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Renewable energy transition in the Turkish power sector: A techno-economic analysis with a high-resolution power expansion model, TR-Power

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—Ronald G. Prinn,
Joint Program Director

Renewable energy transition in the Turkish power sector: A techno-economic analysis with a high-resolution power expansion model, TR-Power

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Abstract: The Turkish power sector achieved a rapid growth after the 1990s in line with economic growth and even beyond. However, this development was not supported by domestic resources and therefore culminated in a high dependency on imported fossil fuels. Over and above, the governments were slow of the mark in introducing policies for increasing the share of renewable energy. Nevertheless, even late actions of the government, as well as significant decreases in the cost of wind and especially solar technologies, have recently brought the Turkish power sector in a promising state. In this study, a large-scale generation expansion power system model (TR-Power) with a high temporal resolution (hours) is developed for the Turkish power generation sector. Several prospective scenarios (high penetration of renewable resources, limiting constraints on GHG emissions, and changes in subsidy schemes on renewable and local resources) were analyzed for assessing their environmental and economic impacts. The results indicate that a transition to a low-carbon power grid with around half of the electricity demand satisfied by renewable resources over a 25-year period would be possible with annual investments of 4.25 to 7.10 Billion 2019 US$. Moreover, TR-Power indicates that the shadow price of CO_2 emissions in the power sector will be around 13.8 and 34.0 $/per tCO_2 by 2042 under 30% and 40% emission reduction targets relative to the reference scenario.

1. Introduction

Turkey satisfies nearly three-fourths of its increasing energy demand by imported fossil fuels. Furthermore, high volatility and unpredictability in the national currency amplify the severity of this dependency. On the other hand, acceleration of investments and market preparations on electric vehicles (EVs) in parallel with developments all over the world as well as sharp and ongoing decreases in renewable energy costs, lead to the need for models that can represent the power sector as realistically as possible and enable policymakers to analyze a wide range of scenarios. Then, a multi-period generation expansion planning (GEP) model of the Turkish power generation sector with a time resolution of hours, TR-Power, is developed in this study. Several scenarios, including various decarbonization pathways, high penetration of renewable technologies, impacts of the proposed nuclear power program, and constraints on the power sector emissions, are analyzed in detail.

GEP models are devised to determine the technology, capacity, time of commissioning, and location of plants in a power system over a long-term planning horizon under technical, regional, economic, political, environmental, and operational constraints. The problems are formulated as non-linear, linear, integer, or dynamic programming models. The objective in these models is to minimize the sum of discounted investment and operational costs in general. The reader is referred to (Kagiannas, Askounis, & Psarras, 2004; Koltsaklis & Dagoumas, 2018) for comprehensive reviews of GEP problems and (Babatunde, Munda, & Hamam, 2019; Oree, Sayed Hassen, & Fleming, 2017) for the review of GEP problems with the integration of renewable energy. Even though the GEP problem is usually formulated with a single objective, i.e., generally the least cost of expansion, significant efforts have been undertaken on representing the multi-objective nature of the problem (e.g., Antunes, Martins, & Brito, 2004; Meza, Yildirim, & Masud, 2007; Tekiner-Mogulkoc, Coit, & Felder, 2012; Tekiner, Coit, & Felder, 2010). The objective functions other than minimizing the total expansion cost are minimizing pollutant emissions and environmental impacts, outages, and corresponding costs, the dependency on imported energy, investment, and fuel price risks or maximizing system reliability, etc. (Antunes & Henriques, 2016).

There have been several studies in the literature that propose GEP models for the Turkish power generation sector. These models are mostly mixed-integer programming formulations where genetic algorithms or adaptive simulated annealing genetic algorithms (ASAGA) are employed to get solutions for these formulations. The planning horizons in these models are defined in either five-years or annual intervals without an hourly or daily time-resolution. Yildi-

rim *et al.* (2006) developed an ASAGA to the GEP problem for the Turkish power generation sector. They employed the proposed model to provide projections for a 20-year planning horizon, with 2003 as the base year and four periods of five-years length. Yildirim and Erkan (2007) examined the feasible range for operating costs of nuclear energy over which it can compete with traditional power generating technologies in the Turkish power sector. The authors developed a mixed-integer programming (MIP) model for the 2006 to 2025 planning horizon with period lengths of five-years and used ASAGA to solve the problem. Ozcan *et al.* (2014), on the other hand, analyzed the inclusion of renewable energy resources in a similar setting for the period 2012-2027 while they employed a genetic algorithm instead of ASAGA and defined the temporal intervals as one year. Ozcan *et al.* (2016) further used their modeling approach for investigating the dependency on natural gas in the Turkish power sector for the period 2015 to 2030.

Transition to energy/power systems with high shares of renewable resources is one of the major research questions in recent years. Dominković *et al.* (2016) modeled the energy system of eleven countries in the South East Europe as a closed system for the period 2012-2050 with a zero-carbon energy target by the end of the horizon. They used EnergyPlan (2020) as the modeling tool, which allows hourly analysis. The study focused on the sustainable use of biomass while keeping a robust mix of various technologies. Fathurrahman (2019) and Önenli (2019) addressed similar targets for Turkey in two recent PhD theses where several modeling approaches were coupled in single frameworks, i.e., a panel-data model is coupled with a simple linear programming model for the 2017-2050 period in the former, while a computable general equilibrium model is coupled with a linear programming model and LEAP (Heaps, 2016) for the 2018-2040 period in the latter. LEAP was also used in two more studies for Turkey (Özer, Görgün, & Incecik, 2013; Şahin, 2014) where Özer *et al.* (2013) compare a business as usual scenario with a mitigation scenario for the 2006-2030 period in annual intervals. The mitigation scenario in this study ignores electricity generation by solar and nuclear technologies. Şahin (2014), on the other hand, employed LEAP to assess the impacts of privatization in the Turkish power industry in which the planning horizon is 2001-2050. In another study, Dal and Koksal (2017) analyzed the least cost capacity expansion plan for the Turkish power generation sector using the ANSWER-TIMES model for the 2016-2035 period in which the external costs of power generation are also integrated into the model.

Above all these studies, Kilickaplan *et al.*, (2017) studied a similar problem for the Turkish power system in a more comprehensive manner for the 2015-2050 planning

horizon with period lengths of 5 years. They employed a linear programming model with some of the variables, i.e., wind, solar, and load profiles, in hourly resolution and is mainly an enhanced version (i.e., regional disaggregation and inclusion of non-energetic industrial gas demand) of the LUT energy system model (Bogdanov & Breyer, 2016; Caldera, Bogdanov, Afanasyeva, & Breyer, 2017; De Barbosa, Bogdanov, Vainikka, & Breyer, 2017). The proposed model is used to provide the optimal transition pathway for satisfying electricity, gas, and water demands under a %100 renewable energy system target throughout the 2015-2050 period. The model does not allow new investments of coal-fired power plants and projects that 100% renewable energy powered electricity target is feasible by 2050 and even before where most of the demand would be satisfied by solar and wind technologies, i.e., 62.3% and 23.9%, respectively, at the end of the planning horizon. Aksoy *et al.* (2020) recently analyzed the optimum capacity mix of the Turkish power sector until 2030. A market simulation model in which the hourly operation decisions are made based on merit order according to the levelized cost of electricity (LCOE) values for each technology. The study explores several scenarios such as pure market-based, low-demand, local-resources, carbon cost, and balanced policy scenarios. The results indicate that the total installed capacity will reach to 129.2-139.3 GW by 2030 where the sum of solar and wind will be 48.0-63.6 GW and the share of renewable resources in total generation is 43.5%-51.5% under the given scenarios.

The model proposed in this study is closer to the bottom-up power models that are suited to the integration of top-down and bottom-up energy-economy models (Octaviano, 2015; Ross, 2014b; Short *et al.*, 2011; Tapia-Ahumada, Octaviano, Rausch, & Pérez-Arriaga, 2014, 2015). The reader is referred to (Kat, 2019) for a review of linked TD-BU models and their solution approaches. The TR-Power model can be run as a stand-alone model or can be coupled with the TR-EDGE model (Kat, Paltsev, & Yuan, 2018) following the integration and block decomposition approaches introduced by Böhringer and Rutherford (2008, 2009) and applied in a limited number of studies (Lanz & Rausch, 2011; Rausch & Mowers, 2014; Ross, 2014a; Tapia-Ahumada *et al.*, 2015; Tuladhar, Yuan, Bernstein, Montgomery, & Smith, 2009).

The contribution of the study can be interpreted as two-fold: in terms of the modeling approach and in terms of scenario analysis that can answer recent questions in the sector, which can be stated more precisely as below:

- Explicit representation of an hourly resolved GEP model for the Turkish power generation sector, which is designed to be integrated with a classical top-down CGE model. The model also employs realistic attributes and constraints those are faced in practice such as the

inclusion of forecast errors, start-up costs, operating reserves etc.

- Determination of the carbon price by the dual (shadow) prices of the emissions constraint.

- Providing the results of scenarios that can answer the recent questions of decision-makers for the Turkish power generation sector, which is highly dynamic when the policy updates and developments even in the last few years are taken into account.

