Energy 215 (2021) 119106

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Social welfare impact from enhanced Trans-Asian electricity trade

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A R T I C L E I N F O

Article history:
Received 7 February 2020
Received in revised form
6 October 2020
Accepted 14 October 2020
Available online 19 October 2020

Keywords:
Electricity system planning
Power transmission
Social welfare
Cost-benefit analysis
Greenhouse gas emissions

A B S T R A C T

Long distance power transmission is commonly considered as an option for reducing carbon footprint in future electricity systems. Accordingly, this article presents economic insights in a transcontinental power interconnection linking four Asian countries with Europe. Enhanced electricity trade through the interconnected countries is assessed via techno-economic modelling. For this purpose two electricity system scenarios are developed for the year 2040: (i) a Reference Scenario, where electricity system development follows the plans of the involved system operators and (ii) a so-called Trans-Asia Scenario, where additional power transmission capacities are added to strengthen the electricity trading route crossing the interconnected countries: Turkey, Georgia, Azerbaijan and Kazakhstan. Economic benefits arising from the proposed Trans-Asia Scenario are estimated as a change in social welfare in the electricity system. Modelling results show a 140 M€ increase in annual social welfare for the Trans-Asia Scenario. The subsequent cost-benefit analysis results in a net present value in the range of −221 M€ to 534 M€, at a discount rate of 4%. This implies that over a life-cycle period of 40 years, the evaluated economic benefit may compensate investments between 1598 M€ and 3251 M€ needed for the additional power transmission capacities.

1. Introduction

Long distance power transmission is regularly presented as an enabler for high deployment of centralized renewable energy sources (RES) [1]. Several projects have been implemented providing flexibility in transcontinental power balance between electricity demand and generation [2]. Wu and Zhang [3] presented a feasibility study of an intercontinental electricity trade between Europe and China with 100% RES generation in 2050. This interconnection significantly decreases annual electricity system running costs. However, electricity systems of countries along the Europe-China connection route are not considered. In this regard, Assembayeva et al. [4] developed an electricity market model of Kazakhstan, with possible further expanding modelling capacity in the Central Asian region. Assembayeva et al. [4] indicates power flow congestions in the electricity grid of Kazakhstan during high electricity demand in winter. According to Gea-Bermúdez et al. [5]; grid congestions can be reduced along with electricity production costs through a sound long-term electricity system planning. In the light of the above considerations, this study presents an elaborated techno-economic modelling approach giving insights in investments in additional electricity trade capacity along a route connecting Europe with a selection of Asian countries in 2040.

Transmission grid reinforcements are proposed on top of the planned transmission infrastructure development plans to allow a cross-border electricity trade capacity of 2000 MW in a selected route from Turkey to Kazakhstan, passing through Georgia, Azerbaijan and the Caspian Sea. This route derives from a study by Ardelean and Minnebo [6] and interlinks with the European transmission grid as shown in Fig. 1. The proposed increase in cross-border trade capacity between the Asian countries to 2000 MW is close to the envisaged electricity trade capacity between Bulgaria-Turkey and Greece-Turkey in the ENTSO-E 2040 scenarios [7].

Next section presents relevant European Union (EU) policies as well as the modelled Trans-Asian electricity systems. Section 3 outlines main modelling assumptions and input data. Section 4 introduces two considered scenarios by explaining differences in the respective power transmission grids. Main modelling results are presented and discussed in Section 5. Social welfare – producer, consumer and merchant surpluses – as well as wholesale electricity prices, CO_2 emissions and utilization of cross-border reinforced electricity trading capacities are compared for both scenarios. In Section 6 the value of the project is estimated as a difference between grid reinforcement costs and benefits. The

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https://doi.org/10.1016/j.energy.2020.119106

