Global Electricity Sector Decarbonization Modelling

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Declaration of originality

I hereby certify that I am the sole author of the work presented in this PhD thesis. The work has not been previously accepted in any form for any degree assessment. I also declare that I have fully cited and referenced all materials and results that are not original to this work.

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Abstract

As variable renewable energies are set to become a key energy source in electricity sector worldwide, there is concern on the impact of the intermittency of their output when penetration is high. This research aims to investigate possible pathways for future electricity sector decarbonization with a focus on renewable development. This research starts with assessing the global capacity and energy potential for wind and solar power technologies, with a consistent approach. Validation of the developed approaches shows high accuracy of the identified potential areas, and high correlation between the estimated capacity factor and observed output records.

When temporal and spatial resolution in a model increases, conventional mathematical programming-based models are limited by computational resources in simulating large systems. To find out the best mix of climate-related energies in a country, this research proposes a novel mathematical models that incorporates objectives of minimizing cost, residual load variation and portfolio output variation. The results suggest that for almost every country, the proposed optimal mix can effectively minimize these objectives simultaneously, promoting the case that a high share of these renewables can be reachable.

Finally this research assesses pathways for electricity sector decarbonization. A framework is developed for modelling the electricity systems at regional market scale. This framework mainly consist of an economic dispatch model and a capacity expansion model. It incorporates measures to improve the system flexibility such as storage systems, reserve services and interconnection. Four scenarios are defined in this research. The results show that considerable emissions reduction is present in a base reference scenario, resulting from high penetration of renewables worldwide. Other scenarios can further cut the emissions, using policy instruments such as higher carbon prices, renewable penetration targets and emissions caps. Moreover, nuclear and carbon capture technologies may further drive the annual emissions down to negative values by 2050.

Abbreviations

ABM	Agent-based model
BECCS	Bioenergy with carbon capture and storage
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
CF	Capacity Factor
CE	Capacity Expansion
CHP	Combined heat and power
CRE	Climate-related Energy
CSP	Concentrating Solar Power
DHI	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
ED	Economic dispatch
EEZ	Exclusive Economic Zone
ENTSO-E	European Network of Transmission System Operators
EGS	Enhanced geothermal system
ESM	Energy System Model
GHI	Global Horizontal Irradiance
GIS	Geographic Information System
GSA	Global Solar Atlas platforms
GWA	Global Wind Atlas
IEA	International energy agency
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LCOE	Levelized cost of energy
MERRA	Modern Era Retrospective Analysis for Research and Applications
MSW	Municipal solid waste
OCGT	Open Cycle Gas Turbine
OSM	Open Street Map
RES	Renewable Energy Sources
PHS	Pumped Hydro Storage
PV	Photovoltaics
ST	Steam Turbine
VRE	Variable Renewable Energy

Symbols

BAT	Battery storage technology (set)
BF_y	Generation declining factor (Parameter)
C_{max}	Maximum cost value in the solution set (Parameter)
C_{min}	Minimum cost value in the solution set (Parameter)
$ca_{z,i,t}^{T1}$	Capacity of primary reserve provided by generator i in zone z at time t (variable)
$ca_{z,i,t}^{T2}$	Capacity of secondary reserve provided by generator i in zone z at time t (variable)
$ca_{z,i,t}^{T3}$	Capacity of tertiary reserve provided by generator i in zone z at time t (variable)
CAF_i	Equivalent availability factor of generator i (Parameter)
CAM_i^{T1}	Maximum capacity for primary reserve of generator i (variable)
CAM_i^{T2}	Maximum capacity for secondary reserve of generator i (variable)
CAM_i^{T3}	Maximum capacity for tertiary reserve of generator i (variable)
CCF_i	Annualized fixed cost per unit capacity of generator i (parameter)
CCG_i	Variable generation cost per unit generation of generator i (parameter)
CDU_i	Storage duration (energy/power ratio) of storage system i (parameter)
CEF_i	Conversion efficiency (LHV) of generator i (parameter)
$cfc_{z,i,t}$	Fuel consumption of generator i in zone z at time t (variable)
$CPM_{n,y,p}$	Maximum capacity of technology p in country n in year y (parameter)
$CRE_{z,t}$	Electricity generation from non-dispatchable renewables in zone z at time t (Parameter)
$ce_{i,t}$	Net power output of operational generator i at time t (variable)
$ce_{i,t}^{charge}$	Charging power of operational storage system i at time t (variable)
$ce_{i,t}^{gross}$	Gross power output of operational generator i at time t (variable)
$CF_{i,t}$	Capacity factor of generator i at time t (parameter)
Cov	Covariance matrix
Cov_m^{DAY}	Covariance matrix calculated from daily mean output profile in month m (Parameter)
Cov_t^{TS}	Covariance matrix calculated from hourly output profile at time-slice t (Parameter)
COU_i	Electricity own use of generator i (Parameter)
cp_i	Capacity of generator i (variable)
CP_i	Capacity of generator i (Parameter)
$CP_{z,i}^{max}$	Maximum capacity of generator i in zone z (Parameter)
d	Day (index)
$D_{z,t}$	Electricity demand in zone z at time t (Parameter)
$D_{n,t}$	Electricity demand in country n at time t (Parameter)
EC_y	Emission cap in year y (parameter)
$FBI_{n,y}$	Biomass supply in country n in year y (parameter)
HD_t	Representing hours of the time-slice t in a day (Parameter)
i	Generation unit / process (index)
j	New generation unit / process (index)
LA_z^{solar}	Available land area for PV and CSP deployment in zone z (Parameter)
$LR_{z,i}$	Required and area per unit installation of generator i in zone z (Parameter)
$LHYD$	Large hydropower (set)
n	Countries (index)
NRE	Non-dispatchable renewable technology (set)
OFZ	Offshore zones (set)
P_{max}	Maximum value of portfolio output variance in the solution set (Parameter)
P_{min}	Minimum value of portfolio output variance in the solution set (Parameter)
R_{max}	Maximum value of residual load variance in the solution set (Parameter)
R_{min}	Minimum value of residual load variance in the solution set (Parameter)
r	Transmission link between two zones (index)
$rl_{z,t}$	Residual load in zone z at time t (variable)
$RR_{z,t}^{T1}$	Required capacity of primary reserve service in zone z at time t (Parameter)
$RR_{z,t}^{T2}$	Required capacity of secondary reserve service in zone z at time t (Parameter)
$RR_{z,t}^{T3}$	Required capacity of tertiary reserve service in zone z at time t (Parameter)
RT_z	Mean of residual load in zone z (Parameter)

SL	Limit of energy spill in a country/district (Parameter)
$sp_{z,t}$	Spilled electricity in zone z at time t (variable)
$STOR$	Storage technology (set)
t	Time-slice (index)
$TEST$	Time-slice of testing cases (set)
TCF_r	Annualized fixed cost per unit capacity of transmission link r (Parameter)
TG	Target of the share of renewable generation in a country/district (Parameter)
$te_{r,t}^{in}$	Instantaneous electricity input in transmission link r at time t (variable)
$te_{r,t}^{out}$	Instantaneous electricity output in transmission link r at time t (variable)
TIC	Electricity importing price (Parameter)
TL_r	Transmission loss of link r (Parameter)
tp_r	Transmission capacity of link r (variable)
TP_r	Transmission capacity of link r (Parameter)
tp_r^{add}	Capacity addition of transmission link r (variable)
y	Year periods in the time horizon (index)
z	Zone (index)
$ze_{z,t}$	Electricity supply in zone in zone z at time t (variable)

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1. Introduction

This work is a thesis prepared for the author's PhD degree examination at Imperial College London. The main purpose of the research is to assess future decarbonization pathway of the electricity sector around the world, with a particular focus on renewable energy integration. This chapter describes motivations behind this research and key objectives.

1.1 Motivations

According to the IEA (IEA, 2019a), around 38.4% of the world's primary energy was consumed in power sector in 2018. Greenhouse gas emissions from electricity and heat sector accounted for 41.6% of the total emissions from energy use in the same year. Also, the demand for electricity in end-use sectors based on current policies scenario is projected to grow 64% by 2040 from 2018, faster than the demand of any other type of energy. It is clear that the power sector is playing a significant role in the future energy mix, and in decarbonization. In an aggressive renewable development scenario proposed by IRENA, renewable energy and electrification can deliver 75% emissions reduction in 2050 (IRENA, 2019b). The core motivation behind this research is based on these estimations to investigate the role of variable renewable energies (VREs) in decarbonizing the future global electricity sector.

The transition towards low-carbon electricity system requires new technologies, new policy instruments, and new market mechanisms. However, from the increasing share of VREs, to advances on system flexibility measures, and to the deregulation of the electricity market, all together make the investment and operation of electricity system more complicated than before. Power sector, consequently, is usually one of the most complex parts within a larger energy system model (ESM), and is receiving significant attention in ESM research groups.

As VRE is set to become a key energy source worldwide, there is concern regarding the impact of the intermittency of its output when penetration is high. ESMs typically tackle this issue by improving modelling resolution to capture the characteristics of local VREs output. To allow for such work within a global model, more and better input datasets are needed on VREs capacity potentials, and energy production over time and space. This requirement motivates a critical work in this research – to assess the global VREs energy potential and their temporal output characteristics. The output datasets need to have sufficiently high spatial and temporal granularity, and must be developed using transparent and consistent approaches.

To combat climate change, most countries have proposed VRE development targets as part of

their overall approach to cut emissions (REN21, 2019). The targets can be an overall VRE generation share or specific goal of installed capacity in target year. Most existing studies on large share VREs integration were conducted for countries in the EU and North America (Hansen et al., 2019). However, the research on VREs development for developing countries are receiving more attention. From the perspective of reducing global emissions, it would be helpful to explore how VREs can be exploited in those less studied countries and regions. Conventional cost optimization models require considerable computational resources in simulating for the optimal mix of renewables when the resolution setting is high. This can be an issue when more components and constraints are added in an electricity system model. This motivates another work on investigate the optimal mix of renewables using novel approaches with high temporal and spatial resolution.

There has been abundant literatures and models developed to analyze the future transitions of large-scale electricity systems. Only a few of them have the coverage at global scale. The existing global ESMs tend to aggregate the geographical representation into dozens of regions. Local VRE potential and output characteristics may not be well presented at this spatial coverage level. In addition, the importance of system flexibility has been recognized is high VRE share electricity systems. Therefore, with a focus on renewable integration, this research aims to investigate decarbonization scenarios with relatively high spatial granularity while many flexibility measures are integrated. The research outputs may be useful for policy makers or stakeholders, especially for those in the countries less studied in the literatures. The results may help to answers to these questions: What will happen if no active measures are taken to curb the emissions (i.e. what is the baseline)? What is the level of carbon price that can trigger more renewable investment? What will be the influences of flexibility measures on renewables uptake and costs in a system? The answers allow them to take more informed decisions ahead of a transition, or to make the transition happen.

1.2 Global variable renewable energies potential assessment

Variable renewable energy (VRE) is renewable energy sources that are not dispatchable, usually referring to wind and solar energies. Renewable energies deployment worldwide has been growing quickly over the past years. Renewable power generation has increased around 60% between 2010 and 2018 (IEA, 2019a). The growth mostly came from wind power, hydropower and solar PV. As suggested by IPCC (IPCC, 2019), VRE is likely to play a crucial role in electricity system decarbonization in many countries. For example, in the Current Policy scenario proposed by the IEA (IEA, 2019a), the global electricity generation from wind and solar technologies is projected to grow several folds

between 2018 and 2040. In the REmap case proposed by IRENA, the global renewable electricity generation will increase to from 5,917 TWh in 2016 to 47,409 TWh in 2050 (IRENA, 2018a).

To support VREs deployment, it is crucial to understand the geographical distribution of wind and solar resources and their temporal output characteristics. While there have been numerous VREs technical potential studies at regional or country level, only a few studies have been conducted at global level. These previous global studies were typically carried out with coarse spatial resolution, and the parameters and constraints applied have significant influence on the potential estimation. Also, the input data and estimation approach used may not fully capture the temporal characteristics.

The intermittency and uneven distribution of VRE potentials create an important challenge to Energy System Models (ESMs). Currently national scale ESMs generally consist of several sub-regions, a set of representative time-slices to capture seasonal and diurnal load profiles, and an overall time horizon up to the year 2050 or 2100. This resolution is often further reduced in models at global scale due to pressure on computational resources, and lack of consistent worldwide data. IRENA (IRENA, 2017c) has identified a set of challenges for current ESMs, and suggests that over-simplified regions and coarse temporal resolution diminish the ability of a model to capture the flexibility requirements in high VRE share systems. For this reason, over the years prior to the time of writing, the IEA-ETSAP TIMES community has developed extension modules (IEA-ETSAP, 2018) for the electricity sector to tackle this issue with higher modelling resolutions and more technical constraints.

The main purpose of the research is to assess future decarbonization scenarios of the electricity sector around the world, with a particular focus on renewable energy integration. The spatial and temporal resolution have to be sufficiently high to allow capture output characteristics of renewables, at least subnational and hourly level. Since existing materials from other studies cannot satisfy this requirement, this research applies a consistent approach to assess global VRE capacity and energy potentials, and prepare the results at fine resolution such that they can be used effectively in this research or other ESMs.

To capture the temporal characteristics, this research simulates capacity factors (CF) of the VREs using hourly meteorological assimilation data for a 10-year period, from 2008 to 2017, at around 50 km^2 gridded cells based on NASA MERRA-2 datasets (Gelaro et al., 2017). The resolved global CF maps in 1 km^2 resolution were produced by reconciling simulated hourly output with the wind and solar resource maps from the Global Wind Atlas (GWA) (Badger et al., 2015) and the Global Solar Atlas (GSA) (Solargis, 2018) platform. This research assesses VREs geographical potential using Geographic Information System (GIS) based approach. Consistent constraints associated with physical limits,

economic considerations and social impacts are applied. Information from the OpenStreetMap (OSM) (OpenStreetMap Contributors, 2018) is used to improve the land cover data and to construct exclusion areas. This work also tests the eligibility masks produced against the location of existing power facilities for validation. Hourly generation records available from ENTSO-E platform are also used to validate the results for European countries.

VRE technologies in this study include onshore wind, offshore wind, utility-scale PV of fixed-tilt and one-axis tracking varieties, distributed PV and concentrated solar power (CSP). To provide results in subnational disaggregation, the study defines 731 terrestrial zones and 339 offshore zones. The capacity potential is processed at 300 m resolution, and the energy output at each pixel is binned into CF classes, thus forming CF tranches. The tranches with their capacity potential form the supply curve in each zone.

1.3 Optimal mix of variable renewable energies

Global renewable energy share is expected to grow significantly. In the Current Policies Scenario proposed by the IEA (IEA, 2019a), the share of electricity generation from renewables will increase from 6,799 *TWh* in 2018 to 15,584 *TWh* in 2040, while climate-related energy (CRE) including hydro, wind and solar power will make up 90% of the renewable generation. The increasing CRE generation in a power system, however, presents challenges on balancing supply and demand due to their variability and intermittency. The IEA argues that there is an increasing need for system flexibility in high renewable share systems due to the variability of net load, and conventional power plants will be essential in providing flexibility services.

There have been numerous studies on high shares of renewable generation in power systems. Modelling approaches that support these studies are typically based on cost optimization. One critical issue of this approach is the cost can be underestimated if flexibility requirements are not properly modelled (IRENA, 2017b), and this issue can be exaggerated if the models use coarse temporal and spatial resolution, which often occurs due to limited computational resource. Furthermore, most of the existing studies that investigate renewable integration usually focus on wind and solar power (Engeland et al., 2017). Only a few studies looked at the integration of all the three types of CRE, despite the fact that there is abundant hydropower in some countries. Also, Europe, the US and Australia are the most researched regions. Other countries are less frequently studied (Hansen et al., 2019). The need to investigate the optimal mix of renewables for every country at subnational level is identified. This investigation has to be based on new approach that captures the variability of

electricity demand and CRE outputs in high resolution but avoids long solving time.

This research proposes the optimal CRE capacity mix for the 171 country/district power systems with a multi-objective modelling approach that solves the challenges faced by high space-time resolution optimization modelling. Several mathematical models are developed, as follows: First, a shared model core was developed which integrates constraints on capacity limits, system balance, transmission, hydropower dispatch, curtailment and a CRE target. Three separate models are then built on this shared core. Model C is based on a minimum cost optimization. Model R is developed to minimize the variation of annual residual load. This model is to capture the overall complementarity of CRE output with load profile, noting that good complementarity may reduce the capacity of conventional thermal units required in a system. Model P minimizes the variation of portfolio output, which reflects the output variability in specific time periods. The optimal solution of this model may result in the minimum need for firm reserve in a system. Finally, Model CP is a multi-objective problem based on compromise programming. The solutions from this model are put forward as the optimal mix in this study. The novelty of this work is this multi-objective approach which performs space-time integrated analysis while taking into account the complementarity of different generation options. It avoids the long solving time in conventional cost optimization approaches.

To narrow the scope and simplify the models, this research only investigates the mix in 2040 with the CRE share targets at 30%, 50% and 70%. Conventional thermal generation technologies are excluded. The modelled technology includes onshore wind, offshore wind, distributed PV, fixed-tilt PV, one-axis tracking PV and concentrated solar power (CSP). The capacity potential of the technologies is further classified into tranches based on annual capacity factor. Most of the input is based on the results from the previous work in this research. This research also estimates monthly hydropower output and power demand profile in each zone. For each country, covariance matrices based on estimated CF of all available installation options is calculated at different time frequencies. The matrices are the core element in Model P.

1.4 Global electricity systems decarbonization

The goal of this research is to investigate possible pathways in decarbonizing the electricity sector. This work aims to develop models which can integrate the materials from previous works and can estimate the development of electricity sector worldwide in different scenarios. This work places a strong emphasis on VRE integration considering space-time energy output variability. There has been abundant literatures and models developed to analyze the future transitions of large-scale electricity

systems. They can be a sub-module in an ESM, or an independent and spatialized ESM. The existing models were created on different purposes, with different methodologies, scopes, resolutions and time horizon. However, only a few of them have the coverage at global scale. The existing global ESMs tend to aggregate the geographical representation into dozens of regions. Local VRE potential and output characteristics may not be well presented at this spatial coverage level. This research is intended to assess decarbonization scenarios with relatively high spatial granularity at global scale, while many flexibility measures are integrated including hydropower dispatch, storage operation, interconnection and reserve services. The outputs may be particularly useful for policy makers or stakeholders in the country which are less studied in the literatures. The results tell when and where a specific renewable technology need to be deployed to reach the decarbonization target.

Models are developed to investigate the optimal capacity CRE mix at country level in the previous part of this research. The work does not integrate dispatchable thermal generation technologies as well as flexibility measures, such as storage and interconnection. In this research, a framework with optimization models are developed to estimate capacity and generation mix of common generation technologies. In the core of this framework, an electricity dispatch (ED) model and a capacity expansion (CE) model are developed. Their constraints include power balance, transmission, hydropower operation, storage operation, reserve requirements, capacity addition and VRE targets. The objective function of ED model is minimizing total variable generation cost in a system. For CE model, the objective function is minimizing overall annualized costs.

Most input data related to renewables are based on the results from the previous works in this research while most of the assumptions used are kept the same. Capacity potentials and electricity generation of geothermal and biomass are estimated with simple approaches in this work. Other necessary assumptions, including techno-economic assumptions for dispatchable power plants, carbon price and fuel prices etc. are obtained from several sources. The model instance is set on integrated market scope. A market can consists of several zones and countries. The ED model performs 24 hours intraday dispatch calculation for each calendar month, in total 288 time-slices in a year. The CE model performs a 5-year interval period modelling from base year 2015 to 2050. The representative time-slices in CE model are reduced to 32, representing 8 daily segments in 4 seasons. Another 12 time-slices are selected dynamically to test system reliability. The geographical representative zones inherit those in the previous works, which consist of 1,070 terrestrial and offshore identified zones. In each zone, the available options for expansion can range from 30 to 90. The wide range is because the renewable technologies are split into different CF output tranches. For

simplification purpose, this research excludes heat supply and demand despites that CHP plants can contribute to electricity supply at certain degree.

Four scenarios are proposed to investigate possible future development. They are reference scenario (REF), high carbon price scenario (HCS), optimal CRE mix scenario (MCP) and carbon neutral scenario (CNS). In these scenarios, most of the settings and assumptions are identical. In HCS scenario, higher carbon cost is applied. The MCP scenario is building on the optimal CRE capacity mix in the countries proposed in the previous work. In CNS scenario, additional constraints are applied to ensure zero emission in the last period.

1.5 Structure of this research

The motivation of this research has discussed in this chapter. This chapter also presents the introduction of the main works in this research. Literature review is presented in Chapter 2. Previous studies on global wind and solar power potential assessment are listed for discussion in this chapter. The discussion covers the temporal and spatial resolutions of these assessments and how these material can be used in ESMs. More insights of the studies compared to the results produced from this research is discussed in Chapter 4. Since most of the existing potential assessments were carried out through GIS works, the problem of GIS-based assessment is identified in this chapter. The issues of VRE output variability and complementarity are also acknowledge in the literature review. This helps to develop a novel approach that finds the optimal CRE mix in a country. Several large-scale electricity system models are selected from comparing their features. Key requirements for developing the electricity system modelling framework are identified from this reviewing process. Lastly, the gaps and possible improvements from literature review are summarized which pinpoint the key directions in this research.

Chapter 3 introduces the methods developed in this research. This chapter provides details on processing the geographic materials in generating suitability maps for wind and solar energy development. The approach of simulating their hourly power generation is also presented in details. The formulation of the models for investigating the optimal capacity mix of CREs and evaluating the decarbonization pathways of global electricity systems is presented in this chapter. All the input data and assumptions are also noted here with discussions on why and how they are used.

Chapter 4 presents the results in this research, including the capacity and energy potential by output tranche, simulated hourly power output in every zone, optimal CRE mix in every country in different target, and the decarbonization pathways in global electricity systems. Validation works have

also carried out for the proposed suitability maps and simulated hourly output using historical data. There is also a discussion on the VRE output complementarity and temporal frequency, as well as the results produced from different objectives in finding the optimal mix. This chapter compares the results with the studies listed in Chapter 2 and discusses potential causes for the differences. Some of the research outputs are compiles in the appendix, and all the output material are available through the link provided.

Chapter 5 concludes the key findings in this research and suggests future research directions in this field of study. This chapter summarizes how the methods developed can solved the problem identified in Chapter 2. More importantly, a list of contributions of this research is presented. This specifies the breakthroughs on the methods and provides the insights in future global power sector decarbonization.

2. Literature review

The literature review includes three main sections: global VRE potential, high share VRE in power systems and electricity system modelling. The review on VRE potential links to the motivation of understanding the existing studies, to investigate the possibility and limitations of using their outputs in this research. The review on high share VRE is also necessary for identifying the problems encountered in this field of study. Lastly, from the review of current large-scale electricity system models, this research determines the methods and critical component for constructing the models to assess future decarbonization pathways.

2.1 Global variable renewable energy potential

This section presents the review of previous studies on global VRE potential assessment. This section summarizes the datasets, resolution and approaches in these assessments. Note that there are numerous studies with regional or country wide coverage on this topic but they are generally not included here. This review only focuses on studies with global coverage. This section also discusses GIS-based techniques in the assessment for most of the latest studies rely on GIS processing works. This review also covers methods for estimating wind and solar power production. Moreover, this section briefly describes what can be the influences of using different temporal and spatial resolution in a model.

2.1.1 Renewable energy potential estimation

The IPCC has noted that the global renewable energy technical potential is substantially higher than total energy demand (IPCC, 2011). Compared to the global primary energy demand of 492 EJ in 2008, the estimated wind energy technical potential ranges from 85 to 580 EJ/year and the direct solar energy technical potential ranges from 1,575 to 49,837 EJ/year. Other estimates also exist, for example, the Global Energy Assessment (Turkenburg et al., 2012) suggested that the onshore wind technical potential is between 250 to 1,200 EJ/year, and the PV and CSP technical potential is estimated at 12,300 EJ/year and 277,000 EJ/year, respectively.

Since available VREs capacity are key constraints in ESMs, some model teams have developed their own approach to assess potentials that suit the spatial configurations in their particular global. For instance, the global renewable potentials proposed by Stetter (2012) is used in the REMix model. Moreover, most global ESMs or integrated assessment models (IAMs) draw upon estimates of the

available capacity from published sources. For example, MESSAGE model (IIASA, 2016) uses the global PV and CSP potential estimation proposed by Pietzcker et al. (2014), and uses the wind potential reported by Eurek et al. (2017). Jacobson et al. (2017) have investigated matching the demand with 100% intermittent wind, water, and sunlight energies in 139 countries. They also rely on multiple data sources for the capacity potential and output profiles in each country.

Most of the GIS-based VRE potential studies estimated energy output profile in gridded cells at 30-50km resolution based on meteorological data, and then calculate available area in each grid cell according to land cover maps. Table 1 summarizes several global VRE potential studies and the main datasets used. For both wind and PV potentials, Hoogwijk (2004) assessed the technical potentials by estimating the full-load hours at each grid cell. This study is one of the earliest that assigns suitability factors with regard to land cover. Stetter (2012) considered the projection of techno-economic assumptions in the future, and presented cost-supply curves for major regions. Teske et al. (2019) estimated the land area for utility-scale solar and wind power development in 75 regions. The solar and wind energy output in selected sites of a region are based on the works by Pfenninger and Staffell (Pfenninger &Staffell, 2016)(Staffell &Pfenninger, 2016).

For wind energy potential, Archer & Jacobson. (2005) is the only study listed that is based on observed data from weather stations, though did not apply land use constraints. Lu et al. (2009), Zhou et al. (2012), Arent et al. (2012) and Eurek et al. (2017) estimated global wind potential with a CF estimation approach mapping wind speed onto turbine power curves, though used different data resolution and constraints. Arent et al. (2012) and Eurek et al. (2017) binned the wind capacity potential into CF classes to form supply curves. Arent et al. (2012) considered more factors such as permafrost areas, sea ice impact, and air density. Dupont et al. (2018) estimated wind energy output with a derived function from the Weibull wind speed distribution and turbine design parameters. This study optimized the capacity density in each grid cell and evaluated the wind energy potential based on Energy Return on Investment. Bosch et al. (2017)(2018) combined MERRA-2 datasets and GWA data maps to perform a spatially resolved assessment, providing CF for 32 time-slice per year for every country.

Table 1. List of global VRE potential studies and the data sources used.

Study	Energy	Meteorological data			Land cover data	
		source	spatial resolution[1]	temporal resolution[2]	source	spatial resolution
Hoogwijk (2004)	wind solar	CRU	0.5°	monthly	IMAGE	0.5°
Stetter (2012)	wind solar	MERRA NASA SRB	0.5° 1°	1h 3h	GLC 2000	300m
Archer & Jacobson. (2005)	wind	NCDC	stations	daily	NA	
Lu et al. (2009)	wind	GEOS	0.5°	6h	MODIS	1km
Zhou et al. (2012)	wind	NCEP CFSR	0.3125°	6h	MODIS	1km
Arent et al. (2012)	wind	NCEP ECMWF	0.25°	6h	NA	
Eurek et al. (2017)	wind	CFDDA	0.4°	hourly /288-TS	GlobCover	1km
Dupont et al. (2018)	wind	ERA-Interim	0.75°	6h	GlobCover	1km
Bosch et al. (2017)(2018)	wind	MERRA-2 GWA 1.0	0.5° 1km	hourly /32-TS	GlobCover	300m
Teske et al. (2019)	wind solar	Vaisala, GAS RE-Ninja	0.5° sites	hourly	GLC 2000	300m
Köberle et al. (2015)	solar	NASA SSE	1°	3h	IMAGE	0.5°
Pietzcker et al. (2014)	solar	NASA SRB	1°	hourly	GLC 2000	300m
Trieb et al. (2009)	solar	NASA SSE	1°	annual		1km

For solar energy, Köberle et al. (2015) developed functions to estimate full load hours in each grid cell and produced cost-supply curves of PV and CSP for 26 regions globally. Pietzcker et al. (2014) investigated the technical and economic potentials with a similar approach to Stetter (2012) and classified the potentials by CF and distance to grid. Trieb et al. (2009) developed a model that estimates CSP full load hours, which are functions of Solar Multiple and annual Direct Normal Irradiance. These equations are in fact used in Stetter (2012), Köberle et al. (2015) and Pietzcker et al. (2014).

All the studies in Table 1 suggested different level of global wind and solar energy potential. Several factors may contribute the differences, such as temporal and spatial resolutions in the estimation processes and the constraints applied to evaluate suitable development area. Some of these studies provide capacity potential or supply curve by country, for example Bosch et al. (2017), Eurek et al. (2017) and Pietzcker et al. (2014). These materials can be useful for this research. However, this research aims to model the electricity systems in subnational spatial granularity. None of these studies can provide the dataset at this scale.

2.1.2 GIS-based geospatial assessment

Most bottom-up VRE potential studies rely on GIS processing to estimate available land area for

[1] 0.5° arc-degree is approximately 50 km and 1° is approximately 100 km.

[2] Temporal resolutions: resolution of the original meteorological data / resolution in estimating energy potential

deployment. For example, land cover such as forest, urban areas and frequently flooded areas should be excluded. Land cover maps are typically generated from satellite surveys and image processes. They are commonly used to support VRE potential studies. Generally, suitability factors that indicates the percentage of area available for development are assigned to every type of land cover. The drawback of using the existing land cover products is their accuracy. When comparing the maps with reference points based on actual land cover information, the accuracy for example is reported to be around 59% to 82% in China (Yang et al., 2017), and 51% to 63% in Africa (Tsendbazar et al., 2015).

Another source of land cover information are Volunteered Geographic Information (VGI) platforms such as OSM. Resch et al. (2014) identified the use of VGI as an important direction for energy potential assessment. Since VGI information is relatively accurate compared to satellite-based maps, it is possible to improve overall data quality by combining the two sources. This has been demonstrated by Fonte et al. (2017) which shows that overall land cover accuracy can be improved by extracting features from OSM and overriding the information in a satellite-based land cover map.

Land use information such as residential areas, protected areas and military areas are also commonly used to identify eligible areas, and such land eligibility constraints influences the result significantly. Ryberg et al. (2018) concluded that the impact of eligibility constraints applied is highly spatially sensitive, and that constraints based on woodland, agriculture areas, irradiance and protected areas are more influential in the analyses. For this reason, it is improper to source the needed energy potential data from several different studies. This research may need to conduct the energy potential assessment by applying consistent methods and constraints for every country.

2.1.3 Wind and solar power production modelling

A common method to estimate wind power production is to map the wind speed at hub height onto turbine power curves. Assumptions of array efficiency loss and electric system losses are applied to calculate net power output, or net capacity factor, of a wind farm. This method is adopted in Lu et al. (2009), Zhou et al. (2012), Stetter (2012) and Bosch et al. (2017). A variation of this method is to estimate the Weibull distribution of wind speed from historical data, then convolve the distribution to wind turbine power curve. This approach can be seen in Hoogwijk (2004), Arent et al. (2012) and Eurek et al. (2017). Furthermore, Dupont et al. (2018) estimated wind energy output with a derived formula from the Weibull wind speed distribution and turbine design parameters. This approach has been increasingly used in wind power production modelling. There are various mathematical models for estimating the Weibull and Rayleigh distribution parameters. Murthy &Rahi (2017) provides a

comprehensive survey of these models. On the other hand, there are also models proposed to estimate power curves using measured wind speed and power output data (Sohoni et al., 2016). This is more commonly used in estimate regional power output. Moreover, since most of the wind speed data are produced from reanalysis models, there may exist bias between modelled output and measured value in specific location. Staffell &Pfenninger (2016) developed equations to calibrate wind speed data in European countries. They proofed that accuracy of the power output estimation can increase significantly.

The PV power production is generally estimated using the amount of solar irradiation on the PV module surface. It is typically assumed that the module can generate at full load when the incoming irradiance on module surface reaches 1,000 W/m^2, since the nominal capacity is tested under 1,000 W/m^2 at 25°C, as Standard Testing Condition (STC). The total irradiance on the surface is the sum of three components: beam irradiance, sky diffuse irradiance and ground diffuse irradiance (Perez et al., 1987). Hoogwijk (2004), Stetter (2012), Pietzcker et al. (2014) and Köberle et al. (2015) all used similar approach to estimate PV power output but adopted different parameters, such as albedo. The beam irradiance can be derived from Global Horizontal Irradiance (GHI), provided in the meteorological dataset, using the location of the sun and the tilt angle of the module surface. However, to determine the diffuse irradiance and other necessary parameters, a solar radiation model is needed, which is unclear in these mentioned studies. Zhang et al. (2017) have provided a critical review of the models used to estimate solar radiation. They compares the models according to the time scale and estimation type. In terms of estimating diffuse irradiance, Dervishi &Mahdavi (2012) compares eight models for estimating diffuse fraction of irradiance. Three models are promoted for their performance in different conditions.

2.1.4 Temporal and spatial resolution

Most global energy potential assessment studies in Table 1 estimated the potential with the temporal and spatial resolution inherited from the meteorological data used. The coarse spatial resolution in these studies (approx. 30-50km) may not reflect the distribution well. Badger et al. (2015) demonstrated that the wind power density can be much higher if assessed with higher spatial resolution. For this reason, Bosch et al. (2017)(2018) developed an approach that increases the spatial resolution of energy potential maps to assess global wind power potentials. The studies provide a promising direction to improve spatial resolution in the assessment in this research.

The selection of temporal resolution in an ESM can significantly influence the outcome regarding

long-term capacity mix. It can cause either overestimates or underestimate (Merrick, 2016). Moreover, modelling with lower temporal resolution can make VREs more preferable and underestimate the need for dispatchable units in a system (Nahmmacher et al., 2016). Previous studies on global VRE integration tend to use annual average or selected time-slice to capture temporal variation, and spatial representation is also aggregated into around 20 world regions (Hansen et al., 2019). The reduced resolution of these global models may underestimate the variability of VRE and the need for flexible units especially for large systems such as China, Russia and Brazil. Bogdanov et al. (2019) investigated the low-carbon transitions of power sector in global 145 regions, and used hourly resolution in their model. This study is in the lead of high resolution energy model. Teske et al. (2019) estimated the pathways to 100% renewable energy. Their model applies hourly resolution and spatial resolution up to 75 regions. Therefore, this research is intended to prepare greater resolution data, at least at hourly and subnational level. The output materials may benefit the ESM research society.

2.2 High share variable renewable energy in power systems

As the role of VREs is increasingly important in future electricity systems. The integration of VREs in large-scale electricity systems has been studied extensively. This review section first investigates the output characteristics and the integration of different types of CRE. The investigation then extends to approach the optimal mix in a power system from minimizing the variability of portfolio output or residual load.

2.2.1 Integrating climate-related energies

The power output variability of VREs is driven by weather and climate conditions. Engeland et al. (2017) reviewed 279 publications on space-time variability of wind, solar and hydropower. They suggested that at local and sub-hour scale the production from CREs exhibits different levels of variability due to small scale atmospheric processes. The pattern sizes of the variability can converge at larger space-time scale, up to 300 km and 3 days. The review also suggested that the complementarity between wind power and solar power production at this scale is pronounced. Moreover, most existing studies on CRE integration were carried out at this scale and focused on their complementarity. For instance, at point scale, Rodrigues & Estanqueiro (2011) demonstrated that adding solar PV to a wind farm can increase the overall capacity factor of the virtual power plant by 5.3%. The correlation between diurnal output and load profile is also increased significantly. At grid scale, Traube et al. (2008) investigated the benefit of blending wind and solar PV power in three

regional power systems in the USA. They found that the optimal portfolio in the systems is at least 28% less variable than with any of the individual systems. At country level, wind and solar power output across Sweden are negatively correlated from hourly to annual time scale (Widén, 2011), and the combined output variability can be minimized with a mix of 30% solar PV and 70% wind power.

Although categorized as CRE, hydropower received relatively less attention with regard to its complementarity with other renewables. Mason et al. (2010) argues that 32% of existing fossil-fuel generation in New Zealand power system can be largely replaced by wind power while maintaining the existing high hydropower penetration level, at around 60%. François et al. (2016a) reported that integrating solar PV and run-of-the-river (RoR) hydropower has positive influence on the energy balance in the Northern Italy. Furthermore, with the capability of dispatch and storage, hydropower offers more benefits than its generation complementarity with other CREs in a system. Pumped-storage hydropower stations equipped with variable-speed pump can not only increase wind power penetration in a power system but also bring remarkable economic benefits (Anagnostopoulos &Papantonis, 2007).

Most studies on CRE integration focus on a single resource or a combination of two, usually wind and solar. There is a need for a common framework to evaluate the integration of all the three CRE resources in power systems (Engeland et al., 2017). François et al. (2016b) re-estimated the optimal mix of solar and wind power by introducing RoR hydropower in 12 regions in Europe. They found that integrating RoR hydropower can increase overall CRE penetration by up to 8%. Schmidt et al. (2016) estimated the optimal mix of the CREs in Brazil power system, and simulated the thermal power dispatch in the system. They demonstrated that a combined hydro-wind-PV system can largely reduce the need for thermal power generation compared to hydro-thermal only system.

All the regional CRE integration studies in this sub-section are based on minimum cost optimization. One critical issue of this approach is the cost can be underestimated if flexibility requirements are not properly modelled (IRENA, 2017b). This issue can be exaggerated if the models use coarse temporal and spatial resolution, which often occurs due to limited computational resource. However, the scope of this research covers every country, and the spatial granularity is set to be subnational level. There is a need to develop new methods to model CRE integration in high resolution but avoids long solving time. Flattening the residual load or portfolio output may be possible directions to approach the optimal mix.

2.2.2 Residual load variation

Power demand profile in a system can be driven by local climate variation as well as human social and economic activities (Engeland et al., 2017). From the climate perspective, seasonal variability reflects on base load. Peak and intermediate load are typically influenced by weather conditions. Human activities also drive the regular variations on seasonal, weekly and daily basis. Residual load is defined as the difference between power demand and generation from must-run units. The generation from CRE is regarded as must-run in this research. As such, residual load variation reflects the requirement for flexible and reliable generation units in a system. High CRE penetration may increase residual load variation. For instance, in the Nordic Countries, high penetration of wind power can increase residual load variation and reserve requirements (Holttinen, 2005).

Some studies have investigated the optimal CRE mix that minimizes residual load variation. Sousa & Martins (2013) investigated the optimal CRE mix in the Portuguese power system. They found the optimal mix will require higher share of hydropower and PV production and less wind power compared to the existing case, and the optimal mix can effectively reduce the residual load variation. This is because wind generation in the system is less correlated with the demand profile in the system. Stetter (2012) formulated three optimization models: minimum production cost, minimum wind and PV output variance, and minimum residual load variance to evaluate the optimal mix of renewable generation. The study used Morocco as a case to compare the performance of the models. However, the study does not include hydropower in the models. The proposed three models are in fact a good reference for this research. The optimal mix of CRE in a country can be based on all these objectives.

2.2.3 Portfolio output variation

In most energy system models, cost optimization is a common modelling approach. When evaluating renewable integration in a system, the cost elements can include flexibility measures, storage, grid connection, and back up units. However, it can be difficult to incorporate the uncertainty on the cost variation in the long run with this approach. As mentioned in the previous sub-sections, one of the model developed in Stetter (2012) is based on minimum wind and PV output variance. This inspires an investigation into minimizing CRE portfolio output variation.

Originally applied in financial area, modern portfolio theory (MPT) (Markowitz, 1952) has been applied in energy system planning. The application of this theory is mean-variance portfolio (MVP) analysis. Studies that applied MPT for energy system planning are mostly based on economic criteria, i.e. the risk is associated with the uncertainty on cost or return such as fuel price and exchange rate. Awerbuch described the original idea of applying MVP in energy system planning (Awerbuch, 2006).

The author indicated that adding renewables to a power system can reduce generation costs and enhance energy security. Cucchiella et al. (2017) investigated the profitability of renewable mixes for the Italian power market using MVP. They concluded that a mix of small hydro and wind is more profitable and sustainable. At whole power system level, using MVP analysis Zhang et al. (2018) reported that applying a non-fossil generation target will reduce the overall cost and risk of the power system in China, as well as improve the diversity of generation sources. Technical constraints can also be taken into account in MVP analysis. Delarue et al. (2011) compared the outputs from a standard MVP model and an MVP model with ramping limits. They suggested that the technical constraints will significantly reduce the penetration of wind power.

A small group of studies have applied MVP analysis on the variability of power output instead of economic factors. An early study on renewable integration with this approach was completed by Traube et al. (2008). The authors developed an optimization model that finds the minimum variation of portfolio output. The results show that diversification either on technology options or geographical sites can reduce overall output variability. Roques et al. (2010) used a similar approach to study the optimal distribution of wind power capacity in European countries with constraints on resource potential and transmission. They highlighted the benefits of coordinated deployment on wind power across the countries. Rombauts et al. (2011) further considered cross-border transmission limits. They concluded that the increase of transmission capacity can effectively flatten the overall wind power output profile in grid connected countries in Europe. Note that, in Roques et al. (2010) and Rombauts et al. (2011), the portfolio return was defined as average capacity factor of wind power over different locations, and the portfolio risk was defined as the variance of wind power output variation. Shahriari & Blumsack (2018) studied the optimal wind and solar power portfolio with MVP in the Eastern Interconnect regions in the US. They indicated that the blended portfolios perform better than any single technology at hourly, daily and weekly scales.

2.3 Electricity system modelling

This review section introduces the models and tools for large-scale electricity system modelling. These models can be a sub-module of an IAM or ESM, but this section concentrates on stand-along models which usually cover more technical details. Several models and tools are selected for comparison which covers their purpose, resolutions and capability on modelling system flexibility. This comparison helps to identify key directions for developing the models in this research.