2. An overview of the Turkish economy and power sector

The Turkish economy achieved a high growth rate until 2007 after the financial crisis in 2001, mainly driven by the structural reforms and improvements in productivity (Acemoglu & Ucer, 2015) as well as by substantial inflow of foreign capital. Moreover, GDP per capita surpassed $10.000 in 2010, which was around $3.500 in 2001. The rate of economic growth then significantly slowed down for which various explanations have been argued, i.e., "stop-go cycle", increase in government spending relative to GDP growth due to loosening in fiscal discipline, being caught in a middle-income trap, etc. (Filiztekin, 2020; Yeldan, Tasci, Voyvoda, & Ozsan, 2013) where the suspension of the accession talks with the EU is also indicated as an important dimension in this slowdown (Acemoglu & Ucer, 2015). Moreover, the coup attempt in 2016, turmoil in neighboring countries, and the final currency and debt crisis in 2018 were followed by three consecutive quarters of contraction, which was broken in the third quarter of 2019.

The GDP values, together with key energy and environmental indicators, are summarized in magnitudes and as percentage changes for the period 1990-2019 in **Table 1** and **Figure 1**, respectively, where the latter is illustrated for the milestones above mentioned. The striking observation from these indicators is that electricity generation is almost constant in the last three years, while the installed capacity is still rising owing to the incentives as well as the decreasing cost in renewable technologies. This observation implicitly indicates the decrease in the utilization of the current installed capacity.

The break-down of the Turkish power generation sector by fuel type in terms of the generation amount and share of each technology can be seen in **Figure 2a** and **Figure 2b**, respectively. As seen from these figures, although the total generation is almost stable, the share of renewables has an increasing trend in the last three years, i.e., they sum up to more than 40%, with a significant decrease in the share of natural gas-fired power plants and increase in the share of the coal-fired power plants. The increase in coal-based generation also explains why total emissions do not decrease,

Table 1. Main economic, energy, and environmental indicators for Turkey, 1990-2019.

	1990	2000	2010	2015	2016	2017	2018	2019
Population (million)[1]	56.473	67.804	73.723	78.741	79.815	80.811	82.004	83.155
GDP (constant 2010 Billion US$)[2]	365.299	520.947	771.902	1087.876	1122.512	1206.373	1240.474	1251.359
Primary Energy Demand (Million TOE)[3]	52.987	80.500	105.827	129.267	136.718	146.797	145.887	-
Electricity Generation (TWh)[4]*	57.543	124.922	211.208	261.783	274.859	289.975	292.145	290.443
Electricity Installed Capacity (GW)[4]	16.318	27.264	49.524	73.147	78.497	84.531	88.526	91.352
CO_2 emissions (Mt CO_2e)[1]	219.368	298.760	398.883	472.595	497.742	523.753	520.942	-

* Does not include unlicensed generation, which is around 10 TWh in 2019.

1   TurkStat, http://www.tuik.gov.tr/UstMenu.do?metod=kategorist

2   World Bank, https://data.worldbank.org/indicator/NY.GDP.MKTP.CD?locations=TR

3   MENR of Turkey, IEA, https://www.enerji.gov.tr/tr-TR/EIGM-Raporlari; https://www.iea.org/countries/turkey

4   MENR of Turkey, Turkish Electricity Transmission Corporation (TEİAŞ), https://ytbsbilgi.teias.gov.tr/ytbsbilgi/frm_istatistikler.jsf
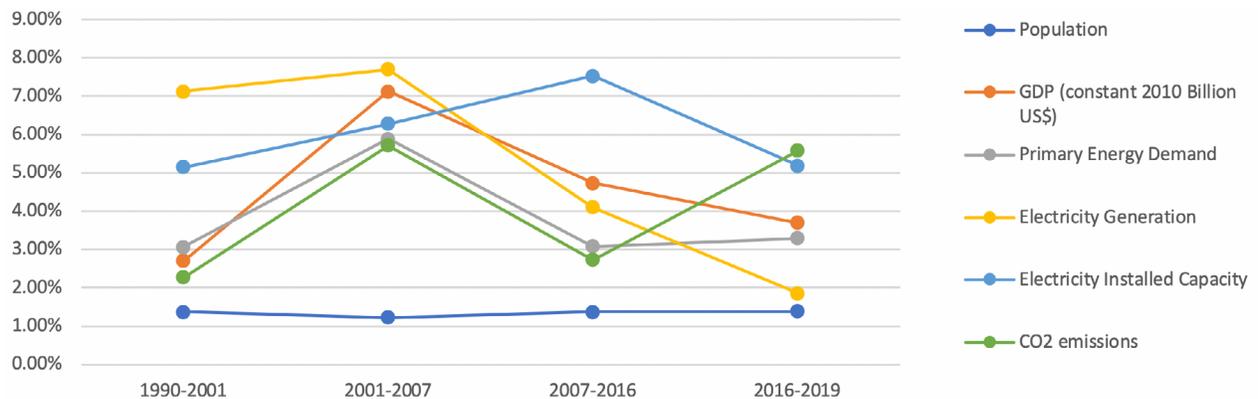

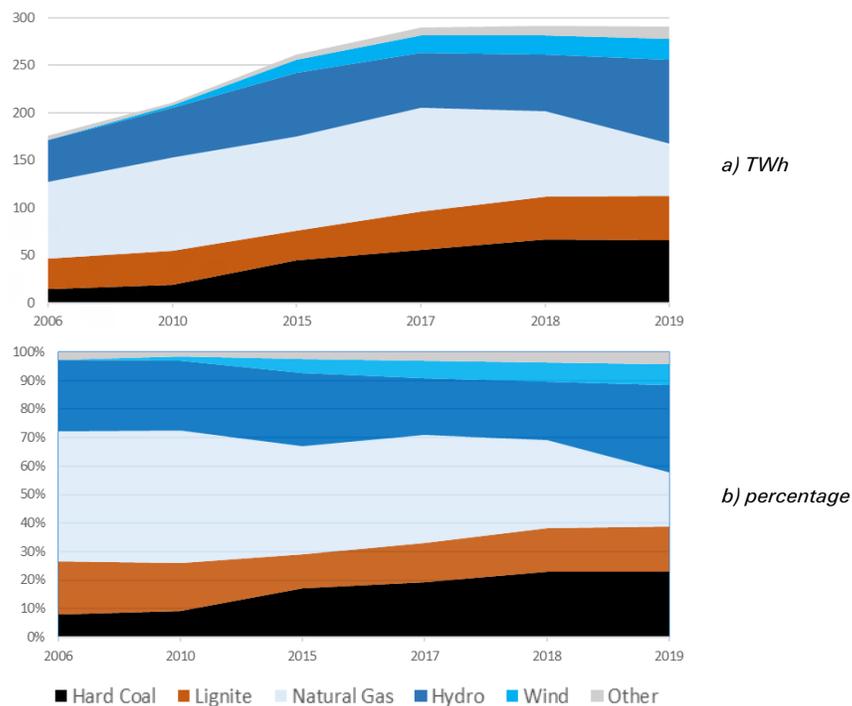**Figure 1.** Percentage changes in main economic, energy, and environmental indicators for Turkey, 1990-2019.

a) TWh

b) percentage

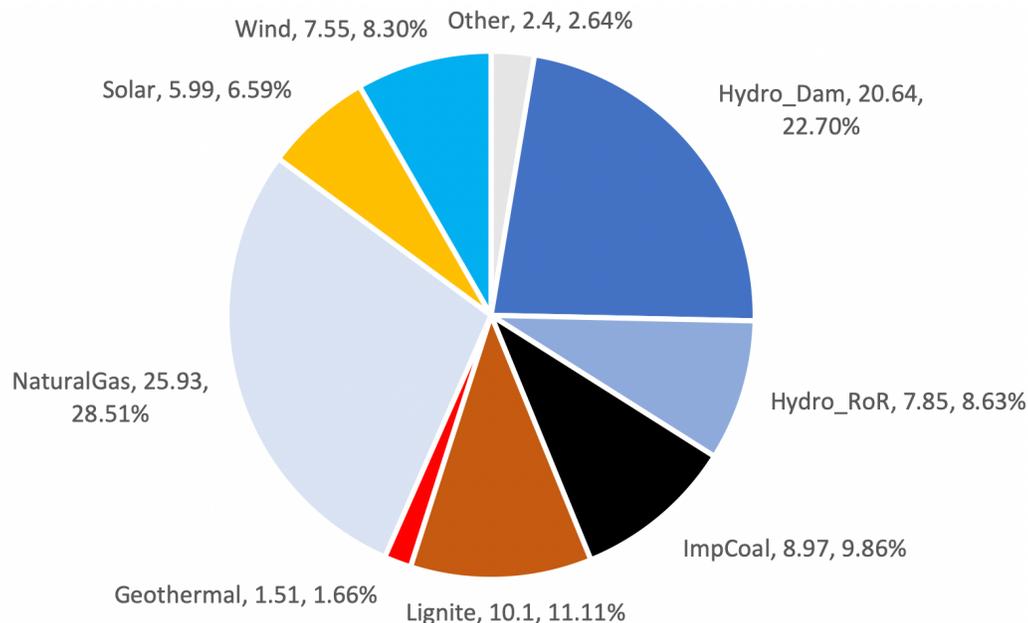**Figure 2.** Electricity generation by technology: 2006-2019. Source: TEİAŞ.

Figure 3. Installed capacity by technology: GW and percentage, 2019. Source: TEİAŞ.

although there is a rise in renewables and a decrease in natural gas-based generation. **Figure 3**, on the other hand, shows the break-down of installed capacities for the year 2019. The most remarkable point in this figure is the 5.99 GW solar and 7.55 GW wind capacities, which used to be negligible several years and a decade ago, respectively. The sharp increase in these technologies is mainly due to the subsidies provided (in terms of purchase guarantee, which increases in case the system includes domestically produced components) (MENR, 2014) as well as the advances in these technologies and the resulting decrease in costs. However, there is still a considerable potential for these resources as indicated by the MENR (2016), i.e., solar energy potential estimated at 1527 kWh/m²year and wind potential at 48 GW.