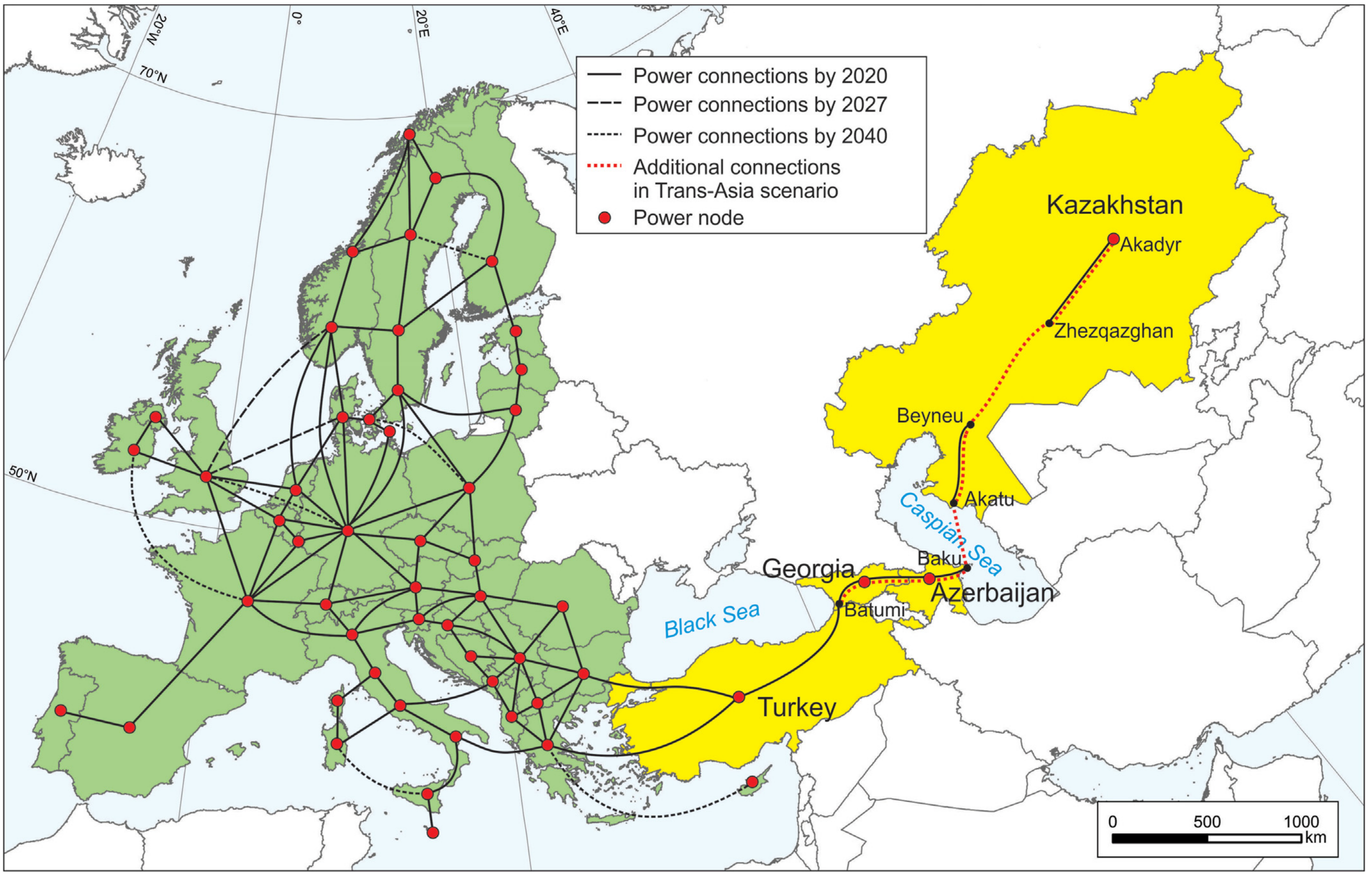

Fig. 1. Modelled countries with their respective interconnections [courtesy of M. Ardelean].

conclusions of this study are given in Section 7.

2. Policy context

EU energy policies open up perspectives for transcontinental power interconnections aiming at beneficial electricity trade. Europe actively seeks for reliable energy partners. The Council of the European Union [8] supports diversification of energy sources, suppliers and routes across continents. A number of particular regions are highlighted in this context, including the Southern Caucasus and Central Asia, which experience a rapid economic growth leading to an increase in electricity consumption in the past decade. Intense electricity trade between Europe and Asia would allow more competitive suppliers accessing markets and offer additional opportunities for energy cooperation. In addition to this, European Commission [9] proposes the EU to engage in efficient connections and networks between Europe and Asia, also aiming at enhanced energy connectivity among and with partners in Asia. The related conclusions of the Council of the European Union [10] highlight that the ongoing transformation towards renewable energy increases demand for electricity interconnections and regional cooperation in Eurasia. With this in mind, the EU helps developing interconnections between the Central Asian countries spurring regional and inter-regional energy trade [11]. The above policies match with the overall EU goal to become a stronger global actor in the energy field. This ambition was already apparent in the Energy Union Package [12].

Following the Paris Climate Change Conference of 2015, numerous countries adopted concrete objectives for their energy sector to limit global warming below 2 °C. A well-known example is the ambitious EU 2050 target for becoming the world first climate-neutral continent [13]. In 2018, EU greenhouse gas emissions decreased by 23% comparing to 1990 levels [14]. Currently roughly, one third of Europe's electricity is generated from RES [14]. Mixed combustion and nuclear power plants produce the rest. The European Commission foresees a steadily increasing RES share in the electricity generation mix in line with its decarbonisation policy. According to Louis et al. [15]; the 2050 target can be supported by half electricity generated from RES.

Similarly, Turkey is expected to increase electricity generation from RES in the next years to anticipate the ongoing trend of rapidly increasing electricity demand [16]. Average demand growth during the last decade has been close to 5% per year [14]. Nowadays, the RES contribution to electricity generation in Turkey is 29% [17]. Fossil fuel combustion power plants cover remaining demand.

The frontrunner in electricity generation from RES among the addressed Asian countries is Georgia. The mountainous landscape of this country offers massive opportunities for the deployment of hydro resources. Accordingly, in 2017 hydro power plants generated most of the electricity: 80% [19]. The remaining share covered natural gas power plants (19%) and wind farms (1%). Although water is the main energy resource, Georgia exploits only 25% of its potential [18]. Due to their high economic feasibility, more than 100 hydropower plants with capacity of 4688 MW are expected by 2025 [19]. Georgia also has planned projects for utilising its considerable resources of solar and wind energy [19].

In Azerbaijan, large reserves of oil and natural gas drive its economic growth [20]. In 2017, thermal power plants, mostly gas-fired, provided 91% of the generated electricity [21]. From RES, hydro power plants contributed with 8%, and wind farms, solar power plants and waste incinerators covered the remaining 1%. The sunny climate through the entire territory and the windy Caspian Sea coast offers a substantial potential for utilization more RES. In addition, relatively high potential for geothermal energy exists in the Autonomous Republic of Nakhchivan. To explore these potentials, the Azerbaijani government founded the State Agency on Alternative and Renewable Energy Sources (AREA) in 2009.

Kazakhstan is the largest country by land area in Western and Central Asia. Its electricity production heavily depends on domestically mined coal. In 2017 most of the Kazakh electricity (81%) was generated by coal-fired power plants, 11% by hydroelectric power stations and 8% by gas-fired plants [22]. Besides hydro, electricity generation from other RES, such as wind and solar, is very low for now. Nevertheless, the government of Kazakhstan has recognized the significant RES potential by setting ambitious goals towards sustainable electricity system development. The 'National Concept for Transition to a Green Economy up to 2050' sets the share of alternative sources of energy in electricity generation at 30% by 2030 and rising to 50% by 2050 [23]. Consequently, the expected reduction of CO_2 emissions in the electricity sector is 15% by 2030 and 40% by 2050 compared to the year of 1992. CO_2 reduction is of particular interest for Kazakhstan as historical observations show average air temperature increase by 0.31 C for every decade since 1936 [24]. From a multi-criteria point of view, Ahmad et al. [25] suggests to emphasise on development of RES technologies. He highlights the importance of the capital cost of these technologies and potential for the local job creation over purely environmental benefits. Assembayeva, Zhakiyev, and Akhmetbekov [26] contribute in electricity system studies in Kazakhstan. They find energy storage essential when handling high RES deployment.