2.3.1 Large-scale electricity system models

There has been numerous studies and models proposed for analyzing the transitions of electricity sector. They can be a module in an IAM or ESM. These models were developed to evaluate the interactions between sectors from a holistic perspective. They can cover a wide range of energy, economics and environment aspects. Such examples of IAM with global coverage include: AIM, ETSAP-TIAM, GCAM, MESSAGE, PLOES, REMIND, WITCH models. They can be found in the IPCC report (IPCC, 2014) in which future energy projections from these models are sorted for comparison. Examples of regional or national EMS include WEM[3], NEMS[4], and PRIMES[5]. There are also modelling tools for building ESM that offer good flexibility in customizing configurations. Examples of such flexible tool are TIMES[6] and OSeMOSYS[7]. These models and tools were developed to analyze energy mix, commodity trade, transmission, investment decisions, total emission, system reliability, market price and social welfare etc. Usually they are developed with bottom-up approach in order to incorporate as much technical details as possible. Electricity in these models is treated as a commodity, and the electricity sector is combination of a set of energy conversion processes. In some ESMs, the electricity sector is developed as independent modules, such can be seen in NEMS and PRIMES. The electricity sector modules inherit the overall method from the core model, i.e. using the same elements in the objective function, and interact with the core model with hard links.

There is a number of stand-alone electricity sector models or tools. Table 2 summarizes a list of selected models and tools for large-scale electricity system modelling. These models were developed with diverse methodologies for different purposes. Similar to ESM, common methods in electricity system modelling are mathematical programming, simulation, partial equilibrium and hybrid models. The mathematical programming approach, or optimization-based approach, can be further divided into linear programming, non-linear programming, mixed integer programming, quadratic constrained programming and dynamic programming etc. Models or tools based on this method

[3] World Energy Model (WEM) is a simulation model developed by IEA. This model produces the scenarios and materials for the annual publication *World Energy Outlook*. Several assumptions in this present research refers to the data by this model. Introduction: https://www.iea.org/weo/weomodel/

[4] National Energy Modeling System (NEMS) is an energy system model developed by EIA. This model produces the materials for the *Annual Energy Outlook* of the US. Information: https://www.eia.gov/outlooks/aeo/info_nems_archive.php

[5] PRIMES is a partial equilibrium models that simulates the energy market in the EU. It is created by E3MLab. Information: https://ec.europa.eu/clima/policies/strategies/analysis/models_en

[6] TIMES is an energy system modelling tools developed by IEA-ETSAP. It is widely used for national energy system modelling. Information: https://iea-etsap.org/index.php/etsap-tools/model-generators/times

[7] OSeMOSYS is open source energy modelling tool. Information: http://www.osemosys.org/

include Calliope, ELMOD, EMMA, LUT ETM, Flextool, LIMES-EU, SWITCH, ReEDS, REMix and WeSim. Models of this type aim to produce optimal solutions with respect to applied constraints. However, they tend to require more computational resources and typically perform at lower temporal and spatial resolution compared with simulation based models. Application of these optimization model is less limited, when compared with simulation approach, since technical and operational details can be converted into mathematical equations more directly.

An example of simulation approach is NEMO. Most agent-based models (ABM) are also based on simulation approach in calculating market clearing price and investment signals. Simulation models can generally overcome the disadvantage of long execution time in optimization-based models. However, they typically cannot deal with much of technical and operational constraints. Agent-based models, can be categorized as hybrid model, are attracting more attention in recent years, the examples include AMES, EMACS and PowerACE. The calculation of market clearing price in these models is usually based on merit order simulation while optimization based approach can be applied when integrating transmission power flow, such can be seen in AMES.

As for the purpose of the models, in addition to supporting dispatch operation and capacity expansion decision, some models are specialized in analyzing large share renewables integration in a system, for example Flextool, LUT ETM, NEMO, SWITCH, ReEDS, and REMix. A group of models, including AMES, ELMOD and EMCAS, have a focus on electricity market simulation and estimating market price. Agent-based models are particularity developed to simulate the interactions of each actors in a market. They try to reflect the imperfect competition or irrational behavior in the real market while this in an optimization model is always assumed to be ideal.

Temporal resolutions and spatial coverage in the models vary widely regarding their purposes. Most of the existing models have fixed temporal resolution setting, and the geographical coverage is usually at national or continental level, mostly focus on EU countries or the North American power system, e.g. DESSTinEE, ELMOD, LIMES-EU, ReEDS and REMix. Some models were developed to investigate zonal electricity supply and demand in a country, e.g. PowerACE and WeSIM. For temporal resolution, most models use dozens of representative time-slices, while some models can perform with hourly resolution. The hourly resolution is usually adopted in models specialized in large share of VRE integration, for example ELMOD, EMMA, REMix and SWITCH. To the author's best knowledge, the most detailed global model is LUT ETM model which evaluates the possibility of 100% renewable system in 145 regions at hourly resolution.

Some commercial modelling tools, for example BID3, EGEAS and PLEXOS, provide numerous

functionalities, such as demand response, system reliability, cascade hydropower systems, stochastic simulation and integrated resource plan and so on. The temporal resolution and spatial coverage can be defined by the user. Conversely, some models are available in open-source form, such as Calliope, ELMOD and Flextool. Note that Table 2 summarizes only a part of the features in the models and tools. These features are the key implementations in this work. In fact the listed models offer diverse capabilities based on their purposes.

Table 2. The list of selected large-scale electricity system models.

Methods: ABM - agent-based model; Sim - simulation; LP – linear programming; NLP – non-linear programming; DP – dynamic programming; MIP – mixed integer programming; MILP – mixed integer linear programming; **Availability**: open – open source or free; Com – commercial; **Application:** UC- unit commitment; ED – economic dispatch; CE – capacity expansion; **Temporal resolution**: LDC – load duration curve; TS – time-slice; **Transmission**: DC-OPF – DC optimal power flow; AC-OPF – AC optimal power flow; **Reserves**: CM – capacity margin; AS – ancillary services;

Model Name	Type	Methods	Availability	Application	Temporal resolution	Spatial coverage	Hydro dispatch	Storage units	Grid	Reserves	Reference
AMES	Tool	ABM/LP	Open	UC/ED/Market	Flexible	Flexible	NA	NA	DC/AC-OPF	CM	Krishnamurthy et al. (2016)
BID3	Tool	LP/MILP	Com	ED/CE/Market	LDC/Flexible	Flexible	YES	YES	NTC	AS	Pöyry (2019)
Calliope	Tool	LP	Open	ED/CE	Flexible	Flexible	NA	YES	NTC	CM	Pfenninger &Pickering (2018)
DESSTinEE	Model	Sim	Open	ED/CE	Hourly	EU Countries	YES	YES	NTC	NA	Bobmann &Staffell (2015)
EGEAS	Tool	NLP/DP	Com	ED/CE	LDC/Flexible	Flexible (10)	YES	YES	NTC	CM	EPRI (2019)
ELMOD	Model	LP	Open	ED/CE/Market	Hourly	Countries	NA	YES	NTC/DC-OPF	NA	Leuthold et al. (2012)
EMACS	Tool	ABM/Sim	Com	CE/Market	Hourly	Flexible	NA	NA	DC/AC-OPF	AS	Macal et al.(2015)
EMLab	Tool	ABM/Sim	Open	Market	LDC	Countries	NA	NA	NA	CM	Chappin et al. (2017)
EMMA	Model	LP	Open	ED/CE	Hourly	Countries	YES	YES	NTC	AS	Hirth (2015)
Flextool	Tool	LP	Open	ED/CE	Flexible	Flexible	YES	YES	NTC	CM	IRENA (2018b)
LIMES-EU	Model	LP	NA	ED/CE	TS	Countries	YES	YES	NTC	NA	Nahmmacher et al. (2014)
LUT ETM	Model	LP	NA	ED	Hourly	Global 170 reg.	YES	YES	NTC	NA	Bogdanov et al.(2019)
NEMO	Model	Sim/Hybrid	Open	CE/Market	Hourly	Country	YES	YES	NTC	NA	Elliston et al. (2013)
PLEXOS	Tool	LP/MILP	Com	UC/ED/CE/Market	LDC/Flexible	Flexible	YES	YES	DC-OPF	AS	Energy Exemplar (2019)
PowerACE	Model	ABM/Sim	NA	ED/Market	Hourly	Germany(nodes)	NA	YES	AC-OPF	AS	Sensfuß (2007), Ringler et al. (2016)
ReEDS	Model	LP	NA	ED/CE	TS	US 336 reg.	NA	YES	DC/AC-OPF	CM/AS	Short et al. (2011)
REMix	Model	LP	NA	ED	Hourly	EU (nodes)	YES	YES	DC-OPF	CM	Scholz (2012), Stetter (2012)
SWITCH	Tool	MIP	Open	ED/CE	Hourly	Country (nodes)	YES	YES	NTC/AC-OPF	CM	Fripp (2012)
WeSIM	Model	MILP	NA	ED/CE	Hourly	UK 5 reg./ Europe 76 reg.	YES	YES	NTC	AS	Pudjianto et al. (2014), Green et al. (2016)

2.3.2 Dispatch operation and capacity expansion

Dispatch operation is to decide the best output level of each generation units in an electricity system with constraints on security, economic and environment aspects. A system usually operates with an economic dispatch (ED) approach which minimizes the overall variable generation cost. In a simulation model, this can be implemented with merit order approach. This approach simply sorts all available generation units and picks the one with the least variable generation cost to produce electricity. This process iterates until demand is completely served. This approach is simple and fast, but it has difficulties in modelling certain technical constraints such as minimal load, interconnection, and storage operation and so on. Yet these technical and operational details still can be implemented with simple algorithm for approximation, for example the inter-zone transmission algorithm in NEMO and DESSTinEE. The simulation of storage operation considering market price and profitability can also be seen in the study by Ward &Staffell (2018). Mathematical programming approach can integrate more technical details. For example, unit scheduling, or unit commitment, which considers minimum load, start-up time, ramp rate, and minimum up time etc. can be easily implemented in optimization models. These technical constraints can be found in Plexos, SWITCH and WeSIM. Dispatch operation in these models usually needs to satisfy reliability requirements and to integrate flexibility measures. Note that unit commitment is to decide the status of all available units in a system in a time period from hours to months. It is an extension of dispatch problem and the constraints can cover reliability, maintenance scheduling, and storage operation. Some of the models listed have implemented the function of unit commitment.

Market simulation is a critical part in ABM. The market may include day-ahead mark, intraday market, real-time market and capacity market etc. Merit order simulation is a simple approach to simulate dispatch decision in a market. Again, when it comes to integrate technical and operational constraints in a market, an optimization-based approach is more suitable. In this regard, AMES, to the

author's knowledge, is one of the most detailed ABM modelling framework. It relies on optimization modules to perform security constrained unit commitment, security constrained economic dispatch and optimal power flow.

Capacity expansion (CE) is to find the best investment options in the long run by taking account of resource availability, system reliability, profitability and environmental impact and so on. This problem can be much complicated when considering a wide range of new technologies in the future. Also, as more intermittent renewable and storage units are expected to present in the global electricity systems, system reliability is becoming an issue. CE problem is, therefore, becoming a crucial part in the future electricity system decarbonization modelling. In some models, CE problem is replaced with pre-defined scenario cases, such can be seen in PowerACE and REMix. The advantage is the reduced modelling complexity.

The CE problem in NEMO is solved with a heuristic approach – genetic algorithm. In ABM models, CE can be implemented by evaluating the profitability of new options. The generation company agents calculate the profitability of an investment option using future estimations on expected generation, fuel price, carbon cost and market price. Since different financial evaluation criteria is applied to the agents, it can result in different investment priority of the agents. Such setting can be found in EMCAS and PowerACE. A more sophisticated investment simulation can be found in the agent-based model BRAIN-Energy (Barazza, 2019). In this study, the market players were further categorized into several types of player. All these players have different characteristics on their aim, preferences, foresight and cost of capital.

The temporal detail in an electricity system model can be full hourly in time series, typical days or weeks, selected time-slices or load duration curves. As noted previously, modelling with coarse temporal resolution can make VRE more preferable and underestimate the need for dispatchable units in a system (Nahmmacher et al., 2016). On the other hand, modelling in full hourly resolutions requires considerable computational resources. CE is more commonly constructed with optimization-

based approach. In optimization models, CE can be built on dispatch problem but with reduced temporal resolution since more constraints need to be applied. The selection of representative time-slices is important and it can influence the results considerably. Some of this issue has been discussed in the previous section. If the selected time-slices cannot reflect all representative supply and demand cases in a year, the CE model may underestimate the reliability issue. For this reason, LIMES-EU developed an approach in selecting representative time-slices. Several types of method in reducing time resolution have been proposed, including downsampling, clustering, and heuristics approaches. While selecting the time-slices should depend on the model design and input data, Pfenninger (2017) suggested that heuristic approaches appear to be more effective.

2.3.3 System flexibility

In a high VRE share electricity system, several flexibility measures are essential to maintain the system reliability. In the long-term, capacity adequacy has to be addressed in CE planning. A model has to ensure sufficient firm capacity or interconnection in a system as VRE increases. A simple way to achieve this is to set a required capacity margin in both ED and CE model. This can be seen in several models in Table 2. In the short-term, several measures can contribute to improve system flexibility include: flexible conventional unit, flexible hydropower operation, energy storage, reserve services, interconnection and demand side measures. These measures have been implemented to certain extends in the models listed.

Storage system is an effective approach in balancing supply and demand. Common storage technology include pumped hydro storage, batteries, compressed air storage and hydrogen. Most of the models in Table 2 have integrated storage system as flexible units. However, it may be difficult for agent-based models to simulate storage operation in a market. At the writing of this research the most common type of storage system is pumped hydro storage (PHS) system which accounts for more than 90% in the total installed capacity globally (IRENA, 2017a). Most of the listed optimization

models have PHS implementation with intraday operation constraints.

Grid connection is another critical source of system flexibility. It can be modelled at different technical levels. The most common approach is net transmission capacity (NTC). It is the capacity available for commercial transactions with proper reliability margin. This definition is sometimes unclear in the models. Some implementation based on transport model, with capacity limit, is also referred as NTC. AC-optimal power flow (AC-OPF) is the most complex approach which is usually used for analyzing regional power grid system. However, physical features in grid system of AC power network may not be a major concern in a large-scale electricity system problem. DC-optimal power flow (DC-OPF) is an approximation approach of AC-OPF. The power flow and transmission capacity limit is rather static compared with AC-OPF, but the problem scale and the non-linearity can be simplified. Either DC-OPF or AC-OPF requires a clear grid network at physical level. All the above mentioned approaches are only possible to be implemented in optimization models.

To ensure a stable balance in an electricity system, especially during contingency events, a system need to maintain certain amount of capacity reserve at any time. Typically only flexible and dispatchable units are qualified to provide capacity reserve. This mechanism can be implemented in both ED and CE models as required capacity margin. This is a common implementation in the listed models. Reserve services, or frequency regulation services, or ancillary services, are measures to maintain the frequency at specific range in an electricity system. They are typically divided into three stages: primary reserve, secondary reserve and tertiary reserve. The capability of a unit to provide addition output upon request depends on its ramping capability. Different technologies are suitable for different reserve services. The constraints of reserve services have been developed in some of the models, such as BID3, PowerACE, ReEDS and WeSIM. This implementation can better capture the physical limits of a generation unit than simply use a capacity margin.

2.3.4 Global electricity sector decarbonization pathways

According to IPCC (Rogelj et al., 2018), to limit the global warming below 1.5°C and 2°C, the remaining global carbon budget are estimated at 420 $GtCO_2$ and 1170 $GtCO_2$ from 2018 with greater than 66% probability. Several process-based IAMs that cover all sectors and regions have proposed hundreds of pathways that can achieve the targets. There have been 89 pathways compatible with 1.5°C mitigation goal proposed. For electricity sector, the supply from renewables in these pathways ranges from 59% to 97%. The share of wind, solar, hydropower and biomass in the composition, however, varies widely in the pathways. Nuclear and fossil fuel CCS are the other two pillars for providing low-carbon electricity. BECCS is particularly important to produce negative emissions in the electricity sector.

Aggressive projections of renewable development can be seen in many studies. IRENA suggests that renewable energies can make up 86% of electricity generation in 2050 (IRENA, 2019a). Wind and solar PV account for 60% of generation in its scenario, and the capacity of wind is over 6,000GW and solar PV is over 8,500GW. There are studies look at even higher renewable generation without other low emissions sources. In the Energy Revolution scenario proposed by Teske et al. (2015) the global electricity supply can source from renewables up to 92% by 2050. In this scenario intermittent sources wind and PV, with 5,575GW and 6,745GW capacity respectively, make up 55% of the generation. More radical pathway to 100% renewable in 2050 proposed by Bogdanov et al. (2019) using the LUT ETM model. The pathway presents a very high share of PV at around 70% in 2050 which is enabled by substantial growth of storage capacity.

2.4 Summaries and research objectives

The main research question to be answered in this research is: What are the possible pathways in decarbonizing the global electricity sector in the future and what is the role of VREs? This high level question and can be answered from many possible perspectives. There have been many studies attempting to provide related insights. Most of them either focuses on specific regions or oversimplify

the space-time energy production profiles of VRE, possibly leading to less useful overall insights. Hence, this present research is attempting to answer this question in a series of works.

From the literature review in section 2.1, it has been found that temporal and spatial resolution in an ESM can significantly influence the outcome regarding long-term capacity mix. The reduced resolution of global models may underestimate the power output variability of VRE and the need for flexible units especially for large systems such as China and the USA. The need to use sub-country level energy potential assumption and spatial representation is identified consequently. Regarding temporal resolution, there is a trend to shorten the frequency to hourly in order to capture the variability of VRE in global electricity system models. However, none of the existing studies provide the material in subnational and hourly resolution dataset freely available. Therefore, the first part of this research has to generate the datasets necessary for the modelling work later on in sufficiently high spatial and temporal resolution. The resulting materials can also be essential inputs for other ESMs which need VRE output profiles at higher resolution.

All the studies in Table 1 proposed different level of global wind and solar energy potential. Several factors may contribute to the differences, such as data resolutions in the estimation processes and the constraints applied to evaluate suitable development area. Since the proposed energy potentials in the studies are several times higher than global electricity demand, this research may apply relatively conservative constraints to evaluate available land for the deployment of VREs. The capacity potential can also be classifies by energy production level which can form a supply curve, as this has been done in some of the studies.

Almost every existing energy potential studies rely on land cover maps to evaluate suitable area. However, the accuracy of land cover maps can be an issue since they are produced from satellite images. A potential approach to improve the accuracy is to use the information from VGI platforms such as OSM. The vector-based data extracted from OSM can be used to update the land cover maps, and it also provide necessary information for identifying restriction area. To the author's knowledge,

there is no other study that has made this effort at global scale prior to this research.

From the literature review in section 2.2, it is clear that wind, solar and hydropower exhibit different levels of space-time output variability. The output complementarity between wind and solar power can be observed commonly. This feature has positive impact on CRE integration. However, hydropower received less attention with regard to its complementarity with wind and solar power. Studies have proven that a combination of all three types of CRE can increase the penetration of clean energy and reduce overall output variability. Also, most of existing VRE integration studies are carried out for developed countries. The review inspires a motivation to estimate the optimal mix of CRE in every region or country.

Electricity system models are commonly based on minimum cost optimization. This approach is typically limited by computing resources when temporal and spatial resolutions increase. Residual load variability can link to the requirement for flexible and reliable generation unit in a system. There are studies approaching this issue with this criteria. On the other hand, some studies have looked at minimizing portfolio output variability which also link to optimizing the complementarity between CREs. MVP analysis is identified as a promising approach in the review, and this approach can be applied over different time frequencies. In addition to minimizing cost, there seems a potential direction to approach the optimal mix of CRE from reducing residual load variability or portfolio output variability. This research may develop models using these objectives, or a combination of them, to estimate the optimal mix of renewables for every country.

The main purpose of the research is to assess future decarbonization pathway of the electricity sector around the world, with a particular focus on renewable energy integration. This requires a practical electricity system model. Section 2.3 reviews current large-scale electricity system models and tools. They are selected for comparison according to their purpose, resolutions and capability on modelling system flexibility. Most of the existing models are optimization-based mathematical models which have better capability to integrate the operation and investment decision. This research

is then intended to construct a framework that accommodate models for electricity dispatch and investment decision modelling based on cost optimization. The importance of measures to improve flexibility, including hydropower dispatch, storage operation, grid and capacity reserve, in an electricity system with high VRE penetration has been acknowledged in the review. Few of the previous models have cover all these measures. This research will attempt to incorporate all these measures. The VREs development limits and energy output profiles in each representative zone and country from previous works are critical inputs for this work. This work is intended to reflect the limits on VREs distribution and capture their space-time energy production characteristics. The last part is to define scenarios, run the models, compare results and discuss possible pathways of future global electricity sector decarbonization.

3. Methods

This chapter introduces methods of the three main works suggested in the review section: global VRE potential assessment, estimating the optimal mix of CREs and global electricity system decarbonization modelling.

3.1 Global variable renewable energy potential assessment

The flow chart of the overall processes is shown in Figure 1. In this work, hourly meteorological data from the MERRA-2 database are used to simulate hourly CF at each grid point. The average CF maps at 1km resolution was then produced by reconciling the data from MERRA-2 and GWA and GSA maps. This idea was first implemented in Bosch et al.(2017) for onshore wind energy potential assessment to increase the spatial resolution which can better capture topographical details. The land cover map is refined with features from the OSM. Based on this, the eligibility maps for VREs development are produced using constraints derived from other maps and OSM features. Finally, all the materials are convolved to generate hourly CF and capacity potential which are further classified into several tranches in each zone.

All the data used, along with their source, resolution and processing steps are summarized in Table 3. The technologies assessed in this work include onshore wind, offshore wind, fixed-tilt utility-scale PV, one-axis tracking utility-scale PV and parabolic though CSP. The subnational geographic boundary of “zones” is defined based on several criterial. The geographic potential is assessed using several constraints and land suitability. Features from OSM are extracted and used to improve land cover maps, and to create eligibility maps. This study estimates the energy potential by simulating hourly capacity factor (CF) with historical meteorological assimilation data. The spatial resolution of the assessment is improved by reconciling the two data resources. The final outputs of each technology in the zones are: 1. CF raster maps; 2. eligibility maps; 3. capacity supply curve by CF

tranche classes and; 4. hourly CF profile by CF tranche.

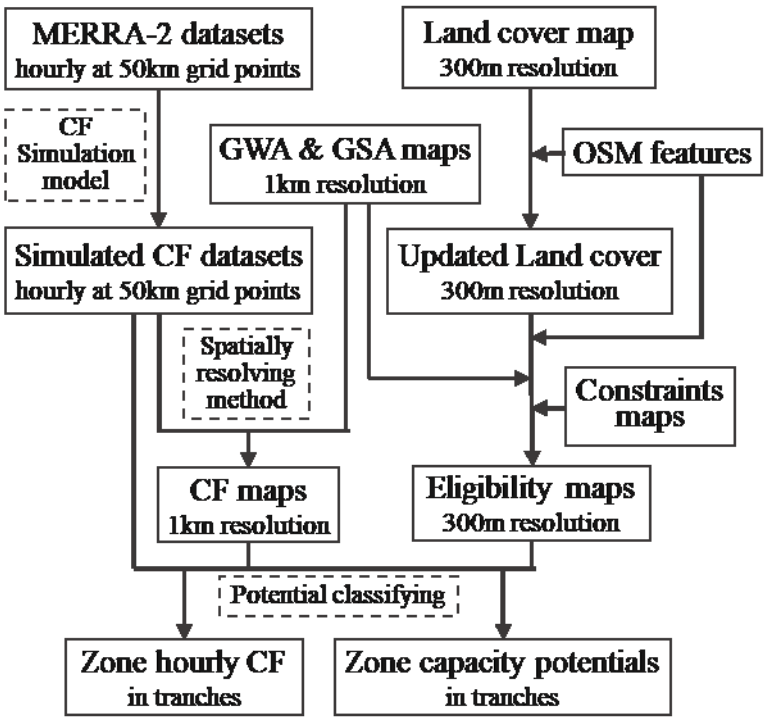


Figure 1. The overall flow chart of the data and processes in this work.
This procedure was applied to all VREs modelled.

NASA's MERRA-2 datasets are used for CF output simulation, as it provides all the required meteorological data, and is freely available in 0.625°×0.5° resolution (approx. 64 km × 54 km at equator). Ten years data, from 2008 to 2017, of all gridded locations globally was collected at hourly resolution. This time period is chosen for the clear uptake of extreme climate events (NOAA, 2019b) and global temperature (NOAA, 2019a) over the past decades. Also, the data processing and modelling works in this research requires considerable computational resource and data storage. This research is not intended to manipulate hourly data spanning over than ten years.

Table 3. All data used and produced in this study with their source, resolution, and processing steps.

The code in the second column is to specify the original or produced materials in this work. The third column indicates the relation of data processes using this code.

Data group	Code	Processed from	Data description	Spatial Res.	Temp. Res.	Data source
Zone	BN		Global administrative area boundaries	Vector		GADM
	BN´	BR	Onshore zones	Vector – 731 zones		
	BF		Global maritime boundaries (EEZ)	Vector		FMI
	BF´	BZ	Offshore zones	Vector – 339 zones		
Physical	PE		Elevation – 1km mean	0.0083°		Amatulli et al.
	PS		Slope – 1km mean	0.0083°		Amatulli et al.
	PL		Land cover map	0.0028°		CCI-LC
	PB		Bathymetry map	0.0083°		GEBCO
	PP		Permafrost	0.0083°		Gruber
Meteorology	MW		Eastward/northward wind (50m)	0.625°×0.5°	87,600 hrs	MERRA-2
	MW´	MW	Wind speed (50m)	0.625°×0.5°	87,600 hrs	
	MI		Surface/TOA incoming shortwave flux	0.625°×0.5°	87,600 hrs	MERRA-2
	ML		Sun's location: zenith, azimuth	0.625°×0.5°	8,760 hrs	
	MI´	MI, ML, MS	GHI, DNI, DHI	0.625°×0.5°	87,600 hrs	
	MT		2-meter air temperature	0.625°×0.5°	87,600 hrs	MERRA-2
	MA		Wind speed map (100m) – 30 km offshore	0.01°		GWA 2.0
	MA´	BF, MW´, MA	Wind speed map (100m) – to EEZ	0.01°		
	MS		GHI, DNI	0.0083°		GSA
	MO		Optimal tilt angle	0.0083°		GSA
OSM	ON		Nature land cover features	Vector		OSM
	OU		Land use features	Vector		OSM
	OS	OU	Land use / social mask	0.0028°		
	OL	ON, OU, PL	OSM Land cover and land use map	0.0028°		
	OR		Road features	Vector		OSM
	OP		Power features	Vector		OSM
Other	TL	PL, OL	Updated land cover and land use map	0.0028°		
	TP		Protected areas	Vector		WDPA
	TS		Global shipping route record 2008/2013	0.0083°		Halpern et al.
	TU		USA shipping route record 2013	0.009°		NOAA
Onshore wind	NE	PE, PS, PP, MA´, OS, OR, TL, TP	Eligibility mask	0.0028°		
	NS	TL	Suitability map	0.0028°		
	NC	MW´, MA´	Simulated capacity factor (10 classes)	0.625°×0.5°	87,600 hrs	
	NM	NC, MA´	Avg. capacity factor map	0.01°		
	NV	BN´, NE, NS, NM	CF-capacity supply curve	731 zones		
	NP	BN´, NC, NM	Simulated capacity factor (10 classes)	731 zones	87,600 hrs	
Offshore wind	FE	PB, OS, TP	Eligibility mask	0.0083°		
	FS	TS, TU	Suitability map	0.0083°		
	FC	MW´, MA´	Simulated capacity factor (10 classes)	0.625°×0.5°	87,600 hrs	
	FM	FC, MA´	Avg. capacity factor map	0.01°		
	FV	BF´, FE, FS, FM	CF-capacity supply curve	339 zones		
	FP	BF´, FC, FM	Simulated capacity factor (10 classes)	339 zones	87,600 hrs	
Utility PV	UE	PS, PP, OS, OR, TP	Eligibility mask	0.0028°		
	US	TL	Suitability map	0.0028°		
	UC	MI´, MS, MT, MO	Simulated capacity factor	0.625°×0.5°	87,600 hrs	
	UM	UC, MS	Avg. capacity factor map	0.0083°		
	UV	UE, US, UM	CF-capacity supply curve	731 zones		
	UP	BN´, UC, UM	Simulated capacity factor (7 classes)	731 zones	87,600 hrs	
Distributed PV	DS	TL	Eligibility / Suitability map	0.0028°		
	DC	MI´, MS, MT	Simulated capacity factor	0.625°×0.5°	87,600 hrs	
	DM	DC, MS	Avg. capacity factor map	0.0083°		
	DP	BN´, DC, DM	Simulated capacity factor (7 classes)	731 zones	87,600 hrs	
CSP	CE	PS, PP, MS, OS, OR, TP	Eligibility mask	0.0028°		
	CS	TL	Suitability map	0.0028°		
	CC	MI´, MS, MT	Simulated capacity factor	0.625°×0.5°	87,600 hrs	
	CM	CC, MS	Avg. capacity factor map	0.0083°		
	CV	CE, CS, CM	CF-capacity supply curve	731 zones		
	CP	BN´, CC, CM	Simulated capacity factor (5 classes)	731 zones	87,600 hrs	

3.1.1 Data preparation for wind and solar energy assessment

For wind assessment, this study collects hourly eastward[8] and northward[9] wind speed at 50m height from MERRA-2 database[10]. The hourly wind speed, as labeled MW´ in Table 3, is calculated using the two data items based on trigonometric relation. To assess the energy potential at finer resolution, this study uses the global wind resource maps from Global Wind Atlas platform (GWA 2.0)[11] (Badger et al., 2015) for resolving the spatial resolution. The GWA maps were developed by a downscaling process with MERRA-2 mesoscale data considering local topography and surface type. It provides global average wind speed maps at 50m, 100m and 200m height at around 1 km^2 spatial resolution. The wind speed raster map at 100m is used in this study.

One limit of the GWA map is that it only covers the area within 30km of the coast. This is a problem for assessing the offshore wind potential since the potential area can extend to the end of exclusive economic zone (EEZ), around 370 km from the coastline. To overcome this problem, extrapolation by combining the MERRA-2 data and the GWA map is performed. Within 30km of the coast, the GWA is used. From the 30km to the end of EEZ (Flanders Marine Institute, 2018), the value of each raster cell is gradually blended linearly with the annual average MERRA-2 wind speed at each grid point. Figure 2 shows an illustrative figure for this process. The cell A and the surrounding points in green color are covered by GWA maps. The cell B to F in blue color are the grid locations where data is available from MERRA-2 at around 50km resolution, where the value of cell A is also available but it already covered by GWA. In this figure, the wind speed at cell G is calculated by bilinear interpolation using values in A,B,D and E. The values in the empty cells are produced with this simple approach. The resulting wind speed map is based on GWA maps' resolution, around 1km. A new average wind speed at 100m

[8] Global hourly instantaneous eastward wind speed at 50m height: U50M in dataset M2I1NXASM

[9] Global hourly instantaneous northward wind speed at 50m height: V50M in dataset M2I1NXASM

[10] Available at https://goldsmr4.gesdisc.eosdis.nasa.gov/data/MERRA2/M2I1NXASM.5.12.4/

[11] Global Wind Atlas platform https://globalwindatlas.info/

height raster map is produced, as labeled MA´ in Table 3.

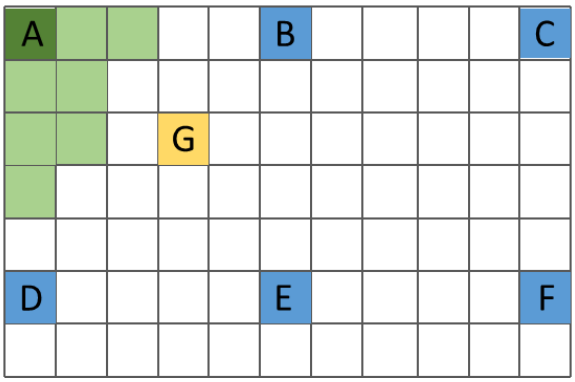


Figure 2. Illustrative figure for blending the two wind resource data in offshore area.

Before performing the above wind speed blending, the MERRA-2 wind speed data at 50m height has to be projected to 100m. The log law approach is used for wind speed extrapolation. The equation is shown as (1.1), where v is wind speed to be calculated at height z; v_r is known wind speed at height z_r; and z_o is a parameter of roughness length (Manwell et al., 2010). Because the blending only applied on offshore area, it is assumed that the surface roughness length in the formula is 0.0002m, as this suggested in Manwell et al. (2010).

$$v = v_r \cdot (ln(z/z_0)/ln(z_r/z_0)) \qquad (1.1)$$

The hourly data collected from MERRA-2[12] for solar energy assessment includes surface[13] and top of atmosphere incoming[14] shortwave flux, and 2-meter air temperature[15]. These datasets are essential for deriving hourly energy output for all solar technologies. The solar resource raster maps used for improving spatial resolution are available on the Global Solar Atlas (GSA) platform[16]. The maps were developed by Solargis (2018) . The maps include average Global Horizontal Irradiance (GHI), Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DHI). Similar to GWA maps,

[12] Available at https://goldsmr4.gesdisc.eosdis.nasa.gov/data/MERRA2/M2T1NXRAD.5.12.4/

[13] Global hourly mean surface incoming shortwave flux SWGDN in dataset M2T1NXRAD

[14] Global hourly mean top of atmosphere incoming shortwave flux SWTDN in dataset M2T1NXRAD

[15] Global hourly mean temperature: T2M in dataset M2I1NXASM

[16] Global Solar Atlas platform https://globalsolaratlas.info/

the maps were produced from solar radiation models with data from several geostationary satellites. The downscaling process in the models take into account the effects of surrounding terrain and temperature. The dataset covers areas between latitudes 60°N to 45°S in 0.0083°arc-degree (approximately 1 km^2) resolution. The area outside this latitude range is excluded in this study. This exclusion has little influence on energy potential since it removes mainly the polar areas in Russia and Canada where are extremely inaccessible.

To estimate hourly energy output of the solar technologies at MERRA-2 grid points, hourly GHI, DNI and DHI data are needed. The surface incoming shortwave flux from the MERRA-2 is regarded as GHI. This work calibrates this hourly GHI values at the grid points with the annual average value on GSA's GHI raster map. The coordinates of a grid point only maps to a 1 km^2 raster cell on the GSA map. To reduce sampling error, this work takes the mean values in 5 km^2 range of the grid point on the raster map for the calibration. The hourly DHI can be estimated by using Clearness Index which is the ratio of surface radiation to extraterrestrial radiation. This work uses the approach proposed by Erbs et al. (1982) to estimate hourly DHI for its simplicity and relatively good performance (Dervishi &Mahdavi, 2012). Since GHI is the sum of DHI and DNI's fraction on Earth surface normal direction, the position of the sun and zenith angle have to be considered. This work uses the method[17] described in Reda & Andreas (2004) to calculate the position of the sun (zenith and azimuth angles) corresponding to the grid point coordinates and the time. Hourly DNI can then be calculated with the GHI, DHI and zenith angle. These processed datasets are labeled as MI´ in Table 3.

3.1.2 Processing the OpenStreetMap features

This study uses the CCI-LC (ESA, 2017) developed by ESA as the base land cover map. The map was produced by relatively new satellite surveys. Its spatial resolution is 0.00278° (approximately

[17] This work used the python package pvlib-python to calculate the solar position. The algorithm is developed by NREL and is available at https://pvlib-python.readthedocs.io/

300m^2) and each pixel is categorized in one of the 22 land cover types. The overall accuracy is around 72%. The accuracy is high for forest, water bodies and permanent snow and ice.

Features on OpenStreetMap (OSM) can be a complementary to the satellite-based land cover map and are necessary for preparing eligibility masks. This work processes the full OSM data package region by region, and extracts features that contain these attributes: natural, land use, highway, aeroway, waterway, amenity and power. The power features on OSM are useful data that indicates the location and type of the power facilities. In this work, location of wind turbines and solar PV systems are extracted, and used to examine how the locations are related to the constraints applied. These power features are important reference for building the links of existing inter-zone grid connection for the research work later on.

As discussed previously, it is possible to improve the accuracy of the satellite-based land cover map by updating with the information extracted from OSM. To the author's best knowledge, no previous study has made this effort at global scale prior to this study. To achieve this, another land cover raster map is created based on extracted OSM features at the same 300m resolution as CCI-LC. The vector-based OSM features are converted into raster form by sampling the central point of each cell. The following is the mapping of land types of CCI-LC to the OSM features tagged with specific attributes:

120 Shrub: scrub, heath
130 Grass: grassland, meadow
202 Sand: sand
203 Rock (not in CCI-LC): scree, shingle, bare rock
180 Wetland: mud, wetland
10 Farmland: allotments, farmland, farmyard, orchard, vineyard
190 urban: residential, commercial

Figure 3 shows how the vector-based OSM features are converted into rasterized map. For example, A is a contour of a residential area and B is meadow noted on OSM. This research converts them into raster-based map with at the same 300m resolution as CCI-LC. The pixels of A' are then

coded in 190 urban and B’ are coded in 130 grass based on CCI-LC coding system. In this case, OSM does not provide information on area C. Therefore, the code of C’ is left blank on this rasterized map. The code of C’ will be updated using CCI-LC’s information to generate a final land cover map.

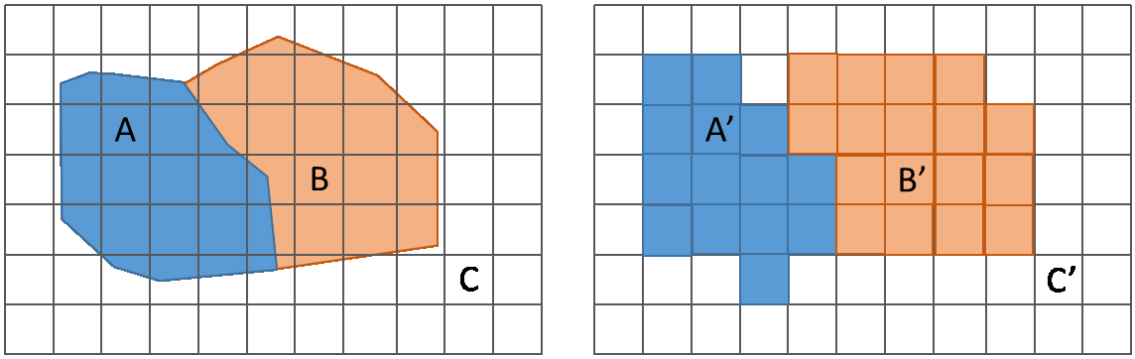
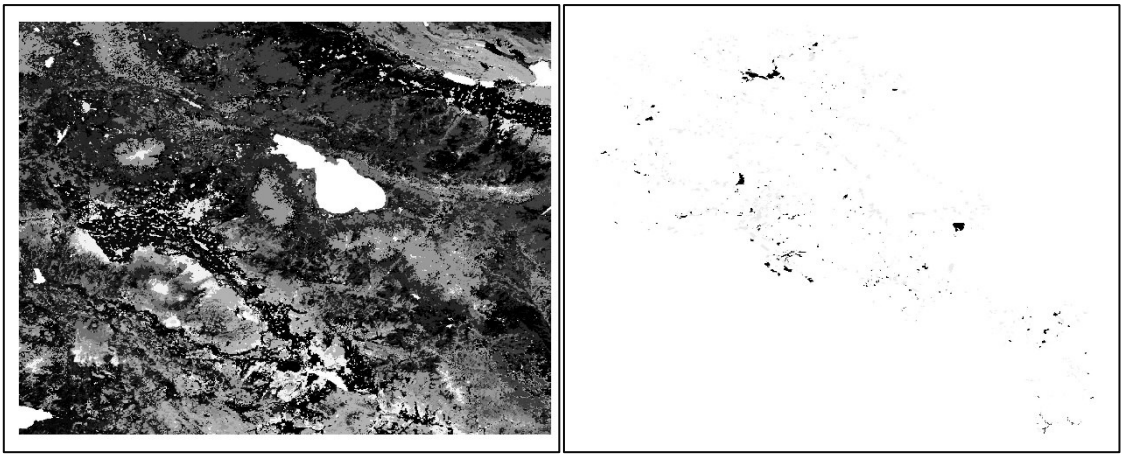


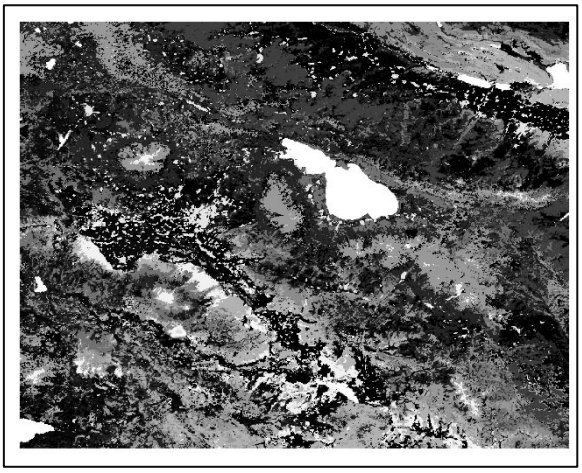
Figure 3. Illustrative figures of OSM features (left) and rasterized map.

Note that forest and water bodies are not included in this process because the CCI-LC map already has high accuracy on these land cover types (ESA, 2017). Also, the huge number of these features slows down the rasterizing process dramatically. The category 203 Rock is created for rocky land that is not suitable for any VRE development. This is to differentiate rocky areas from the main category 200 Bare areas, which is ideal for VRE deployment. The improved land cover map is labeled as TL in Table 3.

Figure 4 demonstrates an example of this process. The original CCI-LC land cover map of Armenia and surrounding area is shown as (A). The grey level color represents the color code defined in CCI-LC, ranging from 0 to 255. The extracted OSM features are converted into figure (B). Only the key features are processed. The white area in this figure has no value. The value in original land cover map is updated with this figure, as shown in the new map (C).



(A) CCI-LC (B) OSM extracted features



(C) New land cover map

Figure 4. Example figures of processing OSM features for Armenia.

The original land cover map (A), rasterized map of extracted OSM features (B), and the new produced land cover map (C) in Armenia.