Furthermore, in the "MENR Strategic Plan: 2019-2023" (MENR, 2019), which sets targets for the year 2023, the goals for hydropower, solar, wind, and geothermal are 32.0 GW, 10.0 GW, 11.9 GW, and 2.9 GW, respectively. Currently, there are no nuclear power plants (NPP) in Turkey; however, two plants are on the government's plans (MENR, 2016). These plants, each having four units, were proposed to be commissioned gradually between the years 2019 and 2028. However, based on the recent economic and political developments as well as past experiences about nuclear programs, the second one is likely to be delayed after 2030 or completely canceled. Besides the renewable energy action plan, there exist targets related to the power generation sector in the Intended Nationally Determined Contribution (INDC) that Turkey submitted

(UNFCCC, 2016) after COP21 in Paris. In this document, Turkey commits to up to 21% reduction in greenhouse gas (GHG) emissions compared to the business-as-usual (BAU) scenario of the government, i.e., this decrease corresponds to have a carbon dioxide equivalent (CO_2e) emission level of 929 million tonnes (Mt) in 2030, having an installed capacity of 10 GW of solar power and 16 GW of wind power, and the full utilization of hydropower, i.e., 36 GW.

As noted from the official targets and the actual figures, these values contain some inconsistencies in themselves, i.e., 2030 INDC target for wind is underestimated considering the recent trends or 2030 INDC target for solar is equal to the 2023 target. Moreover, the fact that the emission value of the BAU scenario of the INDC is quite high as indicated in several studies (e.g., Kat *et al.*, 2018; Yeldan & Voyvoda, 2015). For this reason, all this information, as well as the data provided in (Aksoy *et al.*, 2020; Kat *et al.*, 2018; Kilickaplan *et al.*, 2017), are combined to generate realistic and consistent scenarios in this study.

The load duration curve (LDC) of the Turkish power system can be seen in **Figure 4** for the years 2017, 2018, and 2019. This curve shows the demand for electricity in each hour of the year sorted in descending order. Note that the load duration curves are very close to each other for the last three years. This observation is in line with expectations to some extent due to the stagnation of the Turkish economy and the constant power demand observed in this period. However, not only the total demand (area under these curves) but also the shapes of the curves are almost the same.
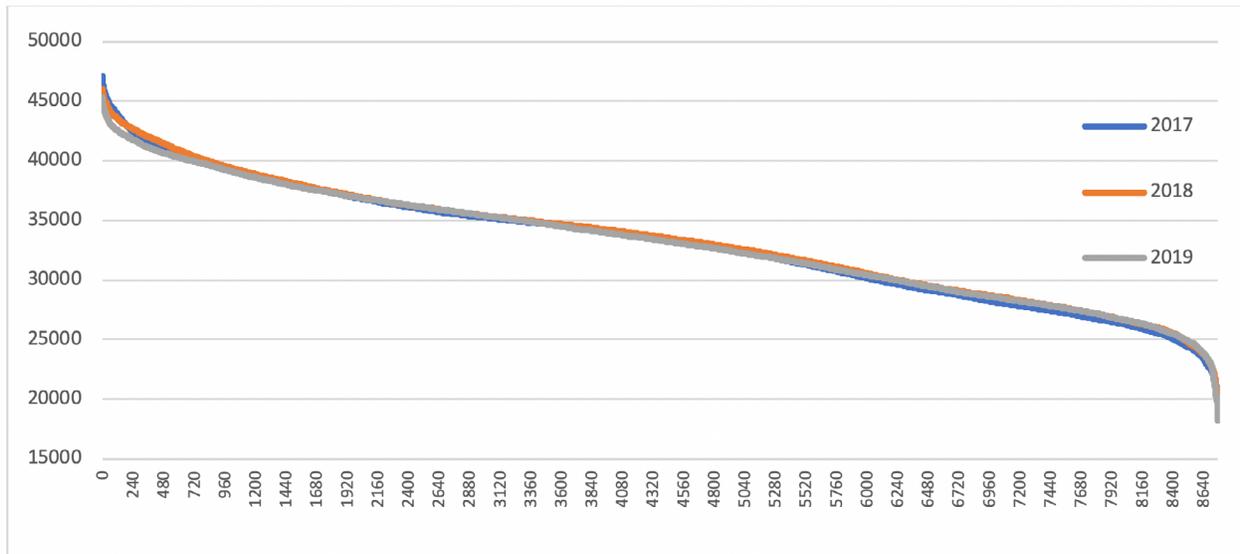
Figure 4. Load duration curves, 2017, 2018, and 2019: hours vs. MWs.

3. TR-Power Model

The generation expansion model developed in this study, TR-Power, is a large-scale linear programming model that minimizes the total discounted cost of the power system where capacity expansion and operation planning, as well as power dispatch decisions, are integrated into a single framework. The system cost includes annualized investment costs, operational and fuel costs, and the cost of non-served electricity. The model does not include an explicit carbon tax or an alternative way of penalizing emissions. However, thorough environmental accounting is integrated into the model. Thus, the implicit cost of emissions can be easily reported via the shadow prices of the total emissions constraint. In other words, in various scenarios, limits on the total or partial emissions are set; then, the corresponding shadow prices of these constraints (also called dual prices/Lagrangian multipliers) measure how the objective function changes with respect to these limiting values, i.e., the unit cost of emissions.

The lists of the sets/indices, parameters, and decision variables are presented in **Table 2**, **Table 3**, and **Table 4**, respectively. The power technology disaggregation by the Turkish Electricity Transmission Corporation (TEİAŞ) is used in the model in line with the hourly load data as well as the

Table 2. List of sets and indices.

Symbol	Definition
i, j	power technologies {Asphaltite, BioMass, Cogeneration, Diesel, FuelOil, Geothermal, HardCoal, Hydro_Dam, Hydro_RoR, ImpCoal, Lignite, LigniteLow, LNG, LPG, Naphta, NaturalGas, Nuclear, Solar, Wind}
thr	thermal technologies {Asphaltite, BioMass, Cogeneration, Diesel, FuelOil, HardCoal, ImpCoal, Lignite, LigniteLow, LNG, LPG, Naphta, NaturalGas}
$nthr$	non-thermal technologies {Geothermal, Hydro_Dam, Hydro_RoR, Nuclear, Solar, Wind}
rnw	renewable technologies {BioMass, Geothermal, Hydro_Dam, Hydro_RoR, Solar, Wind}
h	Hours - 1, ... ,8760
d	Days - 1, … ,365
t_0, t, tt	Years - t_0: 2019; t: 2019, 2022, 2027, … ,2077; tt: 2019, 2022, 2027, … ,2042

Table 3. List of parameters.

Symbol	Definition
$pLoad(t,h)$	Load demand in year t at hour h in MWh
$pLoadProfile(t0,h)$	Load demand in year t at hour h - normalized (hourly load over total annual load)
$pTotLoad(t)$	Total load demand in year t in MWh
$pInsCap0Ret(t,i)$	Retired installed capacity at the beginning of year t by technology i (MW) - built before planning horizon
$pAvFac(i)$	Availability factor of technology i
$pLoadFac(i,h)$	Generation potential of technology i at hour h. It is 1 for non-renewable resources.
$pHeatRate(i)$	Heat rate of generators - Mmbtu per GWh
$pBigGen(t)$	The capacity of the biggest generator in year t – 1.5 GW
$pCapCost(i)$	The annualized capital cost of technology i - $ per kW
$pFuelCost(i)$	Fuel cost of technology i - $ per MMbtu
$pFOMcost(i)$	Fixed O&M cost of technology i - $ per kW
$pVOMcost(i)$	Variable O&M cost of technology i - $ per kWh
$life(i)$	The lifetime of technology i - years
$pSUcost(i)$	The start-up cost of technology i - $ per kW
$pSDcost(i)$	Shut-down cost of technology i - $ per kW
$pMinLoad(i)$	Minimum hourly generation amount of technology i - % of total installed capacity
$pMaxNewIC(i,tt)$	The maximum annual new installed capacity of technology i – GW in period tt
$pMaxTotIC(i)$	Maximum total installed capacity of technology i - GW
$pSbsdy(i)$	Subsidy rate for technology i - percent
$pEleGrowth(t)$	Electricity growth rate - cumulative
$pPeakLoad$	Peak load - the ratio of peak load to the total load in the base year
$pOperRes$	Operating reserve - the ratio of hourly load (2%)
$pFrcstErr$	Forecast error for wind and solar (20%)
$pResMargin$	Reserve margin (15%)
ρ	Social discount rate (8%)
$pAnnEleGrwth$	The annual electricity growth rate
$pVOLL$	Value of lost load (10 $/kWh)
$\alpha(tt)$	The parameter to handle unequal period length; 1 for 2019 and 5 for the rest
$pCO_2coef(i)$	kg CO_2 emissions rate per technology per Mmbtu
$pEmisTotLim(tt)$	Upper bound for emissions in year tt

Table 4. List of decision variables.