RES are expected to contribute significantly in the future energy mix of the discussed electricity systems. High RES deployment results in new challenges for power balancing [27,28]. Power transmission grid reinforcements are generally associated with steadily increasing integration of RES in electricity systems [29] allowing for development of renewable and low carbon energies in the near future. Substantial diversity in generation mix, potential to exploit various RES at large scale and different time zones across continents may lead to a favourable transcontinental electricity trade [30]. Within this framework, the present article considers an enhanced Europe-Asia power interconnection, studying cross-border electricity trading benefits.

3. Electricity system modelling assumptions

The basis for this study is a techno-economic electricity system model, which runs in a commercial power market simulation software PLEXOS [31]. Assuming a perfect forecast, the electricity system model optimizes a day-ahead generation dispatch and power flows, and provides an asset performance valuation in terms of electricity prices. The electricity systems of the selected countries are modelled at hourly time steps for the entire year of 2040. At every hour, the total power generated in the modelled system must be equal to the electricity demand. A standard price formation mechanism is assumed for electricity markets: uniform auction and marginal cost pricing.

Basic modelling assumptions described in this section are validated in a previous study by Huang and Purvins [32]. Although the validation is performed for scenario year 2016 and is limited to a Europe-wide electricity system, methodological concept remains in the future scenarios ensuring reliable modelling accuracy.

Spatial resolution and structure in Europe follows ENTSO-E [7] modelling data. The European system is comprised of 36 countries modelled as 55 power nodes. Additionally, Turkey, Georgia, Azerbaijan and Kazakhstan are modelled as one node per country. All considered countries as well as the power nodes and inter-nodal connections are shown in Fig. 1.

Techno-economic characteristics of the model are based on a previous study by Purvins et al. [30]. Technical characteristics constrain economic generation dispatch. Each power node has its unique aggregated hourly electricity demand profile and aggregated generation capacities by power/fuel source: wind, solar, hydro, pump hydro, biomass, natural gas, coal, lignite, oil and nuclear. Generation from RES and electricity demand derives from weather conditions of 2007 – a typical year since 1990. Energy losses of 2% are assumed in the cross-border connections between the modelled countries. This is close to the average in electricity transmission grids in Europe [33].

Power plant characteristics and fuel prices are listed in Table 1. Generation unit size is an assumption for dispatchable generators adding modelling accuracy when aggregated generation capacities are used [32]. Aggregated generation units build the total generation capacity per technology. Minimum stable level for thermal and hydro generation technologies is expressed as a percentage from unit size and is obtained from ENTSO-E [7]. This property limits power plant flexibility, i.e. plat being in operation cannot reduce power output below minimum stable level. Wind and solar power plants generate following a predefined pattern and can be completely curtailed if necessary.

Heat rate shows energy conversion efficiency from chemical to electrical [34], i.e. the fuel quantity needed (GJ) to produce one MWh of electricity. Heat rate for lignite-fuelled power plants is adjusted following lignite quality in the subject countries [35]. Lower lignite calorific value requires more fuel to produce one MWh of electricity and vice versa. Multiplication of heat rate (GJ/MWh) and fuel price (P_{fuel}, €/GJ) forms fuel cost term in the

Table 1
Power plant characteristics and costs by source.

Source/fuel	Unit size, MW	Min. stable level	Heat rate, GJ/MWh	Price, €/GJ	Variable O&M cost, €/MWh	Planned outage rate	Unplanned outage rate	Mean repair time, days
Wind	–	–	–	–	0.0	–	–	–
Solar	–	–	–	–	0.0	–	–	–
Hydro	100	15%	–	–	5.0	8%	6%	1
Pump hydro	100	15%	–	–	0.0	8%	6%	1
Gas	300	35%	6.21	5.50	2.0	6%	5%	1
Gas, CHP	300	35%	6.31	5.50	4.0	6%	5%	1
Coal	300	43%	8.00	2.50	3.6	7%	8%	1
Lignite	300	43%	8.57	1.10	4.5	7%	8%	1
Nuclear	1000	50%	9.72	0.47	8.0	13%	5%	30
Biomass	100	43%	10.28	5.80	3.8	7%	8%	1
Oil	100	35%	9.00	17.10	11.0	3%	5%	1

marginal generation cost equation:

$$C_m = HeatRate\left(P_{fuel} + P_{CO2} * X_{CO2}\right) + C_{varO\&M} \tag{1}$$

Fossil and nuclear fuel prices are acquired from ENTSO-E [7] Sustainable Transition scenario. Biomass price is estimated by Purvins et al. [30]. CO_2 cost is a multiplication of (i) heat rate, (ii) CO_2 price, $P_{CO2} = 45$ €/t_{CO2} at ENTSO-E [7] Sustainable Transition scenario, and (iii) emission factor in fuel, $X_{CO2,}$ expressed in t_{CO2}/GJ, [36]. CO_2 cost applies to the fossil-fired power plants. Fuel and CO_2 prices are assumed the same for all studied countries. Presence of the CO_2 price partially introduces environmental aspects in the power dispatch [37]. Variable operation and maintenance (O&M) cost, $C_{varO\&M}$, (€/MWh) provided by ENTSO-E [34], adds to the marginal generation cost.

Outage rates for power generators are obtained from the World Energy Council [38]. The unplanned outages are distributed randomly through a year, whereas the planned outages are also distributed randomly but mostly during times of low electricity demand. Outages are not modelled for wind and solar power plants as they generate following a predefined pattern. Average repair time is assumed 30 days for nuclear power plants and one day for the rest.