3.1.3 Creating representative zones

In this research, the smallest geospatial representative area is defined as “zone”. The defining of the smaller representative areas in a country/district is particularly important for big countries such as Brazil, China, Russia and the US. It is noted that there is no single appropriate approach to define the representative zones. Therefore, the creation of the zones is carried out by the following criteria in the order of priority rather than define arbitrarily. First, a survey is carried out for the current power market zones, power distribution regions and existing grid systems. The zones can be defined with

this criteria only for the countries with already well-defined areas in power sector, such as Chile, Italy, Japan, Romania and Thailand. Second, the zones can be defined according to the overall power demand and administrative regions in a country. Most countries are split with this criteria including China, France, Germany, India and the US. This study managed to keep the population of a zone between around 1 to 10 million, and consider the level of power demand at the same time. The North America has around 20 established power market or power reliability assessment areas. However, the zones are not created using the first criterial due to higher demand in this continent. Another reason to regard the 50 states in the US as individual zones is that each state proposes its own renewable target. This might be helpful to model the US energy system planning given that there is no national renewable target. Other criterial include time zone, climate similarity and population distribution. For instance, the Siberia region in Russia is split into three zones due to their different time zone. The Inner Mongolia, Xinjiang and Sichuan provinces in China are further split into two zones due to their large territory and climate patterns.

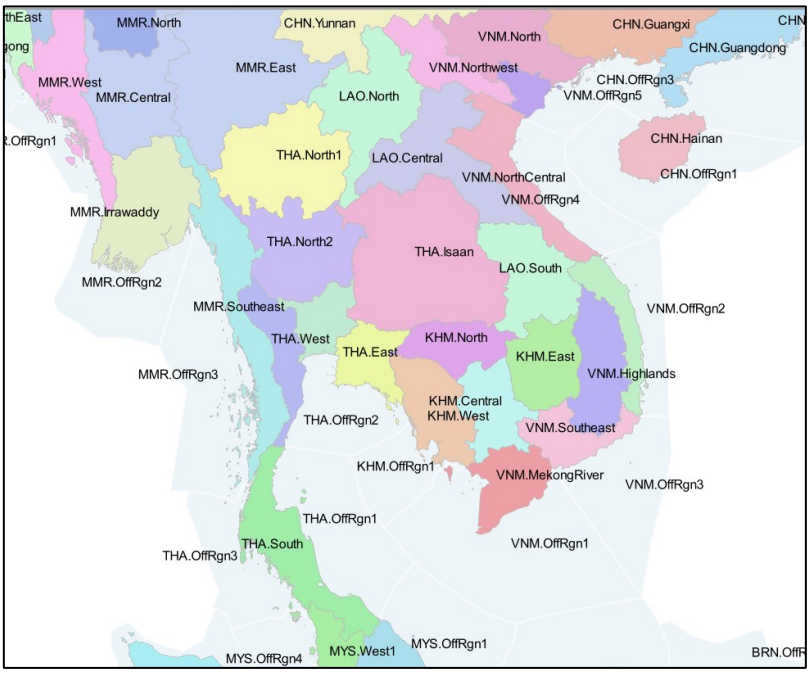


Figure 5. The defined zones in the Southeast Asia.

An example of the created zones is shown in Figure 5. It illustrates the zones in the Southeast Asia. In general, a country is divided into 3 to 8 zones. This can well separate the areas with differences on

electricity demand pattern, climate and landform etc. In this example, the territories of Vietnam has long narrow shape. It has temperate climate in the north and tropical climate in the south; two large river triangles in the north and south, and a central highland area. These distinct features may reflect on both the electricity demand pattern and renewable potential among the zones. These zones are hence created based on the criteria mentioned.

In general, the offshore zones are defined according to the connected terrestrial zones. Only the areas with water depth less than 500 meters is considered, as this is the constraints which will be applied in offshore wind energy assessment. Therefore, the boundary of the zones may not reach the end of the EEZ border. In Figure 5 the light colored areas off the coastline are the offshore zones for wind development. The boundaries do not stretch out to EEZ boarder.

Overall 731 terrestrial zones and 339 offshore zones are created in 171 countries/districts[18] globally. The full list of the zones and the administrative areas they represent is compiled in File 1 of the supplementary Data Package 1. This work has managed to define the zones as small as possible to a degree that can properly reflect different regional generation pattern. This offers a good flexibility to aggregate the data according to the spatial resolution setting in an ESM. In this work the GADM dataset[19] (GADM, 2018) is used for the vector-based administrative areas data. The boundary of the zones are merged from this dataset.

3.1.4 Geographical constraints and eligibility masks

To estimate available area for VREs deployment, a series of work have been carried out including identifying required constraints, assigning reasonable thresholds, converting the restriction area into raster layers and combining all layers to create a binary eligibility mask. All the constraints and value applied for each technology are summarized in Table 4. It is noted that the selection of constraints

[18] Small island nations with land area less than 1,000 km^2 are excluded in this study because they pose difficulties on GIS data processing.

[19] GADM Version 3.6 Level 1 is used for most country/district. Level 2 is used for the UK and Taiwan.

can cause significant influence on identified eligible area. Therefore, this work refers to Eurek et al. (2017) for the most assumptions in assessing available area for wind energy development so that the results can be compared in similar conditions. The final eligibility masks of the technologies are labeled as NE, FE, UE, and CE in Table 3.

Table 4. The constraints applied and their values for preparing the eligible area masks in this study.

Type	Constraint	Technology	Value	reference
Physical	Elevation	Onshore wind	< 2500m	Eurek et al. (2017)
	Slope	Onshore wind	< 20°	Eurek et al. (2017)
		Utility-scale PV	< 10°	Bravo et al. (2007)
		CSP	< 3°	Bravo et al. (Domínguez Bravo et al., 2007)
	Permafrost area	All terrestrial tech.	False	Eurek et al. (2017)
	Latitude*	Offshore wind	< 67°N	(sea ice exclusion)
Economic	Wind speed	Onshore/offshore wind	> 4 m/s (100m)	Setter (2012)
	GNI	CSP	> 1800 $W/m^2/day$	Setter (2012)
	Water depth	Offshore wind	< 500m	James &Costa Ros (2015)
	Road access	All terrestrial tech.	< 20km	Alqaderi et al. (2018)
	Land block	CSP	> 1 km^2	NREL (2018)
	Capacity factor**	Onshore/offshore wind	> 18%	Eurek et al. (2017)
		All PV	> 10%	
		CSP	> 25%	
Social	Urban area	All except Dist. PV	> 500m	Ryberg et al.(2018)
		Distributed PV	True	
	Amenities	All except Dist. PV	> 500m	Ryberg et al.(2018)
	Military area	All except Dist. PV	> 500m	Ryberg et al.(2018)
	Protected area	All	Not in IUCN I-IV	Ryberg et al.(2018)
	Airport	Onshore/offshore wind	> 3km	Ryberg et al.(2018)
	Port/Harbor*	Offshore wind	> 3km	
	Ferry route*	Offshore wind	> 1.5km	

* No previous studies have applies this constraints in global scale. The assumptions are determined from multiple sources.
** This minimum CF is an economic constraints. The final output data will provide a tranche which CF is below this level.

Elevation and slope are the physical limits commonly used for VREs potential assessment. The topographic raster data maps[20] used in this work is produced by Amatulli et al. (2018). The maps were generated from digital elevation model products GMTED2010 and SRTM4. Elevation above 2500 meter is considered unsuitable for onshore wind development since the air density drops as altitude

[20] Global 1,5,10,100-km Topography, available at http://www.earthenv.org/topography

increases. The slope limit applied is 20° for onshore wind, 10° for utility-scale PV and 3° for parabolic though CSP. These setting are the most general configuration across the literatures. Eurek et al. (2017) excluded the polar areas in permafrost for wind energy assessment due to the concern of the damage on wind turbine's underground structure. This study excludes permafrost areas for all the technologies using data from the Global Permafrost Zonation Index Map (Gruber, 2012). In addition, sea ice can also cause the damage to offshore wind turbine's supporting structure. Its impact is rather dynamic. This study simply excludes the sea areas with latitude over 67°N (Arctic Circle) for offshore wind assessment. In fact, the permafrost and sea ice restrictions only exclude large polar areas in Russia and Canada.

Although in areas with low wind energy and solar irradiation the renewable energy is still available for exploitation, the generation cost can be unacceptably high. This work imposed a minimum wind speed and solar irradiation requirement as economic constraints. A minimum average wind speed of 4 m/s at 100m height is applied on both onshore and offshore wind assessments. Compared with other studies, this is a relatively loose constraint, but it removes large areas in tropical area. While in many literatures a minimum average GHI of 3 $kWh/m^2/day$ is applied on PV technologies, this work does not adopt this constraints because it can exclude almost all area in the UK, Ireland and Northern Europe countries. In fact, there has been growing PV installation in these countries. For CSP a minimum DNI of 1800 $W/m^2/day$ is applied, which is also a common limit found in other studies.

In general, a water depth of 1000m is applied as a constraint for offshore wind farm deployment, which can be found in Eurek et al. (2017), Bosch et al. (2018) and Dupont et al. (2018). This work cuts the limit to 500m, since floating offshore wind farm developing at water depth deeper than this level can be uneconomic. According to a report by Carbon Trust (James &Costa Ros, 2015), the optimal water depth of floating platform is in the range from 50 – 500m. It is possible to install in deeper waters than 500m but will lead to increased costs due to the size of the longer mooring lines. The bathymetry map (Weatherall et al., 2015) developed by General Bathymetric Chart of the Oceans

(GEBCO) is used in this study. It is the highest resolution (0.0083°) global bathymetry map freely available[21].

CSP plant, consists of solar field, thermal storage and power generator, is usually developed in a block of land area. The common size of a commercial parabolic trough CSP plant is 50MW and requires around 1 km^2 land area (NREL, 2018). Thus this study sieves out[22] every connected pixels that makes up an area more than 1 km^2. This process is carried out over the final suitability map generated later on.

Road access is another criteria on assessing location suitability out of economic concern. Global road information is available from OSM at several levels. This work extracts the features with attributes "motorway, trunk, primary, secondary, and tertiary" under highway category. A 20km buffer distance is applied on the road network as eligible area for all terrestrial technologies in this study. The road accessibility constraints can be seen in many studies. For example, Ryberg et al. (2018) used a 5km road access distance to evaluate land eligibility of renewable energy sources in Europe. Cevallos-Sierra & Ramos-Martin (Cevallos-Sierra &Ramos-Martin, 2018) performed a multi-criteria evaluation of renewable energy potential in Ecuador. The weight of road access criteria was set to be zero for CSP and PV assessment if an area is at least 10km from major roads. In a CSP site suitability study by Alqaderi et al. (2018) the area outside 20 km buffer zone from the roads is assigned the lowest score in the assessment. This 20km constraint is also used in wind and solar energy assessment in Russia by Melnikova (Melnikova, 2018). In this research, the 20km road accessibility constraint, in fact, has little effect on most countries, but excludes less populated and inhabitable areas such as Western Australia and the Sahara Desert.

Power generation facilities is usually built at a distance from residential area. In most literatures,

[21] Available at https://www.gebco.net/

[22] This is performed using the GIS tool QGIS. The raster-based eligible map is first converted into vector-based contours. Any enclosed contour with area less than $1km^2$ is removed. Lastly, convert the vector-based contours back to raster eligibility map.

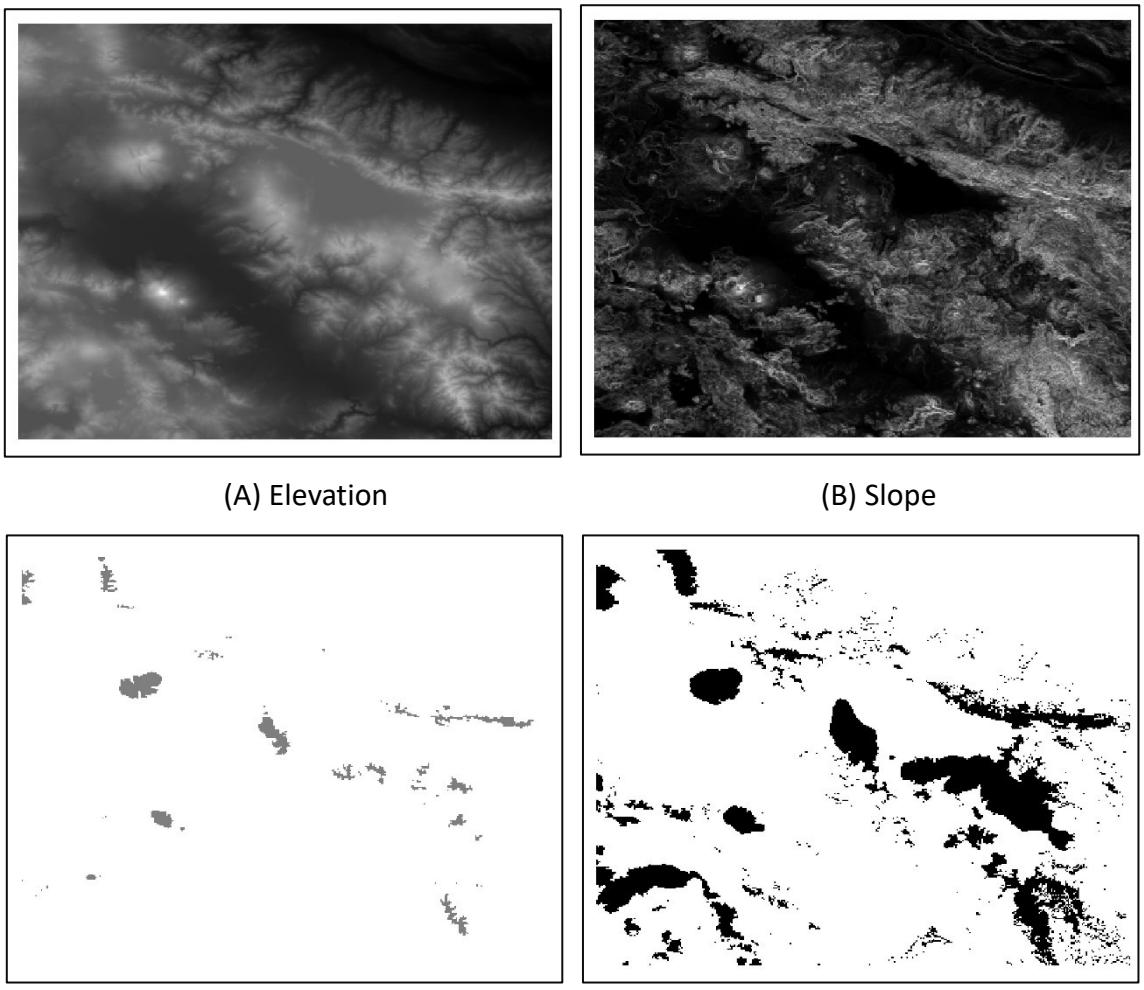
urban area is considered unsuitable for installing large power plants. Some studies, for example Stetter (2012) and Trieb et al. (2009), further assigned a distance margin to the urban area. In this study, urban area with 500m buffer distance is restricted for all VREs deployment, except for distributed PV. This distance is commonly applied to separate settlement area (Ryberg et al., 2018). While development restriction should also be made on area close to amenity facilities, only Trieb et al. (2009) applied this constraint. The lack of data at global scale is likely the main reason. This work tackled this issue with the global amenity features extracted from OSM. For terrestrial technologies, a general 500m buffer is applied on amenity facilities including school, college, university, hospital, library and town hall, as well as on the central point of villages and towns. For wind technologies, a 3km buffered restriction zone is created on airports. This distance in the literatures can be 3km or 5km (Ryberg et al., 2018). Lastly, areas of military use are also excluded for all technologies. The information about military areas is extracted from OSM.

For distance of offshore wind turbine to shipping route, 1 nm (1,852m) is usually a minimum requirement in the industry. This regulation varies by country or by specific area. The Maritime and Coastguard Agency of the UK published a guidance (MCA, 2008) which noted that the distance of 0.8 nautical mile (1,481m) is classified as high risk on safety, and at least 2 nm, from a wind farm is suggested. The US Coastguard recommends that the placement of wind farm facility should be at least 1 nm from traditional shipping routes, and greater than 5 nm is considered low risk (USCG, 2012). In the Netherlands, a distance of 1.5 nm is suggested to avoid collision (Nautical Institute, 2013a). Therefore, this research applies a loosen constraint of 1.5km as the minimum distance from wind farm to shipping route boundary. Also, a 3km buffered distance from port/harbor further considers anchoring area in addition to shipping routes is applied in this research. Again, there is no common guidance on the distance since anchoring area varies by specific port/harbor. The safety distance for anchorage for all vessels is reportedly 1.7 nm (approximately 3.2km) in the Netherlands (Nautical Institute, 2013b).

The restriction also include the protected areas in International Union for Conservation of Nature (IUCN) category I – IV, corresponding to Strict Nature Reserve, Wilderness area, National Park, Natural Monument or feature, and Habitat/species management area. The global protected areas data is available from WDPA (UNEP-WCMC & IUCN, 2016). In general, category I to III is prohibited from any energy production development. For example, in IEA's WEM model (IEA, 2019b), protected area in category I to III is excluded for energy development. Although labeled in category IV, some protected areas are possible for offshore wind farm development. The category IV aims to protect particular species and habitats. Prohibited activity includes industrial fishing, industrial-scale aquaculture, mining, waste discharge and so on. According to the official document (Day et al., 2019), "Within category IV MPAs extractive research is permitted, as is renewable energy generation and restoration/enhancement for other reasons (e.g. beach replenishment, fish aggregation, artificial reefs)." Ideally, category IV is possible for offshore wind power development. This research has checked the category IV areas and the locations of existing and planning wind farms. However, it is found that that none of the current wind farm is located in category IV area. This research is intended to be relatively conservative, so the category IV areas are excluded in this research by default. The purpose of the protected areas noted in this database is vague. They are generally noted as Biological refuge, Wildlife Refuge, Natural Area, Wildlife Management Area, Wildlife Sanctuary, Private Reserve, Nature Reserve, Conservation Area, Aquatic Preserve, and Special Scientific Interest and so on. It is impossible to check the policy of all 6,000 category IV areas. Therefore, this research adds back areas noted with specific purpose which is not in conflict with offshore wind power development, including OSPAR maritime area, Baltic Sea Protected Area (HELCOM), Site of Community Importance (Habitats Directive) in Germany, protected landscape (mostly in Denmark), fishing restrict, trail restrict, fishery protected, fish nursery, fish recovery, prohibited scuba diving, closure area, trap/pot waters area.

All the constraints mentioned above are converted into binary raster maps which indicate eligible area for VREs development. The spatial resolution is based on the finest resolution data maps, i.e.

300m for terrestrial area and 1km for offshore area. Figure 6 shows an example of the created physical limit masks for onshore wind development in Armenia. The maps are in grey level or binary format. Figure (A) and (B) are elevation and slope map. Figure (C) identifies the area of permafrost. When all the physical limits are applied, i.e. 2500m elevation, 20% slop and permafrost, the maps will be converted into the physical limit map as shown in figure (D).



(A) Elevation (B) Slope

(C) Permafrost (D) Combined physical limits

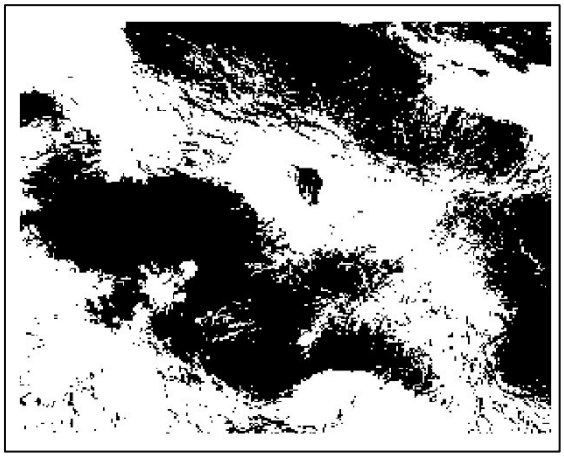
Figure 6. The processed physical limit masks for onshore wind development in Armenia.

Figure 7 shows the masks produced from economic and social constraints. (A) outlines the boundary of the country. (B) shows the area filtered out by low wind speed. (C) shows the exclusion of protected area. (D) shows the restriction of buffered urban area based on the original CCI-LC map. (E) illustrates the eligible area considering social constraints which exclude buffered area from unban,

amenity, military and airport etc. based on the features from OSM. (F) shows the 20km margin area from roads. (G) illustrates the final mask that combines all the masks, including the physical limit mask in Figure 6.



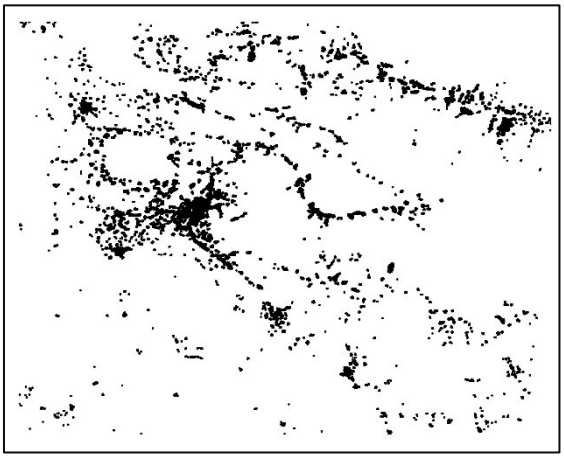
(A) Country boundary



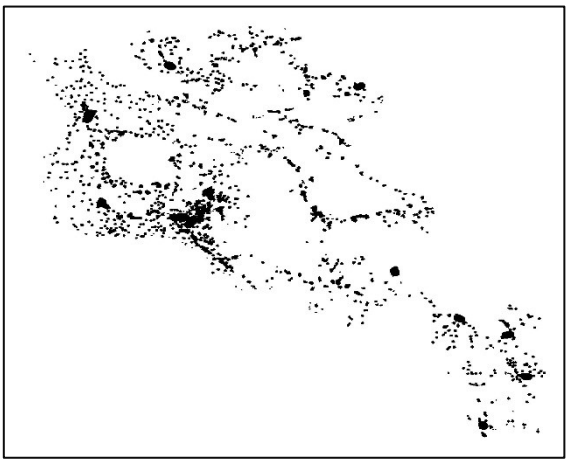
(B) Wind speed mask



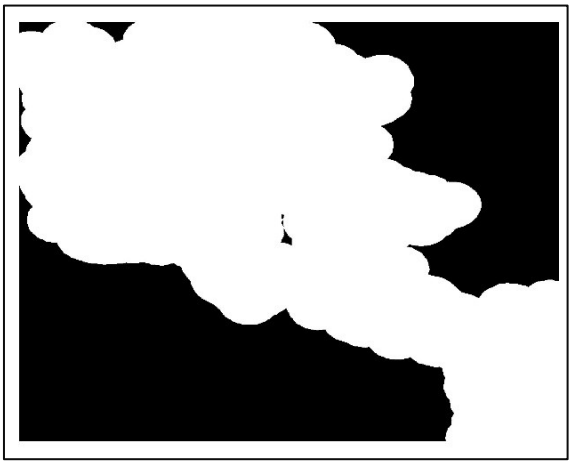
(C) Protected areas mask



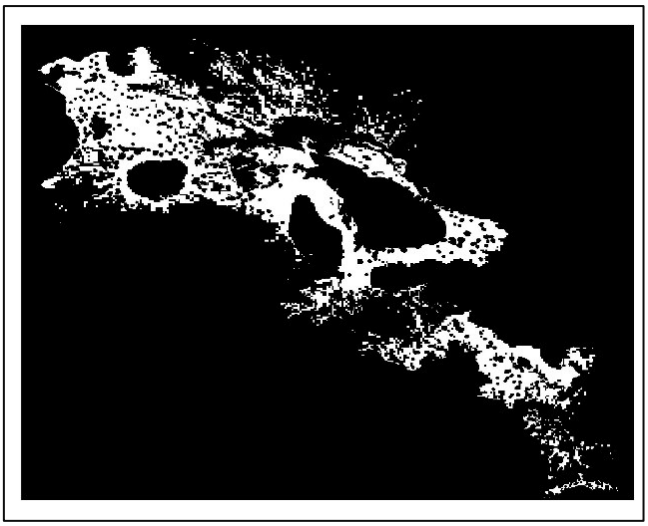
(D) Urban area restriction mask



(E) Social constraint mask



(F) Road access mask



(G) All masks combined

Figure 7. The eligibility masks for onshore wind development in Armenia.

(A) Country boundary; (B) Wind speed mask; (C) Protected areas mask; (D) Urban area restriction mask; (E) Social constraint mask; (F) Road access mask; (G) All masks combined. These masks are in binary format. White pixel is eligible and black pixel is ineligible to the applied constraint.

3.1.5 Suitability factors

The overall land eligibility mask is the intersection of all eligible area layers. With this mask, suitability factors, shown in Table 5, are assigned to each eligible raster cell according to its land cover type. The values for onshore wind are based on Hoogwijk (2004). The suitability factors assigned to centralized PV and CSP vary significantly across the literatures. Here it is assumed that suitable area for solar power development is a subset of onshore wind and totally exclude areas with tree cover.

The Figure 8 below shows an example of applying the suitability factors onto the eligibility map developed previously. This is the Central zone in Thailand where most areas are cropland. The black areas are completely unsuitable or outside of the boundary. The figure on the left is the suitability map for wind development. A large area in the upper part is suitable for wind while this area is almost excluded for utility PV system development, see the figure on the right. The main cause is the difference on suitability factor of cropland.

Table 5. The suitability factors assigned to land cover for each technology types. (Other land cover types not shown in this table are set to zero).

LC code	Land cover category	Onshore wind	Utility PV	CSP
10	Cropland, rainfed	0.7	0	0
30	Natural vegetation (> 50%) cropland (< 50%)	0.7	0.3	0
40	Natural vegetation (< 50%) cropland (> 50%)	0.8	0.3	0
50	Tree cover, broadleaved, evergreen	0.1	0	0
60	Tree cover, broadleaved, deciduous	0.5	0	0
70	Tree cover, needleleaved, evergreen	0.1	0	0
80	Tree cover, needleleaved, evergreen	0.1	0	0
90	Tree cover, mixed leaf type	0.1	0	0
100	Mosaic tree and shrub (> 50%) herbaceous cover (< 50%)	0.5	0.3	0
110	Mosaic tree and shrub (< 50%) herbaceous cover (> 50%)	0.65	0.3	0
120	Shrubland	0.5	0.5	0.5
130	Grassland	0.5	0.5	0.5
140	Lichens and mosses	0.8	0.8	0.8
150	Sparse vegetation	0.8	0.8	0.8
201	Consolidated bare areas	0.9	0.9	0.9

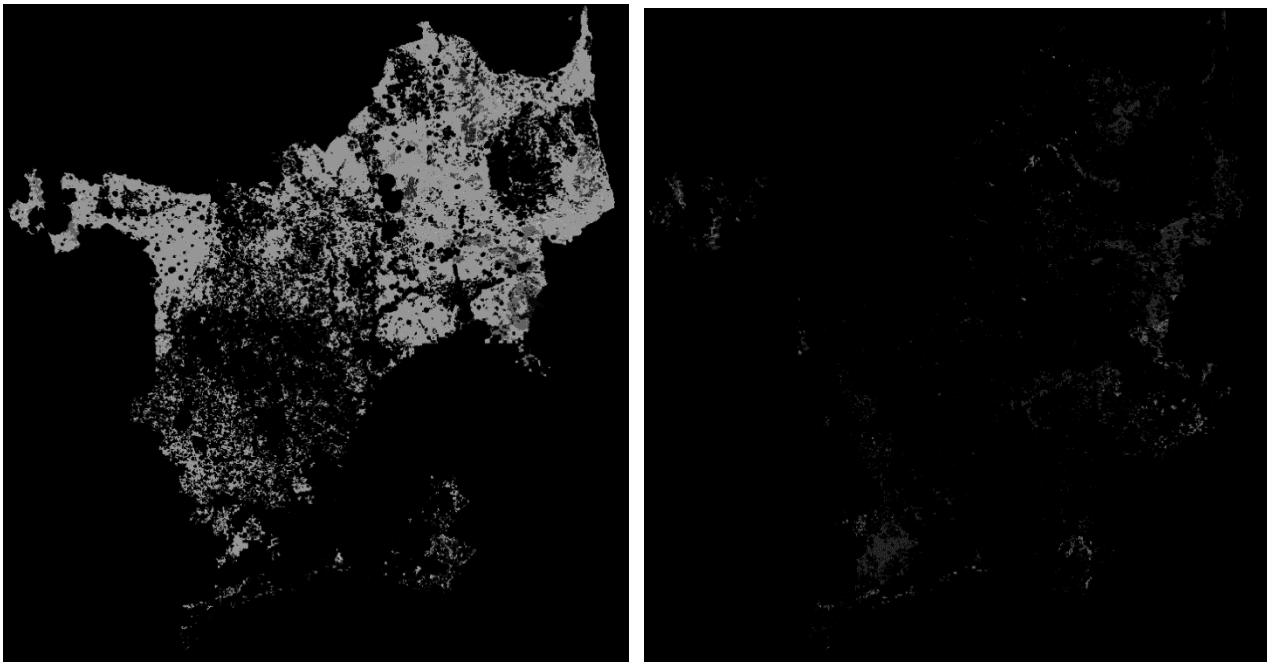


Figure 8. The suitability map of wind and utility PV system of the Central zone in Thailand. (Left figure) wind; (right figure) utility PV;

For offshore wind, some studies, includes Eurek et al. (2017), Dupont et al. (2018) and Bosch et al. (2018), assign suitability factors according to water depth and distance to coast. Other factors, such as sea ice, seabed types and shipping routes, are rarely considered due to the lack of data. This work incorporates the impact of shipping activity at global scale. At the time of writing, the only global shipping data freely available is the raster maps developed by Halpern et al. (2015), which represents the frequency of ships at each location. This work blends the 2008 and 2013 versions of the maps with ship path records around the USA from NOAA (U.S. Coast Guard Navigation Center, 2018). The probability distribution of all cell values has very long upwards tail. Therefore, 50% of the highest value is taken as the ceiling and, the raster values are normalized into a range from 0 to 1 as suitability factor, with 0 implying the area is not eligible due to a high frequency of shipping activity. Figure 9 shows the example of the offshore zone off Croatia in Adriatic Sea. The eligibility mask applied an exclusion distance from urban area, airport, port/harbor, ferry routes and protected zones. The dimmer strip in the middle is the area with high shipping activity as suitability factor being applied.

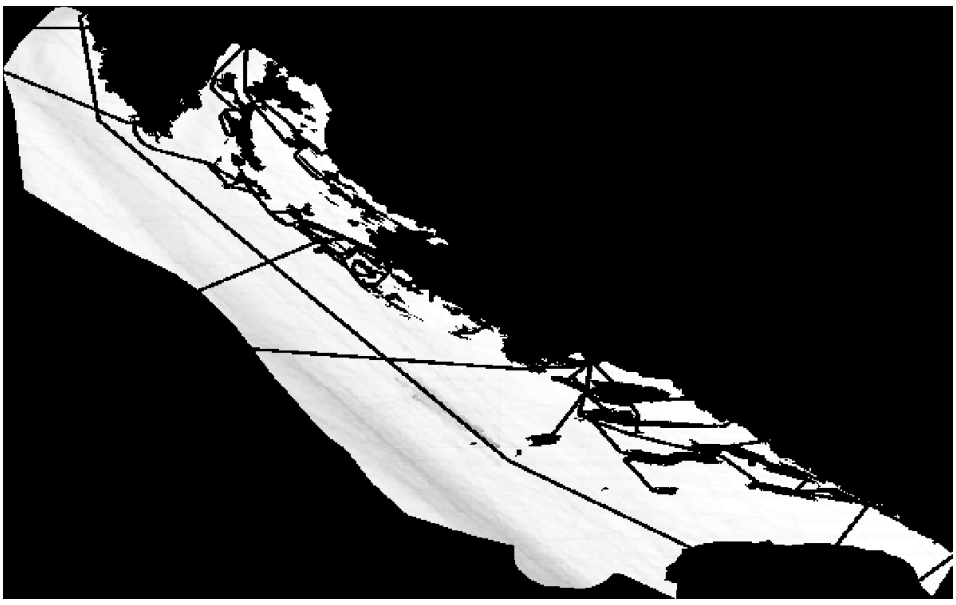


Figure 9. The suitability map of offshore wind development off the coast of Croatia in Adriatic Sea.

3.1.6 Energy potential and CF simulation

This work uses the MERRA-2 datasets for temporal CF simulation. The datasets provide hourly

data at grid points, approximately every 50km^2. As mentioned in the literature review, energy potential can be underestimated if the energy potential assessment is processed in this coarse spatial resolution. To estimate the energy potential in a spatially resolved manner, this work aims to produce average CF maps at 1 km^2 resolution based on GWA and GSA resource maps. One approach to improve the processing resolution is to incorporate with the GWA and GSA energy resource maps which provide data at 1 km^2 resolution. The idea to incorporate the two dataset was first proposed by Bosch et al.(2017) to increase spatial resolution of onshore wind energy potential assessment. The following are the main steps proposed in the study:

1. Calculate the wind speed at hub height using MERRA-2 data at every 50km^2 grid points.
2. Re-scale the wind speed to match GWA dataset (annual average) at the same location at the same hub height to preserve seasonal and diurnal properties.
3. Perform bilinear interpolation to estimate wind speed profile for each 5km x 5km cell.
4. Estimate the capacity factor for each cell using composite wind turbines.
5. Produce a final capacity map in resolved 5km x 5km resolution.

This present research uses later version of GWA maps which provide greater spatial resolution at around 1km. Also, this research is intended to calculate 10-years hourly capacity factor. The approach introduced by Bosch et al.(2017) requires enormous computational resource. To simplify this process, alternatively, hourly CF can be calculated for the MERRA-2 grid points first, then apply interpolation for greater spatial resolution. This approach is flawed if CF is not linear to the input wind speed or solar irradiance. This is especially true for wind technologies. A method to improve this is to estimate the hourly CF profile of multiple wind speed and solar irradiance bands that preserve hourly variation profile at the grid points. The interpolation for average CF in each 1km cell is based on the closest bands directly. No wind speed or solar irradiation profile is generated for each 1km cell. The process can be summarized in these steps:

1. Calculate the wind speed at hub height using MERRA-2 data at every 50km^2 grid points.

2. Re-scale the wind speed to match GWA dataset (annual average) at the same hub height to preserve seasonal and diurnal properties.
3. Re-scale and create hourly profile of multiple wind speed bands at these MERRA-2 grid points.
4. Estimate hourly and average capacity factor for these grid points using composite wind turbines. This process is done for multiple bands of integer average wind speed.
5. Perform trilinear interpolation to estimate CF directly for each $1km$ x $1km$ cell based on its location and the closest bands of the 4 bounding grid points.
6. Produce a final capacity map in resolved $1km$ x $1km$ resolution.

Figure 10 illustrates the idea of this spatial resolving method. The average CF of wind power at raster cell P is to be determined. In this case, it can be problematic if the CF is interpolated or extrapolate bilinearly from the envelope grid points A, B, C and D based on the wind speed at these points. To reduce the error, this work simulated several wind speed bands at the grid points and applied the interpolation based on the closest bands. In another words, this approach creates another dimension for the interpolation. In Figure 10, the annual average wind speed at grid location A is 6.8 m/s (based on MERRA-2 data) and its calculated average CF is 30%. This work estimated the average CF of the 4 envelope grid points in several wind speed bands, for example 5, 6 and 7 m/s. The original hourly wind speed profile is re-scaled linearly to create new wind speed bands. Then these new profile are used to calculate corresponding CF profiles. In this case, if the average wind speed at P is 6.2 (based on GWA value), this work takes the CF computed from 6 and 7 m/s band profiles at the envelope points for the final trilinear interpolation. Similarity, when there is another cell in this envelop has average wind speed 5.7, then the CF of 5 and 6 m/s bands at the envelope points are used for the interpolation.

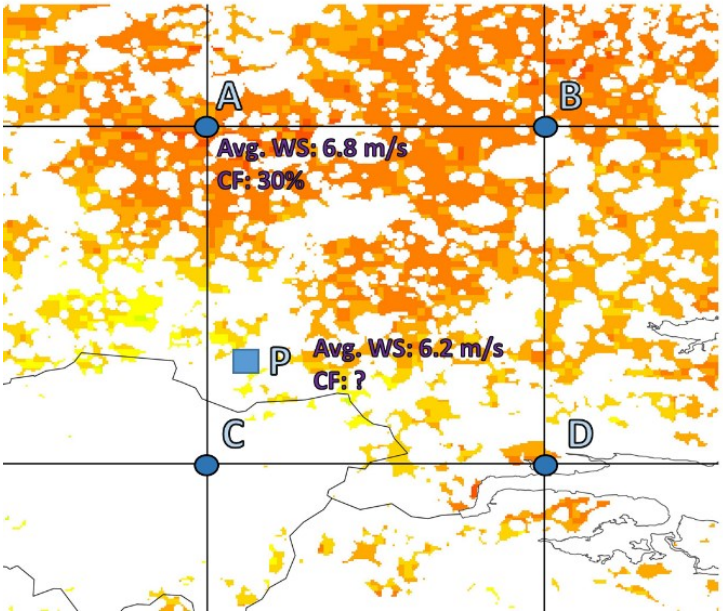


Figure 10. Example figure for explaining the spatial resolving approach used.

The hourly CF estimation is performed by mapping the wind speed onto the wind turbine power curve. This study used the composite power curve proposed in King et al. (2014), with IEC class 1 for offshore wind simulation, and IEC class 2 for onshore wind, as shown in Figure 11. The nominal power output level has been normalized in the range 0 to 1. A spline interpolation function[23] is used to smooth the curves. The cut-off wind speed point is not applied into this function, otherwise it decreases output CF significantly when the input wind speed is close to cut-off point. The CF map based on GWA resolution is generated via the approach described in the previous section.

Newer turbine models in the future may have better performance. Using suitable models according to the local climatic characteristics may also improve wind farm performance. These issues has been noted. It is possible to calculate the output with different turbine models. However, given the high demand on computational resource in this research, the issues is left to future work.

[23] The one-dimensional smoothing spline fit in Python scipy.interpolate package.

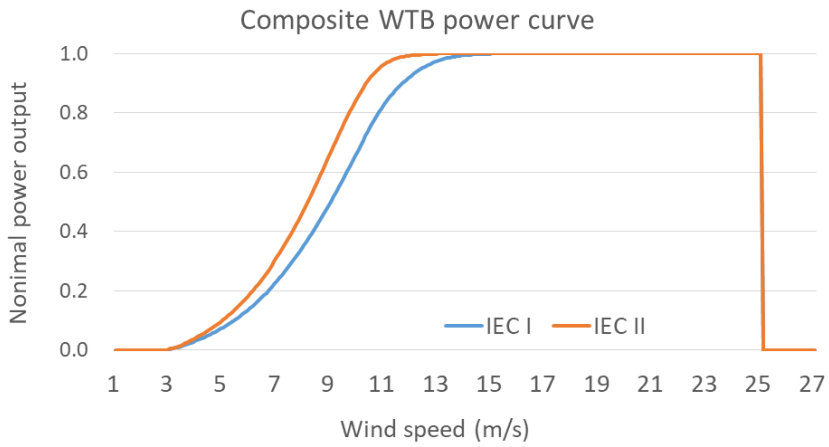


Figure 11. The power curves of wind turbine used for capacity factor simulation.

The equation of net CF is shown in (1.2) where $P(W_i)$ is the nominal output level at wind speed W_i. Since the output level has been normalized, it can be regarded as gross CF. A 10% array efficiency loss η_{array} and 95% system availability η_{avail} are applied generally. The array efficiency reflects the potential energy output loss of a wind farm array due to air flow interference (wake losses) on downwind turbines. The resulting CF of each cell was binned into 10 CF tranche classes[24], the same intervals used in Eurek et al. (2017). Another class for CF higher than 50% is added. By combining this CF map with the suitability map developed in the previous sub-sections, the available land area of each tranche in a zone can be produced. The capacity potential is estimated using 5 MW/km^2 power density for both onshore and offshore wind technology. These configurations are the same as those in Eurek et al. (2017).

$$nCF_i = P(W_i) \cdot (1 - \eta_{array}) \cdot \eta_{avail} \qquad (1.2)$$

In a zone, available area of a specific CF tranche may distributed widely. Therefore, this study computed the final zonal output profile based on the weight assigned to each MERRA-2 grid point in a zone.