Symbol	Definition
$vGen(i,tt,h)$	Generated power by technology i in year tt at hour h in GWh
$vPow(i,tt,h)$	Available power by technology i in year tt at hour h in GW
$vPowD(i,tt,d)$	Available connected power by technology i in year tt on day d in GW
$vUp(thr,tt,d)$	Start-up of technology thr in year tt on day d in GW
$vDw(thr,tt,d)$	Shut-down of technology thr in year tt on day d in GW
$vICnew(i,tt)$	The newly installed capacity of technology i in year tt in GW
$vICtot(i,tt)$	The cumulative installed capacity of technology i in year tt GW
$vFOMc(tt)$	Fixed O&M cost in year tt in 2019 $
$vVOMc(tt)$	Variable O&M cost in year tt in 2019 $
$vCAPc(tt)$	Capital cost in year tt in 2019 $
$vNSE(tt,h)$	Non-served energy in year tt at hour h in GWh
$vNSEc(tt)$	Cost of non-served energy in year tt in 2019 $
$vEMS(i,tt)$	Emissions from technology i in year tt in Mt CO_2
$vUpDwC(tt)$	Cost of up and down of thermal i on day d of year tt in 2019 $
$vAnnCost(tt)$	Annual total cost in year tt in 2019 $
$vTotCost$	Total discounted cost in 2019 $
$vEmis(i,tt)$	CO_2 emissions by technology i in year tt in Mton
$vEmisTot(tt)$	Overall CO_2 emissions in the power sector in year tt in Mton

installed capacities provided by this organization. The mere exception is the lignite power plants for which the total capacity is disaggregated into two groups, i.e., efficient and inefficient ones. The base year of the model is 2019, and time indices go on with 2022, 2027, 2032, … until 2042 with a period length of five years. Namely, the year 2022 is supposed to represent the interval starting from 2020 and ending with 2024; similarly, 2027 represents the interval beginning in 2025 and ending with 2029, and so on. Then, the model covers the period 2019-2044.

The distinction between installed capacity, available capacity, and load generation are noteworthy in the model representation for the incurrence of costs and understanding the dynamics of the system. Specifically, the decision variable $vICtot(i,tt)$ is the installed capacity (or name-plate capacity) of technology i in period tt, which is then related to the capital cost and fixed operation and maintenance (O&M) costs. In contrast, $vPow(i,tt,h)$ is the available capacity at hour h and is related to variable O&M cost and start-up costs. $vGen(i,tt,h)$, on the other hand, is the actual load generated at hour tt, thus affects the total variable O&M cost as well as the total cost of fuels used in power generation. The rest of this section presents the constraints and the objective function of the TR-Power model.

Eqn. (1) and (2) are the annualized capital cost of the newly installed capacity and the fixed O&M cost within the corresponding period, respectively. The total variable cost, on the other hand, is shown by Eqn. (3) in which variable O&M costs and fuel costs are summed up.

$$vCAPc(tt) = 10^6 \cdot \sum_i pCapCost(i) * vICtot(i,tt) \qquad \forall\ tt \quad (1)$$

$$vFOMc(tt) = 10^6 \cdot \sum_i \alpha(tt) * pFOMcost(i) * vICtot(i,tt) \qquad \forall\ tt \quad (2)$$

$$vVOMc(tt) = \alpha(tt)$$
$$* \sum_{i,h} [10^3 * pVOMcost(i) * vPow(i,tt,h) + pHeatRate(i) * pFuelCost(i) * vGen(i,tt,h)] \qquad \forall\ tt \quad (3)$$

Eqn. (4) and Eqn. (5) represent the cost of non-served energy and start-up costs, respectively. Note that $vUp(thr,tt,d)$ has a time-resolution of days, i.e., once the connected power is decided at the beginning of a day, it does not change through the same day, and goes for the thermal units only.

$$vNSEc(tt) = \alpha(tt) * \sum_h [pVOLL * vNSE(tt,h)] \qquad \forall\ tt \quad (4)$$

$$vUpDwC(tt) = 10^6 * \alpha(tt) * \sum_{thr,d} [pSUcost(thr) * vUp(thr,tt,d)] \qquad \forall\ tt \quad (5)$$

Eqn. (6) is the sum of all costs in each period while Eqn. (7) is the objective function of the model, i.e., the total discounted cost of the power system throughout the planning horizon.

$$vAnnCost(tt) = vFOMc(tt) + vVOMc(tt) + vNSEc(tt) + vUpDwC(tt) \qquad \forall\ tt \quad (6)$$

$$vTotCost = \sum_{tt} \left[vAnnCost(tt) \cdot \left(\frac{1}{1+\rho} \right)^{tt-t_0} \right] \qquad (7)$$

Eqn. (8) represents the balance of generation and demand, i.e., total generation plus the non-served electricity should be equal to the demand for each hour where $pLoadProfile(t_0,h)$ is the load profile which is normalized according to the base year (2019) values.

$$\sum_i [vGen(i,tt,h)] + vNSE(tt,h) \geq pLoadProfile(t_0,h) * pTotLoad(tt) \qquad \forall\ tt,h \quad (8)$$

Eqn. (9) states that the total installed capacity in period tt is equal to the sum of the installed capacity in the previous period and newly installed capacity in the current period reduced by the retiring capacity of the base year stock as well as capacities installed within the model horizon. Retirement rates of the initially installed capacities are assigned based on the historical data. Time series of installed capacity values for each technology were obtained from TEİAŞ; then, incremental values are calculated for each year, and the capacities to be retired are identified based on the lifetime of the corresponding technologies. For example, the power plants with a lifetime of 30 years, and those were added to the total stock between 1995 and 1999 are retired in 2027 (representing the period between 2025 and 2029).

$$vICtot(i,tt) = vICtot(i,tt-1) + vICnew(i,tt) - \sum_{0 \leq ttt - tt - life(i) \leq 3} vICnew(i,ttt) - pInsCap0Ret(tt,i) \qquad \forall\ i,tt > t0 \quad (9)$$

Eqn. (10) is the intertemporal continuity constraint for the available thermal power between the days. Namely, connected power in a day is equal to the connected power in the previous day, plus the power started up minus the power shut-down in the current day. Eqn. (11) ensures that the available power from thermal generating units in a day is less than the derated installed capacity of the corresponding units, and this constraint is mapped to all hours of the given day in Eqn. (12). Similarly, Eqn. (13) shows availability constraints for non-thermal units but on an hourly basis.

$$vPowD(thr, tt, d) = vPowD(thr, tt, d - 1) \ + \ vUp(thr, tt, d) \ - \ vDw(thr, tt, d) \qquad \forall \ thr, tt, d \quad (10)$$

$$vPowD(thr, tt, d) \leq pAvFac(thr) \ \cdot \ vICtot(thr, tt) \qquad \forall \ thr, tt, d \quad (11)$$

$$vPow(thr, tt, h) = vPowD(thr, tt, d(h)) \qquad \forall \ thr, tt, h \quad (12)$$

$$vPow(nthr, tt, h) \leq pAvFac(nthr) \ \cdot \ vICtot(nthr, tt) \qquad \forall \ nthr, tt, h \quad (13)$$

Eqn. (14) ensures that the generation in each hour is greater than the minimum generation limit and lower than the available power for the corresponding hour. The load factor of solar, wind and hydro are assigned according to their patterns in 2017, 2018, and 2019, i.e., hourly assignments for solar and monthly assignments for wind and hydro resources. Eqn. (15) and (16), on the other hand, limit the newly installed capacity and total installed capacity for each period per technology.

$$MinLoad(i) \ \leq \ vGen(i, tt, h) \ \leq \ pLoadFac(i, h) \ \cdot \ vPow(i, tt, h) \qquad \forall \ i, tt, h \quad (14)$$

$$vICnew(i, tt) \ \leq \ MaxNewIC(i, tt) \qquad \forall \ i, tt \quad (15)$$

$$vICtot(i, tt) \leq \ MaxTotIC(i) \qquad \forall \ i, tt \quad (16)$$

The operating reserves and reserve margins to meet peak demand are represented in the same way in (Octaviano, 2015). Eqn. (17) guarantees that the maximum available power for the year should be higher than the peak load plus a reserve margin, while Eqn. (18) ensures that the difference between the available power and the actual generation at each hour is at least equal to the sum of the operating reserve, the uncertainty due to the forecast error in wind and solar generation, and the biggest generator in the system.

$$\sum_i [\, pAvFac(i) \cdot vICtot(i, tt)\,] \geq \ (1 + pResMargin) \ \cdot \ pPeakLoad \ \cdot \ pTotLoad(tt) \qquad \forall \ tt \quad (17)$$

$$\sum_i [\, pLoadFac(i, h) \ \cdot \ vPow(i, tt, h) - \ vGen(i, tt, h)\,] \geq$$

$$pOperRes \ \cdot \ pLoadProfile(t0, h) \cdot \ pTotLoad(tt) + pFrcstErr \ \cdot [vGen(\text{Wind}, tt, h) + \ vGen(\text{Solar}, tt, h)] \qquad \forall \ tt, h \quad (18)$$

Equations (19), (20), and (21) are introduced for keeping the accounting of the CO_2 emissions of the power system. The first two expressions determine the annual emissions by each technology and their sum, while the last one limits annual emissions based on the corresponding scenario description.

$$vEmis(i, tt) \ = 10^{-6} \sum_h [pCO2coef(i) \cdot pHeatRate(i) \cdot vGen(i, tt, h)] \qquad \forall \ i, tt \quad (19)$$

$$vEmisTot(tt) = \sum_i vEmis(i, tt) \qquad \forall \ tt \quad (20)$$

$$vEmisTot(tt) \ \leq \ pEmisTotLim(tt) \qquad \forall \ tt \quad (21)$$

4. Scenarios

The scenarios in the study are shaped considering current government plans, recent economic and technological trends, and the technical feasibility or potential of the resources. Besides, hard targets such as achieving a low-carbon renewable grid, which is challenging but needs to be clarified in all aspects, are also considered. The nuclear power program and the policies related to renewable resources along with electricity demand growth rate and emission reduction targets are the main determinants in distinguishing the scenarios.