The modelling exercise is divided in two steps. In Step 1, the techno-economic model is executed for a single target – to estimate additional electricity demand parameters. These parameters are the demand slope and intercept estimated from fixed demand profiles as described by Purvins et al. [30]. The demand slope (b) is obtained from the point elasticity demand (e) equation.

$$b = p \,/\, (q * e) \tag{2}$$

Using Equation (2), the demand intercept (a) now can be estimated from the inverse demand function p(q).

$$p = a + b*q \tag{3}$$

The demand slope (b) is a negative value, whereas the intercept (a) – positive. Estimated parameters, a and b, vary from 1 h to other following changes in electricity demand (q) and equilibrium price (p). An average demand elasticity (e) value, −0.32 [30], is applied for the modelled European and Asian countries.

At Step 1, the overall portfolio of electricity generation costs is minimized. These are total generation costs, which depend on power plant efficiency, fuel and CO_2 prices, and variable operation and maintenance cost. CO_2 price is assigned to CO_2 emissions in fossil-fired power plants.

Fixed electricity demand profiles in Europe and in Turkey are obtained from ENTSO-E [7]; whereas profiles in Georgia, Azerbaijan and Kazakhstan are acquired from PLEXOS World [39]. The Asian profiles are adjusted by a factor to match projected annual demand of the desired future year scenario. According to the strategy adopted by Kazakhstan towards 2050, its economic development may lead to an electricity consumption growth of 2.3% per year up to 136 TWh by 2030, and by 1.2% per year up to 172 TWh by 2050 [23]. Azerbaijan estimates its electricity demand increase at 4% annually to reach 35 TWh by 2025 [40]. Georgia foresees an annual growth of 5% up to 22.3 TWh by 2030 [19]. For the Asian countries, the closest demand projections to 2040 are applied in the modelling. The assumed annual demand in 2040 for all countries is shown in Fig. 2.

In Step 2 the electricity demand is slightly flexible and depends on the electricity price, where the price follows any change in the modelled electricity system. Demand for every modelled hour is now estimated from the inverse demand function (3) using the demand slope and intercept as input from Step 1. In Step 2, the techno-economic model is implemented with the purpose to estimate social welfare in the electricity system. In this modelling step, electricity generation dispatch follows an objective function, which is the maximization of social welfare, under the constraint provided by the energy balance – generation equals demand – at every modelled hour. Social welfare is an indicator of the wealth of a country (society). It is subsequently used in a cost benefit analysis. The social welfare is estimated from an electricity system perspective as the sum of the consumer (CS), producer (π) and merchant (MS) surpluses. Hence, the maximization problem reads:

$$max\{Social\ Welfare\} = max\{CS + \pi + MS\} \tag{4}$$

The consumer surplus is estimated as:

$$CS = U(q_c) - p_c * q_c \tag{5}$$

where p_c is the electricity price that the consumer pays and q_c is the electricity quantity that the consumer buys. $U(q_c)$ is a linear-quadratic utility function [41,42] for every hour:

$$U(q_c) = a * q_c + b * q_c^2 \Big/ 2 \tag{6}$$

The demand intercept is the maximum of the willingness-to-pay for electricity consumption. The ratio of the demand intercept and slope – a/b – is the utility maximizing consumption. Consumers demand electricity and pay the electricity bill, $p_c q_c$, in order to maximize the consumer surplus.

On the supply side producers collect revenues ($p_s q_s$) from selling electricity, where p_s and q_s are the bidding price and quantity

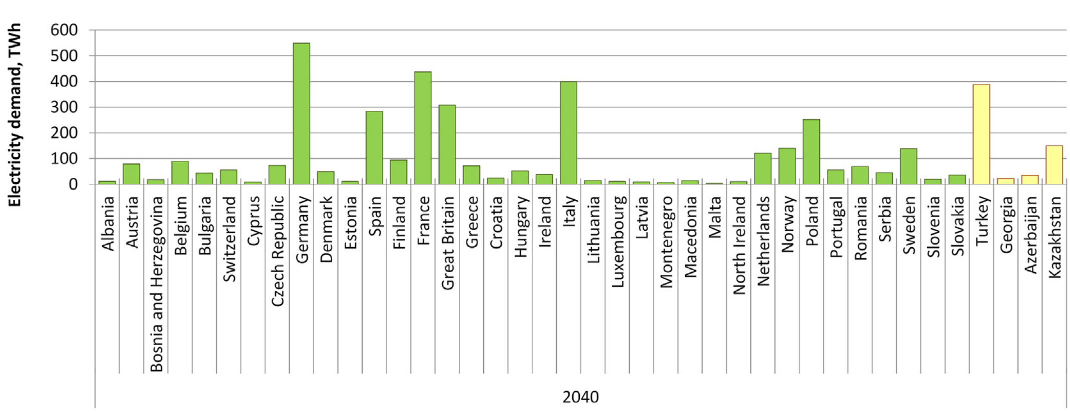

Fig. 2. Assumed annual electricity demand by country in 2040.

respectively. The total generation cost is a cost function:

$$C(q_s) = C_m * q_s \tag{7}$$

Electricity markets are competitive and therefore generators are price takers. The producer surplus is thus estimated as:

$$\pi = p_s * q_s - C(q_s) \tag{8}$$

Since electricity needs to be transferred from generators to consumers (or purchasers), the merchandising surplus (congestion rent) is estimated for every electricity exchange:

$$MS = p_c * q_c - p_s * q_s \tag{9}$$

The optimization problem can now be expressed as:

$$max\{CS + \pi + MS\} = max\{U(q_c) - C(q_s)\} \tag{10}$$

3.1. Load shifting

Load shifting is modelled as a targeted action to reduce electricity consumption during peak load hours. Load shifting potential can be expressed as a percentage of the peak load indicating peak load reduction potential (peak load shaving). In this study, load shifting is assumed at 5% of the annual peak load in the modelled European countries. It is a cautious assumption being slightly below the lowest estimations found by Gils [43] and half of the projections given by Stede [44] for Germany. For example, if the annual peak load in a country is 1000 MW, it could be reduced to 950 MW applying load shifting.

