2025
el_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	MD	RO	500	2022
el_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	MD	RO	500	2025
el_08	Asynchronous Interconnection of ENTSOE and Ukrainian electricity network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	UA	PL	600	2020
el_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	UA	SK	700	2020
el_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	UA	RO	1000	2025
~~el_11~~	~~400/110 kV Substation Kumanovo~~	~~MK~~	-	-	~~2020~~
el_12	400 kV interconnection Skopje 5 - New Kosovo	MK	KO*	?	2026
el_13	400 kV Interconnection Bitola(MK)-Elbasan(AL)	MK	AL	200	2019

By the date of closure of the Interim report (20.04.2016.), data was still missing for projects indicated with “?”. Analysis of these projects is not possible without the submission of data.

Table 13. List of eligible gas projects to be modelled and evaluated

Project code	Project name	Project promoter	From A	To B	Bi-directional?	Capacity from A to B GWh/day	Capacity from B to A GWh/day	Commissioning date year
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	BHGas Ltd	BA	HR	yes	35	44	2023
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzac-Bosanska Krupa)	BHGas Ltd	BA	HR	no	0	73	2023
GAS_03	Interconnection Pipeline BiH HR (PloceMostarSarajevo / ZagvozdPosusje Travnik)	BHGas Ltd	BA	HR	yes	38	73	2021
GAS_04	Interconnector of of the FYR of Macedonia with Bulgaria and Greece	MER JSC Skopje	BG	MK	no	63	0	2020
			GR	MK	no	63	0	2020
GAS_05a	Interconnector of of the FYR of Macedonia with Albania	MER JSC Skopje	MK	AL	yes	?	?	2020
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border	JSC GAMA Skopje	AL	MK	no	25	0	2020
GAS_07	Macedonian part of TESLA project	JSC GAMA Skopje	GR	MK	yes	675	675	2020
			MK	RS	yes	640	640	2020
			RS	HU	yes			
			HU	AT	yes			
GAS_08	Interconnector Serbia-Romania	JP Srbijagas	RS	RO	yes	35	35	2020
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	JP Srbijagas	BG	RS	yes	39.44	39.44	2019
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	JP Srbijagas	HR	RS	yes	32.8	32.8	2023
GAS_11_5b	Gas Interconnector Serbia the FYR of Macedonia	JP Srbijagas and MER JSC Skopje	RS	MK	yes	10.4	10.4	2021
GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	Ministry of Energy & Industry of Albania	AL	KO	?	?	?	2022
GAS_14	Gas Interconnection Poland Ukraine	GAZSYSTEM S.A.; PJSC UKRTRANSGAZ	PL	UA	yes	245	215	2020
GAS_15	Development of the HU to UA firm capacity	PJSC UKRTRANSGAZ	HU	UA	no	178	0	2016
GAS_16	Ionian Adriatic Pipeline	Plinacro	AL	ME	yes	150	150	2021
			ME	HR	yes	150	150	2021
GAS_LNG_17	EAGLE LNG and Pipeline	TransEuropean Energy B.V., Sh.A	FSRU	IT	no	300	-	2020
			FSRU	AL	no	150	-	2020

By the date of closure of the Interim report (20.04.2016.), data was still missing for projects indicated with "?". Analysis of these projects is not possible without the submission of data.

4. PROJECT ASSESSMENT METHODOLOGY

4.1. GENERAL APPROACH

The project assessment methodology aims to provide a framework for evaluating benefits and costs to the Contracting Parties caused by the individual projects and to rank them according to their net benefits for the Contracting Parties of the Energy Community and neighbouring EU Member States. The result will facilitate the Energy Community in identifying Projects of Energy Community Interest (PECIs) and Projects of Mutual Interest (PMIs) that provide the highest benefits at least costs to the Contracting Parties of the reion. For this purpose we suggest applying an economic Cost-Benefit Analysis (CBA)[4] in line with the requirement of the *Adapted Regulation* and in line as much as possible with appropriate methodologies of ENTSO-E and ENTSO-G. The results of the CBA are complemented by the use of additional criteria that are relevant for the project assessment, but cannot be evaluated within the CBA. For the overall integration of the CBA results and the additional criteria we apply the multi-criteria assessment (MCA) described later.

Given the limited number of submitted and eligible oil infrastructure projects (only one) and the specifics of the oil market, we only provide a qualitative analysis of these projects within this report (see section 4.6).

The assessment of the proposed investment projects (and project clusters) is done from an overall economic point of view. Costs and benefits of the individual projects are, therefore, assessed in economic terms for all the effected stakeholders and for all Contracting Parties of the Energy Community and also for neighbouring EU Member countries. The assessment and the associated modelling provide a strong indication of the economic benefit of the investigated project proposals, which is then used to rank the different projects, for internal use only. They neither aim to nor can substitute for detailed project feasibility studies focusing on the specific details related to every individual project. In this respect the exact implementation potential related to every individual project can only be established by a detailed analysis of the project considering the legal and regulatory framework in the specific country (including compliance with environmental legislation), which is outside the scope of this project. Furthermore, the assessment does not imply any conclusion related to pending court cases on individual project proposals. The project funding scheme, the associated equity and debt structure and possible project grants are also not considered in the assessment. These

[4] In this context *economic* relates to the point of view of the assessment, in that possible costs and benefits are evaluated for all stakeholders affected by an investment project taking into account the monetary costs and benefits of the investor as well as the costs and benefits to other stakeholders and the society as a whole.

categories are strictly relevant for the financial analysis of the projects but are not relevant for the adopted economic framework of the analysis.

4.2. ASSESSMENT CRITERIA

The assessment methodology is based on a set of criteria that cover the different dimensions of relevant impacts of the proposed electricity and gas infrastructure projects. The selection of the criteria has taken into account the criteria defined in the Ministerial Council Decision 2015/09 of the Energy Community on the implementation of EU Regulation 347/2013 and the approach described in the EU Regulation (347/2013 Regulation on guidelines of the trans-European energy infrastructure), the 2015 ENTSO-E Cost-Benefit Assessment Guideline as well as the respective ENTSOG methodology, other relevant academic and applied studies on the assessment of infrastructure projects (e.g. ACER 2015 Infrastructure unit investment cost Report), as well as the expert opinion of the members of the consortium (including the Consortium's expertise from the previous PECI assessment process in 2013).

When specifying and defining the assessment criteria the following considerations and principles have been taken into account:

- avoid duplications resulting from a strong correlation or a significant overlapping of criteria of the multi-criteria analysis and criteria evaluated in the CBA
- avoid a discrimination of projects because of differences in the quality and quantity of information submitted by the project promoters
- account for the fact that the analysis is conducted in economic terms irrespective of any financing arrangements
- avoid a subjective and potentially discriminatory assessment based on a lack of detailed information that can only be provided by a detailed feasibility study or environmental impact assessment
- account for the specific characteristics of the electricity and gas markets within the Energy Community
- ensure the compatibility of the criteria with the proposed assessment framework

Based on the principles explained above the criteria shown in the following table have been agreed with the Groups to be applied in the project assessment.[5] As described above, the oil

[5] Criteria related to investors' perceived commercial attractiveness of specific projects or expected public support (governments or local communities) are not explicitly considered in the economic assessment. It is therefore possible – if not likely – that the economic assessment of Projects of Energy Community Interest and Projects of

infrastructure project will be assessed within a different framework, which is described in subchapter 4.6; therefore no criteria and indicators are defined for oil infrastructure projects in the following.

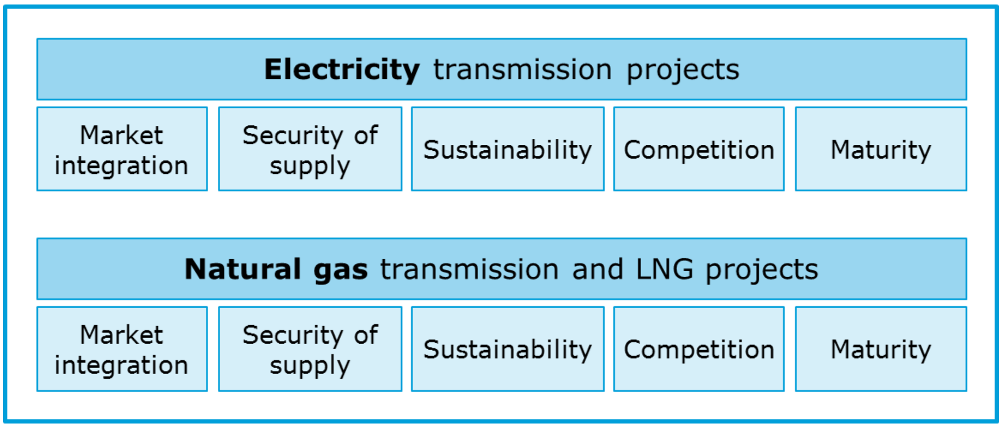


Figure 7. Approved project assessment criteria

Change in Socio-Economic Welfare

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual investment projects (or project clusters) can bring to the Contracting Parties and neighbouring EU Member States. The costs are determined by the capital and operating expenditures of the project. The socio-economic benefits are estimated and monetized through the project's (or project cluster's) impact on market convergence / price changes, improvement of security of supply (measured through the reduction of energy not supplied) and the decrease in CO_2 emissions. The change in socio-economic welfare therefore provides an aggregated criterion for several costs and benefits that will be quantified and measured within the framework of a CBA. The net benefits are calculated based on electricity and gas market models developed by REKK; changes in electricity network losses and energy not supplied are further estimated by an electricity network model, that will be fully presented in the Final Report. (for a more detailed description please see Annex 2)

Market Integration

The benefits of market integration are associated with the aggregate change in the socio-economic welfare of the Contracting Parties as a consequence of the wholesale price change. The new infrastructure creates price change by decreasing congestion, allowing access to lower cost sources and enhancing competition. The aggregate welfare change embodies welfare movements of different market players (consumers, producers, TSOs and in the case

Mutual Interest provides different results and ranking than an assessment carried out on national level (only) or by a financial investor.

of the gas sector storage operators and TOP contract holders) across the Contracting Parties. The assessment is carried out with gas and electricity market models.

Security of Supply

Security of supply is a fundamental pillar of energy policy, particularly for countries heavily dependent on foreign supplies. To that end the value of energy security is a crucial element in the assessment of the economic viability of energy projects.

A new project can increase security of supply by reducing the not-supplied energy either in electricity or in gas. It could potentially enhance system reliability by reducing loading on parallel facilities, especially under outage conditions. At the regional level, the expansion of the major interconnection may also improve the overall system reliability and reduce the loss-of-load probability.