The nuclear power plant debate has a long history in the Turkish energy sector, and it also became a controversial political issue from time to time. The reader is referred to Aydın (2020) for a comprehensive summary of the progress from an environmental justice perspective. Although the first unit of Akkuyu NPP (a Turkish-Russian joint project) is coming to an end, "no nuclear" case is always an option considering Turkey-Russia relations, which is usually on slippery grounds as well as the risks related to accidents and waste management. Such a scenario enables assessing the economic and environmental impacts of the Akkuyu plant, which has to be evaluated, paying attention to the risks mentioned above. In the parliament's planning and budgeting commission at the end of 2019, it was declared by the minister that the first unit of Akkuyu NPP would be commissioned in 2023 while the feasibility analysis for the second NPP (Sinop) prepared by the Japanese party was disapproved[1]. The minister's further statements in the same commission indicated that the Sinop NPP and even a third NPP are still on the government's agenda. However, considering the stated plans and the actions in the last decade, it is only the Akkuyu NPP that is decided to take place in the BAU scenario.

The subsidy program targeting the electricity generation by renewable technologies (Support Mechanism for Renewable Energy Sources, known as YEKDEM in Turkish) was introduced in 2011 and addressed the power plants that went into operation between May 2005 and the end of 2015 where the termination period was then postponed to the end of 2020 with an update in 2013. For the plants registered in the system, the mechanism includes a guarantee of purchase (in USD) for ten years. Moreover, incremental subsidies were introduced based on the domestic share in the system components. Another mechanism proposed by the government is the concept of Renewable Energy Resource Areas (known as YEKA in Turkish) under which the first two single-item auctions (1 GW onshore wind and 1 GW solar PV) were awarded in 2017-2018. The mechanism offers a purchase guarantee for fifteen years together with the connection capacity utilization rights.

The rationale behind relatively large-scale but single-item auctions is to benefit from the economies of scale as well as developing a local renewable energy industry as is due under the YEKA regulatory framework, which forces a particular share of local content in the system (Sarı *et al.*, 2018). Moreover, in the scope of the first PV auction, the winner is obliged to install a solar panel plant in two years (with a capacity of 500 MW per year) besides the other local content requirements. The auctions announced later are multi-item auctions. Recent declarations by the ministry and the records in the parliament's planning and budgeting commission at the end of 2019 imply that mini-YEKA auctions for PV (10-40 MW PV projects in around 40 different cities) will be announced in the first half of 2020.

Pursuing transition pathways to low-carbon power generation system has become a significant research question in recent years. The decrease in the cost of renewable technologies, development in smart grids, and battery technologies paved the way for such promising scenarios. In addition to the international examples (Bogdanov & Breyer, 2016; Caldera *et al.*, 2017; De Barbosa *et al.*, 2017; Dominković *et al.*, 2016), there are also several studies addressing the Turkish power generation sector (Fathurrahman, 2019; Kilickaplan *et al.*, 2017; Önenli, 2019). A low-carbon power grid scenario, similar to those proposed in (Fathurrahman, 2019; Önenli, 2019) has been introduced in the current study, which significantly differs from those by eliminating the main shortcoming of those studies, i.e., those studies take merely the technical attributes of the generation options into account and ignore the economic dimension during scenario generation.

As illustrated in Table 1 and Figure 1, electricity generation has slowed down after 2015, even almost constant in the last three years. However, there is significant evidence that it will start a new increasing pattern in line with the recent economic and technological indicators, i.e., positive growth has been recorded in the second half of 2019 after three consecutive quarters of contraction, and the penetration of electric vehicles into the market is likely to accelerate in the near future in parallel with the developments across the world. Moreover, the official projections[2] prepared by TEİAŞ have been published under three growth scenarios for the period 2019-2039, low growth, reference case, and high growth. The panel data model proposed by (Önenli, 2019) also generates projections that are very close to the official ones. Then, in this study, growth projections (for the period of 2019-2042) similar to TEİAŞ (denoted as lowGR, medGR, and highGR) are employed with average growth rates of 2.94%, 3.49%, and 4.04%, respectively.

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1   http://www.sbb.gov.tr/wp-content/uploads/2020/02/22-Kasim-2019_PBK_Gorusmeler.pdf

As noted in Table 1, GHG emissions have been increasing continuously at a significant rate, which is faster than any Annex I country in the last decade. The emissions originating from the power sector are nearly 30% of the total emissions (520.9 Mt CO_2e in 2018). In the study, two paths (Lim30 and Lim40) have been introduced for CO_2 emissions on the power sector in addition to the no limitation case (Lim00). Both of the paths are based on reducing emissions with respect to the emissions recorded under the reference case (BAU_medGR_Lim00) and propose gradually increasing reductions until 2042. The reduction amount starts at 6% and 7.5% in 2022 and increases to 30% and 40% in 2042, for Lim30 and Lim40, respectively.

Based on the information summarized in this section, four main policy settings, i.e., business as usual (BAU), decisive subsidies for renewable resources (RNW), no subsidy case (NoS), and no-nuclear case (NoN), are defined within the study. All policy alternatives are also coupled to the growth rate paths (lowGR, medGR, highGR) under no emission (Lim00) restriction, while medium growth rate couplings are further solved for 30% emission reduction paths (Lim30).

Moreover, BAU scenario with the medium growth rate is also coupled with the 40% reduction path (Lim40), resulting in a total of 17 scenarios. Besides, the maximum installed capacity stock for imported coal and local lignite power plants are limited to 12.5 GW in renewable scenarios (except the RNW_highGR_Lim00 for which a reliable solution that has a reasonable number of non-served hours could be obtained under the upper limits of 15 GW for imported coal and lignite, and 50 GW for natural gas).

5. Results

Technical and cost parameters and assumptions used in the TR-Power are summarized in **Table 5**. Data are derived from or calculated based on several national and international studies (Aksoy *et al.*, 2020; Böhringer, Löschel, & Rutherford, 2009; Dal & Koksal, 2017; IRENA, 2019; NEA, 2019; Ross, 2014a; Vimmerstedt *et al.*, 2019) as well as from official publications (MENR, 2014, 2016, 2019). The availability and load factors are set based on the 2017-2019 data published by TEİAŞ.

Table 5. Main parameters used in TR-Power.

	Overnight Cap. Cost	Fuel Cost	Fixed O&M cost	Var. O&M cost	Heat Rate	CO_2 coef.	St-Up cost	Min Load	Max NewIC	Max TotIC	life	Avail. Factor	Load Factor*
	$/kW	$/Mmbtu	$/kW	$/MWh	MmBtu /GWh	kgCO₂/ Mmbtu	$/kW	GWh	GW	GW	yrs	%	%
Asphaltite	1200	2.02	40.00	4.00	12053	75.36	0.15	40%	0.033	1	30	85%	100.0%
Biomass	2500	4.03	90.00	1.00	13500	118.17	0.15	0%	0.067	2	20	85%	100.0%
Cogeneration	900	-	-	2.66	6600	-	0.15	0%	0.067	2	30	85%	100.0%
Diesel	900	26.89	11.60	2.66	11095	73.16	0.02	0%	0.033	1	30	85%	100.0%
FuelOil	900	15.84	11.60	2.66	11095	71.30	0.02	0%	0.033	1	30	85%	100.0%
Geothermal	3750	-	40.00	10.00	9756	-	0.15	0%	0.067	2	30	85%	100.0%
HardCoal	1100	2.02	40.00	1.81	12053	95.35	0.15	40%	0.033	1	30	85%	100.0%
Hydro_Dam	2000	-	10.00	0.10	-	-	0.15	0%	1.200	36	40	85%	36.4%
Hydro_RoR	1500	-	7.00	0.10	-	-	0.15	0%	0.400	12	40	85%	33.3%
ImpCoal	1100	3.28	30.00	4.00	10481	95.35	0.15	40%	1.000	30	30	85%	100.0%
Lignite	1200	2.02	40.00	4.00	12053	97.70	0.15	40%	0.250	7.5	30	85%	100.0%
LigniteLow	1200	2.32	40.00	4.00	16874	97.70	0.15	40%	0.750	22.5	30	85%	100.0%
LNG	900	13.89	11.60	2.66	11095	63.07	0.02	0%	0.033	1	30	85%	100.0%
LPG	900	27.75	11.60	2.66	11095	63.07	0.02	0%	0.033	1	30	85%	100.0%
Naphta	1200	5.44	15.47	4.00	10481	73.16	0.15	0%	0.033	1	30	85%	100.0%
NaturalGas	750	8.76	18.00	1.00	7821	53.07	0.02	20%	1.333	40	20	85%	100.0%
Nuclear	7500	-	90.00	5.00	10455	0.00	1.00	90%	2.000	15	50	90%	100.0%
Solar	650	-	15.00	-	-	0.00	0	0%	1.250	40	20	90%	21.1%
Wind	900	-	15.00	0.50	-	0.00	0	0%	1.500	48	20	90%	33.9%

The model's base year results are compared to the actual values in order to validate its representation capability. The model is calibrated in a way that the generation values are within an average of 3.75% (a maximum of 10%) of the actual values for the base year. Moreover, the realized day-ahead market-clearing prices in TL were converted to US $ for each hour, and the weighted average of them is calculated (46.61 $/MWh). The weighted average from the model, on the other hand, is calculated via the marginal (dual) prices of Equation (8), which is 47.24 $/MWh.

Transition to a low-carbon power sector leads to costs and opportunities that need to be quantified. In this section, the power capacity mix, emission levels, and total investment requirements are presented under the scenarios introduced in Section 4. Furthermore, the implicit cost of CO_2 emis-

sions is quantified. A summary of the main indicators is presented in Table 6 at the end of this section.