In the current article, load shifting is modelled as a fully flexible energy storage system with 100% efficiency. It is assumed that the storage system, when fully charged, can provide full power continuously for 2 h. For a 50 MW storage system, the storage capacity can then be estimated as 50 MW * 2 h = 100 MWh. This is a simulated flexible load capacity, which can be shifted in time.

Load shifting is applied to reduce the use of expensive electricity generation capacities. The cost of the load shifting is set slightly below the marginal cost difference between the two most expensive generators. Load shifting is optimized together with generation dispatch and is mostly shifted within a day contributing to daily peak load shaving.

3.2. Electricity generation

Aggregated generation capacities of the modelled countries are shown in Fig. 3. Capacities in Europe and in Turkey are obtained from the ENTSO-E [7] Sustainable Transition 2040 projections. Generation capacities for Georgia [19], Azerbaijan [40] and Kazakhstan [23] are the closest estimates for 2040. Interestingly, countries in Western and Central Asia use different dominant sources of fuel for electricity generation.

Electricity generation profiles in Europe from solar and wind sources are obtained from an open database: http://renewables.ninja/[45,46]. In the modelled Asian countries, these profiles are estimated for the sunniest and most windy regions from solar irradiance and wind speed data from NASA's MERRA-2 database [47]. Wind speed at 100 m altitude is estimated from the original 10 m data, as proposed by Gipe [48]:

$$V_{100m} = V_{10m} * \ln(100m / k) / \ln(10m / k) \tag{11}$$

k (m) is a terrain roughness length constant set at 0.1 m. This value characterizes agricultural land with some houses.

If the aggregated wind or solar power plant capacity in an Asian country is higher than 200 MW, the generation profile is estimated from three locations. Generation capacity is distributed evenly. This results in a smoothened profile with reduced variations [49].

When power plant capacities are known, the generation profiles from solar and wind sources in Asia can be estimated as follows. The predicted photovoltaic (PV) plant capacity (Fig. 3) is the maximum generation power which can be delivered by the plant.

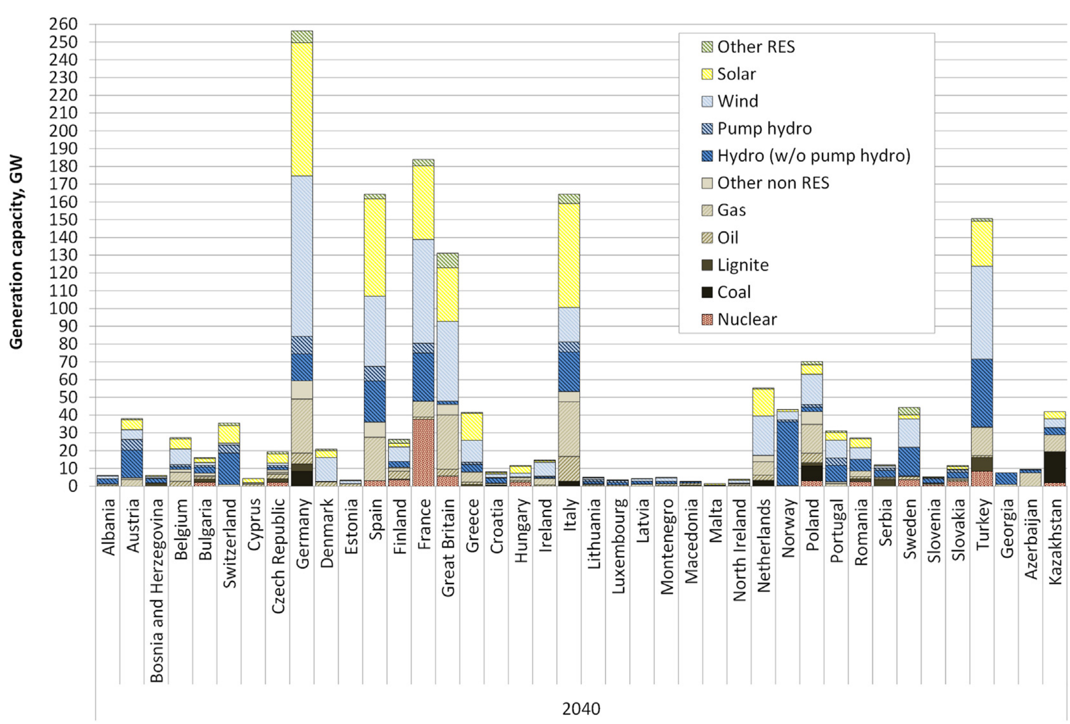

Fig. 3. Aggregated generation capacities by country.

The PV plant reaches peak generation at a solar irradiance of 1000 W/m^2. At lower irradiance PV generation drops proportionally. Similarly, the predicted wind farm capacity is the maximum generation of the farm. Applying a typical wind speed-power curve, no power is produced at wind speeds below 3 m/s and above 25 m/s [50]. At 13 m/s, the maximum power output is reached, which stays constant at further wind speed increases up to 25 m/s. The generation power change from zero at 3 m/s to full power at 13 m/s is assumed to be linear. On top of the estimated generation profiles, 97% availability is applied for both power plant types: wind [61] and PV [51].

Seasonal variations and monthly capacity factors of hydro power plants in Europe and Turkey are obtained from EUROSTAT [14] records of 2007; whereas hydro generation in Georgia, Azerbaijan and Kazakhstan follows the seasonal variations given by PLEXOS World [39].