In order to estimate security supply related benefits of natural gas projects, we use the European Gas Market Model (EGMM) to simulate the disruption of supply. Since the region is predominately dependent on Russian supply, the security of supply scenario (SoS) simulates a monthly disruption (in January) of supplies of Russian deliveries through the Ukraine. Other routes of Russian supply remain unaffected and (e.g. Nord Stream and Yamal, delivery to the Baltic States). Our reference SoS scenario estimates the impact of this disruption scenario without the proposed investment project. In case the analysed project contributes to the security of supply of the region, the CBA results will be higher in the situation where the project has been implemented. The difference in the CBA results is then attributed to the project. The probability of an SoS case (1:20) is reflected in the weight of the CBA results for the normal and the SoS situation.

For electricity projects, the security of supply benefits arising from the new electricity infrastructure will be assessed by quantifying and monetising the Expected Energy Not Supplied (EENS). Reference data on non-supplied electricity and information on the non-supplied electricity is provided by the network modelling carried out by Research Center for Energy and Sustainable Development Macedonian Academy of Sciences and Arts (RCESD-MASA). The reduced volume of non-supplied energy should in theory be multiplied with estimates of the value of lost load (VOLL) in order to monetise a unit of lost load for the Contracting Parties. As VOLL values are however not available in the EnC Contracting Parties, it has been agreed with the Groups to use the GDP divided by electricity consumption as a proxy for the evaluation.

Reduction in CO_2 Emissions

Within the CBA the sustainability benefits are estimated by the impact of projects in changing GHG emissions. For the electricity transmission projects this is done by directly estimating the changes in the regional electricity production patterns and the related CO_2 emissions. In the case of gas infrastructure projects, the impact of the infrastructure on the regional gas consumption is first estimated. Then we assume that a unit increase in gas consumption (due to the new infrastructure) crowds out an 'average' unit (and the associated CO_2 emissions) of electricity consumption in the given country. We hold this assumption only for the electricity sectors, as this substitution effect is not straightforward in the other sectors, e.g. increased gas consumption does not primarily crowd out 'average' energy consumption. We then measure the sustainability benefit of the project by multiplying the estimated regional change in CO_2 emission and assumed CO_2 price.

Changes in network losses

This welfare category applies to electricity transmission projects. As new network elements could also have significant impacts on the network losses, this element will also be included in the assessment. It can change in both directions; a new infrastructure element can reduce losses if it replaces an obsolete line, while loss would increase if a new OHL increases the transport of electricity. The estimation on loss changes will come from the network modelling, or if data availability precludes it, from the ENTSO-E 2014 TYNDP. The monetary value of transmission losses will be assumed equal to the modelled baseload prices of each country.

Enhancement of Competition

In some circumstances the price reductions caused by an interconnection project may be driven not only by a decrease of congestion and the introduction of sources with lower production costs, but also through enhanced competition. This does not affect the production costs but transfers monopoly rents (the price-mark-ups over production costs), gained by producers / importers / traders (due to insufficient competition) to consumers. Interconnection or LNG projects may enhance wholesale competition by providing access to generation capacities from alternative power producers (electricity) or alternative import capacities (natural gas).

For example a new transmission project can enhance market competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load in a broader regional market. The addition of new interconnection capacity can increase the level of forward energy contracting, and can also significantly reduce the ability of suppliers to exercise market power. LNG can limit incumbent market power in countries where it can be feasibly transported.

As the market models used in the CBA assume a competitive market equilibrium, the Groups approved our proposal to incorporate an explicit additional criterion on enhancement of competition.

System Adequacy / Reliability

An electricity transmission project could potentially enhance system reliability, especially under outage conditions. A new electricity transmission facility can provide more options for the maintenance of outages, load relief for parallel facilities, and additional flexibility for switching and protection arrangements. Moreover it can potentially increase reserve sharing and firm capacity purchases, and therefore decrease the amount of power plants that have to be constructed in the importing region to meet reserve adequacy requirements.

Similarly, the expansion of gas interconnection or the construction of new LNG terminals may also improve the overall system reliability and reduce the loss-of-load probability. The projects may also provide increased operational flexibilities for the gas TSOs and thus further enhance the reliability of the network.

Although some aspects of security of supply are already included in the CBA, the Groups approved our proposal to incorporate an additional explicit structural criterion to account for the system adequacy/reliability impact reflecting the ability of the system to withstand extreme conditions. In addition, while security of supply is modelled more explicitly within the gas market model, this is only measured on a monthly basis not accounting for the daily operational flexibility.

Maturity

This criterion aims to test the preliminary implementation potential and favours projects with a clear implementation plan that might have additionally commenced their preparatory activities. The exact implementation potential related to every single project can only be established with detailed analysis of the project characteristics under the legal and regulatory framework in the specific country. At this stage the criterion can only provide an early indication based on the information provided in the questionnaires relating to steps already undertaken for each project at the time of submission. Furthermore, as explained earlier in the report, the progress in securing the financing for a specific project and the commercial strength of a project have not been considered as criteria in our assessment.

4.3. Economic Cost-Benefit Analysis

A cost-benefit analysis (CBA) is a common tool used to provide criteria for investment decision making by systematically comparing the benefits with the costs over the life span of an investment project. It is widely applied on the societal level (collective impact) as well as the company (i.e. the investor's) level (individual impact). Whereas in the private sector appraisal of investments and financial analysis of company costs and benefits take place against maximizing the company's net benefits (profit), the economic CBA focuses on the overall long-term costs and benefits , including externalities such as environmental and reliability impacts, to a broad base of stakeholders. This gives the economic CBA a wider economic scope with the objective of maximizing the welfare of a society (country or in this case the Contracting Parties of the Energy Community) as a whole.

CBA is a widely used technique for project valuation and imposed as a central element for both electricity and gas by the *Adapted Regulation*.

ENTSO-E and ENTSOG developed a framework for a cost benefit analysis in 2015, assessing costs and benefits – and the related indicators – of electricity and gas network developments respectively. This framework is applied for the ten-year network development plans (TYNDP) of 2014 / 2016 (electricity) and 2015 (gas) respectively, and for the selection of candidate projects of common interest (PCI).

In our project assessment the CBA consists of the following main steps:

1) Selection and definition of input data and model parameters
2) Definition of costs and benefits
3) Assumptions on future development of input data and definition of expected values
4) Calculation of the total net economic benefit for different scenarios
5) Sensitivity analysis of the results in order to determine critical input variables

Applying this methodology, an investment project would be beneficial to the investigated stakeholder group if the CBA provides a positive net economic benefit.

For the purposes of this study the economic CBA is carried out with the application of two market models: the European Electricity Market Model (EEMM) and the European Gas Market Model (EGMM). Also an applied electricity network model will provide input to the electricity sector assessment in relation to changes in network losses and values of energy not supplied. If data availability prevents the calculation of these inputs, then the results of the 2014 TYNDP report will be used for those projects that are included in that report. A description of the models is contained in Annex 2 of this report. The project's costs include the direct investment and operating costs of each project after verification of their accuracy. The project's benefits are estimated and monetized by their contribution to regional market integration, security of supply, network loss change (only in electricity) and the reduction of CO_2 emissions (as explained in the previous section). Summing up all benefits and costs of a project or project cluster, the change in socio-economic welfare resulting from the implementation of the project or project cluster can be determined.

Investment Appraisal Methods

There are several quantitative methods to calculate the net economic benefit (or the change in socio-economic welfare) of infrastructure projects, which are based on theory of dynamic investment appraisal. The most common forms apply the Net Present Value (NPV), the Internal Rate of Return (IRR) approach or the benefit/cost ratio. In the context of an economic CBA the economic NPV discounts the incremental costs and benefits of an infrastructure project back to their present values applying an appropriate social discount rate.

Within the project assessment we propose to apply the economic NPV with the same social discount rate of 4% with all projects and project clusters, following the ENTSO-E methodology. In order to obtain comparable NPV values, a time horizon of 25 years will be applied to all projects beginning from the commissioning year, which is in-line with ENTSO-E's CBA recommendations. This approach is shown in the following figure.

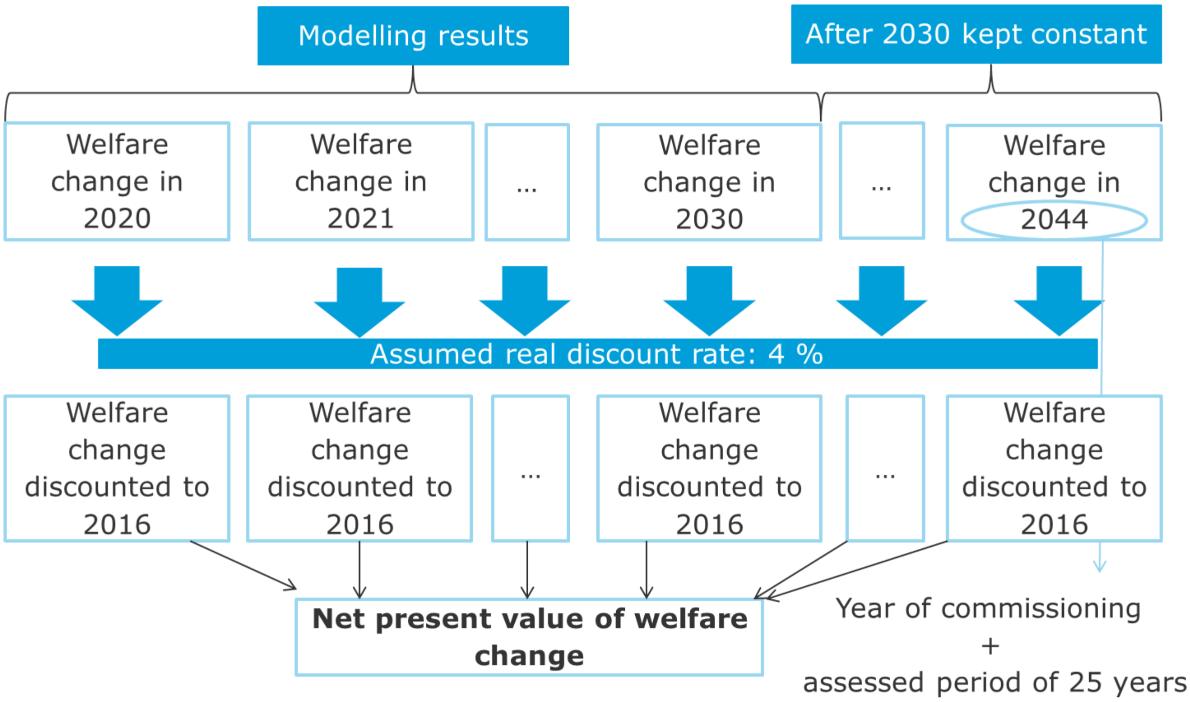


Figure 8. NPV calculations within the CBA framework

Perspective of the Analysis and Distributional Effects

The economic cost-benefit analysis studies the impact on the aggregated welfare of the parties affected by the project. The costs and benefits of an investment project may however be unevenly distributed between different stakeholders and across different states.