The development of total installed capacities in the reference scenario and the other main scenarios are given in **Figure 5a** - **Figure 5d**. The minimum cumulative installed capacity is observed under NoS (190.6 GW by 2042) since the imported coal and natural gas that have higher load factors compared to renewables, have more shares in this scenario. Relatively large capacity under RNW (210.6 GW by 2042) is due to the low load factor of renewable technologies.

The capacity and generation mix profiles throughout 2019-2042 period are presented in **Figure 6** and **Figure 7**, respectively.

Figure 8, on the other hand, demonstrates how substitution occurs among alternative technologies under different

a) BAU_medGR_Lim00

b) NoN_medGR_Lim00

c) NoS_medGR_Lim00

d) RNW_medGR_Lim00
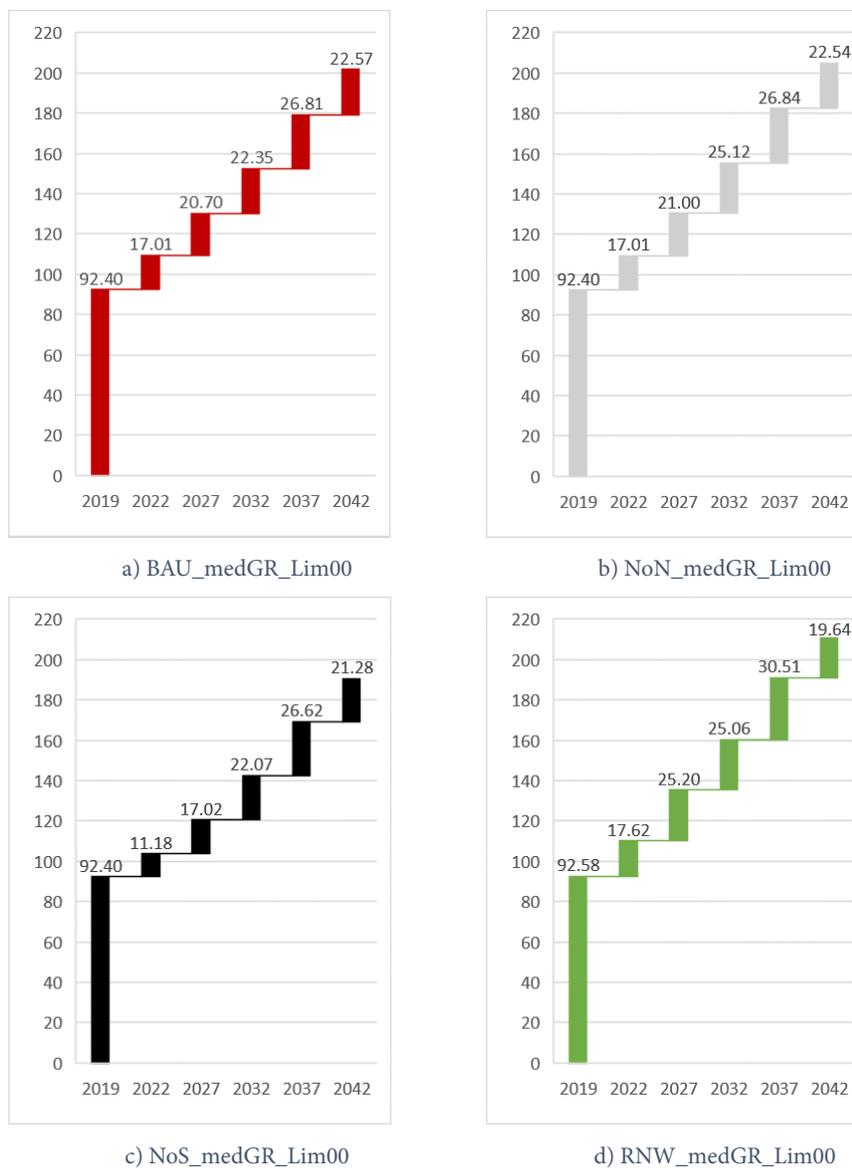
Figure 5. Development of total installed capacity, 2019-2042, GW.

a) BAU_medGR_Lim00   b) NoN_medGR_Lim00   c) NoS_medGR_Lim00   d) RNW_medGR_Lim00
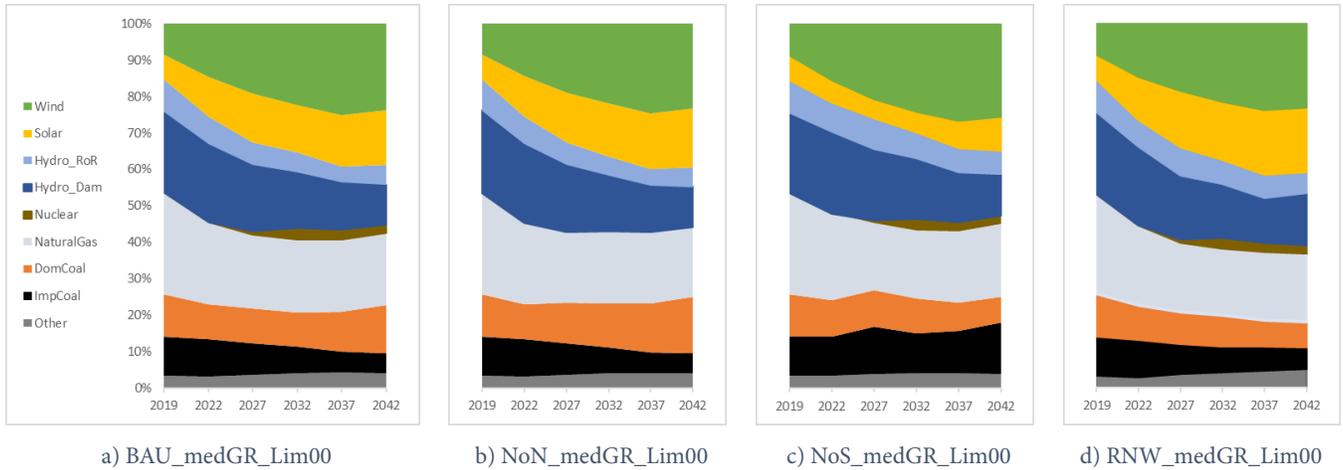
Figure 6. Break-down of installed capacity, 2019-2042, percentage.

a) BAU_medGR_Lim00   b) NoN_medGR_Lim00   c) NoS_medGR_Lim00   d) RNW_medGR_Lim00
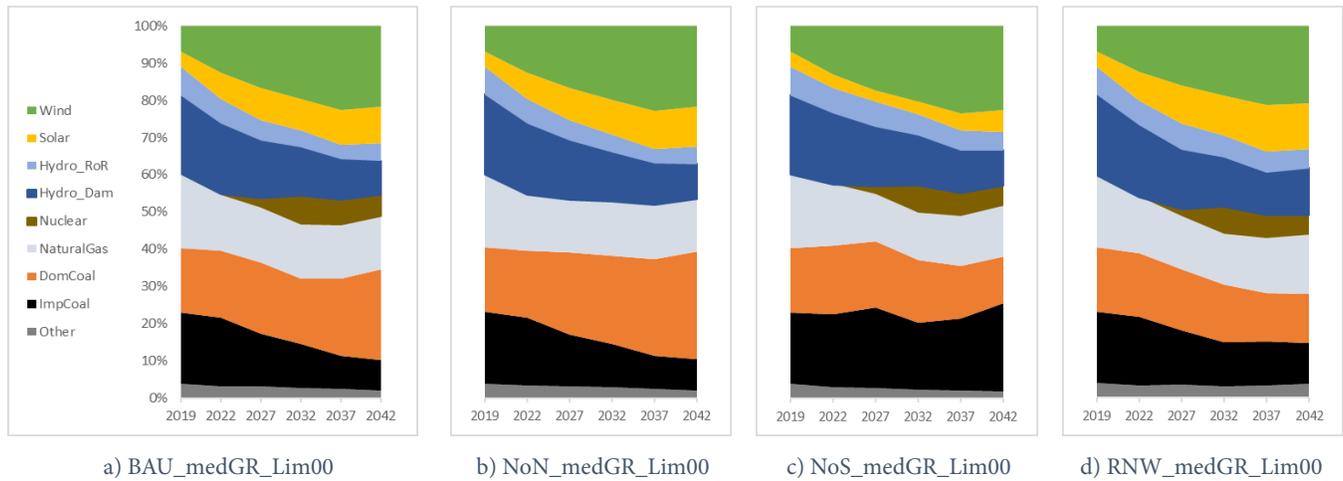
Figure 7. Break-down of electricity generation, 2019-2042, percentage.