Some thermal and hydro power plant capacity in every country is reserved for emergencies. This reserved capacity is used to keep generation and demand balanced during events of forced outages of generators or other electricity system components. In this modelling exercise, emergency power reserves are allocated on spinning generation units of thermal and hydro power plants. The capacity of allocated emergency reserves depends on the size of generation fleet. 1000 MW reserves are assigned for every country with an aggregated thermal power plants capacity of 10 GW or higher. Countries with a smaller generation fleet keep only 300 MW for emergencies. The reserve capacity is kept available at any modelling hour. With this assumption, the reserves capacity may be overestimated. However, knowing that nuclear and fossil-fired power plants provide base load, it is a reasonable assumption. This approach also contributes to electricity system inertia, as continuous provision of power reserves keeps at least one steam turbine spinning.

The heat rate as chemical-to-electrical efficiency of thermal power plants is modelled as a function of generation power. Fig. 4 shows power plant efficiency changes at part load operation. Relative efficiency of 100% is the efficiency of the generator (heat rate) at full generation output. At part load, generator efficiency drops (heat rate rises) and more fuel is needed to produce one energy unit of electricity. The efficiency curves in Fig. 4 are rough estimate from heat rate figures presented by Lew et al. [52]. The relative efficiency curves of the combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) technologies are merged into one, as they are quite similar [52].

4. Scenarios

The feasibility of investments in larger cross-border electricity trading capacities between the considered Asian countries is assessed by comparing two scenarios for 2040: (1) a Reference

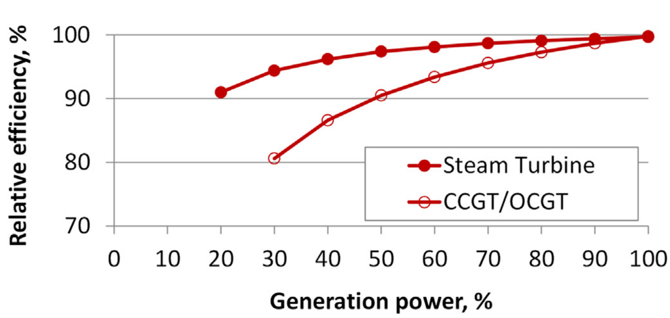

Fig. 4. Estimated relative power plant efficiency at various generation outputs.

Table 2
Assumed cross-border electricity trading capacities in Asia in 2040.

Cross-border electricity trading	Reference Scenario: Existing and planned capacities, MW	Trans-Asia Scenario: Additional capacities, MW
Bulgaria-Turkey	2000	0
Greece-Turkey	2100	0
Turkey-Georgia	1400	600
Georgia-Azerbaijan	1000	1000
Azerbaijan-Kazakhstan	0	2000

Scenario, and (2) a so-called Trans-Asia Scenario.

The Trans-Asia Scenario builds on top of the Reference Scenario by adding extra cross-border trading capacities between the Asian countries as listed in Table 2. The cross-border capacities in the Reference Scenario follows plans of the system operators. Bulgaria-Turkey and Greece-Turkey capacities are obtained from ENTSO-E [7]; whereas Turkey-Georgia and Georgia-Azerbaijan capacities are acquired from Georgian State Electrosystem [19].

Higher cross-border trading considered under the Trans-Asia Scenario requires additional power transmission corridors as listed in Table 2 and depicted above in Fig. 1. They increase the cross-border trading capacity between each couple of neighbouring countries to the envisaged 2000 MW. This is close to the largest planned cross-border capacity in the modelled Asian countries. The additional capacity applies to the existing transmission grid where available. Through Georgia (from Batumi) and Azerbaijan (to Baku), the additional capacity follows the shortest path of the existing high voltage transmission grid of 220 kV and higher voltage. Azerbaijan and Kazakhstan connects with a submarine power cable through the Caspian Sea (Baku-Akatu). In Kazakhstan, Akatu is connected with Beyneu and further with Zhezqazghan and Akadyr via the shortest path. The grid investment costs are estimated at 180–370 k€/1000 MW/km for a double circuit overhead line with an assumed power factor of 0.9 [53]; and 910–1820 k€/1000 MW/km for the submarine cable crossing the Caspian Sea [54]. Converter stations required at both ends of the cable cost 60–125 k€/MW [54]. Given cost range covers variations in labour costs among countries. Total grid reinforcement costs in the Trans-Asia Scenario can amount as high as 3251 M€ (Table 3).

5. Modelling results

General modelling results of both scenarios – the Reference and the Trans-Asia – are compared. Increase in cross-border capacities in the latter scenario brings higher flexibility in power balancing. This affects the generation mix in the modelled countries. Annual generation in the most affected countries is depicted in Fig. 5. The largest changes are found for Azerbaijan and Kazakhstan as these countries only trade electricity in the Trans-Asia Scenario.

Resulting consumer and producer surpluses are listed in Table 4. The Trans-Asia Scenario results in an overall higher consumer surplus. However, the total producer surplus drops in this scenario. These observations are almost entirely related to the situation in Azerbaijan and Kazakhstan and can be explained through the electricity prices listed in Table 5. Electricity price differences lead to net annual electricity flows of 15.7 TWh from Azerbaijan to Kazakhstan (Table 6). Electricity imports in Kazakhstan reduce generation in the local coal burning power plants leading to lower producer surpluses. The opposite effect is observed in Azerbaijan: an increased producer surplus due to higher electricity generation in gas-fired plants. Price drops in Kazakhstan as part of the locally generated power is replaced by cheaper imports. Price rises in

Table 3
Assumptions in additional transmission corridors for the Trans-Asia Scenario.