Clearly costs and benefits directly affect the project developers carrying out the investment. But costs and benefits also indirectly affect other market participants, including network operators, generators, suppliers or customers and the society as a whole. Different stakeholders are also likely to benefit to different extents from a specific investment project. Costs might for example only be borne by one market participant (e.g. the investor), whereas benefits might be split across a larger number of market participants (network operators, suppliers, customers, etc.). Costs might also mostly arise in the short-term, whereas some benefits of the investment might only occur in the long-term. Furthermore extensions of electricity interconnections between two countries may result in reductions of electricity wholesale prices in one country and increases in another country.

We address in our analysis the distributional effects across stakeholders and countries. The benefits per stakeholder groups (consumers, producers, TSOs, etc.) are aggregated by an equalized weight scheme.

Geographical scope

As agreed upon at the 2nd Group Meeting, the CBA studies the total impact for the Contracting Parties of the Energy Community and all neighbouring Member States of the European Union.

PINT vs TOOT methodology

NPV calculations in the CBA assessment could be based on the PINT (put-in-one-at-a-time modelling) and also on the TOOT (take-out-one-at-a-time modelling) methodology. Under the PINT approach, each proposed eligible investment project would be modelled individually, i.e. the change an individual project would bring compared to the status quo will be assessed. Under the TOOT approach, all proposed eligible investment projects would be modelled jointly, i.e. the impact of an individual project compared to a situation where all proposed projects would be realised would be assessed.

The TOOT methodology would provide results reflecting the ‚marginal' contribution of the given infrastructure, as it would be evaluated in an environment where other network elements are already operating in the system and ‚take their market share'. The PINT methodology, in contrast, would tend to result in higher utilisation of the lines, as other network elements are missing from the network.

At the Group Meetings (Vienna, 6 February 2016, 8 April 2016) we advocated the PINT approach as the primarily basis for the CBA assessment (particularly considering the timing of the construction of lines are quite uncertain), which was approved by the Groups. We will also calculate results under the TOOT approach as a sensitivity check to determine if there is a serious impact on the ‚order' of the projects. Also, using both will help to detect competing projects (where TOOT would negatively score them). It must be noted here that in the TYNDP 2014 ENTSO-E has evaluated project clusters by using the TOOT methodology. However, the purpose of the TYNDP is to identify potential projects that would bring net benefits for the region, while in our case we have actual projects proposed by project promoters. In addition, within the TYNDP much larger project clusters are assessed, while in our case projects tend to be smaller and more isolated with relatively uncertain commissioning dates.

The following figure illustrates our selected approach for the PECI assessment

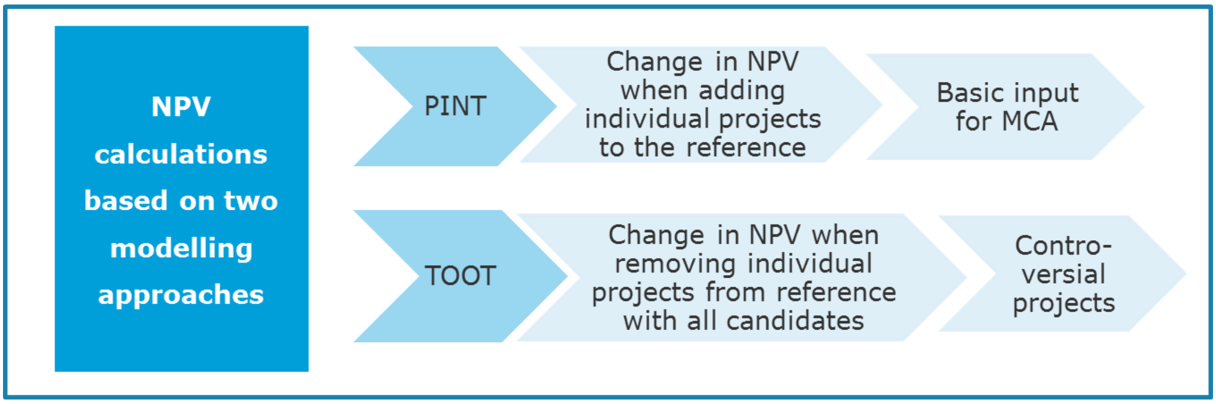


Figure 9. PINT and TOOT approach

4.3.1. Cost-Benefit Analysis for Electricity Transmission Projects

The Consortium will follow the ENTSO-E CBA guideline[6] (February 2015) for its electricity market infrastructure assessment as close as data availability will allow. The main tool for the assessment will be the REKK electricity market model (European Electricity Market Model-EEMM), which was already used in the previous PECI assessment in 2013 as well as other projects assessing the economic viability of infrastructure projects. A concise model description can be found in Annex 2 of this report. This model will be applied to assess the economic impacts of the individual electricity infrastructure elements that will be proposed in the PECI/PMI evaluation process. The most important information source for this assessment is the data gathered through the questionnaires received from the project promoters. Data extracted from the questionnaires has been verified by the Consortium and cross-checked with project promoters via correspondence and at the 2nd Group Meeting. (See chapter 2 for details of the verification process)

The first step in the model-based assessment is determining the reference scenario up to 2030. This will not only cover the whole EnC region, but the whole European electricity system as well, since proposed infrastructure elements will have significant spill-over effect outside the regional boundaries.

Reference Scenario Set-up

The reference scenario will include the latest EU visions for future European electricity sector development (e.g. the EU Impact assessments, as well as the Energy Community obligations: e.g. renewables and energy efficiency targets, the 2050 Roadmaps, and ENTSO-E’s TYNDP). Relevant economic assumptions (fuel cost developments, carbon pricing) and technical parameters (efficiency and availability rates) follow the latest available EU and global forecasts. For a detailed account of assumptions, see Annex 3. The demand pattern and

[6] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects.

generation portfolio data has been updated with the latest available databases and forecasts. The shares of different generation technologies up to 2030 and the demand patterns have been provided by the project promoters and cross-checked and agreed upon with the experts of the Consortium. We would like to point out that, from our expert point of view, values of future electricity demand, the development of future power generation portfolios – and especially electricity generation from renewable energy sources – provided for the Contracting Parties by the project promoters seem to overly optimistic (i.e. too large an increase) given recent developments in the region. Power plant infrastructure projects envisaged for the 2020 reference supply, for example, should already be in more advanced stages to be operational by 2020.

The recently finalised SLED (Support for Low Emission Development in South Eastern Europe) project on the region has equipped REKK with the most recent available data concerning the region's electricity generation and network developments. The trade flow patterns, electricity production by generating unit and the resulting baseload and peak load prices will be endogenously determined by the model for both the reference scenario and for the assessment cases.

As numerous infrastructure development projects are expected to be proposed in the assessment, the reference scenario will be set up without them in order to allow the modelling exercise to compare scenarios in the region with and without the projects.

Once the reference scenario is set up, the Consortium will evaluate the impact of various infrastructure elements individually by introducing them into the EEMM model, consistent with the verified information from the questionnaires (referred to from this point on as Individual Assessment Cases or IACs). The PINT methodology (see section 4.3) will be used to assess the individual impact of the projects or project clusters if they are complementary. This complementarity is to be judged in the verification phase.

Calculation of Assessment Criteria

Security of Supply

In case quantified Expected Energy Not Supplied (EENS) values are provided by the project promoters, the impact is monetized using Value of Loss Load (VOLL) estimations for the region. This step requires a monetary value on the unit of lost load. Ideally, the value of a unit of lost load should be based on a willingness to pay estimation for customers to avoid the loss of a unit of load. Since such data was missing for the Contracting Parties, the Consortium carried out a literature survey to establish the VOLL for the region. The indicator 'GDP/Electricity consumption' will be used as a proxy. This figure will be calculated based on Eurostat or National Statistical Offices data. The Consortium proposed this approach at the 2nd Group Meeting, and this was accepted by the representatives of the Project Promoters.

Socio-Economic Welfare

The Total Surplus approach will be used to measure the socio-economic welfare of the transmission lines rather than the Generation Cost approach (see ENTSO-E CBA methodology). This method captures the overall welfare effect, making it a more holistic way to calculate the total benefits of the transmission lines to the consumers, producers and the TSO. The EEMM model measures all of these effects on the various economic actors (consumer benefits, producer benefits and TSO rents), meaning that they will form a monetised impact category in all assessed cases.

Surpluses will be calculated across all EU Member States; however the geographical scope of the total benefit calculation will only include welfare effects regarding the Contracting Parties of the Energy Community and the neighbouring Member States of the European Union. This approach was agreed upon by the Representatives of the Project Promoters at the 2nd Group Meeting.

Variation in Network Losses

New transmission line elements could either increase or reduce losses in an electricity system depending on certain factors. The new line could be better performing or improve overall load flow patterns. The potential for losses could also increase if the new line elicits additional trade flow (although even in this case unit losses would also reduce). In order to deliver the required electricity for the consumers, losses must be covered by the power plant generation. Therefore the reduction of losses would benefit the system and producer by avoiding the extra generation required to cover the losses. This variation will be monetised by the EEMM model (with increasing or decreasing electricity consumption compared to the reference scenario) and added to the quantified impacts of the evaluation. The quantity changes in the loss values have been requested from the project promoters through the questionnaires.

Variation of CO_2 emissions

In the scenarios, the CO_2 prices from the latest EU impact assessment estimates will be used (Impact Assessment on energy and climate policy up to 2030, SWD (2014) 15) in order to calculate the monetised impacts of carbon emissions. As generators in the EnC Contracting Parties presently do not pay an embedded carbon price for their emissions, it will be applied only from a future standpoint in the modelling. It has been agreed upon the 2nd Group Meeting that power plants located in the EnC Contracting Parties will be required to pay for carbon price from 2020.

The economic impacts are already included in the socio-economic welfare category, so the monetised impacts should not be calculated separately in order to avoid double counting. But according to the ENTSO-E methodology, the quantified impacts (in kt of CO_2 variation) will be reported. In addition, in order to reflect the possibility of a higher carbon value for society than the actual ETS price, a sensitivity analysis for a higher carbon value will be carried out.

TOOT assessment for robustness check

In order to check the robustness of the proposed list of infrastructure projects and also to check for the interaction between the various infrastructure elements, we will also apply the TOOT methodology (see section 4.3) for the selected list of projects, where the number of selected projects depends on the decision of the EnC and on the number of proposed projects. By using this approach, we will check the robustness of the project rankings and whether the realisation of additional simultaneous projects could distort and change the ranking of the proposed project list. The TOOT assessment will highlight the possible complementarity and competing effect between projects.