[24] The CF range of the tranche classes for onshore and offshore wind, Class 1: CF < 18%; Class 2: 18% ≤ CF < 22%; Class 3: 22% ≤ CF < 26%; Class 4: 26% ≤ CF < 30%; Class 5: 30% ≤ CF < 34%; Class 6: 34% ≤ CF < 38%; Class 7: 38% ≤ CF < 42%; Class 8: 42% ≤ CF < 46%; Class 9: 46% ≤ CF < 50%; Class 10: 50% ≤ CF

In this work ground-based PV system installed outside urban area is defined as utility-scale PV, including two types of systems: fixed-tilt and one-axis tracking system. The energy output is computed using the amount of solar irradiation on the PV module surface. It is assumed that the module can generate at full load when the incoming irradiance on module surface reaches 1,000 W/m^2. The total irradiance of a surface I_T is the sum of three components: beam irradiance, sky diffuse irradiance and ground diffuse irradiance. Sky diffuse and ground diffuse irradiance are calculated with the isotropic sky model described in Loutzenhiser et al. (2007). The equation of total irradiance can be written as (1.3) where $I_{T,b}$ is bean irradiance, $I_{h,d}$ is global horizontal diffuse irradiance, β is surface tilt angle, and I_h is global horizontal irradiance. Bean irradiance is calculated from DNI and the incidence angle. This albedo value ρ is the fraction of diffuse reflection from the ground back to space of incidence. It is determined by the type of ground surface, atmospheric condition and solar position. To simplify the calculation, this research applies a constant value 0.25. This value is in the range of grass, heath surface and concrete (Mertens, 2014).

$$I_T = I_{T,b} + I_{h,d}((1 + cos\,\beta)/2) + I_h \cdot \rho \cdot ((1 - cos\,\beta)/2) \qquad (1.3)$$

The temperature of ambient temperature can also influence the output efficiency. The efficiency of PV panel reported by manufacturers is based on test under Standard Testing Condition (STC) with solar irradiance 1,000 W/m^2 and temperature of 25°C. The temperature coefficient of crystalline silicon based modules are reported in the range -0.4 to -0.5 *%/°C* if module temperature varies from STC in several studies, such can be seen in Makrides et al. (2009) and Dash & Gupta (Dash &Gupta, 2015) for example. This work uses -0.5 *%/°C* as a general figure applied to all PV system. The same coefficient is applied in Stetter (2012). The hourly temperature data is also obtained from the MERRA-2 datasets. The net hourly CF of PV systems is shown as equation (1.4) where $I_{T,i}$ is total irradiance on the module surface in the hour i; γ is temperature coefficient, which is set to 0 when the ambient temperature is under 25°C; $T_{amb,i}$ denotes the ambient temperature and T_{ref} is STC

temperature 25°C. The overall system losses η_{loss} and inverter efficiency will be discussed later.

$$nCF_i = I_{T,i}/1000 \cdot \left(1 + \gamma\left(T_{amb,i} - T_{ref}\right)\right) \cdot (1 - \eta_{loss}) \cdot \eta_{inv} \quad (1.4)$$

For fixed-tilt systems, it is assumed that all systems are facing directly southward or northward. The best tilt angle of a location refers to the Optimal Tilt Angle (OPTA) map also prepared by Solargis. For one-axis tracking systems, the tilt angle is also as per OPTA, but the surface azimuth angle varies with the sun's position whenever the sun is above the horizon. The incidence angle α of the module surface can be written in equation (1.5) where the surface tilt angle is β; surface azimuth is γ; solar zenith angle is θ_{sun}; and solar azimuth is γ_{sun}. The hourly CF is thus estimated with the irradiance components, temperature and incidence angle.

$$\alpha = cos^{-1}[sin(\theta_{sun}) \cdot cos(\gamma - \gamma_{sun}) \cdot sin(\beta) + cos(\theta_{sun}) \cdot cos(\beta)] \quad (1.5)$$

All small scale PV systems in urban areas, either roof-top or ground systems, are categorized as distributed PV system in this research. The CF estimation is performed the same way as utility-scale PV technologies. Since the building type and rooftop inclination angle varies across the world, the OPTA value is still used as a default tilt angle. In fact, according to Gagnon et al. (2016), flat rooftops accounts for the majority of large and medium buildings in the United States, which usually allows the buildings to install PV modules with suitable tilt angle. Also by referring the rooftop azimuth angle distribution to Gagnon et al. (2016), it is assumed that all the suitable surfaces for distributed PV consist of 70% of northward/southward, 15% direct eastward, and 15% westward azimuth.

The variety of CSP technologies and the complexity of designing a CSP system is noted in this research. A generalized design of a parabolic trough CSP system is used here to estimate the CF. This work assumes that the trough surface is laid north-to-south and tracks the position of the sun. The main design parameters are: design-point at 950W/m^2, solar multiple of 2.0, and 6 hours of storage capacity. This is common design for 50MW commercial systems (NREL, 2018). To capture the potential

in areas with less solar energy, another system design is proposed with solar multiple of 2.5 and 9 hours of storage capacity. To simplify the calculation, it is assumed that the thermal energy is transmitted to the power block first to generate electricity. At any time when the power block cannot receive enough energy from the solar field to generate at full load, energy from storage flows to the power block until depleted.

The assumption regarding land requirements for utility-scale technologies was $30 MW/km^2$; and $25 MW/km^2$ for CSP with solar multiple at 2.0. The same figures for the two technologies are proposed in Ong et al. (2013), which investigated the land-use requirements for existing PV and CSP projects. For distributed PV, this study assumes that 5% of urban areas is suitable for deployment, based on similar assumptions in Stetter (2012). The capacity potential is calculated using $75 MW/km^2$. There is a 14% combined loss rate and a 96% inverter efficiency applied to all PV technologies, based on Dobos (2014) . The raster cells are binned into 7 CF tranche classes[25] for PV technologies and 5 tranche classes[26] for CSP. The resulting energy output is prepared in the same way as described in wind section.

3.2 Optimal mix of renewable energy in global power systems

This work in this research aims to investigate the optimal CRE mix of each of the 171 countries/districts based on multiple objectives. Models are proposed to solve the optimization problems with CRE generation targets in each country. The models share a set of core common constraints, but differ in objective function. A compromise programming model is developed to find optimal solutions building on the three objectives.

The 1,070 representative global zones are defined in the previous work. The temporal resolution

[25] The CF range of the tranche classes for PV technologies, Class 1: CF < 10%; Class 2: 10% ≤ CF < 13%; Class 3: 13% ≤ CF < 16%; Class 4: 16% ≤ CF < 19%; Class 5: 19% ≤ CF < 22%; Class 6: 22% ≤ CF < 25%; Class 7: 25% ≤ CF

[26] The CF range of the tranche classes for CSP technologies, Class 1: CF < 25%; Class 2: 25% ≤ CF < 30%; Class 3: 30% ≤ CF < 35%; Class 4: 35% ≤ CF < 40%; Class 5: 40% ≤ CF

is 24 daily hours per calendar month in a year, i.e. 288 time-slices. This temporal resolution is selected to capture seasonal and diurnal output features in the long-term. Hydropower dispatch can be modelled in diurnal operation. To narrow the scope and simplify the models, this work only investigates the mix in 2040 with the CRE share targets at 30%, 50% and 70%. No other time period is simulated. Conventional thermal generation technologies are excluded. The modelled technology includes onshore wind, offshore wind, distributed PV, fixed-tilt PV, one-axis tracking PV and concentrated solar power (CSP), small hydropower and large hydropower. The capacity potential of the technologies is further classified into tranches based on annual capacity factor. Most of the input is based on the results from the previous work in this research. This work further estimates the monthly hydropower output and power demand profile in each zone. For each country, a covariance matrix based on estimated capacity factor (CF) of all available installation options is calculated at different time frequencies. The matrices are the core element in Model P.

The main decision variables are the capacity of all available CRE options in a country/district. Candidate development option i is available in zone z in a country/district. Transmission link r connects two adjacent zones. The temporal resolution of the core model is 288 time-slices t, representing 24 daily hours for each calendar month in a year. The demand profile in 288 time-slices is aggregated from the 8760 hourly synthetic profile generated in this work. The power output of each option in 288 time-slices is aggregated from the 10-years simulation data by taking the mean value of each time-slice. In this study, Model C is formulated as a linear programming problem, while Model R, P and CP are developed as quadratic programming problems since the objectives are quadratic functions and the constraints are all linear functions of the variables. The advantage of keeping the quadratic form is its fast solving speed compared with other nonlinear forms.

3.2.1 Model C – minimum annualized cost

This model is developed to solve a minimum annualized cost problem. The objective function (2.1)

consists of two cost elements – annualized costs of generation units and transmission links. The decision variables are the capacity of candidate options cp_i and transmission lines tp_r. Their corresponding annualized fixed cost per unit capacity CCF_i and TCF_r are pre-calculated as parameters. The cost terms only contain capital cost and annualized using service life time and fixed discount rate 5%. This work evaluates the mix in the year 2040 only. There is no other time step in the models.

$$min.\,annualized\ cost\ C = \sum_i cp_i \cdot CCF_i + \sum_r tp_r \cdot TCF_r \qquad (2.1)$$

All candidate options are subject to their maximum capacity limit $CP_{z,i}^{max}$ in a zone (2.2). The limits are estimated in the previous section. For each zone z, PV and CSP technologies compete for limited land area LA_z^{solar}, and each technology have its own required land per unit capacity parameter $LR_{z,i}$ (2.3). The land limit is defined as the total available land for fixed-tilt PV system because the available land for other solar technologies is its subset, as stricter constraints applied in estimating the energy potential for the others.

$$cp_{z,i} \leq CP_{z,i}^{max} \quad \forall z, i \qquad (2.2)$$

$$\sum_{i \in PV,CSP} \left(cp_{z,i} \cdot LR_{z,i}\right) \leq LA_z^{solar} \quad \forall z \qquad (2.3)$$

Temporal output of a generation option at time t is its capacity multiplied by capacity factor at the time-slice $CF_{i,t}$ (2.4). This equation is not applied on dispatchable large hydropower.

$$ce_{i,t} = cp_i \cdot CF_{i,t} \quad \forall t, i \notin LHYD \qquad (2.4)$$

For large hydropower, the maximum output is limited by its capacity (2.5). The minimum output depends on its monthly average CF. When the CF is below 0.2, it is considered not dispatchable. When the CF is above 0.2, the system can dispatch the generation on daily basis with a floor at CF of 0.2 (2.6). The operation of large hydropower is modelled on daily basis. Equation (2.7) describes the dispatchable energy in a day d which is derived from the average CF. The threshold for dispatchable

operation is dependent on the design of the hydropower system. The figure 0.2 is a general number, but is conservative for very large systems[27].

$$ce_{i,t} \leq cp_i \quad \forall t, i \in LHYD \tag{2.5}$$

$$ce_{i,t} \begin{cases} \geq cp_i \cdot 0.2\,, & if\ CF_{i,t} \geq 0.2 \\ = cp_i \cdot CF_{i,t}\,, & if\ CF_{i,t} < 0.2 \end{cases} \quad \forall t, i \in LHYD \tag{2.6}$$

$$\sum_{i,t \in d} ce_{i,t} = \sum_{i,t \in d} cp \cdot CF_{i,t} \quad \forall d, i \in LHYD \tag{2.7}$$

The interconnection is modelled with simple zonal transport model. For each transmission link, its maximum power input (i.e. exports to the other zone) $te_{r,t}^{in}$ is bounded by its capacity tp_r (2.8) at any time. The power output at the other end $te_{r,t}^{out}$, in another zone, takes into account transmission losses TL_r (2.9).

$$te_{r,t}^{in} \leq tp_r \quad \forall t, r \tag{2.8}$$

$$te_{r,t}^{out} = te_{r,t}^{in} \cdot TL_r \quad \forall t, r \tag{2.9}$$

Total CRE power generation in a zone $ze_{z,t}$ at time-slice t is the sum of all output from local generation options (2.10). Equation (2.11) describes the overall power balance in a zone at time t. The power demand in a zone $D_{z,t}$ can be served by local generation $ze_{z,t}$ and import from connected zones through transmission links $\sum_{(r\ in\ z)} te_{r,t}^{out}$. Residual load and spilled energy are noted as $rl_{z,t}$ and $sp_{z,t}$. The power can also be exported to other zones, noted as $\sum_{(r\ in\ z)} te_{r,t}^{in}$. The

[27] This assumption is used in many equations in this research. In the technical guide by IFC (2015), in practice the minimum flow of Pelton turbine is 10%-20% of design flow, Francis turbine is 40% and Kaplan turbine is 20%-40%. These are the major three types of turbines for large hydropower system. If a 100MW hydropower plant consists of two 50MW Francis turbines. This would allow a minimum 20% of design discharge flow instead of 40% because one of the turbine can be turned down in low flow period. A large hydropower plants normally consists of multiple turbines. This is why 20% minimum output is considered conservative setting here. Note that the turbine efficiency is deduced in low flow condition. In 20% design discharge condition, the efficiency is around 80% for Pelton and Kaplan turbine, but can be down to 50% for Francis turbine.

upper bound of residual load should not exceed local demand (2.12).

$$ze_{z,t} = \sum_{(i\ in\ z)} ce_{i,t} \quad \forall z, t \tag{2.10}$$

$$D_{z,t} = ze_{z,t} + rl_{z,t} + sp_{z,t} + \sum_{(r\ in\ z)} te_{r,t}^{out} - \sum_{(r\ in\ z)} te_{r,t}^{in} \quad \forall z, t \tag{2.11}$$

$$rd_{z,t} \leq D_{z,t} \quad \forall z, t \tag{2.12}$$

The annual CRE generation in a country is subject to renewable target TG (2.13). This equation implies that the spilled energy, when generation from CRE is higher than demand, is not counted as contribution to the target share. An annual limit of spilled energy SL, by default 10%, is applied in constraint (2.14) to prevent excessive waste. This constraint is critical to the Model R and P because it prevents the model from spilling power deliberately in order to keep a flat residual load curve instead of serving the demand first.

$$TG = 1 - \frac{\sum_{z,t} rl_{z,t}}{\sum_{z,t} D_{z,t}} \tag{2.13}$$

$$\sum_{z,t} sp_{z,t} \leq SL \cdot \sum_{z,t} ze_{z,t} \tag{2.14}$$

It is very difficult to determine a suitable curtailment limit in the models. According to Bird et al. (Bird, Lew, Milligan, &et al., 2016), wind power curtailment is normally between 1-3%, but in China, Italy, and Texas it exceeded 10% in some years which was caused by limited transmission capacity. Solar generation was not curtailed in any region in the study. More recently, wind generation accounted 29.3% of total power generated in Ireland and North Ireland in 2018 (EIRGRID & SONI, 2019). About 6% of the wind generation in the system was dispatched down. Solar generation accounted 16.9% of total power generated in California ISO system in 2018, and wind generation accounted 10.1% (CAISO, 2019). The curtailment rate of solar generation is 1.6% and wind is 0.2%. These figures are well below 10%. As the penetration increases in the future, the curtailment rate may rise. However, transmission, storage and other flexibility measures may help to reduce

curtailment. If the limit is released to 20% or higher, Model R and Model P will produce solutions with higher cost and more spilled energy.

3.2.2 Model R – minimum residual load variance

This model is developed to find a portfolio that minimizes the variance of residual load over the 288 time-slices, i.e. to maintain a flat residual load. The optimal mix strives to maximize the overall complementarity of the portfolio output and the demand profile, and thus potentially reduces the capacity of conventional thermal generators in the system.

In contrast with other studies (Sousa &Martins, 2013; Stetter, 2012) using only one demand profile in their modelling, this study deals with multiple zonal demand profiles in a country. This work emphasizes the balance at zonal level and considers the influence of transmission. For instance, the USA has 72 defined zones across 6 time zones. This work calculates the required annual CRE generation in each zone to meet the target. With this target generation and zonal load profiles, the desired residual load profile in each zone $RT_{z,t}$ can be pre-calculated. The objective function is shown as (2.15), where σ^2 is residual load variance, σ is its standard deviation, $rl_{z,t}$ is residual load in zone z at time t; and T is a constant of 288 representing total time-slices. This function considers the variance in total terrestrial zones Z in a country.

$$min.\,zonal\ residual\ load\ variance\ \ R = \sigma^2 =$$

$$\frac{1}{T} \cdot \sum_t \frac{1}{Z} \cdot \sum_z \left(rl_{z,t} - RT_{z,t}\right)^2 \quad z \in terrestrial\ zone \qquad (2.15)$$

This model replace objective function (2.1) in Model C with function (2.15) while keeping all other constraints. However, the constraint (2.16) is critical to this problem. It keeps the overall transmission volume below total power supply. It is designed to prevent transmission looping that occurs in certain cases. Without this constraint, the model can waste energy deliberately through transmission looping in the zones, as a way to shape the supply curve. This is because transmission loss is counted. This

constraint cannot resolve this issue completely but can minimize its influence.

$$\sum_r te_{r,t}^{in} \leq \sum_z ze_{z,t} \quad \forall t \tag{2.16}$$

This model is to find a portfolio of which the output profile best fits the variation demand load over the 288 time-slices, i.e. to maintain a flat residual load. This may potentially reduce the capacity of conventional thermal generators in the system. The best output profile in each zone can be pre-calculated given the annual renewable generation target and load profile. This approach is necessary to keep the objective function in quadratic form.

3.2.3 Model P – minimum portfolio output variance

System flexibility is essential in high variable renewable penetration electricity systems. This problem is developed to incorporate short-term portfolio output variability which can reflect the required level of committed units and reserve from thermal power plants. This study uses MVP approach to find a portfolio with minimum output variation at different time frequencies.

As described in Traube et al. (Traube et al., 2008), the standard expression of the portfolio output variance can be presented as (2.17), where n candidate options are available, σ is the standard deviation of portfolio output, a is the share of generation capacity in the system, and E is power output of the options. In short, the output variance is the sum of all elements in their output covariance matrix $Cov(E_j, E_k)$ weighted by their share of capacity in the system.

$$\sigma^2 = \sum_{j=1}^{n} \sum_{k=1}^{n} a_j a_k Cov(E_j, E_k) \tag{2.17}$$

The advantage of using this approach is that the covariance matrix can be calculated beforehand. The model only needs to solve for the share of capacity a. In this work, the hourly CF of each option is available from the previous work. The covariance matrix is calculated using the CF F at different time frequencies. The decision variable a here is the absolute capacity cp_i value, not the share in the system. This can keep the objective function in quadratic form and make the standard deviation

of portfolio output in power units, i.e. MW.

This work does not model this problem with covariance matrices from continuous hourly CF in time series directly. This is because PV output has a clear diurnal pattern that makes it unfavorable due to high variance. Shahriari and Blumsack (2018) argued that the significant solar power change over day and night does not necessarily mean the solar power is unpredictable. In fact, in lower time frequency, e.g. daily and weekly, solar power variation is smaller than wind power. Therefore, this study models the output variance at two time frequency scales: daily variability and time-slice hours variability, as presented in objective function (2.18).

$$min.portfolio\ output\ variance\ \ P = \sigma^2 =$$

$$0.5 \cdot \frac{1}{M} \cdot \sum_m \sum_j \sum_k a_j a_k Cov_m^{DAY}(F_j, F_k) + 0.5 \cdot \frac{1}{T} \cdot \sum_t \sum_j \sum_k a_j a_k Cov_t^{TS}(F_j, F_k) \qquad (2.18)$$

The daily variability is based on the daily output deviation from the daily output in each calendar month. At this time scale, the variability is driven by weather variations. The minimum daily output variation may imply less committed thermal generators. In function (2.18), the covariance element $Cov_m^{DAY}(F_j, F_k)$ of any pair of options for each month m are calculated separately. M is a parameter of 12, representing the calendar months. This first element is assigned a weight of 0.5 in the objective function.

Another variance element in (2.18), assigned another 0.5 weight, is the variability based on the 288 time-slices. It represents the deviation from the expected output at specific hour in a day in each calendar month. At this temporal frequency, the variability is driven by the weather and short-term atmospheric processes. Minimizing the portfolio output variation at this temporal definition may help to reduce the need for capacity reserve in the short-term. The covariance $Cov_t^{TS}(F_j, F_k)$ of any pair of options for each time-slice t are produced. T is a parameter of 288, representing the total time-slices. The covariance is all calculated from 10-year hourly data. The data is produced into 288 covariance tables, representing 24 daily hours for each calendar month. Each table is calculated from

300 hourly data. Therefore, long-term power output characteristics and complementarity can be captured in this way. For example, it may be found that 2pm in April in a zone is windy and sunny. The covariance can be high and positive in this time-slice but be negative in the morning or next month. This time-slice is presented in this example in one of the 288 covariance tables.

This model includes all base power balancing and operation equations in Model C and the equations are also based on 288 TS. The power output and demand profile here are aggregated into 288 time-slice by taking the mean value. Note that hydropower output is not included in the calculation of covariance matrices for several reasons. First, large hydropower offers the flexibility for dispatch generation. Second, the variation of hydropower generation at daily and sub-daily level is usually small. Third, the historical hourly river discharge data across the world is not available.

3.2.4 Model CP – Compromise solutions

When multiple objectives exist, the optimal solution can be any point on the Pareto efficiency frontier. This study is intended to propose a solution that takes into account all three objectives. One common approach of multi-objective optimization is compromise programming. This study utilizes this approach, and the objective function can be formulated as (2.19).

$$min.multi\ objective\ \ CP = \alpha_1 \frac{C - C_{min}}{C_{max} - C_{min}} + \alpha_2 \frac{R - R_{min}}{R_{max} - R_{min}} + \alpha_3 \frac{P - P_{min}}{P_{max} - P_{min}} \qquad (2.19)$$

Where C, R and P are the objective functions discussed previously. C_{max}, R_{max} and P_{max} are the maximum value of annual cost, residual load variance and portfolio output variance obtained by taking the highest value among the three optimal solutions. Similarity, C_{min}, R_{min} and P_{min} are the lowest values. α is the weight assigned to the three objectives respectively. In this work, the solution assigned with equal weight [0.33, 0.33, 0.33] is proposed as the optimal mix. The solutions with other weight assignment [0.5, 0.25, 0.25], [0.25, 0.5, 0.25] and [0.25, 0.25, 0.5] are also calculated to explore sensitivity to this choice.

3.2.5 Model inputs

Most data input in this study is based on the results from the previous energy potential assessment in this research. This work further estimates hydropower capacity potential and capacity output in every terrestrial zone. Other key assumptions include the fixed cost of the CREs in each region and transmission links. The covariance matrix of all available CRE options in a country/district is also produced as necessary model input data in this work.

The previous work has assessed global wind and solar power technical potential using a spatially resolved approach. Ten years of meteorological reanalysis data are used to estimate hourly CF of wind and solar technologies in 171 countries/districts where 731 terrestrial zones and 339 offshore zones are defined. Consistent constraints on physical, geographical and economic limits, as well as social impacts, are applied to evaluate potential areas for deployment. The potential capacity of each technology in a zone is further binned into tranches based on average CF.

The energy potential and capacity potential of hydropower at global level is less studied. This is probably because of the complexity of hydrological system. Also, the development of a hydropower station involves wide environmental concerns and influences on human activities. In this work, two data sources are used for simulating temporal hydropower output in each terrestrial zone. One is the global hydropower theoretical potential dataset prepared by Hoes et al. (2017). The dataset provides potential locations where hydropower station can be built based on the simulation with elevation and river discharge data. In this work, the locations with expected capacity less than 1MW are removed. The locations in protected areas based on WDPA data map (UNEP-WCMC and IUCN, 2016) are also removed. This work regards the potential capacity between 1 MW to 10 MW as small run-of-the-river (RoR) hydropower systems, and capacity larger than 10 MW as large dispatchable hydropower systems. To estimate the temporal output of a hydropower system, the meteorological assimilation datasets from MERRA-2 dataset (Gelaro et al., 2017) are used. The datasets provides

hourly hydrological assimilation data in 0.625°×0.5° grid cells (approximately 50x50 km). Here it is assumed that hourly river discharge is the sum of surface runoff and baseflow[28]. For each potential location, the discharge data referred to its closest upstream grid point in MERRA-2. This study then estimated the hourly river discharge by reconciling the annual discharge energy of the location and hourly discharge of the upstream grid point. With this temporally disaggregated data, this study uses the approach and assumptions described in (IFC, 2015) to determine the capacity factor for each potential location. The hourly power output is simulated with 89% turbine efficiency, 98% generator efficiency and 99% transformer efficiency. In addition, 3% of auxiliary demand and forced outage is deduced from the net output. The initial power output simulation showed significant variability at hourly and daily scale which deviates from normal observed output patterns. This study therefore aggregated the capacity factor to monthly level in the model. In sum, the hydropower CF in a zone is the mean monthly CF of 10 years estimation for each potential location weighted by the capacity. Summary of the capacity and energy potential of all CREs in a country is listed in Appendix C.

Conventional thermal generation technologies are excluded in this study to simplify the models. It is assumed that all new investments occur in 2040 from green field. This work continues to use the sub-country geospatial definition “zone” in the previous work. Over 1,000 zones are defined in 171 countries/districts. This work takes account of interconnection between any two adjacent terrestrial zones in a country, but the offshore zones can only connect to the adjacent terrestrial zones. The length of a transmission line is assumed to be the direct distance between the centroids of two connected zones. The electricity transmission of a link is bounded by its capacity. The techno-economic assumptions of transmission refers to Pam et al. (2017). It is assumed that the break point of switching between HVAC and HVDC transmission technology is 600 km for terrestrial zones. For transmission from offshore to terrestrial zones, only HVDC technology is used. The transmission line loss is 9.4% per 1000 km for HVAC, and 1.6% per 1000 km for HVDC. Another 1.4% converter loss per

[28] RUNOFF and BASEFLOW in dataset M2T1NXLND.

pair is applied on HVDC.

The cost assumptions of the CREs are based on the New Policy Scenario in IEA's report (IEA, 2018b). The report provides cost projections to 2040 for major countries and regions. The assumptions are applied to other countries based on their geographical location and economic development. This mapping can be found in the table presented in Appendix B. Offshore wind in this study is split into three water depth categories. Based on the cost assumption on shallow water offshore wind from IEA, this work estimates the markup cost for intermediate depth and floating offshore wind by referring to (NREL, 2017). The markup cost of one-axis tracking PV systems compared to fixed-tilt systems is based on Fu et al. (2018). For CSP system, the system with solar multiple 2 and 6 hours storage refers to the standard cost in IEA's report. The cost addition of the system with solar multiple 2.5 and 9 hours storage is calculated from the System Advisor Model by NREL (NREL, 2010). All the annualized cost assumptions, which includes capital costs and O&M costs and considers life time and discount rate, are listed in Table 6.

Table 6. The cost assumptions of the CRE technologies in main regions in 2040.

The unit of the figures is annualized cost per MW in million US dollars.

Technology	Onshore Wind	Offshore Wind	Offshore Wind	Offshore Wind	PV	PV	PV	CSP	CSP	Hydro	Hydro
Sub-Group	All	Shallow	Interm.	Deep	Dist.	Fixed-tilt	One-axis tracking	SM2 ST6	SM2.5 ST9	Small	Large
Europe	0.163	0.321	0.398	0.456	0.084	0.067	0.072	0.416	0.494	0.286	0.210
USA	0.152	0.356	0.442	0.508	0.155	0.099	0.106	0.499	0.593	0.294	0.208
Japan	0.192	0.364	0.452	0.518	0.140	0.096	0.103	0.499	0.593	0.255	0.184
Russia	0.189	0.352	0.438	0.502	0.146	0.111	0.119	0.499	0.593	0.260	0.169
China	0.115	0.309	0.384	0.440	0.075	0.066	0.070	0.361	0.428	0.154	0.132
India	0.123	0.324	0.403	0.462	0.067	0.063	0.067	0.423	0.503	0.229	0.161
Middle East	0.174	0.328	0.408	0.468	0.121	0.098	0.105	0.385	0.457	0.252	0.171
Africa	0.166	0.321	0.398	0.456	0.128	0.110	0.117	0.368	0.437	0.239	0.166
Brazil	0.127	0.331	0.413	0.475	0.114	0.088	0.094	0.392	0.466	0.250	0.169

While for some countries the historical power demand record is available from transparency platforms, it is generally not available for most countries. A consistent approach to estimate hourly

power demand profile at sub-country level is required in this study. This study adopted the model proposed by Toktarova et al. (2019) to create synthetic hourly power demand profile projected to 2040 for each terrestrial zone. The authors has shown that the R-squared error values of the results in 56 countries, where actual demand records are available, are at least 0.968. The model is a superposition of sine functions. Each sine function reflects a type of demand oscillation that can be presented as (2.20).

$$\sum a \, sin^n(bx + c) + d \qquad (2.20)$$

Where a is the amplitude, n is the power of sine, b is the frequency, c is the phase shift and d is an offset value. In total 18 sine functions are created that take into account factors include annual power consumption, power consumption in industry sector, GDP, share of clean energy in the existing system, longitude and latitude, projected peak demand, sunset time, monthly temperature range and warmest temperature in a year. The parameters in the model is derived from statistical approach using historical data. Therefore, it cannot capture the increasing impact of weather on long-term demand pattern. Also, it cannot reflect many factors in the future, such as fuel switching, demand management and political influences.

In this work, the power demand projection to 2040, industry sector demand and the share of clean energy are calculated with data from different sources (IEA, 2017c)(IEA, 2017b)(CIA, 2018). The demand of a zone is based on its share of population in the country. The GDP projection of a country is calculated from assumptions in (World Bank, 2018) and (EIA, 2017). Temperature data is also collected from MERRA-2 dataset. Hourly temperature of a zone is calculated from all grid points in MERRA-2 dataset by taking the mean value. The resulting demand profiles for each zone are compiled in File 7 of supplementary Data Package 1[29]. Figure 12 shows examples of the results of a northern and a southern states in India. Daily demand patterns in four months are presented. Higher demand

[29] The diurnal profile in the data is presented in local time.

peak can be observed in the evening in the winter for the northern state. The southern state has relatively high demand in the afternoon in the summer.

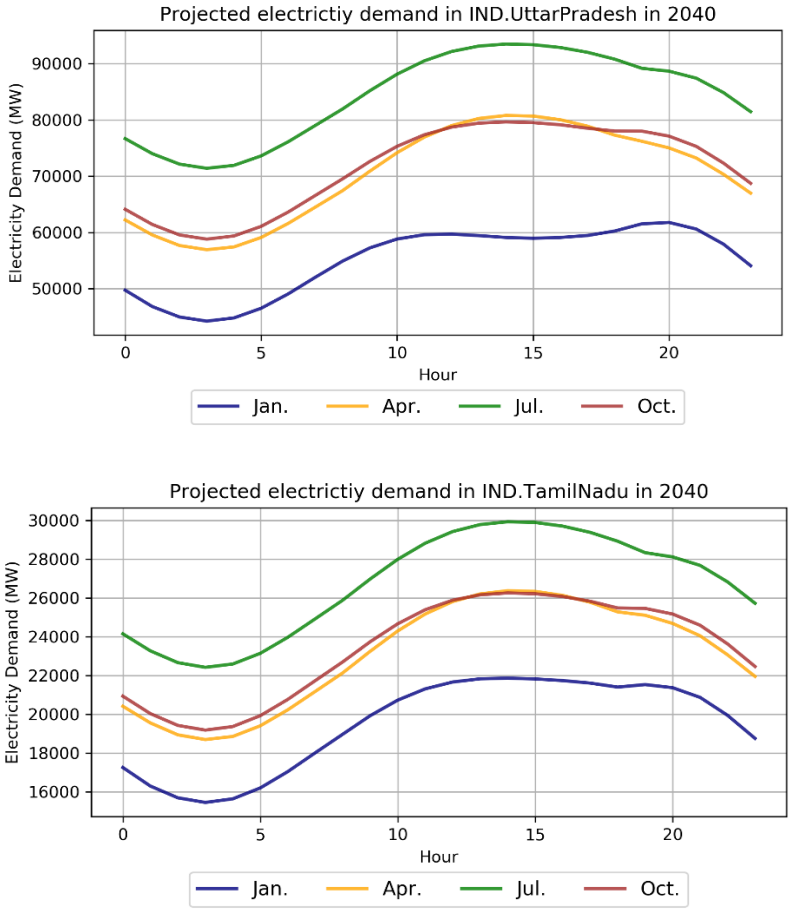


Figure 12. Examples of the synthetic electricity demand profiles produced.
The top figure shows the demand profile of a populated state in northern India in 2040; the bottom figure presents the same data in southern India.

The CF covariance matrices of all available development options in a country are required in Model P. Each element in the matrices represents the covariance of a pair of options. Each element can be noted as $Cov(F_j, F_k)$, where j and k are the options, and F denotes CF. The matrices can be fairly complex for large countries, for instance, Spain (ESP) has 8 terrestrial zones and 4 offshore zones. The major types of technologies can be split into sub-groups and output tranches. In total 169 CRE development options are available in the zones. Therefore a CF covariance matrix will consist of 169^2 elements in Spain.

The CF covariance matrices are calculated at two temporal frequencies in this work. The covariance based on daily CF $Cov_m^{DAY}(F_j, F_k)$ in a calendar month m is calculated from daily average CF of the two options for 10 years, i.e. using the estimated daily CF of around 300 days to compute a single covariance value. In total 12 matrixes are produced for each country. The overall aggregated covariance matrices for each country can be found in File 8 of supplementary Data Package 1. The other covariance set is based on the CF at 288 time-slice t which represents 24 daily hours in each calendar month. Therefore, the covariance $Cov_t^{TS}(F_j, F_k)$ is calculated from the CF of two options at around 300 data points as well, i.e. the same daily hour in the calendar month for 10 years, and 288 matrices are generated for a country.

3.3 Global electricity system decarbonization modelling

This work aims to investigate possible development of future electricity systems in the world using the materials produced in the previous works. A modelling framework is developed for this purpose. The main components have been identified in the literature review. This framework consists of two core optimization models: economic dispatch (ED) model and capacity expansion (CE) model. This section describes the framework and the two proposed models in details.

3.3.1 Modelling framework

In Section 3.2, each country/district is modelled as a single instance separately while international electricity transmission is ignored. This work continues to explore how other non-renewable technologies can influence future development and whether energy resources can be exploited more efficiently at integral market level. In this work, a market consists of multiple zones in one or many countries. The illustrative structure of model instances is shown in Figure 13. The framework performs the modelling on market basis so that international transmission can be considered. After all markets are processed, outputs data can be aggregated into country level. This work covers 1,070 terrestrial and offshore zones in 171 countries/districts. In this research, 35 markets are identify based on existing market zones and current market integration plans. There are 14 major markets include ASEAN, Central America (SIEPAC), Central Africa Power Pool, Central Asia Power System, North Africa Power Pool (COMELEC), East Africa Power Pool, European electricity market, Eurasia (East Europe), MENA, North America, South Asia (SAARC), South America, South Africa Power Pool, West Africa Power Pool. Other markets are mainly island countries which have no clear plan to connect with others. These independent country markets include Cuba, Fiji, Iceland, Jamaica, Japan, Madagascar, South Korea and New Zealand and so on. The structure of the market instances and the countries/districts can be found in Appendix B.

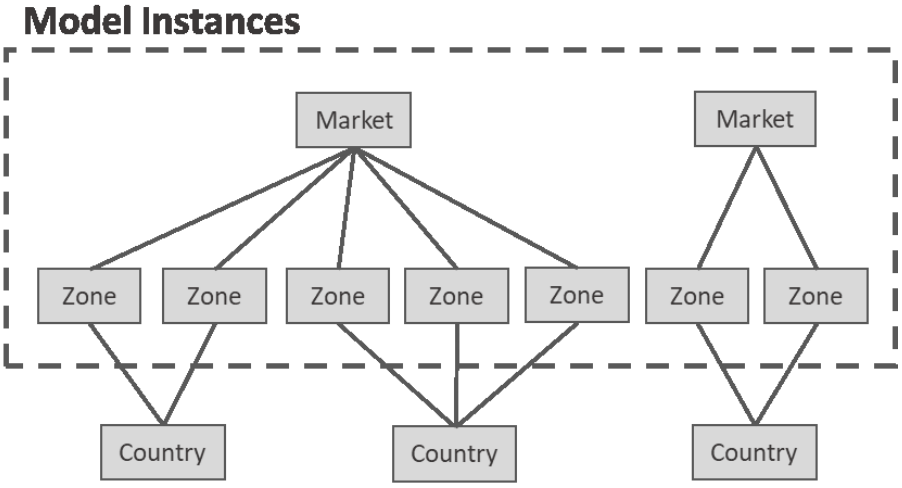


Figure 13. The illustrative structure of market, zone and country of model instances.

The framework of modelling processes and data flow for one market is shown in Figure 14. The ED and CE models are the core components of this framework. Another base year calibration model is created to generate initial inputs for ED model. This calibration model is almost identical to ED model, but it includes additional constraints to calibrate the base year 2015 fuel consumptions. The resulting base year generation then feed into ED model. The purpose of this step is more than energy consumption calibration at country level. It also helps to estimate the generation from different types of power plant at zonal level. More details about this process will be discussed in Section 3.3.4. All these models are formulated in linear programming problems based on minimum cost objective.

The ED model deals with the best dispatch decisions of available generation units considering the physical limits on conventional thermal plants, the operation of storage systems, and the variability of renewable generation. The objective function is based on minimum variable generation cost, which is a typical metric in real operation circumstance. The time-slices of this model is 288, representing daily 24 hours for 12 calendar months. However, the ED problem is split into 12 smaller intraday operation problems for simplification. The framework performs 12 ED modelling iterations for each calendar month. The main purpose of this is to cut the model size, but still allows the model to capture diurnal operation of storage systems. After solving daily dispatch optimization for 12 iterations, the

framework exports a number of key outputs, including emission, fuel consumption, energy flow and costs etc.

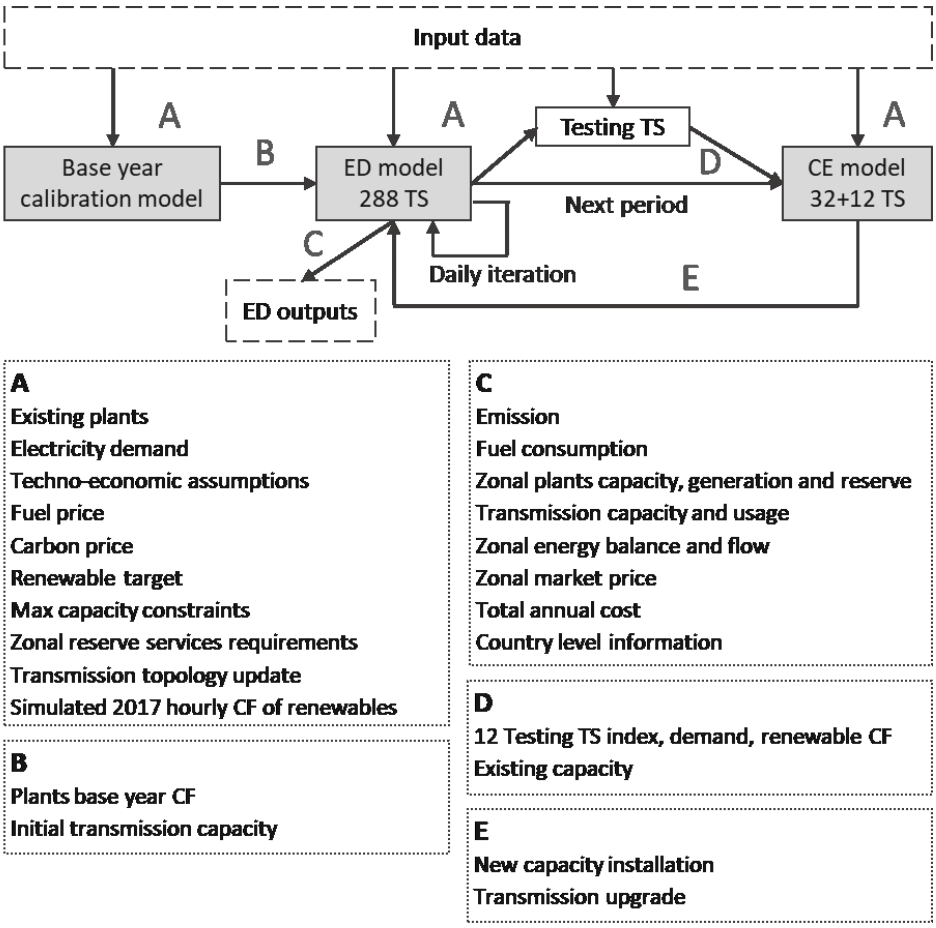


Figure 14. The developed modelling framework and data flow.

The CE model is an extension of ED model. It decides the optimal investment decisions in each period. In general, a capacity expansion model can cover a range of foresight periods. In this work, multiple period foresight requires considerable computational resources for big market, such as Europe and North America, due to the large number of renewable options. For this reason, this work uses 5-years period as a single step, from 2015 to 2050, in CE model. The default time-slice setting is 32 representing 8 daily segments in 4 seasons. After executing this model, the outputs of new capacity installation and transmission upgrade are exported to ED model as endogenous parameters for the next period.

A critical feature of this framework is the mechanism of choosing representative cases dynamically of extreme electricity supply and demand cases. In each main iteration, before building the CE model for calculating next period installation, this framework runs an algorithm to select extreme supply and demand cases in each calendar month. The algorithm takes into account available renewable plants in the next period, and calculate expected hourly residual demand. This is carried out with hourly CF of the renewables in 2017, i.e. the results in the previous work, and with hourly demand profile which also has been produced previously. The algorithm picks one extreme case, i.e. the highest residual demand hour, in each calendar month. Note that the scope of this algorithm is market wide considering supply and demand in every zone in a market. As the generation from different types of renewables can change over the periods, as a result of new investment decisions, the selected 12 representing cases can also change accordingly. These 12 cases of demand and renewable CF of in each zone in the market are then used in the CE model.

Table 7 lists all technology options in the models. Wind, PV and CSP may have several output tranches in a zone. Each tranche is treated as individual technology option since they exhibit different output profiles. All technologies can also be categorized into 6 groups based on input fuel, and be categorized into 4 groups according to their operation mode.

Existing power plants locate in the same zone and committed in the same year are aggregated by technology for the base year input. New build capacity of each available option in a zone is one decision variable in the CE model. This simplification can significantly reduce model size in many markets with a large number of zones. However, the VREs with different CF output tranches are not merged. Furthermore, at the beginning of formulating the CE and ED model in each iteration, the framework removes the plants which have reached their retire time.

The inter-zone and international transmissions in this work are modelled using NTC approach, and capacity limit and transmission losses are considered. An initial aggregated transmission capacity is assigned to each link of two adjacent zones. The initial value is estimated in the base year calibration

model. Transmission capacity upgrade is possible in the CE model but requires capital investment. Every transmission link has a loss factor derived from the distance between the centroids of the two connected zones. The assumptions will be discuss in the following input data section.

Table 7. List of technologies modelled in this research.

Technology	Tranches	Fuel type	Operation mode
Coal – Subcritical		coal	Dispatchable
Coal – Supercritical		coal	Dispatchable
Coal – Ultra supercritical		coal	Dispatchable
Coal – IGCC		coal	Dispatchable
Coal – Supercritical CCS		coal	Dispatchable
Coal – Oxyfuel CCS		coal	Dispatchable
Coal – IGCC CCS		coal	Dispatchable
GAS – OCGT		gas	Dispatchable
GAS – CCGT		gas	Dispatchable
GAS – CCGT CCS		gas	Dispatchable
Oil – ST		oil	Dispatchable
Nuclear - LWR		uranium	Dispatchable
Hydropower - Large		renewable	Hydropower
Hydropower - Small		renewable	Hydropower
Pumped hydro storage		--	Storage
Wind onshore	10	renewable	Non-Dispatchable
Wind offshore - shallow	10	renewable	Non-Dispatchable
Wind offshore - interm.	10	renewable	Non-Dispatchable
Wind offshore - deep	10	renewable	Non-Dispatchable
PV - fixed tilt	7	renewable	Non-Dispatchable
PV - tracking	7	renewable	Non-Dispatchable
PV - distributed	7	renewable	Non-Dispatchable
CSP SM2 6hr	5	renewable	Non-Dispatchable
CSP SM2.5 9hr	5	renewable	Non-Dispatchable
Geothermal (conventional)		renewable	Non-Dispatchable
Biomass – ST		biomass	Dispatchable
Biomass – IGCC CCS		biomass	Dispatchable
Batteries 1hr (Li-ion)		--	Storage
Batteries 4hr (Li-ion)		--	Storage
Batteries 8hr (Li-ion)		--	Storage

The reserve services, or frequency regulation services, are important in sustaining the frequency at targeting range in an electricity system. With the increasing share of VRE, the reserve services are becoming crucial with respect to generation forecast errors. This work is intended to incorporate this issue by modelling the required reserve provided by different sources. This includes three stages of reserve service: primary reserve, secondary reserve, and tertiary reserve. Generation units providing the services have to increase output to required level in 30 seconds, 10 minutes and 30 minutes respectively. Only upward reserve is modelled in this work since downward reserve can be provided from a variety of measures, e.g. renewable output curtailment. The provision of the reserves depends on ramp rate and operation mode of a power plant. In this work, storage system is set to provide primary and secondary reserve, and nuclear plant can only provide tertiary reserve. This is based on current common operation practices.