Power transmission corridor	Connected nodes	Type	Capacity, MW	Length, km	Costs, M€
Via Georgia, Azerbaijan	Batumi-Baku	Overhead line	1000	700	126–259
Via Caspian Sea	Baku-Akatu	Submarine cable	2000	400	968–1956
Via Kazakhstan	Akatu-Beyneu	Overhead line	1000	400	72–148
Via Kazakhstan	Beyneu-Zhezqazghan	Overhead line	2000	1000	360–740
Via Kazakhstan	Zhezqazghan-Akadyr	Overhead line	1000	400	72–148
Total					**1598–3251**

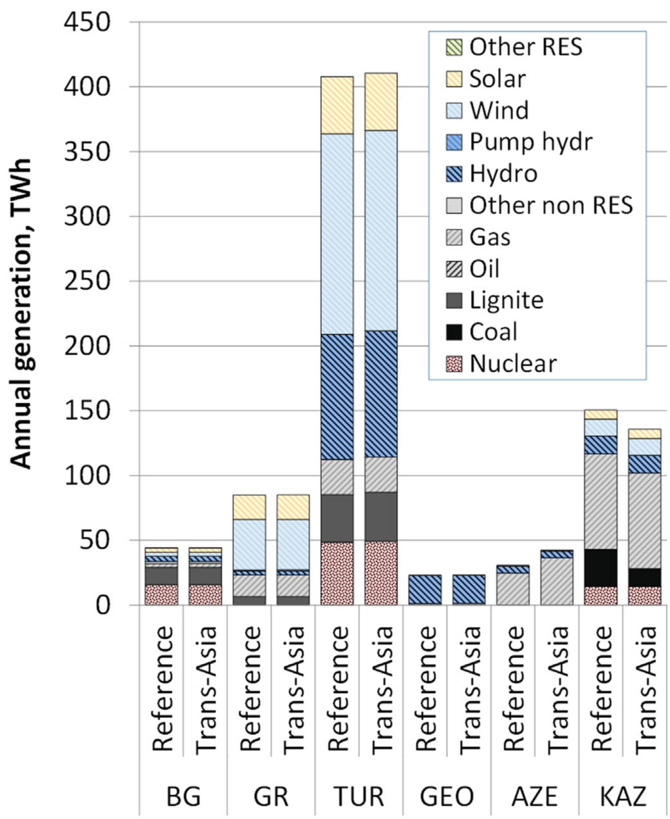

Fig. 5. Annual generation: 2040 [BG – Bulgaria, GR – Greece, TUR – Turkey, GEO – Georgia, AZE – Azerbaijan, KAZ - Kazakhstan].

Table 4
Changes in consumer and producer surpluses: 2040.

Region	Δ Consumer surplus, M€	Δ Producer surplus, M€
Georgia	−8	7
Azerbaijan	−1	277
Kazakhstan	134	−448
Bulgaria	0	0
Greece	−2	3
rest of Europe	1	1
Total	**99**	**−111**

Azerbaijan as more power is generated to cover extra exports to Kazakhstan. Changes in electricity price affect consumer surplus. The highest price drop is in Kazakhstan leading to the highest increase in consumer surplus among the modelled countries. Since electricity demand is a negative function of price, at higher prices, demand tends to drop and vice versa (see Table 5).

Table 6 compares the annual electricity trading between the studied countries. The highest increase in power trading under the Trans-Asia Scenario is between Azerbaijan and Kazakhstan, leading

Table 5
Wholesale load weighted average electricity prices and demand: 2040.

Region	Price, €/MWh		Demand, GWh	
	Reference	Trans-Asia	Reference	Trans-Asia
Turkey	36.43	36.52	380409	379883
Georgia	38.96	39.63	22267	22018
Azerbaijan	47.01	47.06	35083	35073
Kazakhstan	51.79	50.89	150458	151352
Bulgaria	47.83	47.83	43432	43431
Greece	42.28	42.30	70630	70606
rest of Europe	44.69	44.69	3523840	3523848

to the largest change in annual merchant surplus. Indeed, in the Reference Scenario there is no submarine connection, which is intensively used in the Trans-Asia Scenario. High increase in merchant surplus also appears in the Georgia-Azerbaijan connection because of the large difference in electricity prices.

Enhancing the transmission system leads to lower CO_2 emissions from the fossil-fired power plants. The emissions listed in Table 7 are estimated from CO_2 content in fuel as described by Purvins et al. [30]. Emissions follow closely changes in the generation mix. In Kazakhstan CO_2 emissions drop significantly due to lower utilization of coal power plants in the Trans-Asia Scenario. The overall CO_2 emission reduction in the modelled countries is 5370 thousand metric tons per year.

While the sum of producer and consumer surpluses is close to zero or positive in almost every country, this is not true for Kazakhstan, where the overall benefit for consumers and producers is negative: −314 M€. Thus a social planner may not be willing to participate in the enhanced electricity trading. However, Kazakhstan is the only country in the model where significant CO_2 emission reduction is observed: −9776 thousand metric tons. This reduction would lead to important benefits for the Kazakh society, mainly in the field of public health, due to better air quality. Benefits would also be apparent in other areas, like agricultural productivity and water availability, although here the effect is more complex to describe in terms of time frame and territorial expanse. The reduction of CO_2 emissions could be monetized, e.g. through the CO_2 price, which is often used in social cost-benefit analyses of infrastructural projects. ENTSO-E [7] projects 45 €/t_{CO2} in the Sustainable Transition scenario. Also Applied to Kazakhstan, this would lead to an estimated economic benefit of (9776 * 1000) t_{CO2} * 45 €/t_{CO2} = 440 M€. This value is a useful indication, but, due to the factors mentioned above, it is a subject to variability and uncertainty [55].

The presented model takes into account monetized benefits in terms of reduced spreads between electricity prices of the interconnected countries. Although not incorporated in the model, additional outcomes, like CO_2 emission figures, may point at very important co-benefits, even if they are hard to monetize. Given the ambitious climate policies of Kazakhstan, the co-benefit of reduced CO_2 emissions may be a genuine driver for its government to consider enhanced electricity trade.

Table 6
Changes in merchant surplus and utilization of cross-border connections in Asia: 2040.