4.3.2. Cost-Benefit Analysis for Gas Projects

The European Gas Market Model (EGMM) developed by REKK will be applied for the CBA assessment of gas infrastructure PECI / PMI candidate projects; however the guidelines of ENTSOG CBA methodology will be followed to the furthest extent. The former version of this model (Danube Region Gas Market Model, DRGMM) was applied in the previous PECI assessment in 2013. In the extended EGMM model the fundamentals are the same, but the coverage was extended to 35 European countries, covering the EU (except for Malta and Cyprus) and the Energy Community endogenously, and LNG markets are more accurately represented. The current version of the model was already applied in numerous projects ranking the most important infrastructure in Europe. For a detailed model description see Annex 2.

As in the EGMM, the wholesale gas prices are modelled and not exogenously provided, for a more accurate CBA. With actual flows reflecting infrastructure capacities, costs and market prices, capacity utilization of new infrastructure and resulting welfare changes could be better measured. Within REKK models (EEMM and EGMM) welfare changes can be separately calculated for all market participants, which leads to a methodologically strong CBA.

Reference Scenario Set-up

The first step in the model-based assessment is establishing the reference scenarios for all the years between 2016 and 2030. These reference scenarios have been set up together with the Energy Community Secretariat. In line with the guidelines of Regulation 347/2013 as adapted by the Energy Community the modelled years would be each calendar year in the period 2016-2030. After 2030 the welfare change quantified for 2030 will be extrapolated for the projects' lifetime (25 years).

In case of demand, production and infrastructure input data were set up based on ENTSOG TYNDP forecasts (which have been modified in some cases), and the project promoters data submissions. One of the most important questions concerns the infrastructure developments to be assumed in the reference scenario. We have suggested the low infrastructure scenario of ENTSOG which includes existing infrastructures plus those that have achieved Final Investment Decision status. This approach was accepted by the 2nd Group Meeting.

Gas markets are immature or plainly non-existent in some Contracting Parties, therefore special consideration should be given to the analysis of these countries. More specifically, we detect a chicken-egg problem in some analysed Contracting Parties: infrastructure promoted is essential for the meeting of the demand (currently non-existent), which cannot be served without the aforementioned infrastructure element. This is why, for modelling purposes the reported demand decrease in Bosnia, Montenegro, Albania, Kosovo* will be only used when we model the respective infrastructure scenario. Connecting natural gas markets where markets did not exist before can result in huge welfare swings. The implications of this issue will be considered in the final report.

Having the reference scenarios set, the impact of submitted infrastructure elements will be evaluated individually or by project clusters if some projects are complementary.

After completion of the selection process beyond the individual evaluation of projects, the overall welfare effect of selected projects will also be quantified.

Calculation of Assessment Criteria

Socio-economic welfare

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual projects (or project clusters) can bring to the analysed region. The region spans over the territory of the Contracting Parties of the Energy Community together with all neighbouring Member States of the European Union. This approach has been agreed on by the 2nd Group Meeting. The cost data has been provided by project promoters in the questionnaires. The socio-economic benefits will be estimated and monetized through the project's impact on market convergence and price changes, improvement of security of supply and the reduction of CO_2 emissions.

Total positive socio-economic welfare accounted for in the NPV of a modelled period (year) is calculated as the sum of welfare change of all market participants:

1. Consumer surplus [to consumers]
2. Producer surplus (or short-run profit, excluding fixed costs) [to producers]
3. Profit on long-term take-or-pay contracts [to importers]
4. Congestion revenue on cross-border spot trading [to TSOs]
5. Cross-border transportation profit (excluding fixed costs) [to TSOs]
6. Storage operation profit (excluding fixed costs) [to SSOs]
7. Profit on inter-temporal arbitrage via gas storage [to traders]

8. Profit of LNG operators [to LNG operators]

Welfare change for each market participant is assigned with a weight of 1:1.

Security of supply

Security of supply related benefits of a project will be measured by the change in economic welfare due to the implementation of the project in the case of a gas supply disturbance. A gas supply disturbance is assessed as a 100% gas supply disruption via the largest interconnector entry point to the region in January for a given year. The economic welfare change due to the realization of the proposed infrastructure is calculated as the difference between the welfare under disruption with and without the project.

To calculate the project related aggregate change in socio-economic welfare for a given year, we first calculate the weighted sum of project related welfare changes under normal and disturbance conditions. Weights are the assumed probabilities for normal and disturbance scenarios to occur (95% versus 5%). The weights for disturbance scenarios were accepted by the 2nd Group Meeting.

Reduction in CO_2 Emissions

Within the CBA the sustainability benefits are estimated by the impact of projects in changing greenhouse gas emissions. In the case of gas infrastructure projects, the project related environmental benefit is estimated by multiplying the corresponding change in the countries' CO_2 emissions (assuming that change in gas demand substitute an average CO_2 intensity in energy use) with an exogenous carbon value.

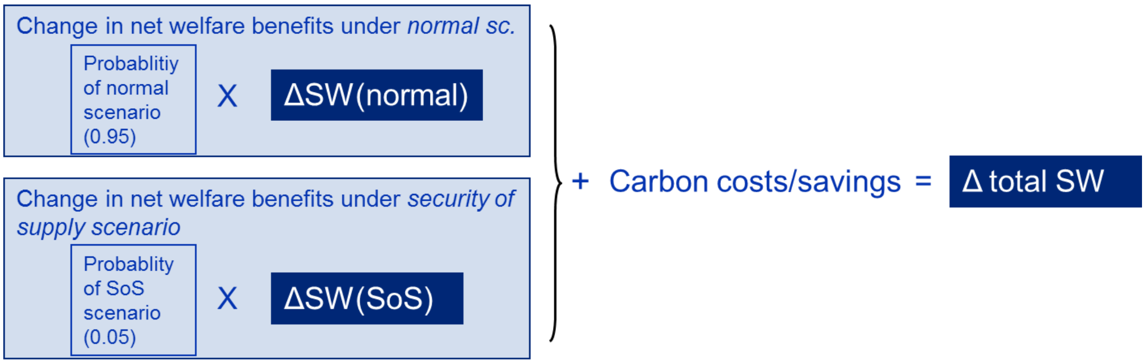


Figure 10. Calculation method of project related aggregate economic welfare change

For each project (or project cluster) we carry out 30 model runs: for the fifteen modelled years (2015/16-2030) with the new infrastructure in place under normal conditions and under security of supply assumptions. The welfare change of the given year under normal and SoS conditions will be weighted and added to the CO_2 quota cost saving change that will be also calculated based on model output.

As a next step the NPV will be calculated for the lifetime of the project. In the context of an economic CBA, the economic NPV discounts the incremental costs and benefits of an infrastructure project arising to all groups of stakeholders back to their present values applying a 4% social discount rate. The 4% rate is a generally accepted figure used by ACER and the ENTSOs in their infrastructure evaluation studies. The 2nd Group Meeting accepted the 4% discount rate.

Sensitivity assessments

To check the robustness of the project rankings, a sensitivity analysis will be carried out on the most important scenario drivers. In line with ENTSOG scenarios we analyse some reasonable combinations of the most important modelling input data (e.g. demand scenarios or assumed price for outside markets, mainly the global LNG market and oil price scenarios).

4.4. Multi-criteria assessment

When a decision-making problem has more than one goal to consider, there is always a trade-off. It is also not possible to sufficiently quantify and monetise all dimensions of impacts in the context of an economic CBA. To integrate both the CBA results and the results of the assessment of the additional criteria for each proposed eligible electricity and gas infrastructure project, it has been agreed with the Groups to apply a Multi-Criteria Assessment (MCA) framework in order to complement the economic CBA. The MCA framework can take into account several criteria and opinions by scoring, ranking and weighing a wide range of qualitative impact categories and criteria and to integrate them with the results of the CBA. As a result of the MCA, a single score reflecting the net benefits of each individual project can be used to comparatively rank the proposed investment projects according to the benefits for the Energy Community. Based on this relative ranking the Groups will be able to select a number of projects that will be awarded PECI/PMI status.

In practical terms the MCA framework consists of the following steps:

1) Identification and definition of relevant additional assessment criteria (the result of the CBA – i.e. the change in socio-economic welfare – is included as one of the criteria)

2) Specification of indicators to measure the fulfilment of each additional criterion by each investment project (including the definition of a scoring system that allows ranking of different indicator values)

3) Setting weights for the selected criteria, based on a pairwise comparison of the relative importance of each criterion against any other criterion

4) Assessment of the fulfilment of each criterion by each investment project

5) Calculation of the total score for each project as the sum of the weight of each criterion multiplied with the score for each criterion and establishment of the ranking

6) Relative ranking of projects in each area based on the project score (i.e. provision of a separate ranking for electricity and gas infrastructure projects)

4.4.1. Assessment Indicators and Scoring

In order to measure the fulfilment of each criterion (specified in section 4.14.2) by each investment project, specific indicators are defined for each criterion. The indices will either quantify the impacts based on changes in different structural variables or score the impacts based on project specific characteristics provided by the answers to the questionnaire.

For each indicator, scores will be assigned reflecting the ability of each project to fulfil the respective criterion. Accordingly we attribute minimal points (one) to a project when the degree of fulfilment is low and maximal points when the degree of fulfilment is high (five). Scores between the minimum and the maximum values are allocated by using linear interpolation. The definition, calculation and application of the indicators is explained below.

Indicators for Electricity Infrastructure Projects

Net Present Value

As described earlier in the report we use the economic NPV as the indicator for the incremental change in socio-economic welfare. The project with the lowest economic NPV in each category (electricity infrastructure and gas infrastructure) receives the minimum score of 1 and the project with the highest economic NPV receives the maximum score of 5. All other projects receive a score between the minimum and maximum scores according to the value of their economic NPV. Since the economic NPV is always calculated in relation to a reference scenario that reflects the state without the implementation of the specific investment project, the economic NPV accounts directly for the project’s incremental impact on the socio-economic welfare.

Herfindahl-Hirschman Index

The competition enhancement of electricity infrastructure projects not accounted for by the electricity market model is approximated with the change of market concentration measured by the Herfindahl-Hirschman Index (HHI). The HHI is defined by the sum of the squared market shares of all market participants. For the electricity infrastructure projects assessed in this project, the HHI is calculated based on the interconnection and power generation capacities in the respective countries. Whereas all existing and proposed generation capacities have been assigned according to the ownership of the power plants,[7] electricity interconnection capacities have been considered as independent players on each border.

The higher the value of the HHI, the more concentrated the market is. In order to measure the incremental impact of an investment project, the HHI needs to be calculated for the countries on each end of an interconnector both with and without the project. The overall number for an individual project – calculated as an average of both countries – therefore approximates the change in competition resulting from the implementation of this project. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest improvement in competition) receives the maximal score of 5 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation.

System Adequacy Index

To measure the additional impact on system adequacy – explicitly accounting for the structural change of capacities by providing an additional source of supply[8] – we suggest applying a System Adequacy Index (SAI). It compares the available production and interconnection capacity with the national system peak load.