A script is developed to compile the final output information from the ED model and aggregate the zonal data into country level. The key information include emission, fuel consumption, annual electricity supply by technology type, annual capacity addition, annual investment and market price etc. The zonal market price is the short run marginal cost of electricity generation considering interconnection. A script is developed to calculate this zonal price. The algorithm is shown as Figure 15. The concept is that the price difference between two connected zones only occurs when the power flow at the time is zero or has reached maximum limit. At any time when a transmission flow exists between two zones, and the flow is under the maximum transmission limit, the zonal market price in the zones are set to be the same. A slight difference on the prices may be caused by transmission loss. The algorithm first estimate the zonal marginal generation price by identifying the generator with the highest marginal cost in each zones, then sort the zonal cost in descending order. This algorithm loops through the stack of zones and through each link they connected. The zonal price will be updated if the criterial mentioned have been satisfied.

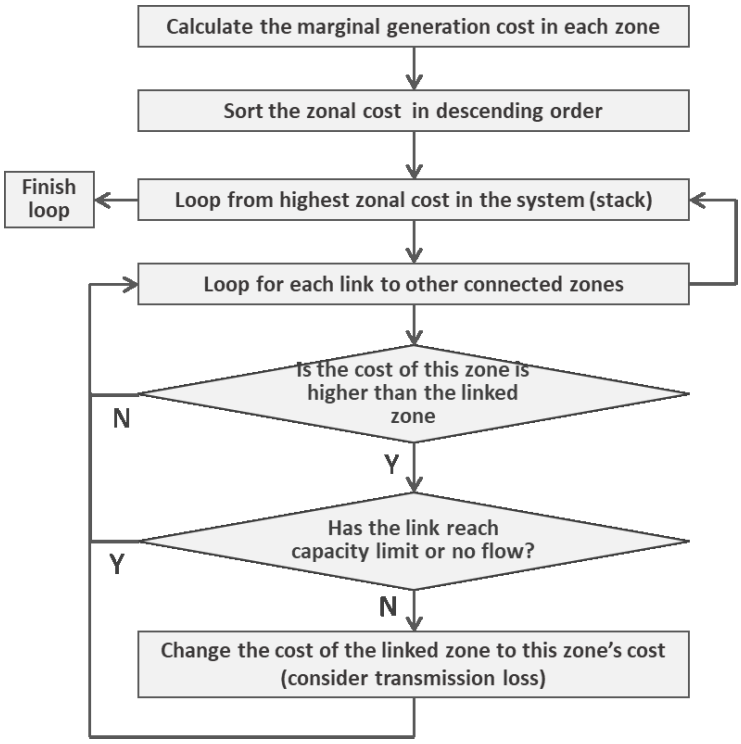


Figure 15. The flow of calculating locational marginal price in an electricity system.

The framework is constructed with the programming language Python. An open-source package Pyomo is used to convert the scripts into optimization model instance. The framework connects to GAMS software on the same PC through standard API. The in-built solver Xpress in GAMS is chosen to perform the optimization tasks. All the input and output data are in CSV file format. This framework is designed with data driven techniques, keeping the configurations and model inputs outside the scripts, so that the models can be customized with little effort. The source code of this framework is available in the Data Package 5 in Appendix A.

The computer processing time depends on the scale of the models. Most of the ED models can be finished in minutes for one iteration. The CE models require longer processing time. The most complicated CE model is the Europe region, consist of 200 zones, which takes around 8 hours to finish one day step. When executing on a 64-bit PC system with Intel Core i7 3.5GHz CPU and 24 GB RAM, this model needs 3 to 4 days to solve the entire market instance of this region for one scenario.

3.3.2 Electricity dispatch model

This section introduces the formulation of the proposed ED model. This model shares several fundamental constraints with the models proposed in Section 3.2, and further incorporates conventional dispatchable plants, storage units and international transmission. Also, the reserve services are an essential part of this model that ensure the system reliability at zonal level. Table 8 summaries all equations applied in the ED and CE model respectively.

Table 8. The summary of equations and their applications in the ED and CE models.

Model	ED	CE			
Installation	Existing	Existing		New installation	
Time-Slice	288	32	12	32	12
Objective function	(3.1)	(3.20)			
General power output	(3.2)(3.3)	(3.2)(3.3)(3.22)		(3.3)(3.21)	
Storage operation	(3.4) (3.5)(3.6)	(3.4)(3.5)(3.6)	(3.25)	(3.6)(3.23)(3.24)	(3.25)
Hydropower operation	(3.7)(3.8)	(3.7)(3.8)	(3.28)	(3.26)(3.27)	(3.28)
Transmission	(3.9)(3.10)	(3.10)(3.29)			
Zone energy balance	(3.11)(3.12)(3.13)	(3.12)(3.13)(3.31)			
Reserve service	(3.14)(3.15)(3.16) (3.17)(3.18)(3.19)	(3.15)(3.16)(3.17) (3.18)(3.19)(3.32)			
Renewables power output	(parameters)	(parameters)		(3.30)	
Other constraints	--	(3.33)(3.34)(3.35)(3.36)(3.37)(3.38)			

The objective function of the ED model is based on minimal variable generation cost as shown in (3.1). The cost comprises of two elements: variable generation cost of all electricity generators and cost of electricity import from other market. The electricity import here is not inter-zone flow in the market modelling instance. It is the energy imported from the connected zones in another market.

$$min.\,variable\ generation\ cost\ C = \sum_{i,t} ce_{i,t} \cdot CCG_i + \sum_{r \in int.t} te_{r,t} \cdot TIC \qquad (3.1)$$

In the function (3.1) $ce_{i,t}$ is the net power output of operational generator i at time t, and CCG_i denotes the parameters of variable generation cost per unit generation (USD/kWh) of generator i. The cost includes three elements: variable operation and maintenance cost, fuel cost, and carbon cost. The fuel cost was calculated from generator's conversion efficiency and fuel price at

the time period of current iteration. The carbon cost was derived from fuel consumption and emission factor. In (3.1) the electricity importing price TIC is set at 0.3 USD/kWh. This cost is high enough to discourage import from other markets but it preserves an electricity supply source in extreme conditions. This import price from other markets is a backstop to reduce infeasible conditions. It is applied only if there exists interconnections with other market, for example, Europe and Eurasia, North America and Central America. This price should be confused with the endogenous zonal price within a market.

Equation (3.2) and (3.3) are basic power output constraints applied to all generators except for VREs. The gross power output $ce_{i,t}^{gross}$ of a generator is bounded by its rated capacity CP_i and takes into account equivalent availability factor CAF_i. This factor is a general availability of the generators which takes account for planned outage and forced outage rates. Net output $ce_{i,t}$ is deduced by the fraction of own use electricity COU_i in the plant. For VRE plants these two constraints are skipped since the losses has already counted in their CF.

$$ce_{i,t}^{gross} \leq CP_i \cdot CAF_i \quad \forall t, i \notin VRE \tag{3.2}$$

$$ce_{i,t} = ce_{i,t}^{gross} \cdot (1 - COU_i) \quad \forall t, i \notin VRE \tag{3.3}$$

For storage system, the power output constraints (3.2) and (3.3) are applied as mentioned above. The $ce_{i,t}$ in storage system denotes the energy discharge. Its energy charging capability $ce_{i,t}^{charge}$ is also limited in the similar way as shown in (3.4)

$$ce_{i,t}^{charge} \leq CP_i \cdot CAF_i \quad \forall t, i \in STOR \tag{3.4}$$

It is assumed that all storage units can only operate the amount of energy of one full storage depth per day, but the state of charge and discharge can change without limit. The maximum daily energy output is equal to the maximum energy storage which is the product of its rated capacity and storage duration hours, as shown in (3.5), where HD_t denotes the representing hours of the time-

slice in a day and CDU_i is the storage duration (energy/power ratio) of the storage system. This constraint is based on the fact that most existing pumped hydro storage are used for load shift. However, for battery storage, it is possible to deliver several full cycles in one day. In this work, the main function of battery storage is to provide primary and secondary reserve services, as it is the main application for current large battery systems (IRENA, 2017a). Hence, this one full depth storage constraint is also applied to battery system without distinguishing it from pumped hydro storage.

$$\sum_{t\in d}\left(ce_{i,t}\cdot HD_t\right) \leq CP_i \cdot CDU_i \quad \forall\, d,\ i \in STOR \tag{3.5}$$

The equation of daily energy balance of a storage unit is show in equation (3.6) which considers operation efficiency CEF_i (LHV). The left hand side of the equation is total charged energy in one day and the right hand side is daily energy output.

$$\sum_{t\in d}\left(ce_{i,t}^{charge}\cdot HD_t\right)\cdot CEF_i = \sum_{t\in d}\left(ce_{i,t}\cdot HD_t\right) \quad \forall\, d,\ i \in STOR \tag{3.6}$$

Small hydropower plants (capacity less than 10MW) in this work is regarded as non-dispatchable and is assigned with fixed load pattern. The load profile is based on monthly CF data processed in Chapter 3. For large hydropower plants, the monthly CF data is also applied as default value. However, they are regarded as dispatchable systems when the flow exceeds certain level. For both type of hydropower, their net output is also limited by equation (3.2) and (3.3). For large hydropower system, when the default CF, noted as $CF_{i,t}$, is below 0.2, it is considered not dispatchable. When the CF is above 0.2, the system can dispatch the generation on daily basis with an output floor at CF 0.2 (3.7). Equation (3.8) describes the total dispatchable energy in a day d which is equal to default energy discharge in the system derived from default daily CF. As mentioned in Section 3.2, this threshold depends on the design of a hydropower system. The figure 0.2 is a general number, but can be conservative for very large systems.

$$ce_{i,t}\begin{cases}\geq CP_i\cdot 0.2\,,\ if\ CF_{i,t}\geq 0.2\\ = CP_i\cdot CF_{i,t}\,,\ if\ CF_{i,t}<0.2\end{cases} \qquad \forall t, i \in LHYD \tag{3.7}$$

$$\sum_{i,t\in d}\left(ce_{i,t}\cdot HD_t\right)=\sum_{i,t\in d}\left(CP_i\cdot CF_{i,t}\cdot HD_t\right)\quad \forall\, d,i\in LHYD \tag{3.8}$$

For each transmission link, its maximum power input $te_{r,t}^{in}$, export to the other zone, is bounded by its capacity TP_r (3.9). The power output at the other end $te_{r,t}^{out}$, in another zone, takes account of the transmission losses TL_r as noted in equation (3.10).

$$te_{r,t}^{in}\ \le\ TP_r\quad \forall t,r \tag{3.9}$$

$$te_{r,t}^{out}=te_{r,t}^{in}\cdot TL_r\quad \forall t,r \tag{3.10}$$

Total power output in a zone $ze_{z,t}$ at time t is the sum of the output from all local generation units. The equation is written in (3.11). It either provided by conventional thermal plants, storage systems and hydropower plants $ce_{z,i,t}$ or non-dispatchable renewable plants $CRE_{z,t}$. In this equation, generation from non-dispatchable renewables is parameter that can be calculated before each iteration with the given capacity and CF.

$$ze_{z,t}=\ \sum_{i\notin NRE}ce_{z,i,t}\ +CRE_{z,t}\qquad \forall z,t \tag{3.11}$$

Zonal electricity balance constraint is shown as equation (3.12). Electricity demand in a zone $D_{z,t}$ can be served by local generation $ze_{z,t}$ and import from connected zones through transmission links, denoted as $\sum_{(r\ in\ z)}te_{r,t}^{out}$. Electricity can also be exported to other zones, noted as $\sum_{(r\ in\ z)}te_{r,t}^{in}$, or be spilled, noted as $sp_{z,t}$. Note that when a transmission link connects to a zone outside the present market, it is categorized as inter-market transmission. Electricity import cost in the objective function $\sum_{r\in int.}te_r\cdot TIC$ is applied on this type of inter-market link. The energy spill variables together with this inter-market import/export variables are crucial in both the ED and CE models in this research. They potentially reduce the chance of obtaining infeasible results or unreasonable solutions.

$$D_{z,t}=ze_{z,t}+sp_{z,t}+\sum_{(r\ in\ z)}te_{r,t}^{out}-\sum_{(r\ in\ z)}te_{r,t}^{in}\qquad \forall z,t \tag{3.12}$$

The equation of energy balance for offshore zones is simpler, as described in (3.13). Electricity can

only be exported to the connected terrestrial zones or be spilled.

$$ze_{z,t} = sp_{z,t} + \sum_{(r\ in\ z)} te_{r,t}^{in} \quad \forall z \in OFZ, t \qquad (3.13)$$

Three types of reserve services are modelled in this work. The reserve requirements in zone z at time-slice t, noted as $RR_{z,t}^{T1}$, $RR_{z,t}^{T2}$ and $RR_{z,t}^{T3}$ respectively, are determined by demand profile. The input data section will describe details of this configuration. Each type of the reserves is served by available generation units in the zone, noted as $ca_{z,i,t}^{T1}$, $ca_{z,i,t}^{T2}$ and $ca_{z,i,t}^{T3}$ in (3.14). Non-dispatchable renewable units are excluded for reserve services.

$$\sum_{i \notin NRE} ca_{z,i,t}^{T1} = RR_{z,t}^{T1} \quad \forall z, t \qquad (3.14a)$$

$$\sum_{i \notin NRE} ca_{z,i,t}^{T2} = RR_{z,t}^{T2} \quad \forall z, t \qquad (3.14b)$$

$$\sum_{i \notin NRE} ca_{z,i,t}^{T3} = RR_{z,t}^{T3} \quad \forall z, t \qquad (3.14c)$$

Each generation unit can provide multiple types of reserve at the same time but limited by its ramping capability CAM_i^{T1}, CAM_i^{T2} and CAM_i^{T3}. This limit is presented in (3.15) below.

$$ca_{i,t}^{T1} \leq CAM_i^{T1} \quad \forall i, t \qquad (3.15a)$$

$$ca_{i,t}^{T2} \leq CAM_i^{T2} \quad \forall i, t \qquad (3.15b)$$

$$ca_{i,t}^{T3} \leq CAM_i^{T3} \quad \forall i, t \qquad (3.15c)$$

The power output together with reserve capacity of a generation units is constrained by its available capacity at any time as shown in equation (3.16).

$$ce_{i,t} + ca_{i,t}^{T1} + ca_{i,t}^{T2} + ca_{i,t}^{T3} \leq CP_i \cdot CAF_i \quad \forall\, t, i \notin NRE \qquad (3.16)$$

Several types of plants can only provide reserve services at spinning state because of long start-up time and low ramp speed. Equation (3.17) ensures that a plant can only offer the reserves when it is producing electricity. The parameter 2 on the right hand side of the equation implies that the

maximum provision of the reserves is about two third of available capacity of a plant. It is designed to ensure minimum load of the plant, typically between 30%-40%, when offering there reserves. Since this is a linear programming model, it is difficult to ensure minimum load of a plant at spinning state. A possible approach is to split the generation into multiple bands, but it can increase the model's complexity considerably. The constraint (3.17) at least requires a plant to offer reserves at generating state instead of starting from offline state.

$$ca_{i,t}^{T1} + ca_{i,t}^{T2} + ca_{i,t}^{T3} \leq ce_{i,t} \cdot 2 \quad \forall i, t, i \notin ST, OCGT, NRE \tag{3.17}$$

The constraint (3.17) does not apply to oil steam turbine (mixed with internal combustion engine in this study) and OGCT since they have fast start-up speed. However, for primary reserve which has to be active within 30 seconds, it needs to be executed at spinning state for any types of plants. Equation (3.18) below is to ensure the spinning state. Similar to (3.17), the parameter 0.5 is to guarantee a reasonable spinning output level.

$$ca_{i,t}^{T1} \leq ce_{i,t} \cdot 0.5 \quad \forall i, t \tag{3.18}$$

The operation of battery storage is rather flexible and dynamic. It cannot provide downward reserve when the storage is full, and cannot provide upward reserve when the storage is empty. In real application when battery is used for supporting frequency regulation services, it is normally operating at a range based on 50% state of charge (SOC) point, which allows it to absorb and deliver power. In this work, therefore, the maximum reserve provision of battery systems is set at 50% of its available capacity, as shown in (3.19) below.

$$ca_{i,t}^{T1} + ca_{i,t}^{T2} \leq CP_i \cdot CAF_i \cdot 0.5 \quad \forall t, i \epsilon BAT \tag{3.19}$$

3.3.3 Capacity expansion model

The CE model is developed to optimize the investment for a 5 years period. In fact, the CE model

is an extension of the ED model. For existing units which still operating in the period, they are mostly applied with the same formulations as those in the ED model but with reduced representative time-slices. The new installation capacity of all candidate options in each zone are the main decision variables in the CE model. In addition to the reduced 32 representative time-slices, another 12 cases for reliability test selected from 2017 hourly data are used to ensure system reliability in extreme conditions. Consequently, this model is more complex with these two extra considerations when compared with ED model.

In the objective function (3.20), variable generation cost $\sum_{i,t} ce_{i,t} \cdot CCG_i$ of existing plants i and electricity import cost $\sum_{r \in int.t} te_{r,t} \cdot TIC$ are the same elements as those in the ED model. The third element is the parameter of annualized fixed cost of existing plants, where CCF_j denotes the parameter of annual fixed cost per unit capacity. This element in fact does not influence the result since it is a summation of parameters. The variable generation cost and fixed annual cost of a new installation plant j are noted as $\sum_{j,t} ce_{j,t} \cdot CCG_j$ and $\sum_j cp_j \cdot CCF_j$, where cp_j is the variable of its installation capacity. The last element is the annual cost of total transmission links, including new expansion capacity, where TCF_j represents the fixed cost per unit capacity of the link r.

$$min.\, total\ system\ cost\ C = \sum_{i,t} ce_{i,t} \cdot CCG_i + \sum_{r \in int.t} te_{r,t} \cdot TIC$$

$$+ \sum_i CP_i \cdot CCF_i + \sum_{j,t} ce_{j,t} \cdot CCG_j + \sum_j cp_j \cdot CCF_j + \sum_r tp_r \cdot TCF_i \qquad (3.20)$$

The general power output constraints of a generation unit in equation (3.2) and (3.3) are still applied on existing units. For new installation options, their installation capacity becomes variables cp_j. Therefore, equation (3.21) which limits the gross output of a plant is applied to replace constraint (3.2), while equation (3.3) are kept the same.

$$ce_{j,t}^{gross} \leq cp_j \cdot CAF_j \quad \forall j, t \qquad (3.21)$$

In this work, some formulations are created to avoid abrupt change on generation mix. The

unreasonable change is rooted from the characteristic of optimization model. When the cost of a specific option become competitive, the option can quickly make up a large share of new installation in the market. This model applies a minimal generation requirement for existing dispatchable plants which are in service in base year 2015. It is assume that their minimum electricity generation declines gradually from 2015 base year level to 0 in 2040, i.e. 20% reduction per period, if the plant is still in service in this time horizon. This constraint does not apply on any new installation. The equation is shown in (3.22) where $CF_{y=base,i,t}$ denotes the generation capacity factor at base year and BF_y is the declining factor. For base year, BF_y was assigned a value of 0.9. This setting is to release the constraint and ensure the ED model generate feasible solutions. Note that this constraints is applied at daily operation level for each calendar month, not for annual total generation. Daily time-slices in CE model has reduced to 8 segments. Each season is assigned a different minimal generation level.

$$\sum_{i,t\in d}\left(ce_{i,t}\cdot HD_t\right) \geq \sum_{i,t\in d}\left(CP_i\cdot CF_{y=base,i,t}\cdot HD_t\right)\cdot BF_y \quad \forall\, d, i \in DISP \qquad (3.22)$$

Similar to the general output constraints for dispatchable thermal plants, the new installation capacity of storage systems is decision variable cp_j. Equations for storage charge and output limit (3.4) and (3.5) are replaced by (3.23) and (3.24) shown below.

$$ce_{j,t}^{charge} \leq cp_j\cdot CAF_j \quad \forall t, j \in STOR \qquad (3.23)$$

$$\sum_{t\in d}\left(ce_{j,t}\cdot HD_t\right) \leq cp_j \cdot CDU_j \quad \forall\, d,\ j \in STOR \qquad (3.24)$$

In the 12 reliability test cases, the output of both existing and new storage options is fixed since the daily operation is not formulated. During the time of building this model, the maximum output is initially capped at their available capacity. However, this configuration may result in overestimating their output in these extreme cases. When fed with this result, the ED model in the next iteration frequently produced infeasible outcomes. Therefore, a relatively conservative configuration is applied, as shown in (3.25). It implies that the storage system operates with equal charge and discharge time

period in the day (12 hours) and with one maximum storage cycle.

$$ce_{j,t} \leq cp_j \cdot CAF_j \cdot CDU_j/12 \quad \forall t \in TEST, j \in STOR \qquad (3.25)$$

The new installation capacity of large hydropower plant is also decision variable cp_j, not fixed parameter CP_i. Equation (3.26) and (3.27) were applied to replace (3.7) and (3.8) for new plants herein.

$$ce_{j,t} \begin{cases} \geq cp_j \cdot 0.2\,, \ if\ CF_{j,t} \geq 0.2 \\ = cp_j \cdot CFA_{j,t}\,, \ if\ CF_{j,t} < 0.2 \end{cases} \quad \forall t, j \in LHYD \qquad (3.26)$$

$$\sum_{j,t\in d}\left(ce_{j,t} \cdot HD_t\right) = \sum_{j,t\in d}\left(cp_j \cdot CF_{j,t} \cdot HD_t\right) \quad \forall\, d, j \in LHYD \qquad (3.27)$$

In the reliability test cases, the output of large hydropower system is fixed at their default CF as presented in (3.28). This is also because the daily dispatch operation is not formulated.

$$ce_{j,t} = cp_j \cdot CF_{j,t} \quad \forall t \in TEST, j \in LHYD \qquad (3.28)$$

In this CE model, investment decision can also be made on transmission capacity. The new upgrade capacity noted as tp_r^{add}. The maximum transmission input constraint (3.9) is modified into (3.29) while the transmission loss constraint (3.10) is kept unchanged.

$$te_{r,t}^{in} \leq TP_r + tp_r^{add} \quad \forall t, r \qquad (3.29)$$

For new non-dispatchable renewable plant, their output $ce_{j,t}$ is the product of their capacity cp_j and the given capacity factor $CF_{j,t}$, shown in (3.30). For all existing plants, the power output is aggregated into the same term $CE_{z,i,t}$ as shown in (3.11)

$$ce_{j,t} = cp_j \cdot CF_{j,t} \quad \forall t, j \in NRE \qquad (3.30)$$

The overall power supply in zone z at time t can be formulated as (3.31) that replaces (3.11) in the ED model. The four elements in this equation are: generation from existing dispatchable, existing non-dispatchable renewable, new dispatchable and new non-dispatchable renewable generation

units. Hydropower and storage system belong to dispatchable elements in these equations. Other zonal supply and demand constraints (3.12) and (3.13) in the ED model are remained the same.

$$ze_{z,t} = \sum_{i \notin NRE} ce_{z,i,t} + CRE_{z,t} + \sum_{j \notin NRE} ce_{z,j,t} + \sum_{j \in NRE} ce_{z,j,t} \quad \forall z,t \qquad (3.31)$$

The reserve services can be provided by existing and new generation units. The equation (3.14) is modified into (3.32). For instance, the required primary reserve in zone z at time t, written as $RR_{z,t}^{T1}$, can be served by all existing plants $ca_{z,i,t}^{T1}$ and new plants $ca_{z,j,t}^{T1}$. Other constraints on the reserves service in the ED model, from (3.15) to (3.19), are kept the same form but applied to both existing and new plants.

$$\sum_{i \notin NRE} ca_{z,i,t}^{T1} + \sum_{j \notin NRE} ca_{z,j,t}^{T1} = RR_{z,t}^{T1} \quad \forall z,t \qquad (3.32a)$$

$$\sum_{i \notin NRE} ca_{z,i,t}^{T2} + \sum_{j \notin NRE} ca_{z,j,t}^{T2} = RR_{z,t}^{T2} \quad \forall z,t \qquad (3.32b)$$

$$\sum_{i \notin NRE} ca_{z,i,t}^{T3} + \sum_{j \notin NRE} ca_{z,j,t}^{T3} = RR_{z,t}^{T3} \quad \forall z,t \qquad (3.32c)$$

Total capacity of technology p in a country n in year y can be subject to several constraints, the equation is shown as (3.33) where the maximum capacity is $CPM_{n,y,p}$. In each 5 year step iteration of the CE model, the framework first checks the limits of available installation capacity taking into account the retirement of existing plant and other available capacity limits. The capacity limits include the list below, more discussion will be presented in the next section.

- Technology readiness – It is assumed that most types of CCS technology will not be commercially viable by 2030, i.e. restriction on new installation for 2020 and 2025 periods.
- Nuclear development – Several countries have announced plan to stop building new nuclear plants. For other countries, new installation is set to be 0 by 2030 except for new plans which have been announced.
- VRE capacity potential – The maximum capacity potential in a zone is proposed in the previous work. This constraint here is formulated at zonal level, not country level.

- Hydropower capacity limit – In some countries the maximum capacity of hydropower is assumed to be twice the capacity of base year. This constraint is to reflect a more realistic limited hydropower capacity addition for the concerns on the impacts on environment and human activities.

$$\sum_{z\in n,i\in p} cp_i + \sum_{z\in n,j\in p} cp_j \leq CPM_{n,y,p} \qquad \forall\, n,p \qquad (3.33)$$

Conversely, there are limits on minimum new build capacity. This constraint is applied in three circumstances. First, renewable development is set to calibrate to 2018 records. The new capacity addition is applied to the CE model for the period of 2020, as shown in (3.34). In some countries, the capacity addition between 2015 and 2018 is considerable. Second, the MCP scenario in this work is based on the optimal capacity mix proposed in Section 3.2. It specifies a minimum capacity of every renewable options in each period. This constraint is presented in (3.35). Finally, most existing biomass plants (including CHP plants) consume MSW and other wastes. The capacity and generation is not expected to decline, and they are set to be at least higher than base year in each period. Equation (3.35) is applied in this case.

$$\sum_{z\in n,i\in p} cp_{y=2020,i} + \sum_{z\in n,j\in p} cp_{y=2020,j} \geq CPM_{n,y=2018,p} \qquad \forall\, n,p \qquad (3.34)$$

$$\sum_{z\in n,i\in p} cp_i + \sum_{z\in n,j\in p} cp_j \geq CPM_{n,y,p} \qquad \forall\, n,p \qquad (3.35)$$

Annual biomass supply is limited in each country. The total biomass consumed in existing and new plants should be less than total supply $FBI_{n,y}$ in a country, as shown in equation (3.36) below.

$$\sum_{z\in n,i\in BIO,t} cfc_{z,i,t} + \sum_{z\in n,j\in BIO,t} cfc_{z,j,t} \leq FBI_{n,y} \qquad \forall\, n \qquad (3.36)$$

As mentioned previously in the discussion on equation (3.22), some constraints may be needed to avoid abrupt change on capacity mix. The equation (3.22) is targeting at sudden drop of generation from old plants committed before base year. On the other hand, limiting the renewable growth may be necessary to produce more convincing results. Equation (3.37) is applied to limit the generation

growth of all renewable energies, including hydropower and biomass. The cap is set to 25% penetration per 5 years period step. It is not a strict constraint but potentially reduce unreasonable surge in some cases. With this configuration, a country still can attain 100% renewable generation within 20 years starting from 0.

$$\sum_{z\in n,i\in(NRE,HYD,BIO),t} CE_{z,i,t} + \sum_{z\in n,i\in(NRE,HYD,BIO),t} ce_{z,j,t} \leq \sum_{z\in n,y-1,i\in(NRE,HYD,BIO)} CE_{z,y-1} + D_{n,t} \cdot 0.25 \quad \forall\, n \tag{3.37}$$

In the proposed carbon neutral scenario, the emissions in a market should be reduced to zero in 2050. This limit can be written in equation (3.38) where $em_{z,i,t}$ denotes the emission of unit i in zone z at t and EC_y is the emission cap in the period y in this market.

$$\sum_{z,i\in DISP,t} em_{z,i,t} + \sum_{z,j\in DISP,t} em_{z,j,t} \leq EC_y \quad \forall\, y \tag{3.38}$$

3.3.4 Data inputs

This section describes all input data and the sources in this work. Most of the inputs related to VREs has been produced from the previous works, and the cost and technical assumptions are kept the same. This section also discusses the steps for calibrating the models with base year data.

Capacity potential and output profile of wind, solar and hydropower technologies are assessed in Section 3.1. Other renewable energies, include geothermal, biomass and marine power, can also contribute to an electricity system. Marine electricity technologies, mainly consist of wave, ocean current and tidal power, are estimated to have relatively little installation capacity in the future. In the most aggressive renewable development scenario proposed by IEA, global marine power can only produce 78 TWh in 2040 (IEA, 2018b). Therefore, this work takes into account geothermal and biomass power generation but ignores marine energies.

Geothermal energy can be exploited for electricity generation and direct heat use. For electricity

generation, typically three types of technology have been explored: flash plant, binary cycle plant and enhanced geothermal systems (EGS) (Goldstein et al., 2011). Flash plant is the most common type of hydrothermal geothermal technology. It pulls up high temperature water (>150°C) stored in geothermal reservoirs, and the hot water boils into steam as pressure decreases. The resulting steam drives turbines to generate power. Binary cycle is another common type of hydrothermal technology. It utilizes fluids with lower boiling point to extract heat from pumped hot water. EGS system is developed to exploit geothermal energy in dry and impermeable rocks, where the energy potential is much higher than conventional hydrothermal types. EGS technology is excluded in this work because it is difficult to estimate a reasonable technical potential in an area without a complete survey on the geological environments, and its complexity also drives a wide range of production cost. Hence, only flash and binary hydrothermal technologies are considered herein. In fact, the production cost of EGS can be several times higher than the other two types (IEA, 2011) that makes it unfavorable in the market.

According to IEA, electricity generated from biomass accounted for 2.4%, or 636TWh, in 2018. Studies on the technical potential of global geothermal electricity generation is limited. Stefansson (2005) estimated that the global technical potential of terrestrial high-temperature geothermal for power generation is around 240 GWe, or 5.7 EJ/year, assuming a CF of 90%. The author argued that the unidentified potential can be up to 5 to 10 times higher. This estimation mainly accounts for high temperature geothermal for conventional technologies. On the other hand, Goldstein et al. (2011) estimated the global technical potential of EGS can range from 89 to 1052 EJ/year, significantly higher than hydrothermal types. Detailed country level studies also exist. For instance, Williams et al. (2008) indicated that the identified potential of conventional geothermal systems is around 9 GW and the potential for EGS system can be up to 517 GW in the US. Van Wees et al. (2013) investigated the economic potential of geothermal electricity generation at country level and reported that the total potential can be over 500 GW in Europe.

There is a lack of comprehensive studies on global geothermal potential at sub-country level. However, this data is necessary in this work for assessing zonal generation mix. One simple approach to identify possible area for geothermal development is by referring to heat flow distribution which is the energy reaches the Earth's surface from the Earth's interior through a unit area. In this study the global heat flow map produced by Goutorbe et al. (2011) is used for estimating the distribution of geothermal potential. The map is adopted for its good overall accuracy and its fine spatial resolution 1°×1°. In this work, it is assumed that the global capacity potential of hydrothermal geothermal is 240 GW, referring to the potential proposed by Stefansson (2005). The capacity potential in each zone is processed with the same GIS and spatial resolving approach introduced in Section 3.1. Eligibility masks and exclusion areas are also created with protected area, road access limit and minimum heat flow of 80 mW/m^2.

The estimated potential of conventional geothermal capacity in the US proposed in this work compared with the identified and undiscovered estimations by Williams et al. (2008) is shown in Table 9. This table only lists the states with installation potential. The simple approach applied in this work does identify potential areas and the capacity potential is mostly in the range of identified and undiscovered potential by Williams et al. (2008). While the real potential is unknown in most countries, this approach yield an approximation of the distribution of geothermal potential worldwide.

Bioenergy is also important to the future power generation decarbonization. In the IEA scenarios (IEA, 2018b) bioenergy can contribute 3-5% of the electricity generation in 2040. Since bioenergy electricity generation is dispatchable, it provides higher value than other renewables in balancing power supply and demand. According to IRENA (IRENA, 2014) only 9.4% of total biomass supply globally was used for power and heat generation in 2010. This figure can grow to 28.7% in 2030 thanks to the electrification of traditional building and transport sector. This work focuses on biomass used for electricity generation, mainly include crop residues, forestry residues, animal wastes and

municipal solid waste (MSW). Dedicated energy crops which are typically processed into biofuel for transport and direct use are excluded herein. The main purpose in this section is to determine the amount of biomass available for power generation in each country in the future.

Table 9. The estimated capacity potential of conventional geothermal in the US in this work compared with another study.

Zones in the US	Estimated capacity in this work (GWe)	Identified mean capacity by Williams et al. (GWe)	Undiscovered mean capacity by Williams et al. (GWe)
USA.AK	0.78	0.68	1.79
USA.AZ	2.42	0.03	1.04
USA.CA	2.78	5.4	11.34
USA.CO	2.74	0.03	1.11
USA.HI	0	0.18	2.44
USA.ID	1.76	0.33	1.87
USA.KS	0.44	-	-
USA.MT	0.91	0.06	0.77
USA.NE	1.35	-	-
USA.NM	2.8	0.17	1.48
USA.NV	2.11	1.39	4.36
USA.OR	0.93	0.54	1.89
USA.SD	0.76	-	-
USA.TX	0.99	-	-
USA.UT	1.65	0.18	1.46
USA.WA	0.37	0.02	0.03
USA.WY	0.41	0.04	0.17
Total	23.2	9.05	29.75

The historical data of domestic production of crop residues, forestry residues and animal wastes is available from Food and Agriculture Organization (FAO) of the United Nations (FAO, 2019) website. For this work, only selected subset data is used. The total amount of crop residues is aggregated from barley, beans, maize, millet, oats, rice, rye, sorghum, soybeans and wheat residues. Forestry residues contain wood pellets and wood residues. Animal wastes are the amount of excreted manure from cattle, chicken and swine. However, from net production to technical potential, there are several

factors have to be considered, such as recoverable fraction (RF) and residual to product ratio (RPR). Different types of residues may be assigned different values in different studies. For this reason, this work refers to the estimations proposed by Rogner et al. (2012) for the technical potentials in major regions projected to 2050. The global estimated technical supply in 2050 are 49 EJ for crop residues, 39 EJ for manures and 19 EJ for forestry residues. The split into country level potential is based on the FAO net production volumes. It is assumed that a maximum of 30% of the crop residues can be used for power generation. This maximum cap for animal wastes is 30% and for wood residues is 50%. The rest amount of biomass will be used in building, manufacture and transport sector. The assumptions is based on the most demanding scenario REmap proposed by IRENA (Nakada et al., 2014). In 2030, around 30% of the biomass will be used in power sector. Forestry residues which accounts for relatively small part of biomass supply is assumed to have 50% used in power sector. This is to reflect that higher proportion wood pellet and wood residual is used to fuel large-scale power plant. The split, however, varies widely between. For example, 91% wood pallet is used in power plant in the UK while 90.6% is used in residential sector for heating in Germany. In the EU member states, the overall split is about 50% (Eurobserv'Er, 2018).

Country level data on Municipal solid waste (MSW) production can be obtained from World Bank website (Kaza et al., 2018) which provides the projection to 2025. The composition and recoverable fraction of MSW varies by country. The overall potential of MSW proposed in Rogner et al. (2012) is also used. The production in each country is based on its share calculated from World Bank data. It is assumed that a maximum of 40% of the MSW can be used for power generation. The split of 40% is also derived from municipal waste used in power generation in Europe countries based on IRENA's power generation estimation (IRENA, 2019c).

The available biomass in a country for electricity generation is the summation of the four resources, and it is assigned a single cost and emission factor for simplification in this study. Note that this figure is the limit of biomass can be used in a country. Although no trading between countries is

considered, a preliminary calculation shows that these figures can satisfy the biomass consumption for electricity generation in each country in the base year. As mentioned in Section 3.3.3, the consumption of biomass is assigned a capacity and generation floor based on base year value. This is to reflect the consumption of cheap MSW and industrial residuals which is unlikely to decline in the future. If this constraint is not applied, the biomass consumption in the modelling usually drop to zero due to its higher overall fuel cost assumption.

Most of the techno-economic assumptions of renewable energies have been introduced in the previous sections, mostly based on IEA's data. For the rest technologies, the cost assumptions are listed in Table 10, and the technical assumption are summarized in Table 11. These assumptions are mainly based on the New Policy Scenario proposed by IEA (IEA, 2018b), and the range of power plant minimum load and ramp rate is based on a report by Agora Energiewende (2017) which indicates the figures of existing and new technologies. Lower minimum load and higher ramp rate are applied for any new installations. The assumptions after 2040 are the extrapolation from the trend between 2035 and 2040. The tables only present the assumptions in ranges among major regions in the world for reducing the length of this article. The model inputs of each country can map to one of these region. This mapping relation can be seen in the country list in Appendix B. In the CE model, the minimal installation capacity is set to be 100 MW for dispatchable technologies and 50 MW for renewable and storage systems instead of using the listed figures.

For calculating annualized cost, a general 5% discount rate is applied to every technology. This research use the method suggested by NREL to calculate LCOE (NREL, 2019). The discount rate alone with service lifetime are used to calculate annuity-based capital recovery factor which represents the costs of financing the capital for a project. The resulting LCOE is the minimum price at which energy must be sold for an energy project to break even. The discount rate typically contain several financial terms. Here it refers to the cost of debt and equity, or weighted-average cost of capital (WACC). Several factors contribute to the variation of WACC of different technologies across the world. For

example, the WACC of wind technologies is reported between 5.2% - 7.6% in the US (Stehly et al., 2018) and the WACC of solar PV by country can range from 3.7% in Japan to 254% in Zimbabwe (Gerlach et al., 2014). This research uses a fixed 5% discount rate to annualized capital cost of all technologies so that different technologies have common ground when comparing their cost. Fixed discount rate can be found in some models, such as LUT ETM and ReEDS.

Table 10. Cost assumptions of thermal power generation and storage technologies in this work.

Technology	Lifetime	CAPEX ($/kW)		OPEX fix ($/kW)		OPEX variable ($/kWh)	
	(year)	2015	2050	2015	2050	2015	2050
Coal – Subcritical	40	600 - 2100	600 - 2100	20 - 55	20 - 55	0.001	0.001
Coal – Supercritical	40	700 - 2400	700 - 2400	30 - 70	30 - 70	0.001	0.001
Coal – Ultra supercritical	40	800 - 2600	800 - 2600	30 - 80	30 - 80	0.001	0.001
Coal – IGCC	40	1100 - 2900	800 - 2650	50 - 100	35 - 95	0.001	0.001
Coal – Supercritical CCS	40	3500 - 5900	2400 - 4700	140 - 180	90 - 140	0.01	0.01
Coal – Oxyfuel CCS	40	3500 - 6100	2550 - 4950	140 - 185	100 - 145	0.01	0.01
Coal – IGCC CCS	40	3650 - 6250	2750 - 5300	165 - 220	130 - 185	0.01	0.01
GAS – OCGT	35	350 - 500	350 - 500	20 -25	20 - 25	0.006	0.006
GAS – CCGT	35	560 - 1100	560 - 1100	20 - 30	20 - 30	0.002	0.002
GAS – CCGT CCS	35	2200 - 3200	1600 - 2500	70 - 100	55 - 80	0.007	0.007
Oil – ST	30	700 - 1000	700 - 1000	40 - 50	40 - 50	0.002	0.002
Nuclear - LWR	60	2000 - 6600	2500 - 4500	120 - 210	120 - 225	0.0024	0.0024
Biomass – ST	30	1600 - 2500	1600 - 2300	55 - 90	55 - 85	0.008	0.008
Biomass – IGCC CCS	40	1870 - 4931	1220 - 4072	64 - 128	48 - 110	0.001	0.001
Batteries 1hr (Li-ion)	15	700	330	0	0	0.0073	0.0073
Batteries 4hr (Li-ion)	15	1700	880	0	0	0.0073	0.0073
Batteries 8hr (Li-ion)	15	3200	1600	0	0	0.0073	0.0073
Geothermal	35	2250 - 3600	1900 - 3250	45 - 70	40 - 60	0	0

The estimation of capacity potentials and output profiles of renewable energies in each zone have been discussed in Section 3.1 and 3.2. The capacity potentials are divided into tranched classes, and the output profile is aggregated from 10-years hourly simulation into 288 time-slice, representing daily 24 hours in each calendar month. The CF of hydropower is on monthly basis, while large hydropower systems have limited dispatch capability based on the monthly CF value. Hydropower operation is defined in constraints (3.7) and (3.26). The conventional geothermal in this work is

assigned a unitary CF of 80%.

Table 11. Technical assumptions of thermal power generation and storage technologies in this work.