a) NoN_medGR_Lim00   b) NoS_medGR_Lim00   c) RNW_medGR_Lim00   d) BAU_medGR_Lim30
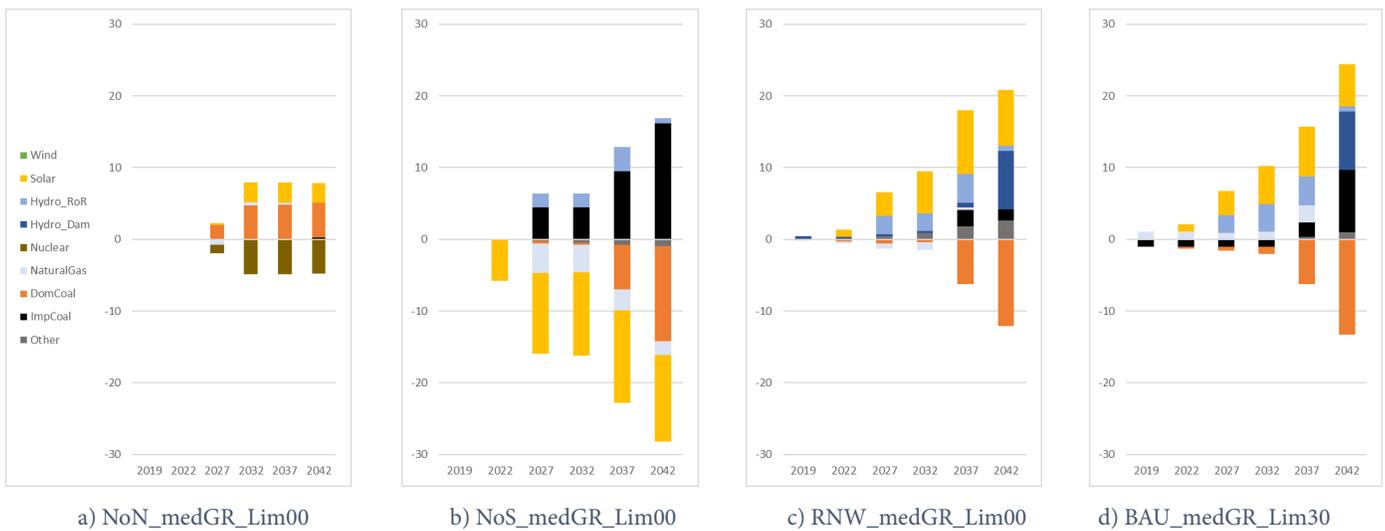
Figure 8. Substitution patterns of installed capacity with respect to the reference case for medium growth rates, GW.
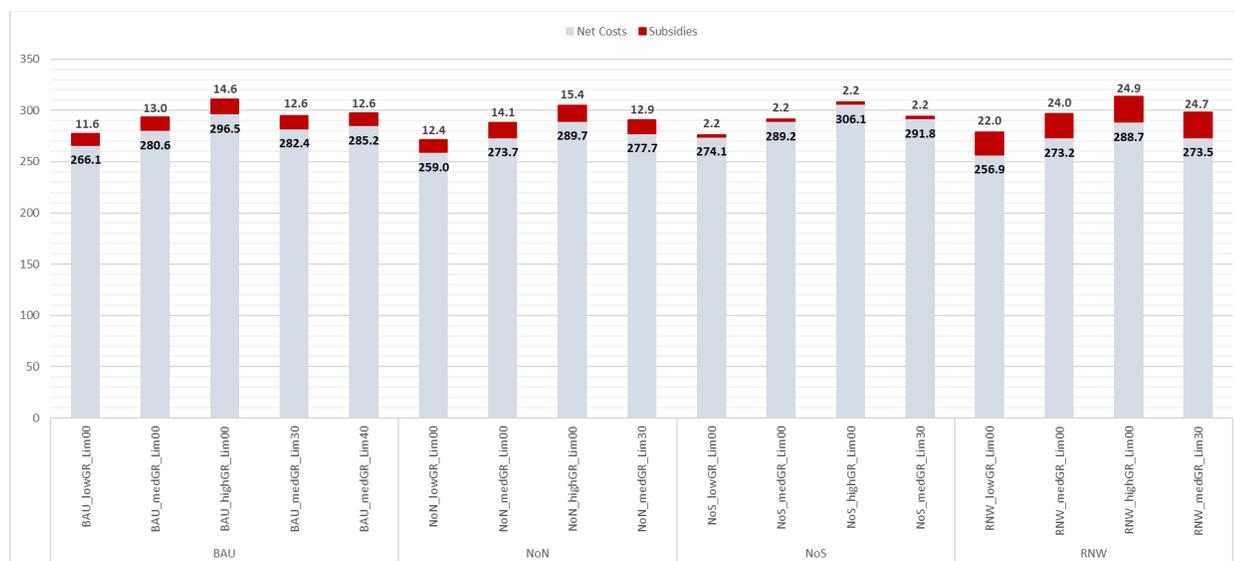
Figure 9. Total discounted cost and subsidies over 2019-2042, Billion 2019 US$.

scenarios in comparison to the reference case. The main inferences from these figures are:

- Wind power, without any subsidy, has an increasing trend under all scenarios.

- Solar power highly depends on subsidies. Lignite plants, on the other hand, can survive in case the current subsidies are eliminated.

- In NoN scenario, nuclear is replaced by lignite and solar.

- The share of renewable generation reaches 53.3% by 2042 under RNW, which is 6.9 points greater than BAU.

- Eliminating subsidies would decrease the capacity of solar and lignite. Moreover, a decrease in natural gas capacity is observed since some of this capacity was used to be installed for solar energy back-up.

- Under emission restrictions, lignite is replaced by renewable resources (solar and hydro) as well as fossil fuels that have lower carbon content (imported coal).

Total discounted costs with the subsidies explicitly highlighted are illustrated in **Figure 9**, where the total costs range between 271.46 and 313.57 Billion 2019 US$. The figure shows that the RNW cases, for which relatively high subsidies are required, result in higher costs. Note that the subsidies in NoS cases come from the base year. Another critical remark observed in Figure 9 is that the emission reduction scenarios bring additional total discounted costs of 1.01 to 2.78 Billion 2019 US$ for 30%, and 4.22 Billion 2019 US$ for 40%, respectively. The composition of subsidies, on the other hand, can be seen in **Figure 10**. Total subsidies lie between 11.63 and 24.92 Billion 2019 US$. Solar and lignite subsidies make up a significant portion of the total for BAU and NoN, while RNW subsidies mainly cover the hydro and solar plants.

Besides the total discounted costs, the total investment requirement for new capital is also calculated, as seen in **Figure 11**. The figure indicates that the new capital investment is higher for the RNW compared to the other scenarios while the minimum is observed under NoN. The total amounts correspond to 4.25 to 7.10 Billion 2019 US$ equal annualized investments.

TR-Power has the capability of calculating the implicit cost of CO_2 emissions via the dual price of Equation (1). Instead of single 30% and 40% reduction targets in the terminal year, realistic pathways are defined in a way that the CO_2 prices follow a smooth transition similar to the approach in (Kat *et al.*, 2018). The results (see **Figure 12a**) show that the CO_2 price is ~14 $/tCO_2$ for BAU_medGR_Lim30 and converges to ~34 $/tCO_2$ for NoN_medGR_Lim30 and BAU_medGR_Lim40. It is under 10 $/tCO_2$ for RWN_medGR_Lim30. **Figure 12b**, on the other hand, illustrates the total emissions under the main scenarios. Total emissions range between 244.4 and 387.4 MtCO_2, i.e., RNW generates 37% lower emissions compared to BAU.

The total generation and installed capacities with the share of renewable technologies can be seen in **Table 6**. The most striking outcomes observed in this table are as follows:

- More than half of the total load demand in 2042 would be satisfied by renewable technologies either by introducing a subsidy scheme promoting renewables or a carbon tax.