The System Adequacy Index is defined as:

$$\mathrm{SAI} = \frac{\left(\text{generation capacity} + \text{interconnection capacity-system peak demand}\right)}{\text{system peak demand}}$$

The generation capacity is measured with the installed net capacity (after auxiliary needs) adjusted to account for the potentially limited availability of intermittent and hydro generators. The interconnection capacity is set equal to the net transfer capacity (NTC) applied in the modelling process. The system peak demand is the highest hourly demand in the respective year.

We calculate the SAI for the countries on each end of an interconnector both with and without the project. In this way we measure the incremental impact of the project on the SAI. The index change is measured in the year of the project commissioning.

[7] For hydro and wind power plant capacities, availability factors will be applied considering that the production of these plants will depend on the weather conditions. Where power plants are owned by different companies, market shares will be allocated to each of the owners based on their shares in equity. Also different companies owned by the same parent company will be attributed accordingly.

[8] It can be argued that an ideal quantitative model with integrated network, perfect planning assumptions and very robust estimation of value of unsupplied energy, may completely internalize and monetize the security of supply benefits.

The project with the highest index change (the largest improvement in system adequacy) receives the maximal score of 5 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation.

Maturity of Project Indicator

The progress in the implementation of each project will be tracked by the information provided in the questionnaires with respect to the following project development phases:

Table 14. Scores assigned to different project development phases

Project Phase	Score
Consideration phase	1.00
Planning approval	1.36
Preliminary design studies	1.73
Market test	2.09
Preliminary investment decision	2.45
Public consultation (according to Art. 9(4) of adapted Regulation 347/2013)	2.82
Permitting	3.18
Financing secured	3.55
Final investment decision	3.91
Tendering	4.27
Construction	4.64
Commissioning	5.00

Based on the responses provided in the questionnaires, the maximum score (five points) will be provided to projects that have already reached a significant stage of commissioning. The projects that are in a very early stage, e.g. the consideration phase, will be allocated the minimum score (one point). The phases in between will be given a score that increases equally from consideration to commissioning phase. For interconnection projects where answers to the questionnaire have been provided separately for each section on both sides of a border and where the project maturity is significantly different on each side of a border, the project phase of the least developed part will be applied for the calculation of the index. The score assigned to an individual project in relation to the progress in the implementation will be specified as Maturity of Project Indicator (MPI).

Indicators for Natural Gas Infrastructure Projects

Import Route Diversification Indicator

The enhancement of competition in the area of natural gas is approximated by the Import Route Diversification Indicator (IDI). This simplified competition indicator measures the diversification of gas routes to reach a country based on system entry via interconnectors, offshore pipelines and LNG terminals. It provides a rough proxy to the assessment of counterparty diversification. In order to calculate the impact on competition resulting from the implementation of a gas infrastructure project in more detail, it would be necessary to consider the specific current contractual situation on each interconnection pipeline, LNG terminal and gas storage facility as well as the specific market structure in domestic gas production.

The Import Route Diversification Indicator is defined as:

$$IDI = \sum\left(\frac{\text{technical interconnection capacity at each border}}{\text{total system entry capacities}}\right)^2 + \sum\left(\frac{\text{technical send-out capacity at each LNG terminal}}{\text{total system entry capacities}}\right)^2$$

The technical interconnection capacity is the maximum technical entry capacity at the international interconnection points of the respective country. Interconnection capacities at each border are aggregated into a single number. The LNG extraction capacity is the maximum send-out capacity of the LNG facilities in the respective country. Total system entry capacities are calculated as the sum of all interconnection and LNG extraction capacities in the respective country.

We calculate the IDI for the countries on each end of an interconnector both with and without the project (or on national level for LNG projects). In this way we measure the incremental impact of the project on the IDI. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest assumed enhancement in competition) receives the maximal score of 5 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation. For countries that will only be connected to gas supply with the implementation of the proposed interconnection project a score of 5 points will be assigned.

System Reliability Index

To measure the additional impact on daily operational flexibility and ability of the system to withstand extreme conditions – explicitly accounting for the structural change of daily capacities by providing an additional source of supply[9] – we suggest applying a System Reliability Index (SRI) as a simplified daily indicator for N-1 security. It compares the available interconnection, production, storage and LNG capacities with the single largest supply facility and the capacity of the national daily gas demand.

The System Reliability Index is defined as:

$$\text{SRI (N-1)} = \frac{\left(\begin{array}{c}\text{technical entry capacity + local production capacity + storage extraction capacity} \\ \text{+ LNG send-out capacity - single largest supply capacity}\end{array}\right)}{\text{total daily gas demand}}$$

The entry capacity is the maximum technical entry capacity at the international interconnection points of the respective country. The storage extraction capacity is the maximum extraction capacity of the storage facilities, and the LNG extraction capacity is the maximum send-out capacity of the LNG facilities in the respective country. The single largest supply capacity relates to the technical capacity of the main gas infrastructure (interconnection, production, storage or LNG facility) with the highest capacity to supply the market. The system peak demand is the highest daily domestic demand in the respective year.

We calculate the SRI for the countries on each end of an interconnector both with and without the project (or on national level for LNG projects). In this way we measure the incremental impact of the project on the SRI. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest improvement in system reliability) receives the maximal score of 5 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation. For countries that will only be connected to gas supply with the implementation of the proposed interconnection project a score of 5 points will be assigned.

Maturity of Project Indicator

The same approach as for electricity will be applied here (see above).

[9] It can be argued that an ideal quantitative model with integrated network, perfect planning assumptions and very robust estimation of value of unsupplied energy, may completely internalize and monetize the security of supply benefits.

4.4.2. *Determination of Weights*

The weights for each criterion are set according to the AHP approach. The analytic hierarchy process (AHP) is a structured technique for organizing and analysing complex decisions. The methodology is considered to be particularly efficient whenever investment projects have to be assessed based on different quantifiable and qualitative criteria taking into account various aspects of decision making. In the context discussed here the AHP approach is used to determine the weights of the identified project assessment criteria by measuring their relative importance.

The basis of the AHP approach is a pairwise comparison of the relative importance of a criterion over any other criterion expressed by a numerical rating scale from 1 to 9 (separately for electricity and natural gas),[10] which allows for the comparison between diverse criteria in a rational and consistent way. By using the eigenvectors, the weights (i.e. the percentages) of each criterion are then calculated.

Table 15. Scale for the measurement of the relative importance of indicators

Project Phase	Scale
Both criteria are equally important	1
Criterion A is slightly more important than criterion B	3
Criterion A is more important than criterion B	5
Criterion A is much more important than criterion B	7
Criterion A is absolutely more important than criterion B	9

The pairwise comparison has been carried out separately by the experts of the consortium partners (DNV GL and REKK) and a single weight for each criterion has been calculated by equally weighing the assessments of each consortium partner. The suggested weights for the different groups are presented below. Since oil infrastructure projects are not assessed within the multi-criteria framework, no weights are provided for oil infrastructure projects in the following tables.

[10] The reciprocal number of this value is assigned to the other criterion in the pair.

Table 16. Criteria weights for electricity projects

Project Phase	Weight
Net Present Value (NPV, result of CBA)	60%
Herfindahl-Hirschman-Index (HHI)	15%
System Adequacy Index (SAI)	15%
Maturity of Project Indicator (MPI)	10%

Table 17. Criteria weights for natural gas projects

Project Phase	Weight
Net Present Value (NPV, result of CBA)	60%
Import Route Diversification (IRD)	12%
System Reliability Index (SRI)	18%
Maturity of Project Indicator (MPI)	10%

4.4.3. Calculation of Total Scores and Final Ranking

The total score for each project is calculated as the sum of the weight of each criterion multiplied with the score for each criterion. The following graphs summarise the elements of the MCA methodology described above for electricity and natural gas.