Cross-border connections	Δ Merchant surplus, M€	Utilization		Net flow, GWh	
		Reference	Trans-Asia	Reference	Trans-Asia
Turkey- > Georgia	24	45%	52%	3849	7371
Georgia- > Azerbaijan	66	55%	51%	4464	8389
Azerbaijan- > Kazakhstan	67	n/a	89%	n/a	15706
Bulgaria- > Turkey	−1	74%	74%	−12604	−12527
Greece- > Turkey	−1	60%	59%	−6922	−6805
rest of Europe	−1	–	–	–	–
Total	**154**	–	–	–	–

Table 7
Changes in CO_2 emissions: 2040.

Region	Δ CO2 emissions, thousand metric tons
Georgia	38
Azerbaijan	3414
Kazakhstan	−9776
Bulgaria	7
Greece	31
rest of Europe	26
Total	−5370

6. Cost-benefit estimations

The standard approach for assessing the socio-economic impact and public value of infrastructure projects is based on a cost-benefit analysis (CBA). This analysis was used in various power transmission grid expansion projects by Turvey [56], De Nooij [57], Purvis et al. [30] and Sereno and Efthimiadis [58]. Hereafter the CBA is applied to estimate the overall economic feasibility of the proposed Trans-Asia Scenario. The CBA is performed by means of the net present value (NPV) approach, i.e. the values of benefits and costs are discounted and then added. The NPV includes the extra investment costs in the cross-border power transmission capacities and the benefits from electricity trading. These benefits are changes in the total social welfare in the modelled electricity system — the sum of consumer, producer and merchant surpluses — summarized in Table 8.

As listed in Table 3, the overall investment costs required to increase the cross-border trading in the Asian countries can range from 1598 M€ to 3251 M€. The benefit expressed as increase of total annual social welfare is 140 M€. It is obtained from Tables 4 and 6. The cash flow is estimated over a period of 40 years (2040–2080), which is the average economic life of a power transmission line [59]. The costs and benefits are discounted at rate i to the present year of 2020. Assuming constant benefits during 40 years, the present value of the benefit is estimated as:

$$PV_{ben} = \frac{1}{(1+i)^{20}} \sum_{year=1}^{40} \frac{Benefit}{(1+i)^{year}} \quad (12)$$

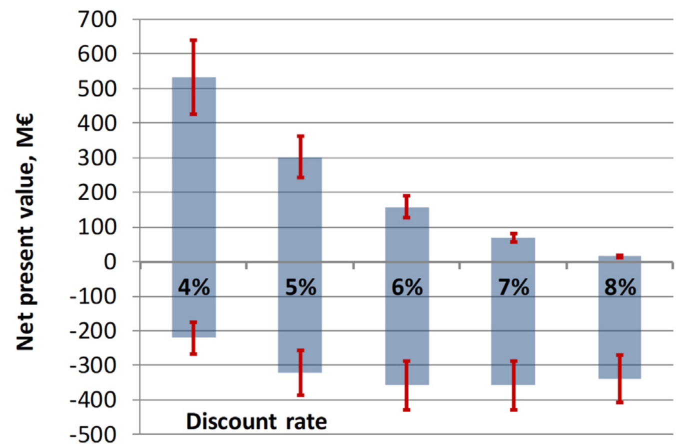

Fig. 6. Net present values of enhanced electricity trade in Asia: 2040–2080.

The investment costs are paid at once in 2040. With this assumption, the present value of the investment costs is obtained as follows.

$$PV_{cost} = \frac{1}{(1+i)^{20}} * Investment \quad (13)$$

The NPV — the difference between the present values of benefits and costs — of enhanced electricity trade in Asia is depicted in Fig. 6. A positive NPV indicates that the investment is worthwhile. 4% is the benchmark discount rate reflecting social time preferences. This rate is also used by European Commission [60] for evaluating public infrastructure projects. The NPV ranges cover variations in the investment costs. At all discount rates, the NPV turns negative at high investment costs. However, at low investment costs, the NPV stays positive in the presented discount rate range. The red error bars show the impact of uncertainty due to various risk factors. For example, an increase of the CO_2 price during the economic life of the project reduces the NPV, while technological breakthrough may reduce investment costs resulting in higher NPV. The uncertainty analysis in this case is performed by varying the project

Table 8
Summary of the extra investment costs and differential social welfare between the Reference and Trans-Asia scenarios: 2040.

	Europe	Asia	Total
Extra power transmission investment, M€	**0**	**1598–3251**	**1598–3251**
Δ Annual social welfare, M€, a sum of	**1**	**139**	**140**
Δ Consumer Surplus, M€	0	99	99
Δ Producer surplus, M€	4	−115	−111
Δ Merchant surplus, M€	−3	155	152

NPV by ±20%.

7. Conclusion and policy implications

This article provides basic insights in the economic costs and benefits from investments establishing a 2000 MW electricity trading capacity in an interconnected Eurasian electricity system for the year 2040. The estimated power transmission grid investment of 1598−3251 M€ results in an annual increase in the total social welfare of 140 M€ and in CO_2 emissions reduction by 5370 thousand metric tons annually. The welfare benefit is limited to the modelled electricity system. Environmental and health benefits due to CO_2 reduction are not monetized.

Best-estimate assumptions including a 40 years asset life-cycle and a 4% discount rate give rise to a NPV of −221 to 534 M€. The NPV range covers variations in the investment costs. Lower investment costs may be compensated during the expected life-cycle period.

The identified economic benefits arising from intensified electricity trade between Europe and Central Asia are as such appealing in the context of existing EU policies. These policies, which focus on enhanced energy connectivity among and with partners in Central Asia, obviously require regional cooperation. The latter aspect remains an important challenge for EU energy diplomacy given the latent mutual distrust among Central Asian countries and their consequent policies aiming at energy self-sufficiency. Further research, including dedicated geopolitical studies, can give insights in effective diplomatic efforts addressing this issue.

Credit author statement

Arturs Purvins: Formal analysis, Validation, Methodology, Investigation, Data curation, Writing - original draft. Hana Gerbelova, Investigation, Data curation, Writing - original draft. Luigi Sereno, Methodology, Writing - original draft. Philip Minnebo, Conceptualization, Writing - review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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