Technology	Unit size (MW)	Efficiency (gross, LHV) %		Min. Load %	Ramp rate %P/Min	Equ. Avail. Factor %	Auxiliary cons. %	CCS Capture rate %
		2015	2050					
Coal – Subcritical	600	35 - 39	35 - 39	30 - 40	2 - 3	90	7	-
Coal – Supercritical	600	39 - 43	39 - 43	30 - 40	2 - 3	90	7	-
Coal – Ultra supercritical	600	41 - 45	45 - 48	30 - 40	2 - 3	90	7	-
Coal – IGCC	600	41 - 44	47 - 51	30 - 40	2 - 3	85	7	-
Coal – Supercritical CCS	600	31 - 36	32 - 37	30 - 40	2 - 3	88	7	85
Coal – Oxyfuel CCS	600	31 - 36	32 - 37	30 - 40	2 - 3	88	7	90
Coal – IGCC CCS	600	32 - 36	38 - 42	30 - 40	2 - 3	88	7	85
GAS – OCGT	50	38 - 40	43	30	10 - 12	92	7	-
GAS – CCGT	500	56 - 59	58 - 62	30 - 40	5 - 6	90	7	-
GAS – CCGT CCS	500	48 - 52	49 - 52	30 - 40	5 - 6	88	7	95
Oil – ST	50	29 - 32	29 - 32	10	8	90	7	-
Nuclear - LWR	500	33	33	50	2	90	6	-
Biomass – ST	50	29 - 32	29 - 32	10	4	90	7	-
Biomass – IGCC CCS	300	27 - 30	42 - 45	30 - 40	2 - 3	85	7	85
Batteries 1hr (Li-ion)	50	92	96	-	200	95	-	-
Batteries 4hr (Li-ion)	50	92	96	-	200	95	-	-
Batteries 8hr (Li-ion)	50	92	96	-	200	95	-	-
Geothermal	50	10	10	-	-	95	6	-

In 2017, pumped hydro storage (PHS) is the main source of energy storage in power system worldwide, account for 96% of the total installed capacity, and around 90% of the PHS capacity was used for electric energy time shift (IRENA, 2017a). However, assessing PHS potential in an area is a difficult work. It requires dedicated models that identify potential locations of reservoirs with constraints on nature terrain, land-use, human activity, environment protection, distance between water bodies and economic considerations. The assessment carried out by EU JRC is a good example to show the complexity (Gimeno-Gutiérrez &Lacal-Arántegui, 2013). For this work, it is not intend to assess PHS potential at global scale. The available PHS capacity in a zone is estimated with the overall hydropower capacity potential. The PHS capacity potential is assumed to be 10% of hydropower

capacity, as this figure is based on the existing data in 2018 when global renewable hydropower was 1172 GW and PHS is 121 GW. Each PHS is assigned a fixed energy to power ratio of 8 hours and 80% efficiency.

Power demand profiles of each zone have also been produced in Section 3.2. The annual electricity demand of all end-use sectors is based on IEA statistics (IEA, 2017b). A fraction of overall system loss and own use in industry are also derived from IEA data and added to end-use demand as the system demand for electricity. Other own uses include power plant auxiliary consumption and pumped hydro efficiency losses are to be determined in the models. The overall system loss in the base year can be very high in several developing countries according to the IEA statistics. For instance, it is around 20% in Brazil and India. It is assumed that the losses can be reduced overtime. Hence in this study the assumption on the overall loss is a constant based on base year value, but is capped at 10%. This assumption however can cause the underestimation on electricity generation, fuel demand and emissions in the early periods.

The carbon price projections in this work refer to the New Policy Scenario (NPS) and Sustainable Development Scenario (SDS) proposed by IEA (IEA, 2018b), as shown in Table 12. The two projections are used as the prices in reference scenario and high carbon price scenario proposed in this work. For advanced economies the price is set at 63, 140 and 191 in the year 2025, 2040 and 2050 respectively in high carbon price scenario. For developing economies, the values is a little below these levels. This level of carbon price is also supported by Stiglitz et al. (2017). This study assessed the outputs from major global IAMs for the carbon prices in 2050 that is consistent with 2°C scenario.

Table 12. Scenarios of carbon price projection in this work.

	Unit	2015	2020	2025	2030	2035	2040	2045	2050
SDS OECD	USD/tCO2e	0	15	63	89	114	140	166	191
SDS Non-OECD	USD/tCO2e	0	10	43	70	98	125	152	180
NPS	USD/tCO2e	0	10	25	31	37	43	49	55

The fuel price projections for oil, gas and coal are also based on the NPS in IEA WEO 2018. The projections in 2050 are based on the trend before 2040. The price for uranium and biomass refer to Pregger et al. (2019). The heat values of each type of the fuels also refer to this study. All these assumptions are provided for major regions, and split into the countries accordingly. The fuel assumptions are summarized in Table 13. All values have converted into USD per GJ.

Table 13. Fuel cost assumptions in major regions in this work.

Fuel	Region Group	Unit	2015	2020	2025	2030	2035	2040	2045	2050
oil	NPS	USD/GJ	8.5	13.2	14.7	16.0	17.5	18.7	19.8	21.0
gas	NPS_US	USD/GJ	2.5	2.9	3.1	3.6	4.1	4.7	5.2	5.8
gas	NPS_EU	USD/GJ	6.7	6.8	7.4	7.8	8.2	8.6	8.9	9.3
gas	NPS_CN	USD/GJ	9.2	8.4	8.7	8.9	9.0	9.3	9.6	9.9
gas	NPS_JP	USD/GJ	9.8	8.7	9.3	9.5	9.5	9.6	9.7	9.8
coal	NPS_US	USD/GJ	2.3	2.7	2.8	2.8	2.9	2.9	2.9	2.9
coal	NPS_EU	USD/GJ	2.6	3.7	3.6	3.7	3.8	3.8	3.9	3.9
coal	NPS_JP	USD/GJ	2.7	4.1	3.8	4.0	4.0	4.1	4.1	4.1
coal	NPS_CN	USD/GJ	3.2	4.4	4.1	4.2	4.2	4.2	4.2	4.2
uranium	NPS	USD/GJ	1.1	1.2	1.4	1.5	1.7	1.8	2.0	2.1
biomass	NPS_Africa	USD/GJ	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
biomass	NPS_Asia	USD/GJ	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
biomass	NPS_EU	USD/GJ	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
biomass	NPS_NA	USD/GJ	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
biomass	NPS_OECDPac	USD/GJ	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
biomass	NPS_LatA	USD/GJ	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
biomass	NPS_world	USD/GJ	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0

Providing sufficient reserve services, or ancillary services, is essential to the reliability of an electricity system. In general, 4 types of services: frequency response, frequency regulation, spinning reserve and supplemental reserve are required to ensure the frequency of a system sustaining within target range (Milligan, 2018). This work incorporates these service with a focus on the last three elements, corresponding to primary, secondary and tertiary frequency control services. Power plants offering these services have to response in 30 seconds, 10 minutes and 30 minutes respectively in this work. Also, to decrease model complexity this work only takes into account upward reserve. Downward reserves are ignored given that in a high VRE share system downward reserves can be

attained by reducing the output level of VRE.

The designs and requirements of the services varies from system to system. There is no standard way to decide the required amount of the services. In most cases it is designed according to past operation experiences. Usually the required reserve capacity can be the capacity of the biggest power plant in a supply region, or a certain percentage of peak demand. For this work, each type of reserve requires in a zone is equal to 3% of daily peak demand. This level is close to a general requirement at 10% of system demand (Gan et al., 2013).

According to IRENA (IRENA, 2017a), nearly 60% of electro-chemical based power storage (mainly Lithium-ion battery) was developed for supplying frequency regulation and spinning reserve in 2017. The provision of these reserve services will be more desirable in the future electricity system with high VRE share. Therefore, battery technologies modelled in this work emphasis on providing system reserve services. In this study, hydropower and battery cannot provide tertiary reserve. Nuclear cannot provide first and secondary reserve services for its slow ramp rate. This is based on common operation criterial.

3.3.5 Base year assumptions and calibration

There are hundreds of thousands of existing power plants around the world. It requires considerable computational resources to incorporate every pant with the models developed. Therefore, for simplification purpose, generation units installed in the same zone in the period are aggregated by their type. Another issue is the lack of reliable and complete databased of existing plants. In this work, a huge effort has been made to calibrate the existing plant capacity in the zones. The steps in processing the existing plants are summarized as follows:

1. At the time of conducting this research, there is one global power plant database freely available on World Resources Institute compiled by multiple institute (Global Energy Observatory and others, 2018). This database is particularly important to this work since it

provides information about the location of the power plants. However, it only covers around 70-80% plants in each country. Most of the gaps come from the missing data on CHP plants. This can be an issue for countries rely heavily on CHP, for instance Denmark and Ukraine. The power plants are first allocated to the zones according to its location, and aggregated into 5 years period based on their committed time.

2. Datasets of power plant installed capacity at country level are available from several sources. The IEA database (IEA, 2017a) provide historical capacity by generation types, but it only provides complete capacity data for OECD countries. Capacity data is also available from EIA database (EIA, 2019), but the capacity of conventional thermal unit in a country is all merged. CIA provides capacity data for literally every country/district (CIA, 2018). It is particularly useful for some developing countries as the data is usually missing in other sources.
3. For renewable technologies, complete capacity information is available from IRENA database (IRENA, 2019c). The unallocated capacity, which is the gap between the global power plant database in step 1 and IRENA, is allocated to the zones according to the total capacity potential estimation in this work. Furthermore, the existing capacity is assigned to higher CF tranche by default. In addition to the base year calibration, this study further extend the calibration to 2018 records with equation (4.35). In the period 2020, the renewable capacity should be no less than 2018 values.
4. Base year electricity generation data of major fuel types can also be obtained from the IEA database (IEA, 2017b). Generation data from main activity power producer, main activity CHP producer and auto producer are merged. This dataset is also used for estimating a minimum existing capacity by main fuel types in a country. It is assumed that the minimum capacity can produce the electricity that match IEA data at 80% CF.
5. It is found that the global power plant database in step 1 clearly underestimated the capacity when compared with other sources. Step 2, 3 and 4 are crucial to fill the gap. The additional

thermal power capacity is allocated in the zones based on the share of power demand in a country. For countries with notable difference, manual work is carried out to update the distribution of the capacity in the zones based on any available official data.

6. In some cases, using the resulting data from the previous steps, i.e. capacity by technology in each zone, could produce infeasible solution in the base year calibration model. Some further adjustment has been carried out to increase the existing capacity in a zone by a small margin, though this situation is rare.

While there is no complete and freely available source on global gird connections, it is very difficult to check the existing interconnection links. This is less problematic for EU region since the ENTSO-E platform provides a detailed grid map as well as data on physical trade records (ENTSO-E, 2019). The features extracted from OSM contain information about existing links in global coverage but no further information about the capacity and type. Figure 16 shows an example of extracted power grid features in South America. This is the key reference in setting up global interconnection links in this work. More effort has made to check public data and literatures to build the network of existing links.

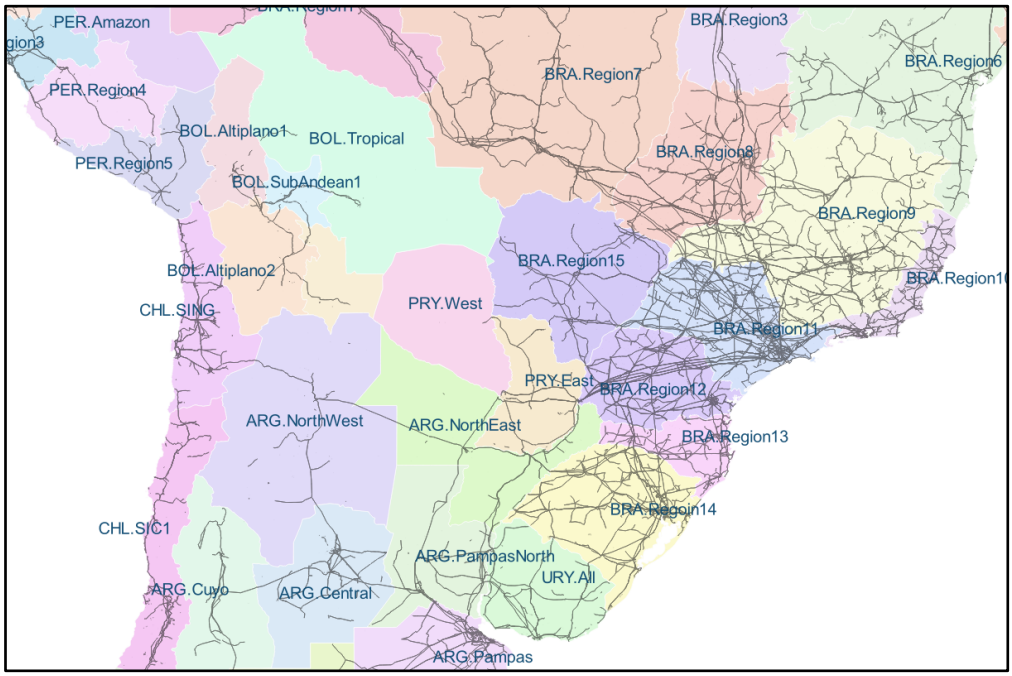


Figure 16. Power transmission line features in South America extracted from OpenStreetMap.

Not all adjacent zones already have a built grid connection. Though it is possible to build the link in the future, it is left to the models to estimate. Therefore, in equation (3.29), new transmission link can only be built after the period 2030. There are some instances that the linkage has already built or planned to be built between two non-adjacent zones, for example the link between the UK and Norway, and Sweden and Poland. The proposed models have no problem dealing with these links but extra attention should be paid to identify these new links.

With all the assumptions and calibration mentioned in this section, it can be expected that the ED model output would not perfectly match base year generation record. In this work an initial dispatch model is developed. It is based on the ED model but with a few changes on the constraints. An additional constraint on the minimal generation of thermal plants is applied to ensure the dispatch result can align with base year values. This initial dispatch modelling offers several advantages:

- It decides the output profile of each dispatchable units in the base year. This profile is the base generation factor $CF_{y=base,i,t}$ in constraints (3.22). Without this constraints, the generation in the ED model can concentrate on cheap options. In addition, the electricity import/export of a country is also applied with a floor based on IEA data.
- The existing interconnection links have been identified but their capacity is mostly unknown. This initial run helps to estimate the capacity of these links.
- This initial dispatch modelling, more importantly, is to check if the overall ED model can produce feasible solutions for every market instances.

The initial base year dispatch modelling generates the transmission capacity for each existing links. For some links with capacity less than 100MW, they are assign an initial value of 100MW in the first iteration period in the ED and CE models. Also, in a few cases, the base year transmission capacity is adjusted manually by a small margin to make the problem solvable.

3.3.6 Decarbonization scenarios

This work aims to investigate the possible development of electricity sector in several decarbonization scenarios. Four scenarios are proposed to investigate possible future development in different conditions. They are listed below:

- Reference scenario (REF) – The scenario is created with the assumptions described in this section. All the settings are close the New Policy Scenario proposed by IEA.
- High carbon price scenario (HCS) - This scenario is based on higher carbon price, referring to SDS projection in Table 12. This scenario is developed to examine to what degree higher carbon cost can influence decarbonization development.
- Optimal CRE mix scenario (MCP) - The scenario is based on the previous result of optimal CRE mix in the countries produced from model CP in the previous work. It is defined as the projection to reach 70% CRE share for each country in 2040. After 2040, the installed capacity constraints continue to 2050 with 2040 level. This scenario is to assess whether the proposed mix can reach renewable generation target without causing unbearable negative influences. Also, it is important for checking the effectiveness of regional market integration since in this scenario each country has to meet a self-sufficiency target.
- Carbon neutral scenario (CNS) – This scenario is proposed to investigate a best pathway to reach zero annual emissions in 2050. The emissions limit in each period is the linear interpolation between 2020 and 2050. In this scenario, the emissions reduction burden is shared with the countries in the same market. This can assess how the resources can be utilized efficiently in the region.

4. Results and discussions

This chapter presents and discusses the results of the three main works: global VRE potential assessment, estimating the optimal mix of CREs and global electricity system decarbonization modelling.

4.1 Global variable renewable energy potential

This section demonstrates the results on the improvement of land cover information, validation of eligibility masks, and validation of hourly CF produced. The capacity and energy potential of wind and solar technologies in each zone are proposed. This section compares the global results with other studies and discusses the possible causes of the differences. Moreover, examples are shown to demonstrate the capacity potential and space-time output characteristics of VREs at zonal level.

4.1.1 Improving land cover map accuracy

This research extracts land cover and land use information from the OSM. The land cover features are then used to improve the base land cover map CCI-LC. The full statistics of this process are compiled in the File 2 of supplementary Data Package 1. Table 14 shows the results of selected countries. Overall, 3.23% of global land area is covered. This only includes selected types of features, mainly nature, farmland and urban areas. Forests and water bodies that account for a large number of the OSM features are excluded since the original CCI-LC has high accuracy on them. The OSM relies on voluntary actions to create and update the features. Clearly, the activity is more extensive in some countries. However, the improved accuracy on urban areas is crucial in this research because buffered restriction zone is generated based on the areas, and also because it defines the available areas for distributed PV deployment.

Table 14. The percentage of land cover areas covered by the OSM features in selected countries.

Country	% of area covered by OSM features			
	Total	Nature	Farmland	Urban
Canada	1.27	1.17	0.03	0.06
China	1.55	1.07	0.14	0.34
Germany	31.93	2.40	20.95	8.58
France	42.15	12.88	24.37	4.91
UK	16.76	4.86	6.66	5.24
India	2.05	1.24	0.23	0.58
Japan	1.79	0.04	1.44	0.31
USA	2.29	1.21	0.61	0.47
Nigeria	1.28	0.38	0.14	0.76
World	3.23	1.70	1.15	0.47

4.1.2 Validating the eligibility masks and suitability maps

The power features extracted from OSM are ideal reference for testing the eligibility masks produced. Table 15 shows the statistics of existing onshore wind turbines (WTBs) relative to the constraints defined in this work. While the eligible area for WTB installation accounts for 32.7% of global terrestrial area, 83.7% of existing WTBs are located inside the eligible area derived in this work, suggesting a pronounced accuracy of the masks. The detailed statistics is available in the File 3 of supplementary Data Package 1.

Investigating the WTB located in restricted areas can provide useful insight. For Belgium, Germany, Japan and Morocco, a high percentage of the WTBs are installed within the buffered distance from urban areas. In CCI-LC, all artificial surfaces are identified as urban areas. Where WTBs can be installed close to factories and large power facilities, their location may therefore be inside the buffered restriction zone. Figure 17 shows the case of Flanders, Belgium where very high percentage of the WTBs are located in the urban area defied in this work. The areas in yellow on the upper figure are the urban areas defined in original CCI-LC map with 500m buffer. It is clear that almost every WTB is located in the urban zones. Conversely, the green areas in the bottom figure are the urban areas with

a 500m buffer processed from OSM features. Most of the WTBs locate outside these areas precisely, which demonstrates the high accuracy of the masks produced from the OSM features. However, in this work the areas not covered by any OSM feature are not updated onto the CCI-LC map. The WTBs in this case are located in the urban areas defined by CCI-LC map.

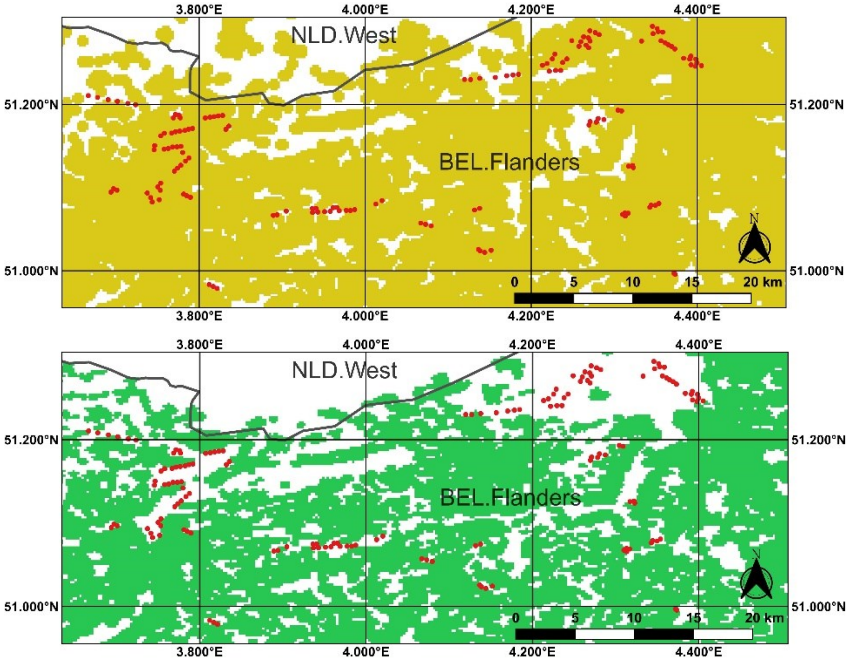


Figure 17. The locations of onshore wind turbines in Flanders, Belgium mapping on the masks. The red dots are the locations of installed wind turbines. The yellow areas on the top figure are the restricted urban areas identified by CCI-LC. The green areas on the bottom figures are the restricted area defined by the OSM features

Globally around 4.7% of the WTBs are located in unsuitable land cover areas including irrigated cropland, wetland, water body, urban area and sands etc. This can also be attributed to the accuracy of CCI-LC map, though an attempt has been made reduce these errors by updating information from OSM. Nevertheless, the restriction area defined by amenity features still causes noticeable errors. The strict 3km buffer zone from any airport, including small civilian airdromes, and the 500m buffer zone from military areas are the main categories responsible for the errors.

Information about existing 2,506 offshore WTBs worldwide is also extracted from the OSM. Similar verification process is carried out. Most of the existing WTBs are in the eligible areas defined in this work. However, social impact restrictions, including 3km from port/harbor, 1.5km buffer from

ferry route, other amenities and urban area restrictions, can cause errors, especially in the Netherlands. The average suitability factor, based on shipping activity, is 0.83, which supports the idea of using a shipping activity map to calculate a reasonable amount of area for offshore wind power development.

Existing solar power features are also obtained from the OSM. However, the information does not reveal their type and scale. To validate the eligibility masks, this research does not separate utility-scale PV and distributed PV systems. If a feature is located in either of the eligible areas, it is counted as a correct entry. The validation results using this approach by zone and by country are also compiled in the File 3 of supplementary Data Package 1, and Table 16 shows the statistics of selected countries. Around 142,000 sites were tested, resulting in overall installation in eligible areas in over 90% of cases. Most of the sites, around 74%, are in the urban areas. This may suggest that the extracted features are mostly distributed systems or rooftop systems. Most of the incorrect entries is related to the land cover masks. This is particularly the case for France, Greece, Italy and Spain. In general, the accuracy of certain type of tree cover is the main cause of these misallocations.

Table 15. The statistics of onshore wind turbines relative to the eligible and ineligible areas identified in this work in selected countries.

Country	Eligible area for install (%)	Total WTB	% of total WTB												
			In eligible areas						In restriction areas						
			Total	Installed in land cover					Unsuit LC	Low wind speed	Urban area	Amenity restrict	Protect area	Road access	Nature restrict
				Bare area	Sparse Veget.	Crop lands	Shrub/ grass	Trees							
Austria	40.4%	1,217	92.8%	0.0%	0.0%	82.6%	5.7%	4.5%	0.8%	0.1%	4.4%	4.4%	0.3%	0.0%	0.0%
Belgium	20.9%	782	27.1%	0.0%	0.0%	24.4%	2.6%	0.1%	30.7%	0.0%	61.0%	13.7%	15.6%	0.0%	0.0%
Brazil	33.0%	10,222	75.8%	4.2%	7.8%	20.3%	34.7%	8.7%	5.4%	0.0%	3.2%	1.8%	16.9%	1.5%	0.0%
Canada	14.8%	5,216	94.9%	0.3%	1.2%	56.8%	5.2%	31.4%	0.7%	0.0%	1.2%	1.2%	0.1%	2.5%	0.2%
China	36.3%	34,817	82.2%	22.3%	8.7%	10.0%	37.6%	3.6%	8.0%	0.1%	5.0%	3.8%	0.0%	2.7%	2.5%
Germany	47.0%	26,065	83.3%	0.0%	0.1%	68.7%	9.0%	5.6%	1.2%	0.0%	13.1%	7.3%	0.6%	0.0%	0.0%
India	38.3%	23,327	85.7%	0.4%	3.8%	59.0%	21.0%	1.5%	2.2%	0.0%	2.9%	6.3%	5.0%	0.0%	0.0%
Japan	52.0%	934	56.6%	0.2%	4.5%	21.4%	3.9%	26.7%	14.5%	0.4%	16.1%	3.2%	28.5%	0.0%	1.1%
Morocco	57.9%	579	44.4%	0.3%	1.7%	5.9%	23.1%	13.3%	50.9%	0.0%	53.9%	3.8%	9.3%	0.0%	0.0%
Spain	67.3%	18,629	93.3%	0.1%	12.1%	30.8%	39.7%	10.5%	1.1%	0.1%	0.6%	1.2%	3.9%	0.0%	0.1%
USA	51.4%	13,738	93.6%	8.4%	0.5%	23.2%	57.5%	4.0%	0.3%	0.1%	3.6%	1.8%	2.0%	0.0%	0.0%
World	32.7%	184,099	83.7%	5.8%	4.8%	39.2%	27.4%	6.4%	4.7%	0.1%	6.7%	4.4%	3.8%	0.8%	0.6%

Table 16. The statistics of PV systems relative to the eligible and ineligible areas identified in this work in selected countries.

Country /District	Eligible area for PV deployment to total land area (%)	Total PV sites	Mask correctness	In eligible area						In restriction area			
				Total sites in eligible areas	in Bare area	in Vegetation	in Grassland	in Mosaic Veg.	in Urban	in unsuit. LC	in mask WDPA	in mask Road	in mask Nature
AUS	37.2%	231	71%	163	1	25	14	17	106	23	33	19	0
CHN	28.7%	635	95%	605	25	4	88	9	479	20	0	1	18
DEU	52.2%	39217	93%	36637	0	0	235	272	36130	4896	1855	0	74
DZA	30.6%	1240	98%	1217	433	454	0	0	330	39	17	4	0
FRA	39.8%	1733	58%	1011	0	0	50	10	951	720	76	1	25
GBR	48.9%	2967	94%	2780	1	0	75	4	2700	139	119	0	0
IND	21.1%	342	82%	281	0	0	18	9	254	91	17	0	2
ITA	29.2%	4557	49%	2212	17	3	31	187	1974	1083	99	2	96
JPN	20.5%	3099	86%	2669	1	0	0	60	2608	926	478	0	38
PRT	50.6%	2861	94%	2689	0	0	1	293	2395	370	34	0	3
USA	30.0%	70560	99%	69769	4	1	19432	83	50249	1468	230	9	43
Total		141971	90%	128287	534	589	20202	1643	105319	13091	3361	64	575

4.1.3 Validating the estimated hourly capacity factors

In this research, the historical VREs generation data on ENTSO-E platform is used to validate the accuracy for several European countries. The correlation coefficients and root-mean-square error (RMSE) of onshore wind and PV between the hourly records from ENTSO-E and the estimated CF in this work are presented in Table 17. All results are available in the File 4 of supplementary Data Package 1. The overall result shows acceptable correlation, generally above 0.9. The RMSE is generally below 10%. The error can come from many factors, including data quality and the approach applied to aggregate CF data into country level.

Table 17. The correlation coefficient[30] of onshore wind and PV[31] between hourly records from ENTSO-E and the estimated CF in this work in 2017.
This table only shows selected European countries where installed capacity was above 500MW.

Correlation coef.	**AUT**	**BEL**	**CZE**	**DEU**	**DNK**	**ESP**	**FIN**	**FRA**
Wind CF	0.89	0.93	0.88	0.96	0.95	0.93	0.84	0.95
Solar PV CF	0.90	0.90	0.93	0.96	0.93	0.92	--	0.96
Correlation coef.	**GBR**	**GRC**	**IRL**	**ITA**	**NLD**	**POL**	**PRT**	**SWE**
Wind CF	0.93	0.75	0.96	0.91	0.92	0.95	0.87	0.85
Solar PV CF	0.93	0.95	--	0.96	0.90	--	0.91	--
RMSE	**AUT**	**BEL**	**CZE**	**DEU**	**DNK**	**ESP**	**FIN**	**FRA**
Wind CF	11.7%	7.3%	9.5%	5.0%	7.0%	7.0%	13.8%	5.3%
Solar PV CF	8.8%	9.0%	8.3%	5.1%	9.2%	11.5%	--	6.1%
RMSE	**GBR**	**GRC**	**IRL**	**ITA**	**NLD**	**POL**	**PRT**	**SWE**
Wind CF	7.1%	13.3%	7.7%	7.9%	9.2%	6.3%	10.0%	10.1%
Solar PV CF	6.4%	7.9%	--	4.8%	8.6%	--	11.9%	--

[30] The ENTSO-E platform provides hourly generation records on country basis. The hourly CF of onshore wind and PV are calculated by using the installed capacity information provided. On the other hand, the aggregation of CF into country level is based on the weights assigned to each zone in the country. The weights are based on the distribution of existing wind and PV plants in the zones. Also, this study computes the annual average CF from the records, and choose the corresponding CF tranche data in our model to calculate the correlation coefficients. With these processes country level output approximation can be generated, but they all contribute to the deviation from historical records.

[31] This study only considers the hours when the PV systems are actually generating power, i.e. night hours are removed in the calculation.

The correlation is high in several countries. Figure 18 shows the ENTSO-E records and estimated CF in the first week of June and the last week of 2017 in Germany for onshore wind and PV. In general, the deviation is less than 10% while in some periods the two datasets align perfectly. In some countries the correlation is just acceptable and the RMSE is high, this, again can link to how zonal output be aggregated into country level for the error test. However, the author recommends that the users should adjust the estimation wherever historical records are available before using the data. Such a calibration can be seen in Staffell &Pfenninger (2016) and Bosch et al. (2018) for instance.

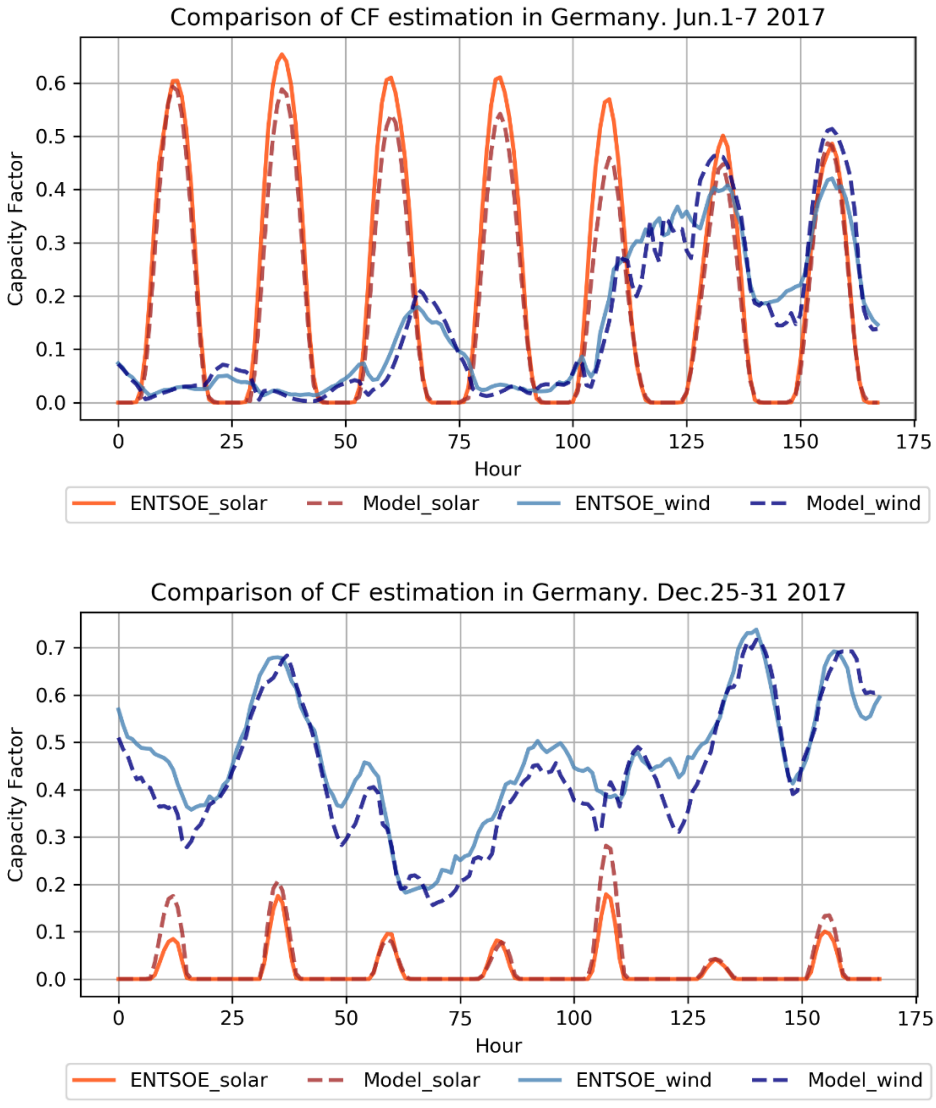


Figure 18. The hourly CF records from the ENTSO-E platform and the estimated CF in this research. The figures show the comparison in Germany (DEU) for onshore wind and utility-scale PV. This chart shows the first week of June (top) and the last week of 2017 (bottom).

4.1.4 Global variable renewable energy potential

The global energy potentials of wind and solar technologies proposed in this research are summarized in Table 18 and Table 19, where they are compared with other studies. The first CF class is excluded[32] for economic reasons, which corresponds to average CF less than 18% for wind technology, below 10% for PV, and below 25% for CSP. This exclusion has negligible influence on PV and CSP, but reduces wind energy potential by around 10%. The overall energy potentials of onshore and offshore wind are around 211,000 and 216,000 *TWh/year*; fixed-tilt and one-axis tracking utility-scale PV are 836,000 and 981,000 *TWh/year*; and the CSP is 587,000 *TWh/year*. The potentials are significantly higher than the global power demand 21,000 TWh/year in 2016 (IEA, 2018b). In the long term, the energy potentials from these renewable technologies could supply the total primary energy demand of about 400,000 *TWh/year* in 2100 (Breyer et al. 2017). Distributed PV alone can supply 5,300 *TWh/year*, around 25% of power demand in 2016. Note that fixed-tilt PV, one-axis tracking PV and CSP are competing for the same available areas.

This research adopts relatively conservative constraints for onshore wind assessment. The permafrost and road access restrictions eliminate large areas in Australia, Canada, Russia, the Amazon basin and the Sahara desert. The minimum average wind speed of 4 *m/s* and minimum 18% CF further eliminate available areas, especially for areas at low latitudes. When the road access constraint is removed, the capacity and energy potential for onshore wind and solar technologies can increase about 70-80%, detailed figures at country level can be found in the supplementary files. The potentials are still much less than many of other studies. In fact, the majority of the increase comes from Australia and the Sahara desert.

Lu et al. (2009) and Bosch et al. (2017) all reported onshore wind energy potential around 3 times

[32] Although the low energy potential areas are excluded in the comparison, the modelling result are still available in the File 5 of supplementary Data Package 1.

higher than this research. This is mainly because they include large areas from polar and unsettled area such as Western Australia, the Middle East and the Sahara Desert. The studies assigned similar land suitability factors as this research does, and the capacity density is also at similar level. Clearly, the road access constraint and permafrost exclusion have significant influence in the assessment. Stetter (2012) also suggested a capacity about 3 times higher and used the same suitability factors. This study took into account social restrictions but double up the installation density.

Most of the assumptions and constraints of this research refer to Eurek et al. (2017), but it reported about 2.6 times higher energy potential. One possible cause is that the study did not exclude any area by wind speed. The resource accessibility defined in the study is the distance to cities and power plants. The study does not specify how this accessibility constraints is applied. Judging from the proposed capacity potential in Russia, Australia and Brazil, it is very likely this constraint did not exclude massive remote and unpopulated areas as this research does.

The onshore wind potential by Hoogwijk (2004) is about tow third of that in this research, and its energy potential is much less. The coarse spatial resolution in the study could be the main reason. The lower capacity density assumption can be another reason. Compared with other studies using similar suitability assumptions, Hoogwijk (2004), with unknown constraints, excludes most areas in China, Africa and South America, but includes some polar areas with high energy output potential.

The minimum average wind speed of 6.9 *m/s* at 80m height applied in Archer et al. (2005) is very likely the cause of less capacity potential but higher energy output. Moreover, this is the only study in Table 1 not assign land cover suitability factors, and not apply any constraints in addition to wind speed. This study used the data measured from sounding and surface stations. Only 12.1% of the stations reach the average wind speed of 6.9 *m/s* at 80m height. It seems this early study underestimated the energy which can be captured by today's wind turbine technology.

In Zhou et al. (2012), the maximum 9 *c/kWh* generation cost is the dominant constraint which reduces the potential to around 60% of this research. The constraint links to the cost assumptions it

applied. It is difficult to make the comparison with this research directly. However, the study suggested that about 50% of the global onshore wind potential has a cost above 9 *c/kWh.* This implies that if the cost constraint is not applied, this study may estimate the same level of energy potential as this research. Dupont et al. (2018) applied a low capacity density assumption that yields lower capacity potential when compared with the others. This study argues that the array efficiency is overestimated in most studies. However, its unique constraint of minimum Energy Return on Investment (EROI) make it difficult to compare with other studies directly.

The capacity potential proposed by Teske et al. (2019) is the highest even without counting part of the Eurasia region. This is very likely because the study did not consider land suitability factor despite its application of wind speed and social related constraints.

The proposed offshore wind energy is within a 50% range when compared with other studies. The main causes for these differences are the constraints on water depth, distance from the coast and the minimum capacity factor. This study also applies suitability factors based on shipping activity, which reduces approximately 20% of capacity potential. The less energy potential suggested by Lu et al. (2009), Arent et al. (2012) and Stetter (2012) can be attributed to the constraints of maximum distance to coast and water depth. On the other hand, Eurek et al. (2017) and Bosch et al. (2018) proposed a higher energy potential without these restrictions. Dupont et al. (2018) reported much less offshore wind capacity and energy potential than others. Same as onshore wind, it suggests that the influence of array efficiency can be significant, often underestimated.

The global utility-scale PV energy potentials proposed by Hoogwijk (2004) and Köberle et al. (2015) are significantly less than this research. It is because they assign much smaller suitability factors to land cover. Conversely, Trieb. et al. (2009) used similar suitability assumptions as this research and suggested a much higher capacity potential. As accessibility constraints are not considered, Trieb. et al. (2009) includes large unpopulated areas, such as Australia, Sahara Desert and the Middle East. The high installation density assumption in Stetter (2012) obviously produced higher potentials. High

capacity density is also applied in Pietzcker et al. (2014). It proposed a close level of energy and capacity potentials, but the available land area is only half. It seems the 100km distance to settlement constraint is the main cause. The capacity potential proposed by Teske et al. (2019) is again the highest. This is also because accessibility such as distance to infrastructure or settlement is not considered. Therefore the capacity potential in North and Central Africa account for around half of the global potential in the study.

For CSP, the available area in this research is cut by the restrictions on slope, land cover and minimum land area. This makes the value very close to it in Pietzcker et al. (2014). However, the study used higher SM and storage hours. It can be observed form this case that higher SM require more land for collecting the energy, and more storage hours can increase the overall capacity factor. For the rest studies, the finding is same as those have been discussed in the utility-scale PV potential comparison.

Table 18. Comparison of global wind energy potentials between this research and others.
(LSF: land suitability factor; WS: wind speed; SI: social impact; AC: accessibility)

Authors	Capacity Density (MW/km^2)	Global onshore wind				Global offshore wind		
		Key constraints	Available area (km^2)	Capacity potential (GW)	Energy potential (TWh/y)	Key constraints	Capacity potential (GW)	Energy potential (TWh/y)
Hoogwijk (2004)	4	LSF, $\overline{WS_{10}}$ > 4m/s	11,230,000		96,000			
Lu et al. (2009)	4.05/5.8	LSF, $\overline{CF}$ > 20%			690,000	Depth <200m, $\overline{CF}$ >20%, dist. <50nm		157,000
Zhou et al. (2012)	5	LSF, SI, Cost < $9c/kWh$			119,500			
Archer et al. (2005)	9	$\overline{WS_{80}}$ > 6.9m/s		72,000	627,000			
Arent et al. (2012)	5					Depth <200m, $\overline{CF}$ >20%, dist. <50nm		192,800
	5					$\overline{WS_{90}}$ >8.0m/s	74,000	
Stetter (2012)	10.4	LSF, SI, $\overline{WS_{10}}$ > 4m/s			684,000	Depth <40m, dist. <40km		201,000
Eurek et al. (2017)	5	LSF, AC, permafrost	59,665,000	298,000	557,000	dist. <100nm	126,000	315,000
Bosch et al. (2017)	6.5	LSF, $\overline{CF}$ > 15%	41,748,000	260,000	587,000			
Bosch et al. (2018)	3.14					$\overline{CF}$ > 15%	86,000	330,000
Teske et al. (2019)[33]	5	$\overline{WS_{80}}$ > 5m/s, SI	67,270,000	336,000				
Dupont et al. (2018)	2	LSF, EROImin ≥ 5		90,000	132,000	EROImin ≥ 5	24,000	65,000
This research	5	LSF, SI, AC, permafrost, $\overline{CF}$ > 18%	16,855,000	84,000	**211,000**	Depth < 500m, $\overline{CF}$ > 18%, ship route	71,000	**216,000**

[33] The estimation for part of Eurasia is incomplete

Table 19. Comparison of global solar energy potentials between this research and others.
(LSF: land suitability factor; SI: social impact; AC: accessibility; SM: solar multiple)

Authors	Global utility-scale PV				Global CSP (parabolic trough)			
	Key constraints & assumptions	Available area (km^2)	Capacity potential (GW)	Energy potential (TWh/y)	Key constraints & assumptions	Available area (km^2)	Capacity potential (GW	Energy potential (TWh/y)
Hoogwijk (2004)	LSF Module eff. 14%, Losses 25%	2,300,000		366,000				
Stetter (2012)	LSF, SI Module eff. 16%, Losses 18.9%, Inst. density 130.6 MW/km^2			5,404,000	LSF, SI, DNI>1800kWh/m^2/y Design point 800W/m^2, SM1.5 Inst. density 65.2 MW/km^2			1,719,000
Teske et al. (2019)[34]	LSF, SI Inst. density 25 MW/km^2	71,660,000	1,1792,000		DNI>2000kWh/m^2/y			
Köberle et al. (2015)	LSF solar-to-electricity eff 13% Land use factor 47%			101,000	LSF, DNI>3kWh/m^2/day SM 2.0, 6h storage solar-to-electricity eff 12% Land use factor 37%			173,000
Pietzcker et al. (2014)	LSF Dist. to settlement <100km Inst. density 92 MW/km^2	8,045,000	725,000	952,000	LSF, Dist. To settlement <100km SM 3.0, 12h storage Inst. density 22 MW/km^2	7,641,000	170,000	656,000
Trieb. Et al. (2009)					LSF, SI, DNI>2000kWh/m^2/y SM 1-4, 6h storage Land use efficiency 4.5%			2,946,000
This research	LSF, SI, AC, Lat.<60º, $\overline{CF}$>10% Losses 17.5% Inst. density 30 MW/km^2,	16,383,000 **(fixed-tilt)** 16,424,000 **(tracking)**	491,000 493,000	**836,000** **981,000**	LSF, SI, AC, $\overline{CF}$>25% DNI>1800kWh/m^2/y Design point 950W/m^2, SM 2, 6h storage Inst. density 25 MW/km^2	7,614,000	190,000	**587,000**
	Distributed PV	53,000	3,950	**5,250**				

[34] The CSP potential in this study is merged into utility-scale PV. The estimation for part of Eurasia is incomplete.