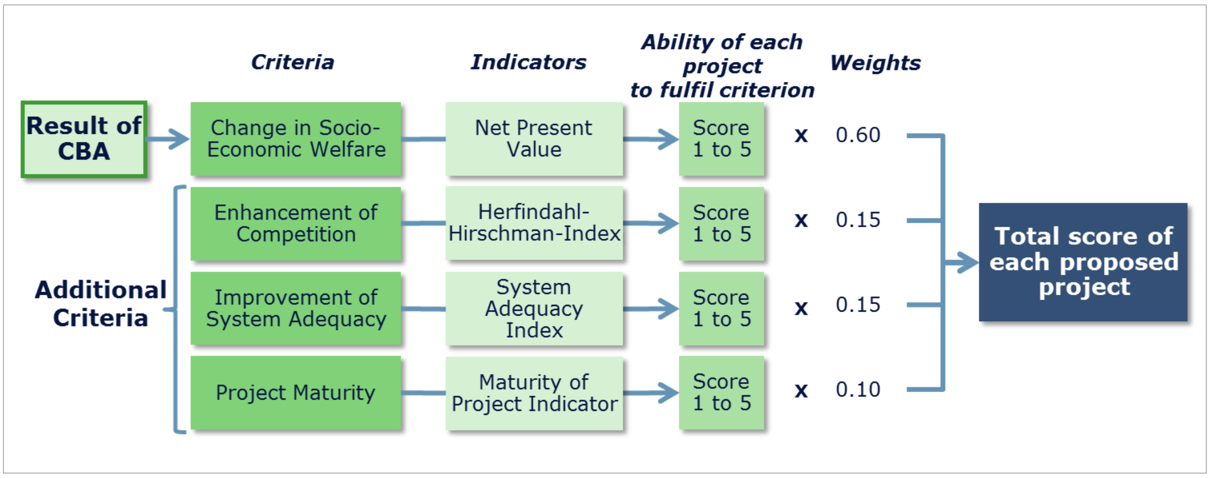


Figure 11. Overview on multi-criteria assessment methodology for electricity

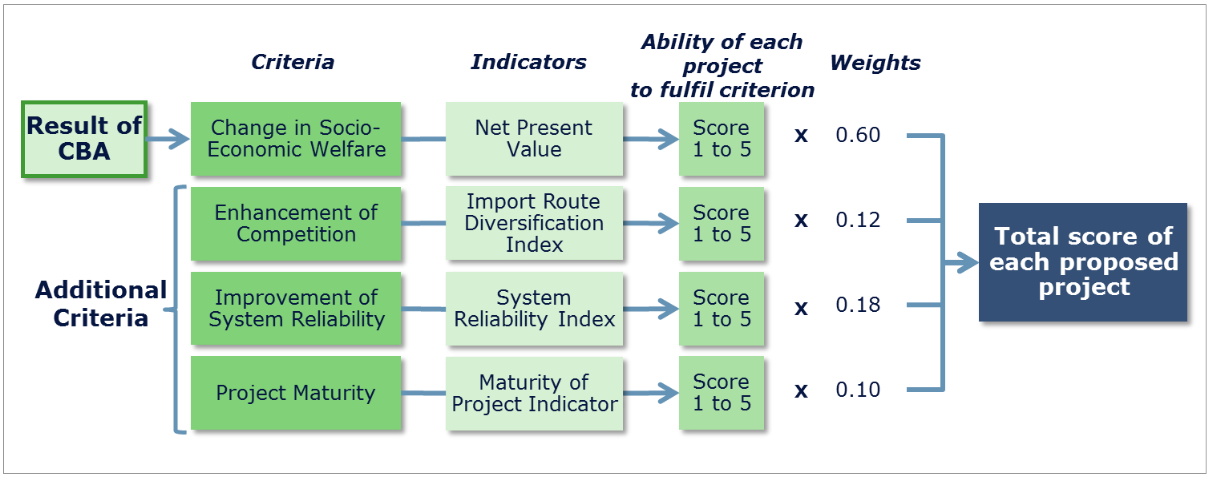


Figure 12. Overview on multi-criteria assessment methodology for natural gas

Based on the calculated total scores of each individual project a relative ranking of all eligible projects (i.e. a comparison of each individual project with the other submitted projects) will be provided in the final step of our assessment.[11] This relative ranking will be conducted separately for electricity infrastructure and gas infrastructure projects. The final list of projects awarded the PECI / PMI status will not contain any kind of ranking, but should be decided based on the evaluation results. The relative ranking delivered by this assessment will therefore provide guidance for the Group on the selection of projects to be put on this final list. The number of projects to be selected is not pre-defined, but will be decided by the Group.

[11] The relative ranking will not specify whether the difference is large or small and not tell whether the project is commercially attractive for a private investor or not, as the assessment is conducted from an economic point of view and not from a national perspective, but from the perspective of the Energy Community.

The following table provides a virtual example for the calculation of the total score and the relative ranking among four electricity infrastructure projects.

Table 18. Example for the calculation of the total score and the relative ranking of electricity projects

	Indicators (Scores)				Weights				Indicators (Weighted Scores)				Total Score	Relative Rank
Project	NPV	HHI	SAI	MPI	NPV	HHI	SAI	MPI	NPV	HHI	SAI	MPI		
P 1	5,00	5,00	2,00	3,91	60%	15%	15%	10%	3,00	0,75	0,30	0,39	4,44	1
P 2	1,00	2,80	1,00	4,27	60%	15%	15%	10%	0,60	0,42	0,15	0,43	1,60	4
P 3	4,30	1,33	5,00	3,55	60%	15%	15%	10%	2,58	0,20	0,75	0,36	3,88	2
P 4	4,58	1,00	3,63	3,18	60%	15%	15%	10%	2,75	0,15	0,54	0,32	3,76	3

4.5. Robustness check and sensitivity

For electricity and gas projects, we will also carry out a sensitivity assessment on the most important scenario drivers (e.g. assumed carbon value, demand, gas price, oil price) in order to check if the ranking of the projects are robust in relation to these factors. This assessment will demonstrate how reliable the selection of the PECI / PMI projects is according to the overall economic and technical factors.

Moreover, the TOOT assessment will be used to check the robustness of CBA results. For the detailed TOOT methodology please refer to Section 4.3.1.

4.6. Methodology for the evaluation of projects in the oil infrastructure

Annex II. Of the *Adapted Regulation* Section 2 (6) said that:

“For proposed oil transport projects falling under the categories set out in Annex I.3, the Energy Community Secretariat shall evaluate the application of the criteria set out in Article 4.”. The Consortia will assist the Energy Community Secretariat in the evaluation of the criteria. The first assessment of the criterion has already been described during the eligibility check in chapter 3.1 of this report.

5. NEXT STEPS

The Energy Community Secretariat will invite interested parties to a public consultation starting at the end of April. Further project submissions might occur during the consultation phase.

Modelling of projects will be carried out using the PINT methodology first (during May), hence TOOT can only be carried out when all submissions are complete.

The network modelling is planned to be carried out using data received from SECI project and from TSOs in Ukraine and Moldova. The network modelling will start as soon as the Consortium receives the data from the Energy Community Secretariat.

The results of the assessment will be provided sufficiently in advance to the next meeting of the Groups, which is scheduled for 29-30 June 2016.

ANNEX 1: SUBMITTED PROJECTS

Table 19. List of submitted electricity projects (as of 26.02.2016.)

	Project name	Promoter	From	To	Capacity	Commissioning date	Lifetime
EL_01	Transbalkan corridor phase 1	JP Elektromreza Srbije	RO	RS	750	2018	40
			RS	RO	450	2018	40
			RS	ME	500	2018	40
			ME	RS	500	2018	40
			RS	BA	600	2023	40
			BA	RS	500	2023	40
EL_02	Transbalkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	JP Elektromreza Srbije	RS	RS	?	2027	40
EL_03	TransBalkan Electricity Corridor, Grid Section in Montenegro	CGES	ME	RS	1000	2020	80
			RS	ME	1100	2020	80
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	HOPS, EMS	BA	HR	504	2030	40
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	SE Moldelectrica	MD	RO	500	2025	25
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	SE Moldelectrica	MD	RO	500	2022	30
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	SE Moldelectrica	MD	RO	500	2025	30
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian electri List of submitted electricity projects (as of 26.02.2016.)city network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	NPC Ukrenergo; The Ministry of Energy and Coal Industry of Ukraine	UA	PL	600	2020	30
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	NPC Ukrenergo; The Ministry of Energy and Coal Industry of Ukraine	UA	SK	700	2020	30
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	UKRAINE Ministry of Fuel and Energy	UA	RO	1000	2025	25
EL_11	400/110 kV Substation Kumanovo	MEPSO	MK	-	-	2020	50
EL_12	400 kV interconnection Skopje 5 - New Kosovo	MEPSO	MK	KO*	?	2020	40
EL_13	400 kV Interconnection Bitola(MK)Elbasan(AL)	MEPSO	MK	AL	200/250/300	2019	50

Table 20. List of submitted natural gas projects (as of 26.02.2016.)

Project code	Project name	Project promoter	From A	To B	Bi-directional?	Capacity from A to B	Capacity from B to A	Commissioning date	Lifetime
						GWh/day	GWh/day	year	years
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	BHGas Ltd	BA	HR	yes	44	44	2023	50
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzacBosanska Krupa)	BHGas Ltd	BA	HR	no	0	73	2023	50
GAS_03	Interconnection Pipeline BiH HR (PloceMostarSarajevo / Zagvozd-Posusje Travnik)	BHGas Ltd	BA	HR	yes	38	73	2021	50
GAS_04	Interconnector of the FYR of Macedonia with Bulgaria and Greece	MER JSC Skopje	BG	MK	no	?	?	2020	?
			GR	MK	no	?	?	2020	?
GAS_05	Interconnector of of the FYR of Macedonia with Kosovo, Albania and Serbia	MER JSC Skopje	MK	KO*	yes	?	?	2020	?
			MK	RS	yes	?	?	2020	?
			MK	AL	yes	?	?	2020	?
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border	JSC GAMA Skopje	AL	MK	no	25	0	2020	20
GAS_07	Macedonian part of TESLA project	JSC GAMA Skopje	GR	MK	yes	675	675	2020	20
			MK	RS	yes	640	640	2020	20

Project code	Project name	Project promoter	From A	To B	Bi-directional?	Capacity from A to B	Capacity from B to A	Commissioning date	Lifetime
						GWh/day	GWh/day	year	years
GAS_08	Interconnector Serbia-Romania	JP Srbijagas	RS	RO	yes	35	35	2020	30
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	JP Srbijagas	BG	RS	yes	39,44	39,44	2019	30
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	JP Srbijagas	HR	RS	yes	32,8	32,8	2022	30
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia Section on the Serbian territory	JP Srbijagas	RS	MK	yes	10,4	10,4	2021	30
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo) Section Nis (Doljevac) Pristina	JP Srbijagas	RS	KO	?	26,4	?	2023	30
GAS_13	AlbaniaKosovo Gas Pipeline (ALKOGAP)	Ministry of Energy & Industry of Albania	AL	KO	?	?	?	2022	25
GAS_14	Gas Interconnection Poland Ukraine	GAZSYSTEM S.A.; PJSC UKRTRANSGAZ	PL	UA	yes	245	215	2020	20
GAS_15	Development of the HU to UA firm capacity	PJSC UKRTRANSGAZ	HU	UA	no	178	0	2016	25
GAS_16	Ionian Adriatic Pipeline	Plinacro	AL	ME	yes	150	150	2021	40
			ME	HR	yes	150	150	2021	40
GAS_LNG_17	EAGLE LNG and Pipeline	TransEuropean Energy B.V., Sh.A	FSRU	IT	no	300	-	2020	30
			FSRU	AL	no	150	-	2020	30

Table 21. List of submitted smart grid projects (as of 26.02.2016.)

	Project name	Promoter	Hosting country
SG_01	Reduction of Grid Losses; achieved with Investments in the electrical Distribution grid in the area of Low Voltage	EVN Macedonia AD	MK
SG_02	Kosovo Smart Meter Project	Kosovo Electricity Distribution and Supply Company J.S.C	KO*

Table 22. List of submitted oil project (as of 26.02.2016.)

Project code	Project name	Project promoter	From A	To B	Commissioning date	Lifetime	Letter of intent?
					year	years	
Oil_01	Construction of the Brody Adamowo oil pipeline	MPR Sarmatia	UA	PL	2020	20	Joint submission

ANNEX 2: DESCRIPTION OF MODELS

EUROPEAN ELECTRICITY MARKET MODEL

The European Electricity Market Model (EEMM) simulates the operation of a European electricity wholesale market in a stylized manner. This section describes the economic principles that govern the simulation.

Analyzed countries

The figure below shows the countries involved in our analysis. We divided the analysed countries into two groups: for countries in orange prices are derived from the demand-supply balance, and for countries in yellow the prices are given exogenously.