- Decreasing 2042 emissions below 200 Mton or attaining a renewable share of more than 55% seems to be technically and economically infeasible unless sharp improvements on the efficiency of renewable technologies emerge or large-scale and reliable storage technologies become commercially widespread.
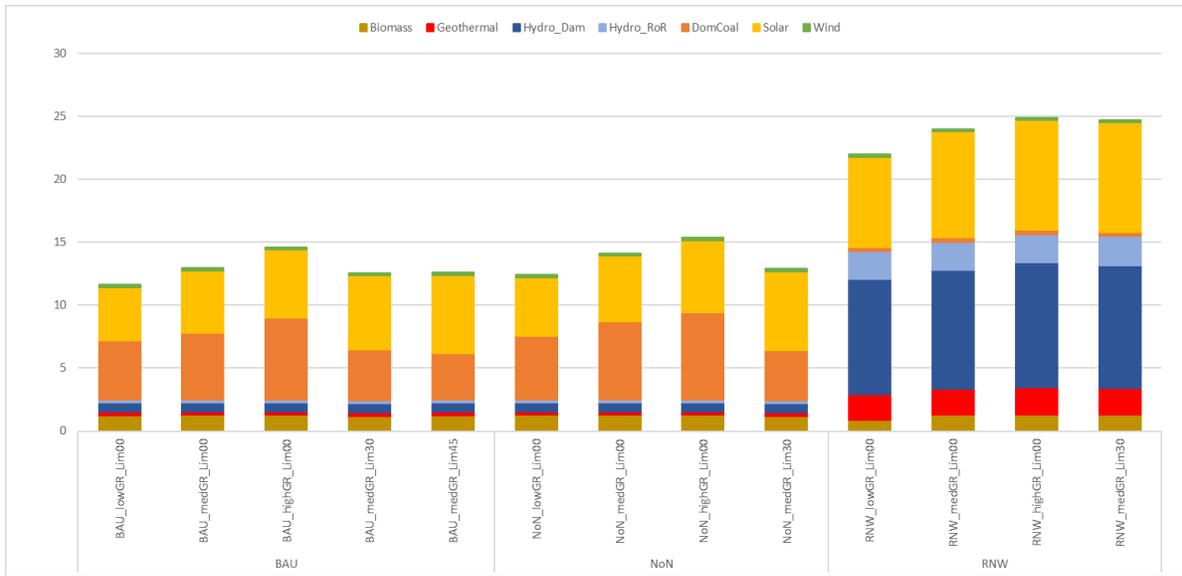
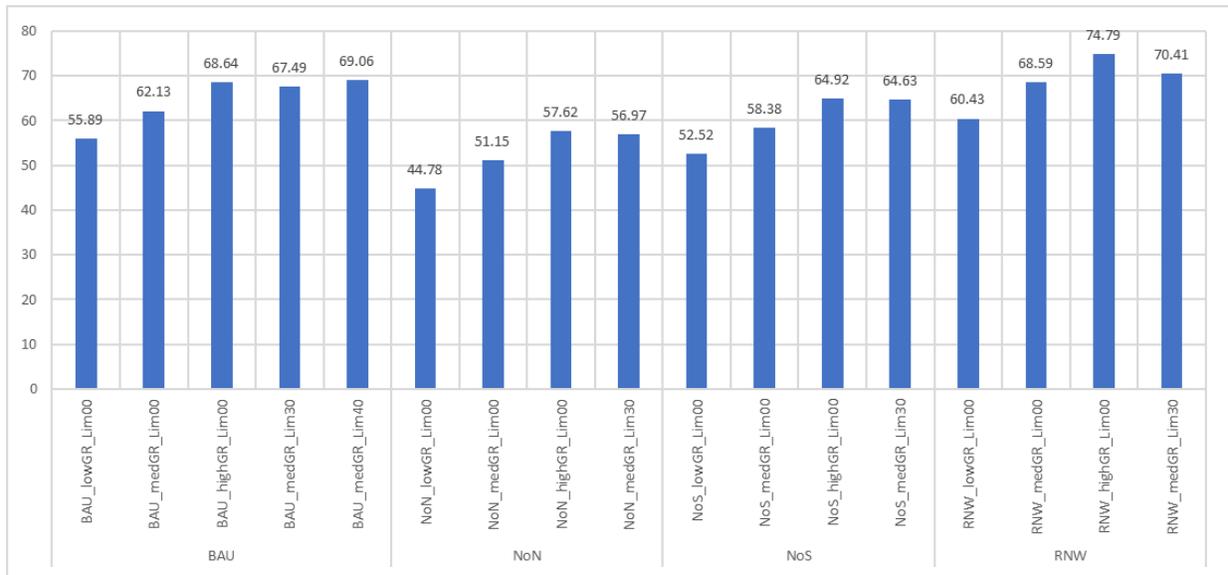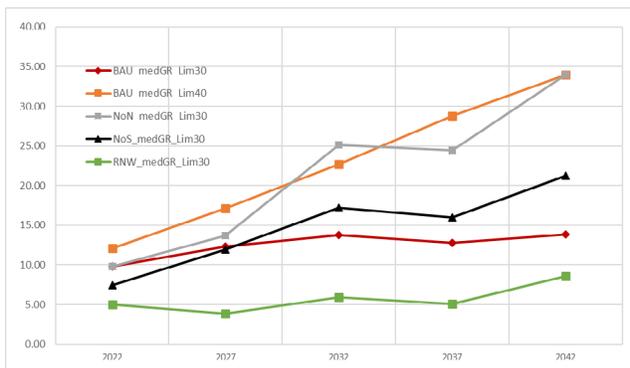**Figure 10.** Total discounted value of the subsidies over 2019-2042: Billion 2019 US$

Figure 11. Total discounted new capital investment requirement over 2019-2042, Billion 2019 US$.

a) Shadow price of CO_2 emissions 2019\$/tCO_2.

b) Total CO_2 emissions $MtCO_2$.

Figure 12. Environmental indicators

Table 6. Main results of TR-Power.

	Generation (2032)		Generation (2042)		total InsCap (2032)		total InsCap (2042)		CO$_2$ (2042)
	TWh	*% of rnw.*	*TWh*	*% of rnw.*	*GW*	*% of rnw.*	*GW*	*% of rnw.*	*Mton*
BAU_lowGR_Lim00	463.3	49.1%	593.0	49.3%	141.3	58.4%	182.0	57.6%	253.6
BAU_medGR_Lim00	500.5	47.6%	670.5	46.4%	152.5	57.3%	201.8	55.8%	336.6
BAU_highGR_Lim00	540.4	45.2%	757.6	42.6%	162.0	55.8%	221.6	53.1%	437.3
BAU_medGR_Lim30	500.5	50.3%	670.5	51.3%	160.7	60.1%	213.0	60.2%	235.7
BAU_medGR_Lim40	500.5	51.3%	670.5	52.1%	163.9	61.2%	216.6	61.7%	202.0
NoN_lowGR_Lim00	463.3	51.7%	593.0	50.6%	146.6	59.7%	185.5	58.2%	300.5
NoN_medGR_Lim00	500.5	49.0%	670.5	47.5%	155.5	58.0%	204.9	56.3%	387.4
NoN_highGR_Lim00	540.4	46.7%	757.6	43.5%	165.6	56.6%	224.6	53.6%	471.3
NoN_medGR_Lim30	500.5	53.5%	670.5	52.8%	165.4	61.8%	216.9	61.3%	235.7
NoS_lowGR_Lim00	463.3	45.8%	593.0	46.9%	133.8	55.8%	172.5	55.5%	243.9
NoS_medGR_Lim00	500.5	44.2%	670.5	43.5%	142.7	54.5%	190.6	53.1%	303.0
NoS_highGR_Lim00	540.4	42.5%	757.6	41.2%	152.1	53.2%	211.2	51.5%	390.4
NoS_medGR_Lim30	500.5	49.0%	670.5	50.6%	154.3	58.5%	208.2	59.3%	235.7
RNW_lowGR_Lim00	463.3	51.6%	593.0	52.8%	146.8	60.9%	188.1	60.2%	200.5
RNW_medGR_Lim00	500.5	50.8%	670.3	53.3%	160.5	60.4%	210.6	62.6%	244.4
RNW_highGR_Lim00	540.4	49.9%	757.4	48.7%	171.5	59.5%	227.8	58.8%	312.3
RNW_medGR_Lim30	500.5	52.6%	670.3	53.5%	163.9	61.9%	212.8	63.0%	235.7

6. Conclusion

After recent political, economic, and social turbulences following more than a decade lasting economic growth, Turkey now tries to climb out of recession and leap forward with a new start. As a matter of fact, the sharp slowdown in the economy and accompanying stability in electricity demand provided room for the transition to clean energy technologies and domestic resources. In other words, the pressure of satisfying the rapid increases in demand would have brought quick, costly, and dirty solutions as experienced in the near past. Then, the need for a comprehensive framework that addresses the transition in the Turkish power generation sector in a broad sense and considers all of these sudden economic and technological changes emerged. On top of these, environmental targets and timetables such as the INDC submitted to the United Nations Framework on Climate Change Convention (UNFCCC) within the scope of the Paris Agreement, make this kind of analysis vital given a significant amount of emissions that currently originate from the power generation sector.

This study includes originality in terms of both methodological and policy analysis aspects. At the outset, differently from the study by Kilickaplan *et al.* (Kilickaplan *et al.*, 2017) which utilizes a generic but comprehensive country model for Turkey; it is the first attempt to develop a GEP model (TR-Power) that is specifically formulated to solve the Turkish power generation sector's GEP problem with a time resolution of hours, and considers daily start-up levels and their corresponding costs. TR-Power also differs from the literature in terms of the scenarios for which the highest attention is paid to represent the cost and technical characteristics in the Turkish power sector that has significantly changed in the recent few years. Furthermore, TR-Power has the ability to calculate the implicit value of CO$_2$ emissions by the shadow prices of the emission limiting constraints.

TR-Power is run under 17 different scenarios that cover various policy options, electricity demand growth rates, and emission reduction constraints. The results show that:

- The share of renewable capacity would be increased by 6.9 points (or 14.7%) compared to BAU with an additional annual investment of 610 Million 2019 US$.

- Implicit CO$_2$ price in the power sector will be around 14 and 34 $/per tCO$_2$ by 2042 under 30% and 40% reduction targets compared to the reference scenario, respectively.

- Wind power has an increasing trend under all scenarios without any subsidy scheme.

- Solar power highly depends on subsidies.

- The technical and economic constraints restrain Turkey from having higher levels of renewable generation and decreasing the emission levels. This is mainly due to the back-up requirement of intermittent solar and wind, where this study indicates that lignite and natural gas plants are employed as back-up for Turkey.

TR-Power model needs further research on several issues. First, the current version of the model does not comprise the storage technologies, which is an inevitable option for the near future (Saygın *et al.*, 2019), considering intermittency due to the high penetration of solar and wind technologies. It is evident that the high penetration of renewable technologies is not realistic without the widespread integration of storage technologies into the grid. A detailed analysis of storage technologies in terms of capacity, cost projections, and location in the grid considering the transmission constraints would be addressed in a further study. On the other hand, high penetration of electric vehicles coupled with demand-side management policies would make a higher share (more than 60%) renewable grid possible to some extent, i.e., EVs can serve as storage nodes in the grid. Next, again closely related to the solar and wind resources, inte-grating the uncertainty into the model in a more comprehensive manner will enhance the representation capability of the model. Finally, as indicated in the introduction part, TR-Power is formulated as a bottom-up module paying regard to its integration with a top-down counterpart such as TR-EDGE (Kat *et al.*, 2018). Then, it will be coupled with TR-EDGE in line with the state-of-art implementations, e.g., (Lanz & Rausch, 2011; Rausch & Mowers, 2014; Ross, 2014a; Tapia-Ahumada *et al.*, 2015; Tuladhar *et al.*, 2009). The applicability of the developed model to other contexts beyond the Turkish power generation sector is also possible given that the precise cost, resource, and technical parameters or their reasonable benchmarks are available.

Acknowledgment

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