4.1.5 Global capacity potential by country

Figure 19 and Figure 20 show the highest potential countries for onshore wind and utility-scale PV capacity by CF tranches. For wind power, the USA and Australia possess the highest capacity potential. Although Russia, Canada and Brazil have large land area, their potentials are restricted by permafrost, forest and road access, while they can rank at the top in other studies. As for high CF potential tranches, if only high CF tranches are regarded, some countries, for example Kazakhstan (KAZ) and Algeria (DZA), can rank higher.

Contrary to wind potential, Kazakhstan ranks at the 9th on utility-scale PV potential, but its energy output is lower than most countries on the chart. This is actually the purpose of splitting the output potential in tranches in this research. High output tranche implies higher economic value. This cannot be recognized directly from the overall energy potential in a country.

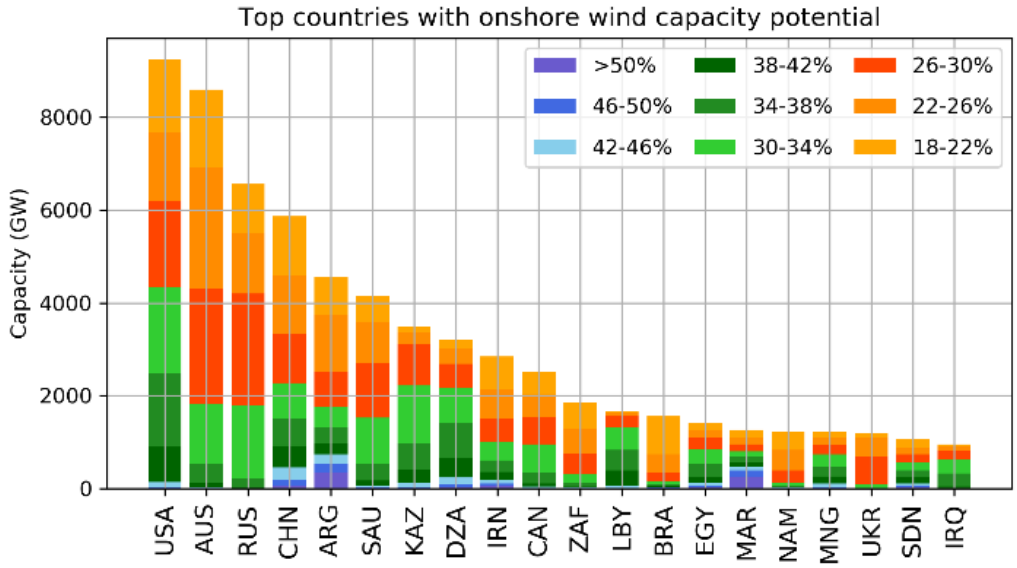


Figure 19. Highest onshore wind capacity potential countries and the CF tranches breakdown.

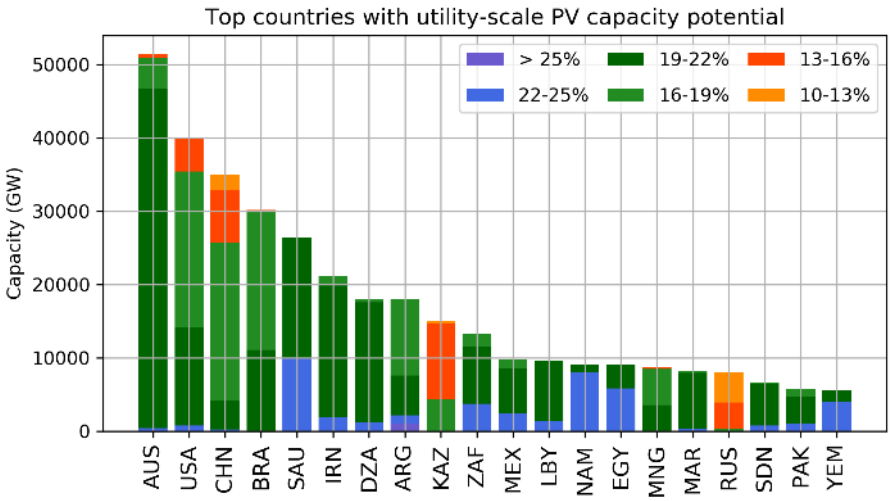


Figure 20. Highest utility-scale PV capacity potential countries and the CF tranches breakdown.

4.1.6 Space-time output

In this work, available area, capacity potential and average CF of each technologies, along with the simulated hourly CF are produced for each zone. The available area and capacity are compiled in File 5 of supplementary Data Package 1. This work aggregated the hourly CF into 288 month-hour (24 diurnal hours for each calendar month) CF profile, compiled in the File 6 of supplementary Data Package 1. This temporal scale may be more useful for large ESMs.

Figure 21 shows an example of the offshore wind potential around the Philippines. The suitable area is constrained by the EEZ boundary and 500m water depth, as well as social impact constraints such as airports, ports, and ferry routes. The offshore area around the Philippines is split into 7 regions. The capacity potential is concentrated on region 3 and 4, as shown in Figure 21. The detailed capacity in the regions by tranche is presented in Figure 22. Although the overall capacity potential is promising, the potential in shallow waters is relatively small. Only about 21GW of the potential is located in shallow water with CF higher than 30%. In fact, globally only 21.8% of the proposed capacity potential is in shallow depth areas.

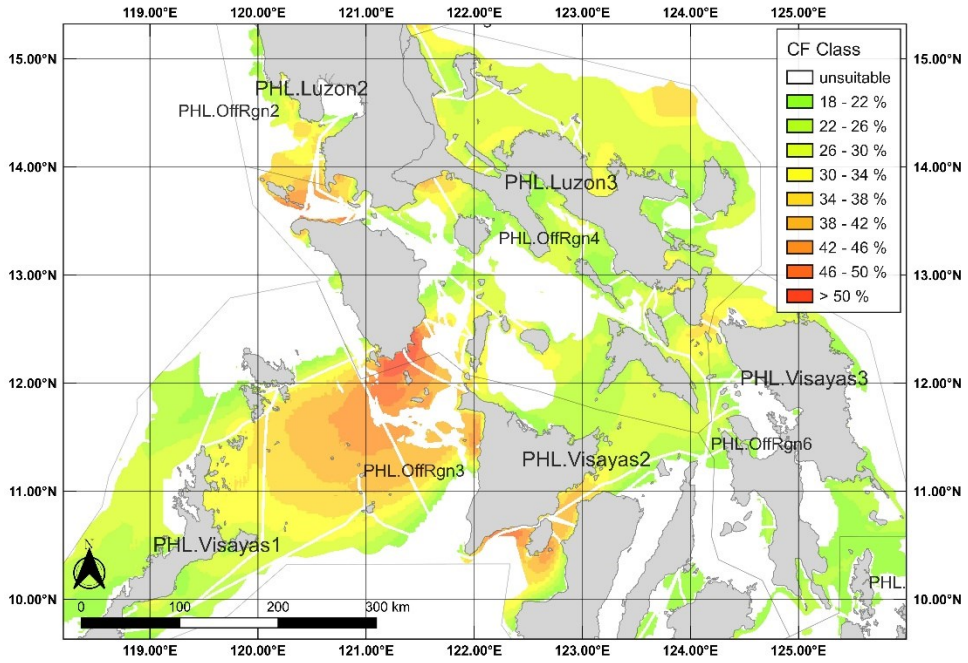


Figure 21. The suitable areas and gross capacity factor of offshore wind energy around the Philippines.

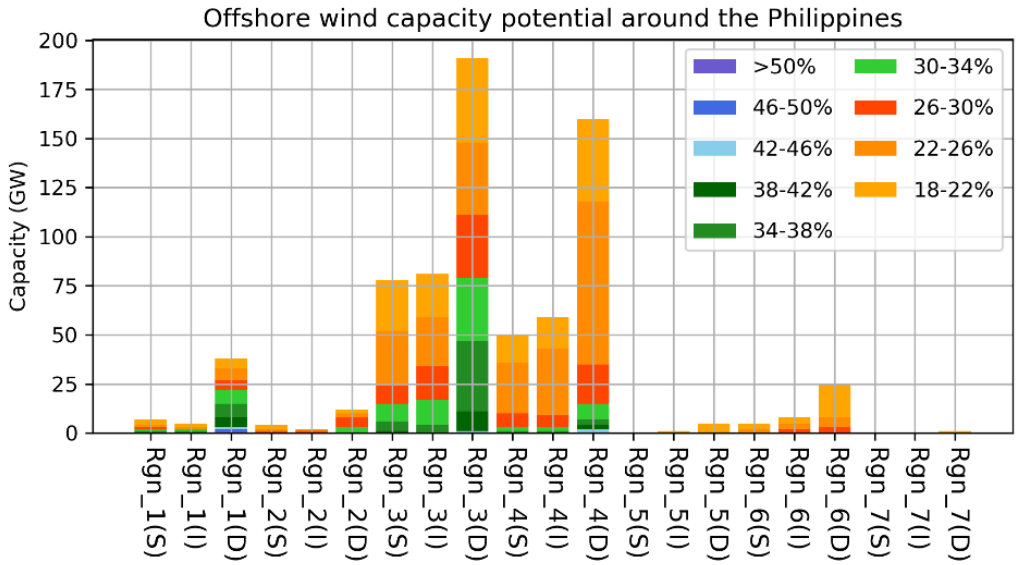


Figure 22. The offshore wind capacity potential by CF tranches in the Philippian waters.

S denotes the potential in shallow waters (<30m). I for intermediate depth waters (30-60m). D for deep waters (60-500m).

Figure 23 and Figure 24 show the distribution of onshore wind and utility-scale PV potential in Western Cape, South Africa. The wind power generation is high in certain mountainous area across the zone, and the PV generation is generally strong in this zone. The exclusion areas on the wind

potential map are mainly due to low generation potential. The exclusion areas on the PV potential map are mainly unsuitable terrain and land cover. There are restriction areas derived from road access in another zone to the north which is a less developed barren area of the country.

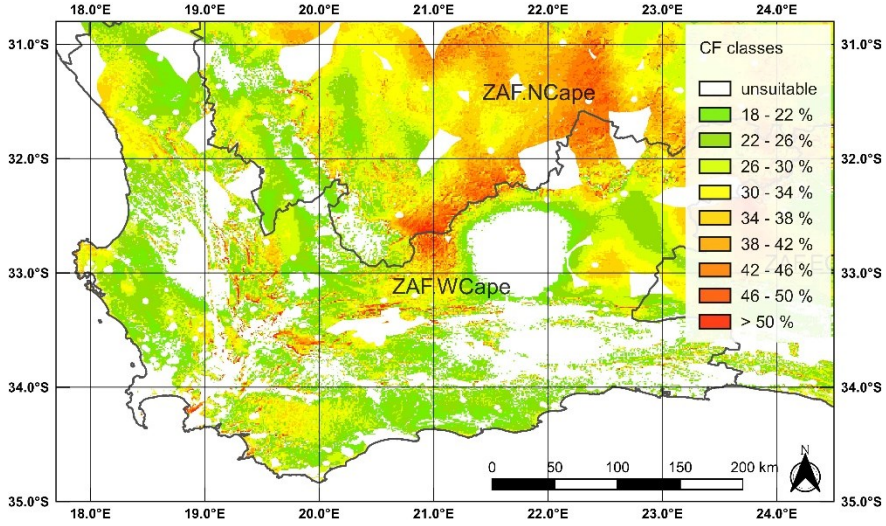


Figure 23. The estimated CF map of onshore wind in Western Cape, South Africa.

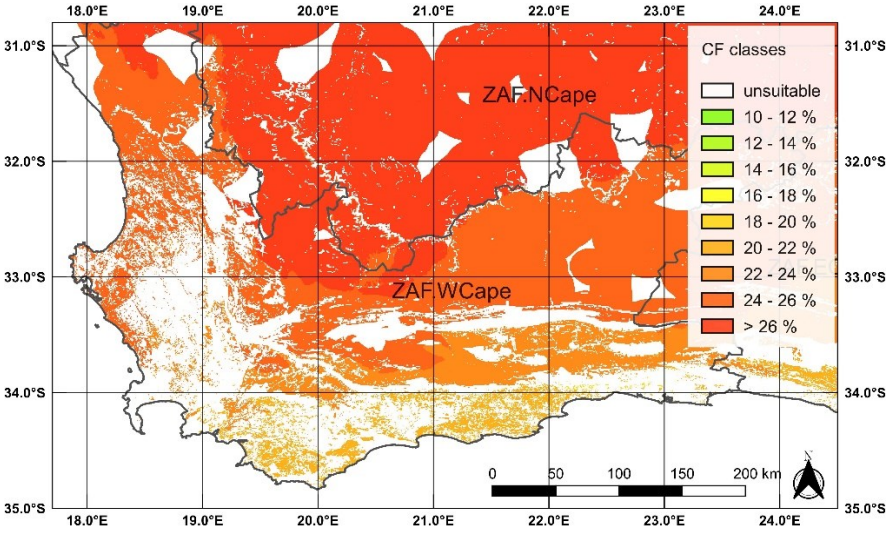


Figure 24. The estimated CF map of utility-scale PV in Western Cape, South Africa.

In South Africa, this work identifies 166 VRE development options. This is based on available capacity in different CF tranches, technologies and zones, where the capacity potential is not zero. This work identifies 21 VRE options in the Western Cape zone. To show the variability of their output, hourly CF in the first 3 days in 2017 of selected technologies are plotted on Figure 25. This interesting

case is chosen to show how the space-time output can be so variable that higher annual CF does not guarantee more generation at certain period of time. For the PV technologies, the energy production of fixed-tilt PV can sometimes be higher than tracking systems in the same tranche. For wind, class 4 outperforms class 6 between hour 15 and hour 20. This feature is the result of their distribution of potential development area in the zone. This example demonstrates that high spatial and temporal resolution could capture local weather variation in better detail.

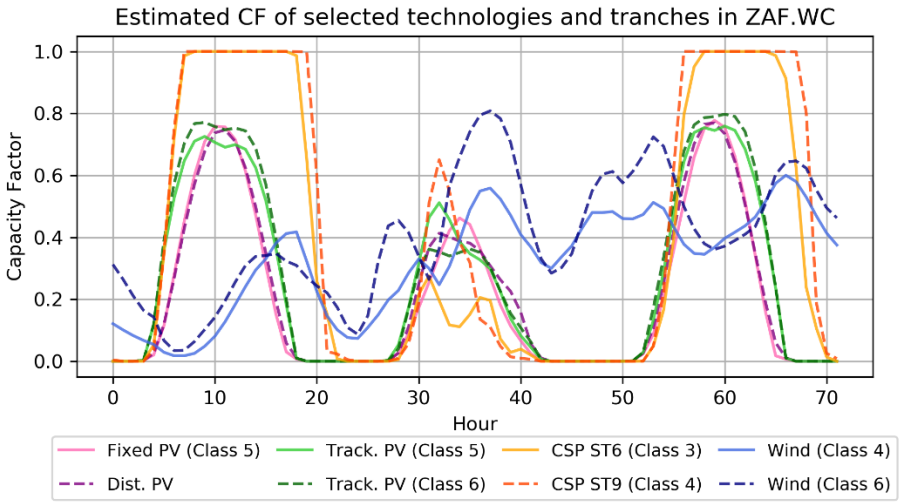


Figure 25. The simulated CF of selected technologies in Western Cape, South Africa for the period of the first 3 days in 2017.

4.1.7 Summary

The main purpose of this work has been to assess the global VREs potentials with consistent constraints and approach. The latest datasets at the time of writing are applied, and a wide range of constraints are considered. Information from the OpenStreetMap (OSM) is used to improve the quality of the assessment. The MERRA-2 datasets are used for temporal CF estimation, while energy resource maps from GWA and GSA are used to improve the spatial resolution. The resulting data are hourly CF profiles for each technology in multiple CF tranches, and the results cover 731 terrestrial zones and 339 offshore zones in the world.

In this work, the accuracy of the land cover map is improved with information from OSM. The

improved identification on urban area is particularly important to this work. Analyses comparing the eligibility masks produced with existing wind turbine and solar PV sites locations demonstrate high accuracy of the produced masks in most countries. In total, 83.7% of existing wind turbines are located inside the eligible areas identified. The accuracy for PV systems is even higher. The validation shows a notable number of cases where there are errors as a result of inaccurate the land cover maps. Hence, future study on this topic to update the land cover using newer geographic information from platforms such as the OSM is advisable. This work also validates the estimated CF with records from ESTSO-E platform. The results also demonstrate very high correlation of onshore wind and PV output in most EU countries.

In general, the capacity and energy potentials reported in this study are conservative compared with other studies, stemming from the stricter social impact restrictions, permafrost areas, road access and minimum CF requirement. However, the reported potentials are significantly higher than the global power demand. It is recognized that the parameters used have significant influence on the estimated potential. The installation density is clearly important, and one can generate an alternative estimation using different assumption easily. This flexibility is achievable with the identified potentials proposed in this work. However, for hourly CF, whenever the observed data is available, a further process of calibration for the results is advisable.

An important contribution of this work is that it provides data on VREs potentials at subnational level with hourly CF estimation, categorized into CF tranche classes to provide capacity supply curves. These are essential inputs for regional or global ESMs that are striving to improve modelling resolution. Another significant advance is the use of the OSM information to improve land cover data and to construct constraints on eligible areas. To the authors' knowledge, there is no study that has made this effort at global scale prior to this research. Also, this research acknowledges the claim in several studies that the global wind and solar energy potentials are significantly higher than the power demand, and also could serve the total primary energy demand in the future.

It is crucial to consider the space-time variability of VREs in modelling the future energy system. The data generated in this work can be adopted in other energy system planning studies. The data, in hourly and subnational representation, can be aggregated easily into coarser resolution when required. This work does not estimate electricity production cost explicitly for the technologies. The following works continue to explore the optimal mix of renewable energies in each country. Several factors, include cost, will be considered in the investigation.

4.2 Optimal mix of renewable energy

This section presents two groups of data produced in this research: the covariance matrices built from all available options in each country and the optimal mix of CREs produced from the models. This section uses Spain as the main example to discuss the results. An analysis on the distribution of capacity mix of all countries is presented at the end of this section.

4.2.1 Capacity factor covariance

This work computes the CF covariance matrices at three time frequencies. Two of them are used in Model P. Table 20 shows the mean CF correlation coefficient and CF covariance between the main types of technologies aggregated from the data of all options in Spain. For instance, the pair of the tranche 6 of onshore wind in zone ESP.Leon and the tranche 5 of one-axis tracking PV in ESP.Madrid is an element in column ONW-PV. This study uses this example to discuss general observations from all the generated data. Note that, the CF covariance is not a dimensionless correlation coefficient. It is in the units of the square of capacity factor, also ranging from 0 to 1 in this case, which implies the deviation on both output correlation and intensity.

The output complementarity of wind and solar PV can be observed as a negative correlation coefficient shown at row (A)(B)(C) in Table 20. However, the complementarity is not pronounced. The PV-PV has the highest correlation at hourly frequency scale as shown in (A), which is the result of clear diurnal generation pattern. This is why this study avoids using the covariance calculated from hourly data directly. Alternatively, this study uses the daily output (B) and the output in specific diurnal hour (C) in a calendar month.

The covariance further reveals the degree of variability of the technology pairs. (D)(E)(F) are the covariance corresponding to (A)(B)(C) at the same time frequencies. Again, as suggested in Shahriari & Blumsack (2018), if the covariance is calculated directly from the CF in hourly time series, as shown in row (D), PV pairs will yield strong variance or covariance because of their diurnal pattern. CSP pairs

can be worse because of its more persistent output in a day. Conversely, in (E)(F) PV and CSP are more stable than wind technologies. In general, combining wind and PV pairs can produce small negative covariance. The pairs of wind technologies, either onshore or offshore, have strong positive covariance at all the temporal frequencies which suggest the variation pattern is more consistent across a wide range of time frequency levels.

Comparing the daily covariance in January (E1) and July (E2) in Spain, the overall output in summer seems less volatile. The complementarity of wind and PV can be observed only in winter. The rows (F1)(F2)(F3) show that the covariance generally remain at the same level throughout the day in July. Wind is relatively volatile in this case, but the CSP output in the evening is more variable.

4.2.2 Optimal mix of climate-related energy

This research estimates the CRE mix in the countries using the proposed multi-objective model. The solutions can be plotted in 3D space with the dimensions representing the objectives respectively. All the charts along with detailed model outputs are available in the supplementary Data Package 3. The model outputs of the EU countries (including Norway and Switzerland) in 70% CRE target are summarized in Table 21. The model execution time depends on the scale of the models. It ranges from minutes to hours. The most complicated instance in this study is the USA, which consist of over 1,000 technology options and around 300 interconnection links. When executing on a 64-bit PC system with Intel Core i7 3.5GHz CPU and 24 GB RAM, it takes around 3 hours to solve Model CP. The overall solving time is kept at acceptable level.

A comparison can be made between the proposed mix and current installation. The UK, as shown in Table 21, is a good case to discuss the model results and reality, since the power demand projected to 2040 in this study is only 2% higher than 2018 record. The optimal mix of the UK in 70% CRE target proposed in this research is 47.7 GW (49%) onshore wind, 1.8 (2%) GW offshore wind, 43.8 GW (46%) PV and 3.6 GW (4%) hydropower. For 30% CRE target, this research suggests 16.4 GW onshore wind,

22.7 GW PV, 3.6 GW hydropower no offshore wind installation. In reality, at the end of 2018, the UK has 13.6 GW onshore wind installation, 8.2 GW offshore wind, 13.1 GW PV and 1.5 GW hydropower (National Statistics, 2019). All these renewables accounted for 22.6% of total electricity generation. Clearly, this research proposes a mix with more PV but much less offshore wind capacity. The main reason could be the cost assumption in 2040 when PV installation cost being reduced substantially and become cheaper than offshore wind. The distribution of installation also demonstrates a significant difference. In reality, onshore wind installation concentrates on Scotland and North Ireland, and PV installation is more popular in the southern regions of England. In this research, the distribution of onshore wind and PV is more even across all the regions in the UK. This could attribute to the objective that reduces the variability of residual load of every region. Therefore, to compare with current renewable development, these differences should be noted.

In this section Spain is used as an example to discuss the results and general findings. Figure 26 illustrates the solutions for Spain (ESP) in30%, 50% and 70% CRE targets. The charts actually show common patterns that can be observed in most countries. The most important finding is that the compromise solutions are usually the closest point to the origin among the objectives, as shown in Figure 26, effectively reducing the value on the three objectives simultaneously. More examples of the EU countries can be found in Table 21. Compared with the compromise solutions, the cost optimal solutions generally require around 10% less cost, but the residual load and portfolio output variation increase greatly. This supports the idea of using the compromise solutions as general reference for power system planning in this work. A summary of optimal CRE mix in 70% target in the 171 countries/districts can be found in Appendix D.

Table 20. The mean CF correlation coefficient and covariance of the main types of technologies in Spain.

The columns are the pairs of 5 main technology types which are aggregated from 154 available generation options in Spain. Data row (A) is correlation coefficient based on hourly CF of 10 years. (B) is the correlation coefficient computed from mean daily CF in each calendar month. The figures in this row is the mean of 12 months values. (C) is the correlation coefficient calculated at 288 time-slices. The figures shown is the mean of 288 TS data. Data row (D) is covariance based on hourly CF. (E) is covariance computed from mean daily CF in each calendar month which is the first element in model P. The result of January and July are listed in rows (E1) and (E2). (F) is the covariance calculated at 288 TS. It is the second element of model P. The rows (F1)(F2)(F3) are the covariance calculated exactly at one of the 288 TS, at 6AM, 12AM and 6PM in July respectively. (ONW: onshore wind, OFW: offshore wind)

Time scale\ Tech. pair	ONW-ONW	ONW-PV	ONW-CSP	ONW - OFW	PV-PV	PV-CSP	PV-OFW	CSP-CSP	CSP-OFW	OFW - OFW
(A) correlation hourly	0.5707	-0.0999	-0.0996	0.3868	0.9353	0.8141	-0.0679	0.8910	-0.0945	0.4287
(B) correlation daily	0.6061	-0.1400	-0.0753	0.4133	0.6277	0.5909	-0.0941	0.6997	-0.0711	0.4398
(C) correlation 288TS	0.5409	-0.1138	-0.0648	0.3509	0.5719	0.4562	-0.0634	0.6051	-0.0543	0.3970
(D) covariance hourly	0.0319	-0.0057	-0.0095	0.0235	0.0555	0.0809	-0.0041	0.1484	-0.0097	0.0296
(E) covariance daily	0.0214	-0.0012	-0.0016	0.0163	0.0014	0.0034	-0.0009	0.0102	-0.0018	0.0206
(F) covariance 288TS	0.0270	-0.0020	-0.0026	0.0193	0.0037	0.0069	-0.0012	0.0218	-0.0025	0.0255
(E1) cov. daily: Jan.	0.0338	-0.0016	-0.0015	0.0274	0.0013	0.0020	-0.0017	0.0038	-0.0026	0.0310
(E2) cov. daily: Jul.	0.0073	0.0000	0.0002	0.0056	0.0005	0.0015	0.0002	0.0061	0.0003	0.0124
(F1) cov. 288TS: Jul.6AM	0.0096	0.0000	0.0000	0.0093	0.0000	0.0000	0.0000	0.0000	0.0000	0.0164
(F2) cov. 288TS: Jul.12AM	0.0136	-0.0013	-0.0014	0.0068	0.0022	0.0029	0.0001	0.0066	-0.0004	0.0168
(F3) cov. 288 TS: Jul.6PM	0.0140	-0.0003	-0.0003	0.0060	0.0019	0.0042	0.0003	0.0167	-0.0012	0.0148

Table 21. Summary of model CP outputs of the EU countries in 70% CRE target.

The following table lists the Model CP solutions in 70% CRE target for EU countries (Luxembourg LUX is removed because these is no feasible solution). The percentage of residual demand variation (RL Var.) is calculated as the average zonal variation stander deviation divided by average demand. The percentage of portfolio output variation (PO Var.) is calculated as the standard deviation of system output variation divided by total CRE capacity. This table also compares the outputs from the other three models with those in Model CP. (ONW - onshore wind; OFW - offshore wind; Ann. Cost - annual cost; RL Var. – zonal residual load variation; PO Var. – portfolio output variation)

Country /District	Terrest. zones	Offs. zones	Install. options	Ann. Dem. In 2040	CRE Supply	Spilled Energy	Ann. Cost	LCOE	RL Var.	PO Var.	CRE share						Optimal solutions of other models compares to Model CP								
																	Model C			Model R			Model P		
											Total capacity	ONW	OFW	PV	CSP	Hydro	Ann. Cost	RL Var.	PO Var.	Ann. Cost	RL Var.	PO Var.	Ann. Cost	RL Var.	PO Var.
				TWh	TWh	TWh	B.USD	USD /kWh	%	%	GW	%	%	%	%	%	%	%	%	%	%	%	%	%	%
AUT	3	0	51	68.1	48	0	2.3	0.048	12.40%	4.90%	13.3	22%	0%	20%	0%	59%	98%	314%	158%	124%	23%	332%	133%	181%	0%
BEL	2	1	19	91.4	64.7	0.3	4.4	0.069	16.40%	12.80%	31.6	52%	7%	40%	0%	1%	100%	164%	101%	119%	46%	122%	111%	132%	96%
BGR	3	2	43	41.9	29.4	0	2	0.067	14.40%	6.80%	11.2	34%	0%	31%	0%	35%	98%	207%	135%	123%	36%	260%	121%	163%	46%
CHE	1	0	16	65.2	48.1	2.4	2.3	0.051	18.10%	3.00%	11.5	15%	0%	0%	0%	85%	94%	205%	56%	180%	35%	914%	101%	125%	0%
CYP	1	1	15	6.1	4.3	0	0.5	0.108	18.20%	14.60%	2.3	80%	1%	5%	12%	2%	96%	101%	116%	123%	86%	114%	111%	109%	89%
CZE	2	0	21	61	42.9	0.1	2.8	0.065	15.00%	11.10%	20.5	57%	0%	37%	0%	6%	99%	143%	109%	119%	39%	133%	101%	153%	96%
DEU	12	2	136	576	409.6	2.8	26.1	0.064	16.60%	8.90%	186.3	41%	5%	45%	0%	9%	91%	239%	129%	133%	19%	127%	125%	228%	89%
DNK	2	3	27	34.4	24.8	0.6	1.4	0.059	8.40%	16.40%	8.7	52%	16%	32%	0%	0%	80%	186%	121%	154%	59%	113%	165%	217%	81%
ESP	8	4	169	259.7	186.9	2.8	11.3	0.061	18.80%	5.30%	71.1	29%	3%	42%	0%	26%	78%	201%	177%	206%	31%	198%	144%	197%	85%
EST	1	1	14	7.7	5.4	0.1	0.4	0.069	7.80%	13.10%	2.2	55%	0%	29%	0%	16%	92%	205%	128%	133%	48%	123%	164%	222%	81%
FIN	5	3	54	87.8	62.7	0.2	4.1	0.066	9.70%	13.10%	21.7	74%	0%	1%	0%	25%	93%	231%	133%	118%	38%	135%	122%	346%	89%
FRA	12	7	173	475.5	340.6	2.3	19.4	0.057	15.30%	6.60%	133.3	40%	0%	41%	0%	20%	92%	263%	137%	153%	10%	187%	134%	293%	81%
GBR	12	8	149	338.9	241	1	12.6	0.052	16.80%	10.80%	96.1	49%	2%	46%	0%	4%	86%	242%	142%	148%	35%	136%	173%	249%	80%
GRC	6	3	124	56.8	40.5	0.5	2.2	0.054	18.20%	7.20%	14	32%	1%	40%	0%	27%	78%	204%	165%	191%	31%	217%	136%	230%	64%
HRV	2	1	35	22.7	16.1	0	0.8	0.051	12.00%	5.80%	5.5	20%	0%	39%	0%	41%	86%	269%	252%	141%	43%	249%	133%	204%	0%
HUN	3	0	30	40.5	28.6	0.1	1.9	0.068	15.90%	10.80%	14.2	55%	0%	36%	0%	9%	98%	181%	109%	129%	40%	136%	108%	216%	94%
IRL	2	2	29	28.1	19.7	0	0.9	0.045	9.60%	13.40%	6.5	49%	0%	41%	0%	10%	81%	119%	145%	129%	52%	124%	167%	288%	81%
ITA	9	10	163	321.7	232.6	5.4	13.2	0.058	14.50%	4.50%	82.3	22%	0%	41%	0%	37%	89%	246%	163%	178%	50%	286%	106%	225%	72%
LTU	1	1	13	13.8	9.8	0.2	0.7	0.075	5.60%	13.80%	4	62%	2%	23%	0%	12%	90%	219%	126%	164%	39%	111%	143%	290%	78%
LVA	1	1	13	9.6	6.7	0	0.4	0.065	8.90%	9.10%	2.5	42%	0%	18%	0%	41%	95%	253%	138%	178%	22%	168%	132%	224%	66%
MLT	1	1	9	3.1	2.2	0	0.4	0.172	23.00%	18.70%	1	8%	72%	20%	0%	0%	99%	100%	100%	104%	96%	104%	102%	100%	99%
NLD	4	2	40	115.4	82.4	1.1	5.6	0.069	14.80%	13.10%	36.3	39%	17%	43%	0%	1%	87%	159%	112%	124%	47%	115%	127%	165%	88%
NOR	5	4	93	124	88.3	0.3	3.6	0.041	15.70%	10.50%	19.1	54%	0%	0%	0%	46%	87%	239%	191%	147%	0%	230%	125%	303%	37%
POL	5	1	54	143	101.7	0.8	6.9	0.068	15.60%	9.10%	46.6	42%	7%	43%	0%	8%	87%	210%	124%	143%	15%	129%	122%	222%	94%
PRT	2	2	42	51.3	36.8	0.8	2.1	0.059	14.70%	7.90%	15.2	43%	0%	37%	0%	20%	94%	184%	93%	183%	35%	188%	132%	197%	47%
ROU	7	1	91	63.7	44.8	0	2.9	0.065	14.40%	5.80%	15.7	34%	0%	20%	0%	46%	99%	229%	148%	127%	32%	266%	122%	219%	53%
SVK	2	0	27	27.3	19.1	0	1.2	0.062	13.20%	8.90%	7.9	44%	0%	33%	0%	24%	96%	201%	107%	120%	34%	205%	103%	165%	68%
SVN	1	1	17	14.3	10	0	0.5	0.052	10.60%	4.30%	3.4	14%	0%	38%	0%	48%	99%	286%	134%	120%	37%	339%	126%	125%	0%
SWE	4	5	62	139.7	101.4	1.9	5.7	0.057	16.90%	9.60%	28.9	54%	0%	7%	0%	39%	94%	175%	176%	137%	11%	186%	124%	251%	55%
Total EU	119	67	1729	3288.5	2349.3	24	138.7				912.9	41%	3%	37%	0%	19%	41%								

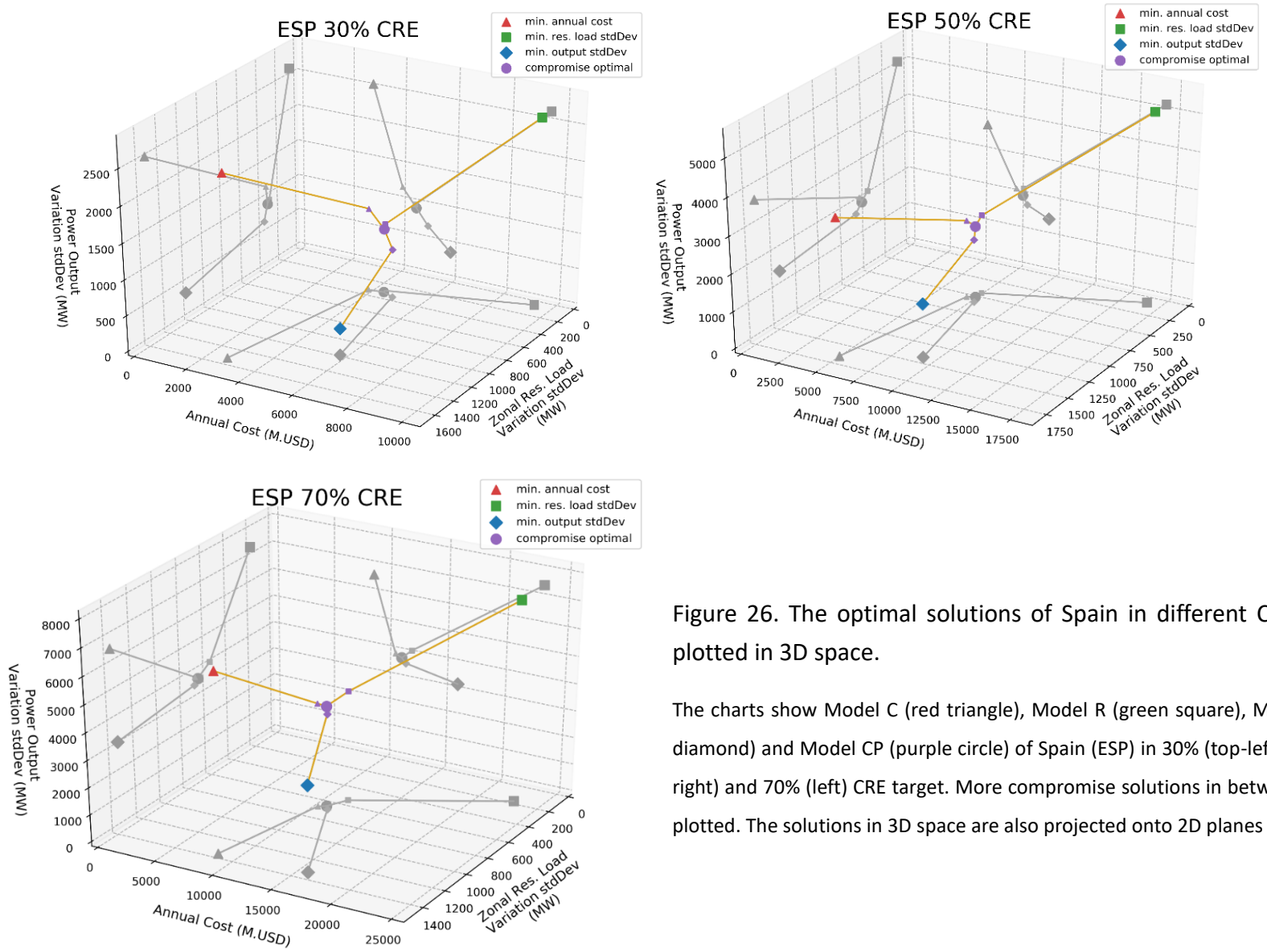


Figure 26. The optimal solutions of Spain in different CRE targets plotted in 3D space.

The charts show Model C (red triangle), Model R (green square), Model P (blue diamond) and Model CP (purple circle) of Spain (ESP) in 30% (top-left), 50% (top-right) and 70% (left) CRE target. More compromise solutions in between are also plotted. The solutions in 3D space are also projected onto 2D planes in grey color

In some countries with limited CRE resources, the solutions in high CRE penetration can be fairly close, but the compromise solutions are still the closest points to the origin. However, China (CHN) is the only exception in this study. Its compromise solution is worse than minimum cost solutions in all CRE targets. This is because the cost assumptions of solar and hydro technologies are much lower compared with other countries. The cost optimum model produces a solution with relatively less residual load variation.

Comparing the optimal solutions of Model CP of Spain in the three CRE targets, as shown in Table 22, the linearity can be observed for almost every element between 30% and 50% CRE targets. However, moving from 50% to 70% target requires more wind and less solar. This is mainly due to the constraints on curtailment and system balance. More PV in the system can cause more spill during daylight hours and increase the residual load variation. This effect can also be observed in many countries such as Germany and Japan.

The capacity mix produced from the models can differ significantly. Table 22 lists capacity mix of the models in 70% target. The breakdown of capacity mix in the solutions are listed in Table 23. The table shows the capacity mix of available options in ESP.South and the offshore zones it connects to. It can be observed that Model C selects the top tranches of onshore wind and one-axis tracking PV which are the cheapest options in this case. The mix in Model R concentrates on wind and results in less residual load variation. Model P focuses on PV technologies since their covariance are smaller than wind as discussed previously. The compromise solution in Model CP shows a diverse and balanced portfolio among the technologies.

To demonstrate the space-time integration, this work also uses Spain as an example, shown in Figure 27. It shows the electricity flows in the zones. The ESP.South, ESP.East and ESP.Madrid are the demand center and relaying on power imports. The other zones supply wind and solar power and export to these zones. Hydropower ramps up in the evening to flatten the residual demand as they are mostly dispatchable. The wind and PV power demonstrate little complementarity in this case. The residual load has a valley at the mid-day but reaches a peak in the evening. This is the balancing pattern actually can be found in most countries as notable level of the electricity is provided by solar technologies.

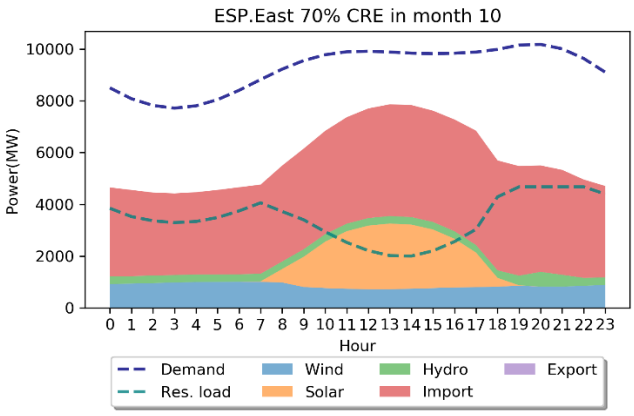
Table 22. The summary of the optimal solutions of Spain in different CRE targets.