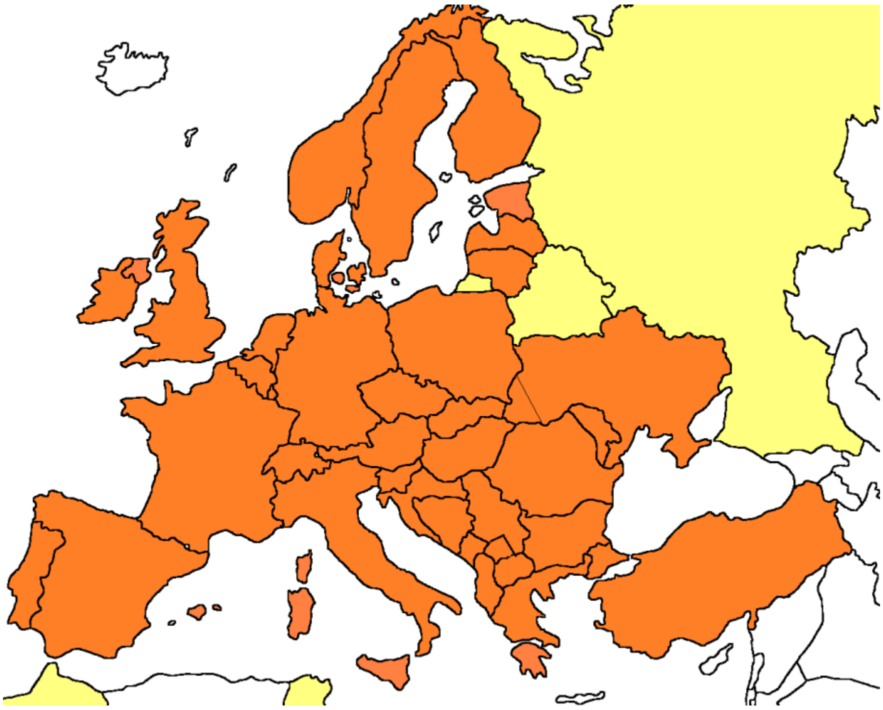


Figure 13. Modelled countries in the EEMM

Market participants

There are three types of market participants in the model: producers, consumers, and traders. All of them behave in a price-taking manner where the prevailing market price is given, and assume that whatever action they decide upon has a negligible effect on this price.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation is capacity constrained at the level of available capacity.

The model only takes into account short term variable costs with the following three main components: fuel costs, variable OPEX, and CO_2 costs (where applicable). As a result, the approach is best viewed as a simulation of short term (e.g. day-ahead) market competition.

Price-taking producer behaviour implies that whenever the market price is above the marginal generation cost of a unit, the unit is operated at full available capacity. If the price is below the marginal cost, there is no production at all, and if the marginal cost and the market price coincide, then the level of production is determined by the market clearing condition (supply must equal demand).

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. In each demand period, there is an inverse relationship between the market price and the quantity consumed: the higher the price, the lower the consumption. This relationship is approximated by a downward sloping linear function.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Cross-border trade takes place on capacity constrained interconnectors between neighbouring countries. Electricity exchanges always occur from a less expensive country to a more expensive one, until one of two things happen: either (1) prices, net of direct transmission costs or export tariffs, equalize across the two markets, or (2) the transmission capacity of the interconnector is reached. In the second case, a considerable price difference may remain between the two markets.

Trading with countries outside the modeled region

The model only simulates the supply-demand characteristics of the European region. However, trade still takes place at the region’s borders, e.g. with Russia or Morocco. Our assumptions regarding the cross-border trade with countries outside the modeled region is that prices in these countries are exogenously given and not influenced by the amount or direction of the cross-border transactions.

Equilibrium

The model calculates the simultaneous equilibrium allocation in all markets with the following properties:

- Producers maximize their short term profits given the prevailing market prices.
- Total domestic consumption is given by the aggregate electricity demand function in each country.

- Electricity transactions (export and import) occur between neighbouring countries until market prices are equalized or transmission capacity is exhausted.
- Energy produced and imported is in balance with energy consumed and exported.

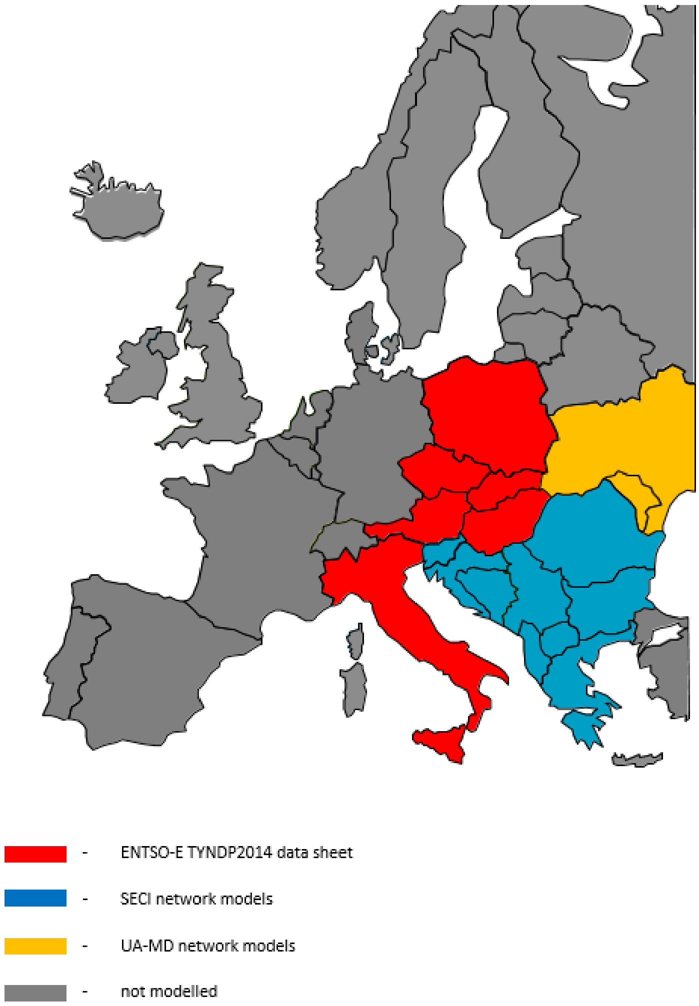
Given our assumptions about demand and supply, market equilibrium always exists and is unique in the model.

Electricity product prices

The calculated market equilibrium is a static one: it only describes situations with the same demand, supply, and transmission characteristics. However, these market features are constantly in motion. As a result, short run equilibrium prices are changing as well.

To simulate the price development of more complex electricity products, such as those for base load or a peak load delivery, we perform several model runs with typical market parameters and take the weighted average of the resulting short term prices.

ELECTRICITY NETWORK MODEL



Energy Community Electricity Transmission (**EC-ET**) model is developed to simulate the power flow in the transmission network in the Contracting Parties of the Energy Community. Except these counties the model also covers all neighbouring countries of the Energy Community. Thus, EC-ET model includes the following countries: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, Hungary, Kosovo*, Montenegro, the FYR of Macedonia, Romania, Serbia, Slovenia, Ukraine, Moldova and Poland.

This model will be implemented for three planning years, 2020, 2025 and 2030. Also, two methodologies will be applied, the first one is Take Out One at the Time (TOOT) and the second one is Put In one at the Time (PINT). Detailed description of both methodologies is given in the previous chapters.

EC-ET model is developed in Matpower[12]. Matpower is a package of Matlab® M-files for solving power flow and optimal power flow problems. Matpower is designed to give the best performance possible while keeping the code simple to understand and modify. Matpower employs all of the standard steady-state models typically used for power flow analysis.

EC-ET model mainly is use for calculation of the following three indicators:

- *Changes in transmission losses*
- *Changes in energy not served*
- *Changes in net transfer capacity (NTC)*

Load flow calculations for a static operating point in power systems are the most frequently performed routines as a stand-alone application as well as a part of more complex optimization procedures. In general, the “accurate” AC power flow model is used but the application of the approximate DC power flow model is fairly common. The main advantages of the DC model include: non-iterative, reliable and unique solutions, acceptable accuracy for the heavily loaded branches that might constrain system operation, minimal data requirements and simple and efficient optimization procedures[13]. At the same time its linearity fits the economic theory on which much of electricity markets are designed – an area which is of increased interest today.

Furthermore, the DC model can be used to develop a relation which connects the branch power flows directly to the generator power outputs[14]. The procedure is based on the well-known PTDF matrix which is reduced in size. The matrix size reduction is twofold: 1) column reduction due to elimination of columns for buses with fixed load injections, and 2) row reduction with omitting rows for non-binding branch flow limits.

[12] http://www.pserc.cornell.edu/matpower/

[13] B. Stott, J. Jardim, and O. Alsaç, “DC Power Flow Revisited,” *IEEE Transactions on Power Systems*, vol. 24, no. 3, pp. 1290-1300, Aug. 2009.

[14] M. Todorovski, and R. Ačkovski, “Reduction of PTDF Matrix and Its Application in DC Optimal Power Flow”, *International Transactions on Electrical Energy Systems*, John Wiley & Sons, April, 2014.

The compact size PTDF matrix enables formulation of optimization problems in a minimal form. The number of decision variables in the optimization is reduced and equal to number of generators (much less than the number of buses) and the number of constraint is also minimal. For example, in the case of TTC calculations the dimensions of PTDF matrix for a system with 3279 branches and 2764 buses is reduced in size from 3279×2746 to 4×11, which illustrates the enormous problem size reduction[14].

As known the DC power flow solution does not consider **power losses**. However, they may be well estimated using the following relation

$$\Delta P \approx \sum_{i=1}^{Nb} R_i \frac{P_i^2}{\cos^2 \varphi_i \cdot U_i^2} \; ,$$

where all quantities are related to branch i and they are: R_i – branch resistance, P_i – branch active power flow, $\cos\varphi_i$ – branch power factor and U_i – voltage of the branch sending node. In absence of relevant data, we may use $\cos\varphi_i$ = 0.95÷1 and set U_i = 1 pu. Number of branches is N_b.

In some cases, one may adjust the branch power flows such that they include the losses. Firstly, the losses are treated as load injections in the branch sending and receiving node, both equal to half of the branch losses. Secondly, generator power injections are proportionally scaled to consider additional power generation required by the losses. Finally, DC power flow calculations are performed once more so that the newly calculated branch flows take into account the losses as well. This procedure is recommended to be used in cases when losses are considerable, which is a very rare situation in power transmission networks.

The value of **energy not served (ENS)** is calculated by a probabilistic simulation using the Monte Carlo method. This approach was chosen since all other deterministic methods require definition of very large number of contingency cases with one or more outage of generators and/or branches, so that the underlying model is extremely hard to solve. The Monte Carlo simulation consists of repetitions of the following three main steps: 1) define the state of each system element considering its specific outage probability curve by using random number generator, 2) check for possible power shortage, solve the power flow problem and check whether there are overloaded branches, 3) in case of detected problems in step 2 optimize the power system operation such that minimum power shortages are achieved – this is a linear programing problem where the objective is to maximize power generation taking into account branch flow limits. If the maximum possible power generation is less than the power demand the ENS is simply calculated as a difference of the two. In this approach the power shortage is proportionally spread over all loads in the system. Of course, it is possible to consider localized load reduction in order to avoid branch overload and to cope with the insufficient generation but for this purpose one has to have priority list for load reduction for all loads in the system. The latter list is usually unavailable.

Simulating the system operation multiple times with different randomly defined states, where we consider generator/branch outages following their specific probabilistic characteristics, we obtain large amount of results which are used for statistical analysis. The most expected value of ENS is simply an average value of all values for ENS calculated by the Monte Carlo simulation. In addition, we may calculate additional indicators such as standard deviation of the ENS and its probability distribution function.

A transfer capacity of a power system is the capability to enable active power transfer from one area to another trough all transmission power lines between those areas. **Total Transfer Capacity (TTC)** is the maximum transmission power from one to another area.

The transfer capacities are estimated through calculations performed by each transmission system operator (TSO) for its own network area, starting with one given working state of the whole interconnected system. In order to coordinate the calculation of the individual transmission operators the ETSO (European Transmission System Operators) Organization has developed a procedure to determine the transmission capacity indicators. Therefore, the calculation should be based on a most reliable input data exchanged between the transmission operators, in order to have the same baseline scenario, i.e. same initial working state of the whole interconnection.

The estimation of transfer capacity is done through load flow calculations, usually by using DC-model. The initial power exchange, in the reference scenario, between two interconnected areas or power systems is called Base Case Exchange (BCE). The extra amount of power over the BCE that can be exchanged continuously from one area to another ensuring safe operation of both interconnected areas, represents a value ΔE. The total transfer capacity is calculated as a sum of this value ΔE and the BCE.

Actually, when calculating the maximum power that can be transmitted from one area to another, the following procedure is used: the power of the generators in the first area is increased for a certain value, while at the same time the power of the generators in the other area is reduced for the same value. The power of the generators is increased/decreased until the transmission network is overloaded to such an extent that the power flow in some of the lines achieves their maximum capacity. The procedure may also be stopped before the transmission network becomes overloaded, if the generators that increase their power achieve their maximum capacity

Usually, in the operation of a power system there is some reserve left in the capacity of the generators and the transmission lines to cover the frequency regulation of the power system and some uncertainties in the analyzed state of the power system. The uncertainties are usually a consequence of inaccuracy in measurements and input data forecasts, as well as of the simplified load flow calculations. Therefore, the TTC value is reduced for a certain amount called Transmission Reliability Margin (TRM) and the result is the Net Transfer Capacity (NTC):

$$\mathrm{NTC} = \mathrm{TTC} - \mathrm{TRM}$$

The value of TRM is determined by the TSO in a most convenient way for its power system. Usually, TRM value is around 10% of the TTC value, although there are cases where the TRM is a constant value that does not depend on TTC.

The NTC value should also be calculated using the N-1 analyses, which means that the same procedure should be repeated N times, by eliminating one element at a time. The final NTC will be selected as the lowest value of all the calculated NTCs.

EUROPEAN GAS MARKET MODEL

REKK's European Gas Market Model (EGMM) has been developed to simulate the operation of an international wholesale natural gas market in the whole of Europe (35 countries). Large external markets, such as Russia, Norway, Turkey, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices, long-term supply contracts and physical connections to Europe.

Given the input data, the model calculates a dynamic competitive market equilibrium for the modelled countries, and returns the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions and long-term contract deliveries. Based on these outputs the model also calculates the components of social welfare.

Model calculations refer to 12 consecutive months, with a default setting of April-to-March.[15] Dynamic connections between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and TOP constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual "make-up").

The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) long-term take-or-pay (TOP) contracts; and (7) spot trading. We will describe each of them in detail below.

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above. In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders.[16]

Local consumers decide about gas utilization based on the market price. This decision is governed entirely by the local demand functions.

Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, TOP quantities, penalties) and local supply-demand conditions. Second,

[15] The start of the modeling year can be set to any other month.

[16] We leave out storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.

traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection and working gas capacity, as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[17,18] Finally, traders also perform spot transactions, based on prices in each local and outside market and the available cross-border transmission capacities to and from those markets, including countries such as Russia, Norway, Turkey, Libya, Algeria or LNG markets, which are not explicitly included in the supply-demand equalization.

Table 23. Sources of input data used in the EGMM

Input data	Unit	Source of data
Demand	TWh/year	Eurostat 2015
Production	TWh/year, max GWh/day	Eurostat 2015 fact
Pipeline capacity	GWh/day	ENTSOG capacity map 2015
LNG capacity (regasification)	GWh/day	GLE capacity data + PL LNG terminal
Storage capacity (injection, withdrawal, working gas)	GWh/day , TWh/year	GSE 2015
Tariffs (LNG, storage, pipeline entry and exit)	€/MWh	REKK calculation based on TSO published tariffs as of January 2016
LTC (ACQ, price, route)	TWh/year, flexibility, €/MWh	Cedigas, REKK collection and calculation of price based on statistical reports for 2015
Outside market prices (NO, RU, DZ, LNG)	€/MWh	REKK calculation based on statistical data

[17] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.
[18] A similar intertemporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

ANNEX 3: INPUT DATA USED FOR THE ENERGY COMMUNITY MODELLING

European Electricity Market Model

Table 24. Forecast of electricity demand in EnC Contracting Parties, GWh

<table>
<tr><th></th><th>2015</th><th>2020</th><th>2025</th><th>2030</th></tr>
<tr><td>AL</td><td>7 842</td><td>9 163</td><td>10 704</td><td>12 399</td></tr>
<tr><td>BA</td><td>12 606</td><td>13 000</td><td>14 000</td><td>15 000</td></tr>
<tr><td>KO*</td><td>5 570</td><td>6 318</td><td>9 216</td><td>10 484</td></tr>
<tr><td>ME</td><td>3 395</td><td>3 419</td><td>3 870</td><td>4 366</td></tr>
<tr><td>MD</td><td>5 861</td><td>6 567</td><td>7 357</td><td>8 243</td></tr>
<tr><td>MK</td><td>7 491</td><td>9 262</td><td>10 226</td><td>11 290</td></tr>
<tr><td>RS</td><td>37 735</td><td>36 648</td><td>38 600</td><td>40 845</td></tr>
<tr><td>UA_E</td><td>143 915</td><td rowspan="2">160 937</td><td rowspan="2">166 292</td><td rowspan="2">176 679</td></tr>
<tr><td>UA_W</td><td>4 429</td></tr>
</table>

Table 25. Installed capacity in 2015 in EnC Contracting Parties, MWe

	Coal and lignite	Natural gas	Nuclear	Wind	HFO/LFO	Hydro	Other RES
AL	0	0	0	0	0	1 801	1
BA	1 765	0	0	0	0	2 162	0
KO*	1 171	0	0	1	0	53	0
ME	219	0	0	0	0	668	0
MD	1 000	1 727	0	1	0	64	3
MK	736	260	0	37	198	671	20
RS	4 075	417	0	10	0	3 018	13
UA_E	20 069	11 721	13 835	420	0	5 771	395
UA_W	2 334	217	0	7	0	38	19

Table 26. Planned fossil-based power generation capacities in EnC Contracting Parties MWe

	2016-2020			2021-2025			2026-2030		
	Coal and lignite	Natural gas	HFO/LFO	Coal and lignite	Natural gas	HFO/LFO	Coal and lignite	Natural gas	HFO/LFO
AL	0	200	0	0	160	0	0	0	0
BA	1100	390	0	300	0	0	0	0	0
KO*	0	0	0	500	0	0	500	0	0
ME	225	0	0	0	0	0	0	0	0
MD	0	0	0	0	0	0	0	0	0
MK	120	30	0	0	150	0	200	420	420
RS	0	478	0	700	0	0	350	0	0
UA_E	1300	550	0	1000	200	0	0	0	0
UA_W	0	0	0	0	0	0	0	0	0

Table 27. Planned RES-E capacities in EnC Contracting Parties, MWe

	Hydro			PV			Wind			Other		
	2016-2020	2021-2025	2026-2030	2016-2020	2021-2025	2026-2030	2016-2020	2021-2025	2026-2030	2016-2020	2021-2025	2026-2030
AL	523	457	457	30	26	26	30	25	25	0	0	0
BA	285	65	0	10	0	0	232	0	0	0	0	0
KO*	212	0	0	10	0	0	149	0	0	10	0	0
ME	54	451	0	10	14	8	151	17	21	31	10	8
MD	0	0	0	0	0	0	149	124	124	8	8	8
MK	114	26	45	7	8	30	13	50	50	3	5	10
RS	458	100	780	5	90	100	500	0	100	144	69	72
UA_E	1 330	2 400	0	1 170	0	0	1 600	265	0	165	2 000	0
UA_W	0	0	0	0	0	0	0	0	0	0	0	0

European Gas Market Model

Table 28. Forecast of gas demand in the EnC Contracting Parties, TWh/year

	Gas demand TWh/year				source	Note
	2015	2020	2025	2030		
Albania	0	4.9	8.82	11.76	ECA	conditional on new infra
Bosnia	1.66	1.66	8.37	8.92	BH-GAS	conditional on new infra
Kosovo*	0	0	3.92	5.88	MED (Energy Balance), ERO(annual report) and KSOTT	conditional on new infra
Montenegro	0	0	0.26	0.4		conditional on new infra
Moldova	10	11	12	13	REKK	
FYR of Macedonia	1.96	6.61	6.85	6.88	TYNDP	conditional on new infra
Serbia	22	27	30	35	Energy balance 2015 Energy sector development strategy	
Ukraine	369	368	371	375	Naftogas	

NOTE: for Albania, Bosnia, Kosovo*, Montenegro and the FYR of Macedonia the gas demand forecast will be used only when new infra on the territory of the respective county is modelled. For other projects' assessments the 2015 consumption data is used constantly

Source: TYNDP 2015; ECA: Gas to power study: https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/3758164/192E17AC7BED4BDEE053C92FA8C0D198.PDF, Montenegro govenment official

Table 29. Forecast of gas production in the EnC Contracting Parties, TWh/year

Gas production TWh/year					source
	2015	2020	2025	2030	
Albania	0	0	0	0	ECA
Bosnia	0	0	0	0	TYNDP
Kosovo*	0	0	0	0	ECA
Montenegro	0	0	0	0	ECA
Moldova	0	0	0	0	REKK
FYR of Macedonia	0	0	0	0	TYNDP
Serbia	5.43	3.72	2.78	1.9	Energy balance 2015 Energy sector development strategy
Ukraine	208.1	222.5	237.0	251.4	Naftogas

Table 30. LTCs assumed in modelling

Long term contract with Russia			
	ACQ	Price in 2016 \Q1	contract expiry
	TWh/year	€/MWh	
Albania	0	0.0	n.a
Bosnia	1.66	28.5	yearly
Kosovo*	0	0.0	n.a
Montenegro	0	0.0	n.a
Moldova	10	17.6	yearly
FYR of Macedonia	1	20.8	yearly
Serbia	up to 50	18.6	2021
Ukraine	60	13.4	2020

Source: REKK based on EUROGAS