		Annual Cost	Zonal Res. Load Var. stdDev	Portfolio Output Var. stdDev	CRE Supply	Spilled Energy	Total Capacity	Onshore Wind	Offshore Wind	PV	CSP	Hydro
CRE %	model	B.USD	GW	GW	TWh	TWh	GW	GW	GW	GW	GW	GW
30%	**CP**	**4.6**	**0.4**	**0.9**	**78.8**	**0.0**	**30.4**	**3.3**	**0.0**	**14.8**	**0.0**	**12.2**
30%	C	2.9	1.6	2.5	77.9	0.0	39.1	0.5	0.0	38.6	0.0	0.0
30%	R	9.5	0.1	2.6	87.1	7.8	28.3	6.0	9.3	2.8	6.0	4.1
30%	P	5.9	1.2	0.4	78.2	0.0	29.5	1.0	0.5	9.3	0.0	18.7
50%	**CP**	**7.7**	**0.6**	**1.9**	**132.3**	**1.0**	**51.4**	**9.9**	**0.0**	**24.9**	**0.0**	**16.7**
50%	C	5.3	1.7	3.7	131.0	1.1	55.8	13.6	0.0	42.3	0.0	0.0
50%	R	16.8	0.1	5.1	145.0	12.9	45.3	10.7	20.6	0.8	8.8	4.4
50%	P	9.5	1.5	1.4	130.7	0.0	60.9	3.6	2.3	36.3	0.0	18.7
70%	**CP**	**11.3**	**0.7**	**3.7**	**186.9**	**2.8**	**71.1**	**20.4**	**2.2**	**29.6**	**0.3**	**18.7**
70%	C	8.8	1.4	6.6	184.1	1.1	68.1	32.9	0.0	29.8	0.0	5.5
70%	R	23.2	0.2	7.4	196.9	11.9	64.3	18.7	30.1	1.5	9.7	4.3
70%	P	16.2	1.4	3.2	184.9	0.9	68.0	8.1	10.2	24.2	6.9	18.7

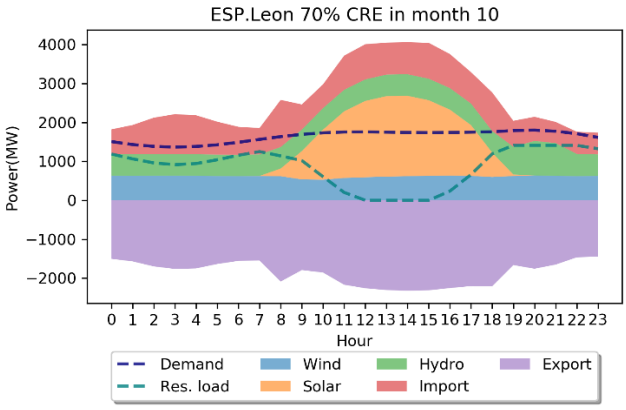
Table 23. The model CP solution in detailed CF tranches in ESP.South and the offshore zones it connects to.

The options and tranches with no installation in the models are not shown in this table. The offshore wind in different water depth entries are aggregated.

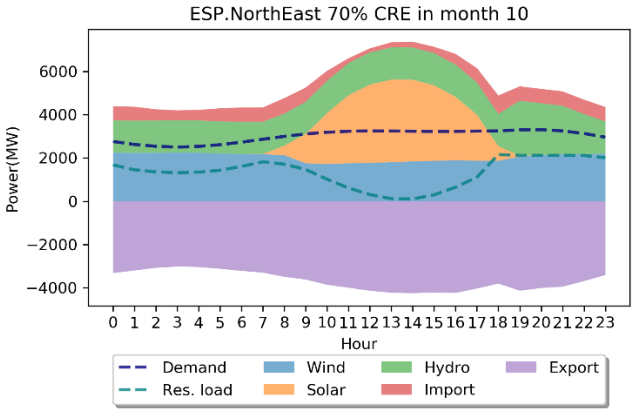
Zone	Technology	CF Tranche	Limit	Model C	Model R	Model P	Model CP
			GW	GW	GW	GW	GW
ESP.South	OnWind	5	3.2	0	1.1	0	3.2
ESP.South	OnWind	6	1.2	1.2	0	0	1.2
ESP.South	OnWind	7	0.5	0.5	0.5	0.5	0.5
ESP.South	OnWind	8	0.2	0.2	0.2	0.2	0.2
ESP.South	OnWind	9	0.2	0.2	0.2	0.2	0.2
ESP.South	PV tracking	6	281.6	8.9	0	5.8	5.3
ESP.South	CSP ST9	4	17.9	0	0	2.5	0
ESP.South	CSP ST9	5	0.3	0	0.3	0.3	0.3
ESP.South	L-Hydro		0.1	0	0.1	0.1	0.1
ESP.South	S-Hydro		0.8	0	0	0.8	0.8
ESP.OffRgn1	OffWind	6	3.8	0	3.8	0.8	0.6
ESP.OffRgn1	OffWind	7	2.8	0	2.8	1.3	0.8
ESP.OffRgn4	OffWind	5	1.8	0	0	0	0
ESP.OffRgn4	OffWind	6	3.3	0	3.3	0.9	0.1


ESP.East 70% CRE in month 10
Power(MW)
Hour
Demand
Res. load
Wind
Solar
Hydro
Import
Export

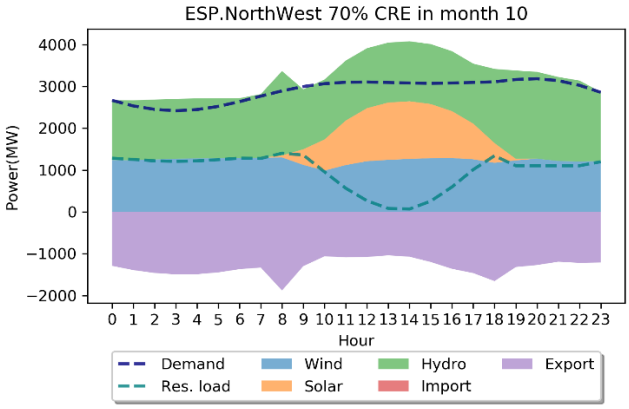
(A)


ESP.Leon 70% CRE in month 10
Power(MW)
Hour
Demand
Res. load
Wind
Solar
Hydro
Import
Export

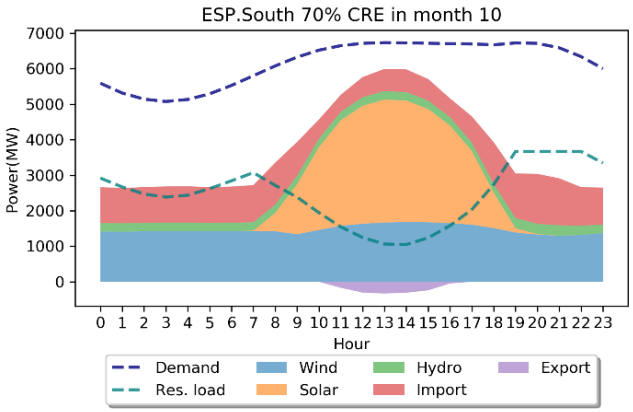
(B)


ESP.NorthEast 70% CRE in month 10
Power(MW)
Hour
Demand
Res. load
Wind
Solar
Hydro
Import
Export

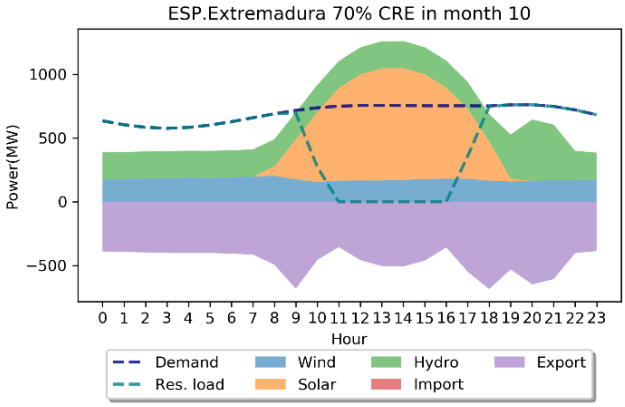
(C)


ESP.NorthWest 70% CRE in month 10
Power(MW)
Hour
Demand
Res. load
Wind
Solar
Hydro
Import
Export

(D)


ESP.South 70% CRE in month 10
Power(MW)
Hour
Demand
Res. load
Wind
Solar
Hydro
Import
Export

(E)


ESP.Extremadura 70% CRE in month 10
Power(MW)
Hour
Demand
Res. load
Wind
Solar
Hydro
Import
Export

(F)

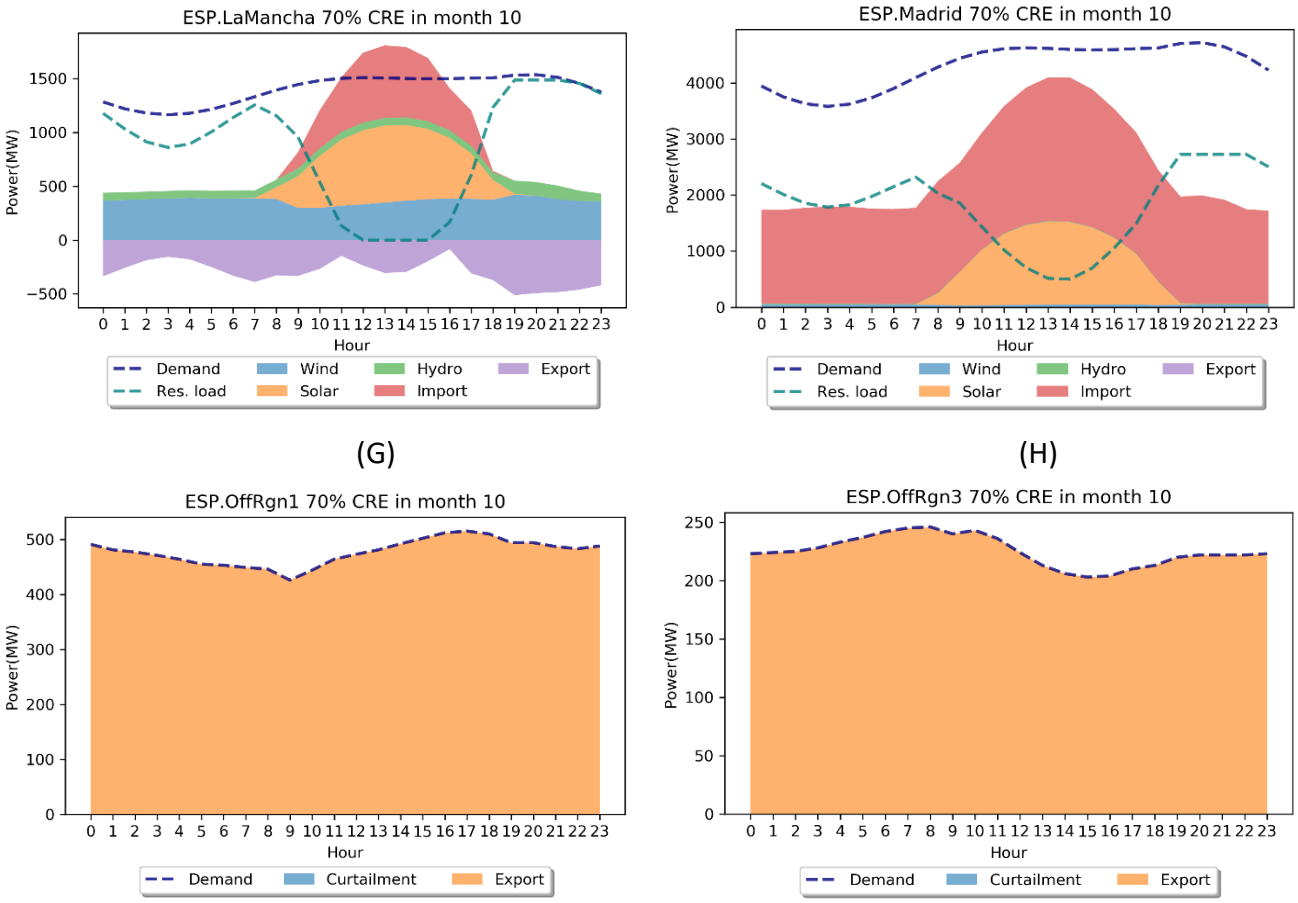


Figure 27. The daily power demand, supply and transmission in the zones in Spain in October. The figures shown are the results of Model CR in 70% CRE target in terrestrial zones (A-H) and offshore zones (I,J).

Since hydropower output is not calculated in the covariance matrices, Model P tends to maximize hydropower capacity since large hydropower system is dispatchable in this work. In many cases, the model exploits hydropower potential to the capacity limit. However, the monthly output variation of hydropower is still considered in the models. In countries with limited hydropower potential, such as Belgium (BEL) and the Netherlands (NLD), the development of hydropower is usually maximized. This implies that hydropower may be the most important resource in an electricity system for its cost, ability of dispatch and stable output.

In this work, 30% and 50% of CRE penetration are solvable in all countries/districts, except for Singapore (SGP). For 70% target, feasible solutions cannot be found for Burkina Faso (BFA), Bhutan (BTN), Luxembourg (LUX) and South Korea (KOR) unless the constraint of annual 10% curtailment is released. This is because of their limited CRE resources, or the resources concentrate on certain types.

This may suggest that high renewable penetration can be attainable in almost every country. However, this would require further modelling work that investigates the entire power system. The details of the solutions for each country is compiled in the supplementary Data Package 3.

4.2.3 Global analysis on the optimal mix

The share of the main CREs, i.e. wind, solar and water, in all assessed countries/districts are plotted on the ternary charts, as shown in Figure 28, Figure 29 and Figure 30. The distribution of capacity mix in 30% CRE target is shown in Figure 28. In Model C, it can be observed that the dots are mostly on two edges. It suggests that these countries rely on the combination of cheap wind and hydropower to reach the target. Model CP produces a very different distribution where most solutions scatter in the middle. There is no clear pattern regarding cost in 30% target.

When the target increase to 50%, a number of dots move away from the edges in model C, as shown in the left figure of Figure 29. In model CP, the dots move closer to the center compared to that in 30% target. This may suggests a reduced reliance on specific sources. The cost information reveals that higher cost may be required when the share of wind is high.

Figure 30 shows the distribution of 70% target with more information about residual demand variation and portfolio output variation. In model C, the dots move towards the end of high wind power share, as shown in the top left figure. The result of model CP also demonstrates a similar trend. It can be observed that solar penetration cannot exceed 50% in this target level. The top-right figure, colored with cost information, may imply that higher wind penetration can make the production cost higher. The bottom-right figure, colored according to portfolio output level, shows that higher share of hydropower reflects low output variation. However, there seems no clear pattern between the capacity mix and the residual load variation, shown on the bottom-left chart.

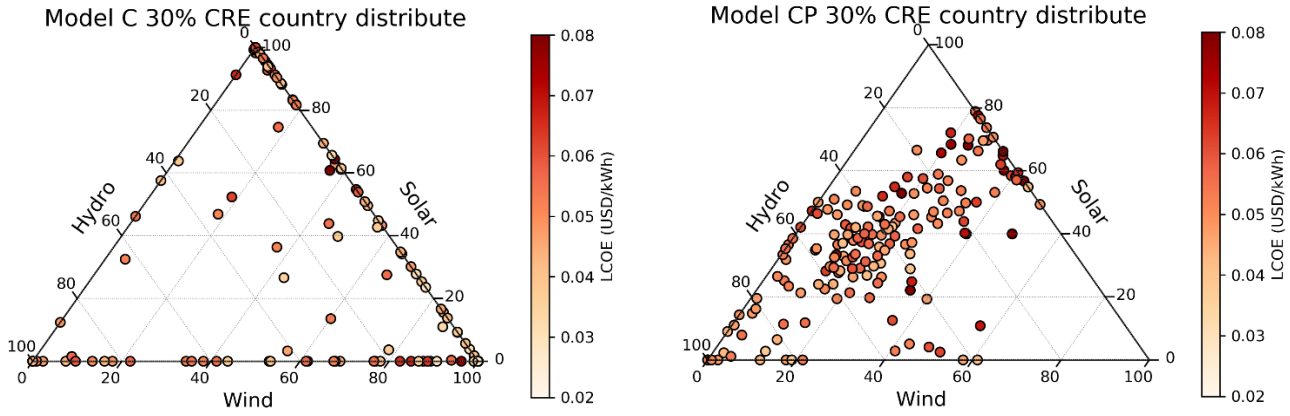


Figure 28. The distribution of the capacity mix of every countries in 30% CRE target. The chart on the left if the results of Model C, and the chart on the right is model CP.

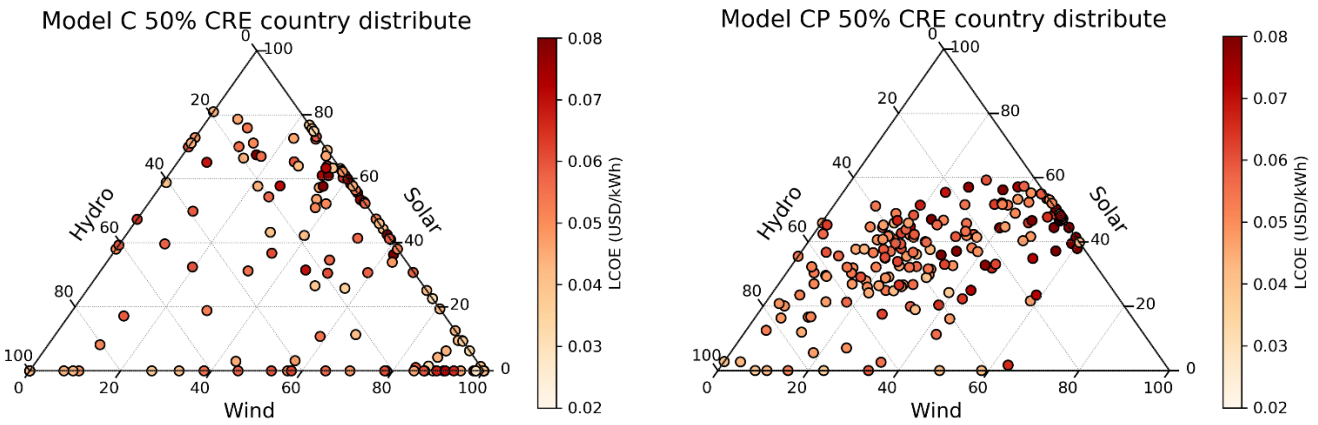


Figure 29. The distribution of the capacity mix of every countries in 50% CRE target. The chart on the left if the results of Model C, and the chart on the right is model CP.

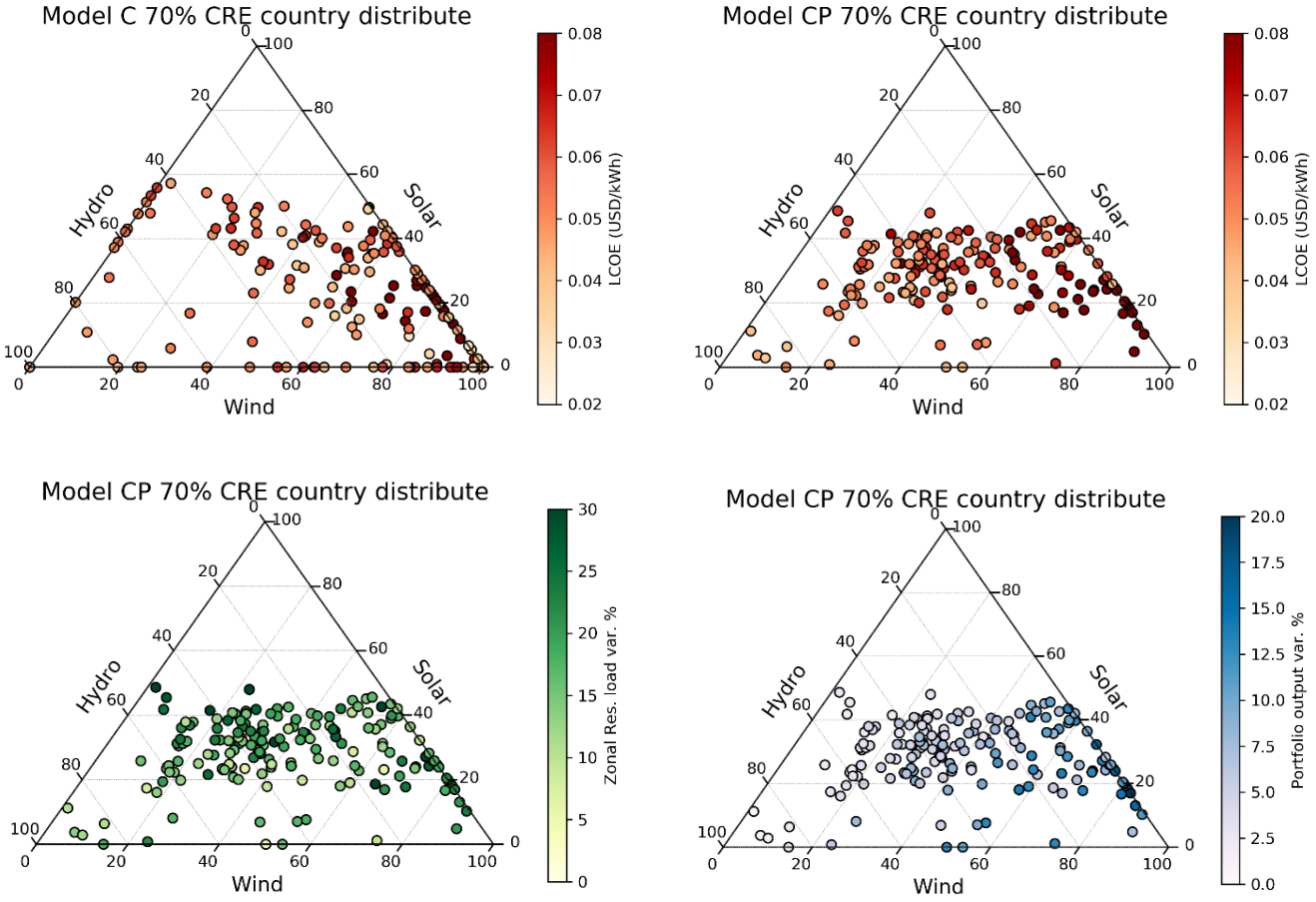


Figure 30. The distribution of the capacity mix of every countries in 70% CRE target in Model CR.

The chart on top-left is the distribution of 70% CRE target in Model C. The rest charts are the 70% target in Model CP but colored by the range on LCOE (top-right), zonal residual load variation (bottom-left) and portfolio output variation (bottom-right). The percentage of residual demand variation is calculated as the average zonal variation standard deviation divided by average demand. The percentage of portfolio output variation is calculated as the standard deviation of system output variation divided by total CRE capacity.

Since most of the techno-economic assumptions in this work referred to the Sustainable Development Scenario (SDS) proposed by the IEA (IEA, 2018b), a simple comparison of the results can be made. In SDS, the share of CRE generation to the total power produced in Europe in 2040 is around 60%. In this scenario, the capacity share of hydro, wind and solar power are 24%, 43% and 33% respectively, while the figures proposed in this work in 70% target are 19%, 44% and 37%. At global scale, the scenario by IEA estimates around 60% generation, or 9,420 GW capacity, is from CRE in 2040. The capacity share of hydro, wind and solar power are 22%, 30% and 48% respectively, while the figures in this work for the 70% CRE target are 21%, 50% and 29% with total capacity of 9,976 GW. Clearly, the difference on the share is significant at global scale. The scenario proposed by the IEA is modelled at hourly and country level, but it considers storage technologies and grid interconnection in the model. This could be the reason of higher share of solar power being integrated into the regional systems. Therefore, the next work in this research will create models that incorporate the operation of conventional thermal generators, interconnection and flexibility requirements.

4.2.4 Summary

Existing power system models are usually based on cost optimization approach. They may capture the reliability and flexibility requirements in a high renewable penetration system with complex models. However, their temporal and spatial resolution can often be limited because of the problem size, as well as data availability. Moreover, only few of existing studies have attempted to take into account the VRE output complementarity. Therefore, this main purpose of this study is to address these issues by breaking down the problem into different objectives and to perform the modelling with fine space-time resolution. Since the problems are kept in quadratic form, they can be solved much faster than other non-linear problems. The most complex case in this study can be solved within a few hours. This work focuses on CRE resources, and proposed the optimal mix in each country system globally.

In this work, mathematical models are formulated to investigate the optimal CRE mix. The shared model core contains the constraints on capacity limit, system balance, transmission, hydropower dispatch, curtailment and CRE target. Model C is based on minimum cost optimization. Model R is designed to minimize the residual load variance. This model deals with the overall complementarity of portfolio output to load profile. Model P is developed to minimize the portfolio output variance which may reflect on reduced need for committed thermal units and required reserve. The Model CP

includes all the three objectives using compromise programming. This work regards the solution from Model CP as the proposed optimal mix. All the models are performed with aggregated CF and demand profile of 288 time-slices for 1,070 representative zones in 171 countries/districts globally. The modelling scenario is set to investigate the optimal CRE mix in 2040 with the generation targets at 30%, 50% and 70% in the countries. In addition, this work further has estimated the required data of monthly hydropower output and power demand profile in the zones.

The CF covariance matrices of all available CRE options in a country are produced. Each element in the matrices represents the covariance of a pair of options, and the matrices are calculated at two temporal frequencies. It is confirmed that the output complementarity exits for wind and solar technologies at sub-country level at hourly and daily time frequencies. Wind power demonstrates persistent variability patterns at all the time scale, while the variability of solar power can be severe at hourly level but relatively stable at daily scale.

General findings from the outputs are: first, the compromise solutions proposed can be good reference for policy makers since it can effectively reduce the three objective values; second, wind power is crucial in higher CRE share systems while solar is bounded at around 50% capacity share; third, higher CRE penetration may be attainable in most countries but further modelling work is needed. Comparing with the high renewable share scenario proposed by IEA, this study shows heavier reliance on wind power. It is possibly because flexible measures such as storage and interconnection are not considered in this study, and also the curtailment was limited. To the author's knowledge, no research prior this work has investigated the optimal mix of CRE country by country with consistent approach. Thus this work can be a one of the reference for policy makers in planning low-carbon power systems to reach country targets.

4.3 Electricity system decarbonization

This section presents the results of several global decarbonization scenarios, and compares the results with the scenario proposed by IEA. Examples are presented to discuss the effects of including system flexibility measures in the model.

4.3.1 Global decarbonization scenarios

The models have produced a large amount of output data. For the most detailed generator output, inter-zone flow and other information, they can be downloaded through the links in the Data Package 4 in Appendix A. Aggregated global results of the scenarios are summarized in Appendix E. Selected output data of each country/district is compiled in Appendix F.

In this work, the global carbon dioxide emissions from electricity sector in the scenarios is shown in Figure 31, and the cumulative emission is shown in Figure 32. The emissions in REF scenario decrease from the 2020 peak at a little over 10,000 million tonnes to around 4,000 million tonnes in 2050. HCS and MCP scenario have similar trend before 2040, and produce less emissions than REF scenario. After 2040, HCS scenario reduces further down below zero thanks to the development of BECCS. It is the most aggressive reduction pathway. The emissions in MCP scenario sustains at the same level after 2040. It is because the minimum renewable capacity of each type is fixed at 2040 afterward. The emissions in CNS scenario decrease steadily to zero in 2050. It is a result of the linear decreasing emission limits assigned to each period.

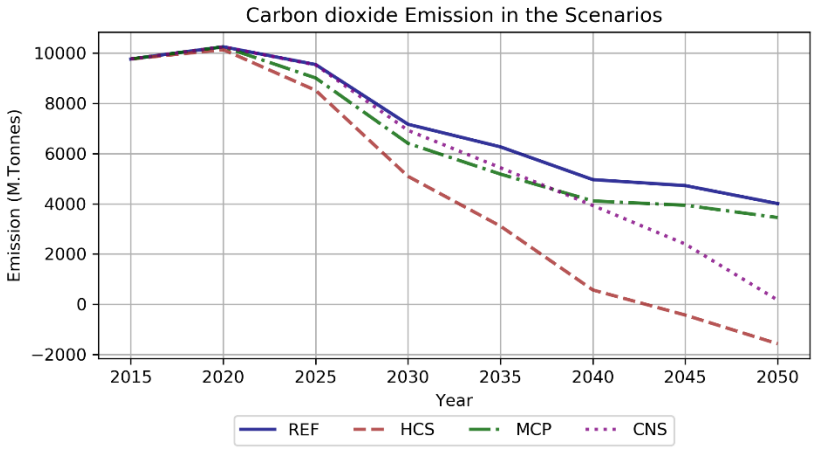


Figure 31. The global carbon dioxide emission from electricity sector in the scenarios.

The global electricity sector emissions in base year seem underestimated when compared with the statistics by IEA (IEA, 2017c) which indicates a level of 13,000 million tonnes. The main cause of

the shortage is that the IEA's figures include both power and heat generation while in this work heat generation is excluded. Several other reasons also contribute to the underestimation. The default conversion efficiency of existing power plants is applied with the same figure of a new build in 2015 due to the lack of data. The nuclear generation is about 190TWh higher because the ED model is in favor to nuclear for its low variable generation cost. This additional generation fills the generation gap in equation (4.22) when the generation floor of the existing units is released with a small range. Also, the existing renewable installation is assigned to the highest output tranches by default.

The cumulative emissions from electricity sector in HCS scenario peaks at around 2040, at around 160 $GtCO_2$, while the emissions in other scenarios keep growing in the time horizon. Since the scope of this work only covers electricity sector, whether the pathways in the scenarios are compatible with the 1.5°C and 2°C emission targets requires further investigation. Given that the remaining emission budget for 1.5°C targets with higher probability is 420 $GtCO_2$ (from 2018), the cumulative emission from other sectors in HCS scenario have to keep as low as 200 $GtCO_2$ to reach the target. This seems to be a very challenging target. However, the 2°C target may be more attainable in HCS scenario if other sectors can keep the cumulative emissions below 940 $GtCO_2$.

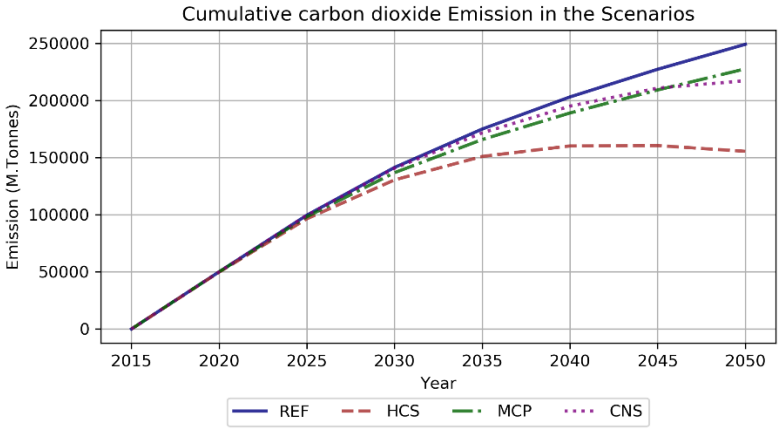


Figure 32. The global cumulative carbon dioxide emission from electricity sector in the scenarios.

The global annual spending in electricity sector is shown in Figure 33. The cost in REF scenario grow steadily to 2050. There is a small jump in 2025 in every scenario. It is because old plants which have already reached their service lifetime but were still in operation in base year are forced to retire in 2025 in this work. HCS scenario requires more spending in early periods but overtaken by other scenarios after 2040. The cost in CNS scenario remains close to REF before 2035 but shows a stiff increase afterward.

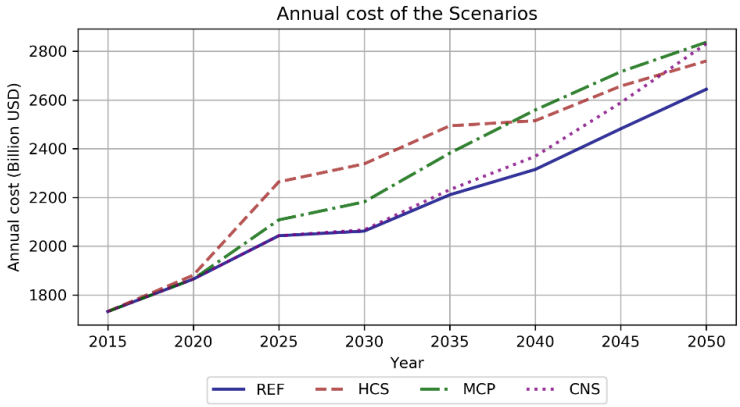


Figure 33. The annual cost of global electricity sector in the scenarios.

The results of global electricity generation and capacity by main technology group in the scenarios are presented in Figure 34 and Figure 35. In general, there are no evident differences on the mix among the scenarios. The renewable development in the scenarios demonstrates a fairly similar trend, as wind and PV make up at least half of the generation and capacity mix. The share of dispatchable thermal technologies in HCS and CNS scenarios shows a higher reliance on CCS[35] and nuclear. In the long run, the generation and capacity of coal power plant is shrinking.

In HCS scenario conventional fossil fuel plants are replaced by nuclear and CCS due to higher carbon cost. BECCS become cost competitive from 2040. Its deployment thereafter drives the annual global emissions down to negative. MCP scenario[36] is based on the optimal capacity mix of CRE in all countries proposed in the previous work. The countries attain higher self-sufficiency to meet their CRE generation target. Although the share of renewable in MCP scenario is almost same as HCS and CNS, this scenario does demonstrate more efficient utilization of dispatchable sources. Its capacity of thermal generators as well as storage system is the lowest among the four scenarios. This actually reflects the objectives in constructing MCP, i.e. finding an efficient balance among total cost, zonal residual load and CRE portfolio output. Clearly, the total cost is compromised for reducing the variability of residual load and CRE output, which results in less firm and flexible capacity needed. It can be observed that CNS scenario generates a similar pathway to REF scenario before 2035, but it reduces the emissions aggressively in the last periods. To meet the zero emissions target in 2050, this

[35] CCS here contains all types of CCS technology including BECCS.

[36] The resulting capacity mix of MCP scenario would not be the same as in the optimal CRE mix proposed previously. First, the applied capacity targets of each technology in MCP are inequality constraints. The installations of the CRE can be more in MCP. Second, in several developed countries, there are additional maximum capacity limited applied on total hydropower installation, see the constraints (4.33).

scenario has to install more renewables, nuclear and CCS in the last periods, and this causes a drastic increase of cost. The MENA region is a good example to show this transition. The generation and capacity mix of REF and CNS scenario in this region are identical before 2045.

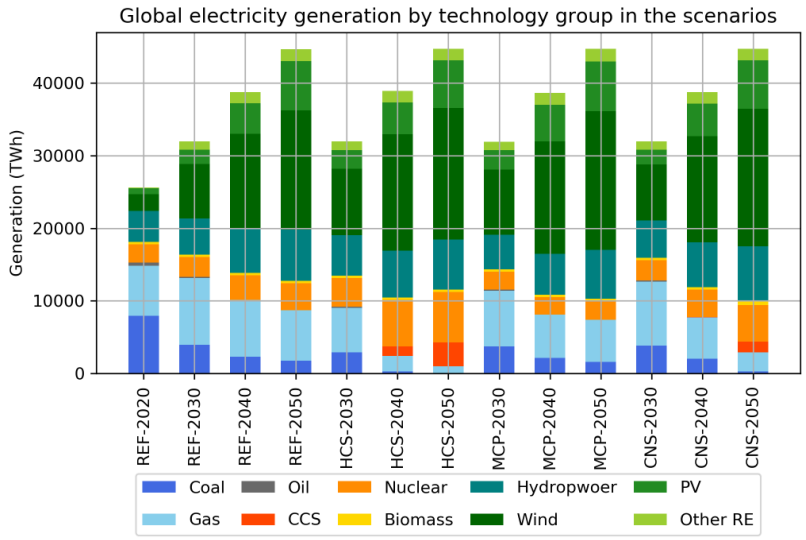


Figure 34. The global electricity generation by technology group in the scenarios.

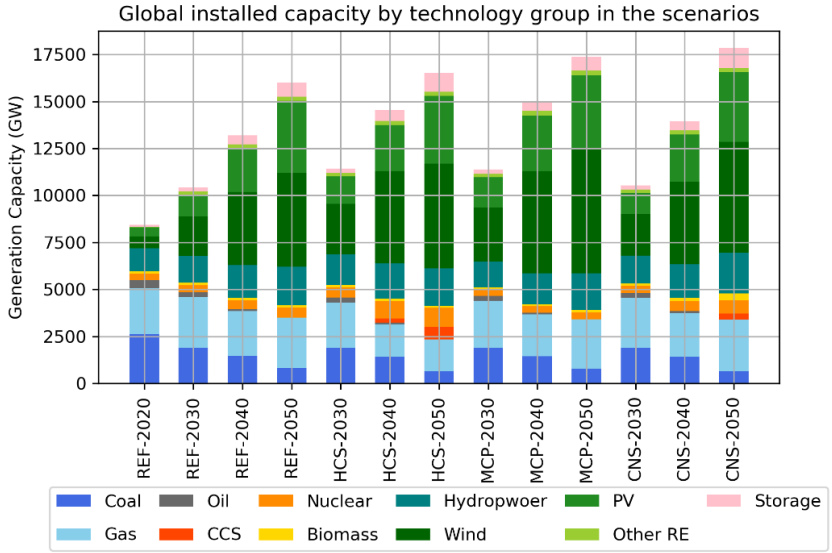


Figure 35. The global installed capacity by technology group in the scenarios.

In this work most of the techno-economic assumptions referred to the New Policy Scenario by IEA (IEA, 2018b). Table 24 shows the summary of global capacity and generation of the 4 scenarios compared with NPS and SDS scenarios by IEA. The two studies have similar level of demand projection, and the global electricity generation in 2040 are very close, at round 40,000 TWh. It be found that

higher share of renewables presents in the scenarios of this research. For example, in REF scenario only 6% generation is from coal plants in 2040. It is about 20% less compared with IEA-NPS scenario, and the gap is filled by generation from renewables. This also results in a reduced emission in notable amount. Comparing the scenarios with high carbon cost, i.e. HCS and IEA-SDS scenarios, the difference on renewable generation is reduced. However, the emissions in HCS scenario reaches almost zero in 2040 while IEA-SDS generates over 3,000 $MtCO_2$ in this period. It is difficult to figure out the causes of the differences since the two studies are based on different type of modelling approach. The World Energy Model (WEM) developed by IEA for constructing the scenarios is based on simulation approach (IEA, 2018a). The WEM model investigated the energy system at country level, and dealt with electricity supply and demand at hourly resolution. A possible cause of more capacity of dispatchable units is its investment constraints. In the capacity planning phase, its algorithm calculates the value-adjusted LCOE (VALCOE) of each potential candidate, which is a function of energy value, capacity value and generation flexibility. The VALCOE tends to be higher for variable renewable energies when the penetration is high and makes variable renewables unfavorable. In addition, international electricity trading is only implemented for Europe region. This may underestimate the efficiency of using resources in other integrated regions.

The global generation from renewables in REF scenario is around 70% in 2050 while the other three can reach 75%. High penetration of variable renewables at this level is also presented in several pathways compatible with 1.5°C and 2°C targets proposed by global IAMs (Huppmann et al., 2018). The pathways of 100% renewable of electricity sector in 2050 are also proposed in the studies by Teske et al. (2015) and Bogdanov et al. (2019). The share of wind, solar, hydropower and biomass in the composition, however, varies widely among all the pathways proposed. In general this work produces relatively higher share of wind power. On the other hand, nuclear and CCS are the other two pillars in providing low-carbon electricity across the pathways by the IAMs. However, in this work new installation of nuclear and CCS is only promising in the last periods of HCS and CNS scenario. It suggests that nuclear and CCS are generally uneconomic in most of the countries through the time.

4.3.2 Measures to improve system flexibility

To inspect how the models utilize the resources, Figure 36 shows the example of South Korea[37] in MCP scenario in July 2050. The figures illustrate the electricity supply by types and electricity flow

[37] South Korea is modelled as independent market in this case.

in the zones. Most of the zones rely on importing wind power from 5 offshore zones which are not shown in this figure. Gyeonggi is the large metropolitan area of the capital and the electricity demand is the highest. Available area for renewable development is limited in this zone. It dependents on nuclear generation to serve over half of the demand. Nuclear generation can also be found in the second largest demand area Gyeongsang in which nuclear provides stable base load. In other zones, the generation mix is rather diverse. Solar power is an important source during daytime hours in summer. Generation from gas is flexible and complement to others. Storage systems in the zones operate differently, but their generation is to fill the surge in the evening. Coal and biomass generation also concentrates on the evening hours. This generation pattern results in higher zonal market price in the evening, as shown in Figure 37. The price in the capital zone is always high while in other zones the price drops when solar power is strong. In Chungcheong and Gangwon where renewable provides nearly 100% of electricity in July, including import from offshore, the zonal market price also grows in the evening because of generation from OGCT. This is an example of supply and demand in a market.

Table 24. Summary of the global generation and capacity in the scenarios.

		Generation (TWh)			Capacity (GW)			Generation (%)			Capacity (%)		
		2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
REF	Coal	3961	2309	1757	1902	1458	804	12	6	4	19	11	5
REF	Gas	9176	7836	6927	2683	2392	2702	29	20	16	26	19	18
REF	Nuclear	2774	3384	3743	379	469	528	9	9	8	4	4	3
REF	Wind	7490	13076	16415	2128	3884	5015	23	34	37	21	31	33
REF	Solar PV	1969	4180	6815	1133	2307	3814	6	11	15	11	18	25
REF	Hydro	4952	6090	7039	1425	1763	2047	15	16	16	14	14	13
HCS	Coal	2902	454	229	1887	1449	678	9	1	1	18	11	4
HCS	Gas	6155	2692	1731	2417	1813	1854	19	7	4	24	14	12
HCS	Nuclear	3949	6392	6923	561	919	1004	12	16	16	5	7	7
HCS	Wind	9183	16019	18079	2701	4917	5580	29	41	41	26	39	37
HCS	Solar PV	2571	4393	6570	1463	2433	3590	8	11	15	14	19	24
HCS	Hydro	5558	6498	6917	1611	1884	1992	17	17	16	16	15	13
MCP	Coal	3744	2120	1596	1893	1442	784	12	5	4	19	11	5
MCP	Gas	7654	5979	5781	2508	2228	2632	24	15	13	25	18	17
MCP	Nuclear	2472	2411	2596	340	338	377	8	6	6	3	3	2
MCP	Wind	8939	15464	19134	2859	5444	6597	28	40	43	28	43	43
MCP	Solar PV	2722	5053	6803	1617	2946	3930	9	13	15	16	23	26
MCP	Hydro	4774	5662	6715	1373	1639	1951	15	15	15	13	13	13
CNS	Coal	3832	2104	359	1890	1438	669	12	5	1	19	11	4
CNS	Gas	8822	5684	2759	2662	2320	2784	28	15	6	26	18	18
CNS	Nuclear	2800	3737	4996	383	518	711	9	10	11	4	4	5
CNS	Wind	7726	14607	18923	2199	4391	5889	24	38	42	22	35	39
CNS	Solar PV	1981	4524	6662	1140	2517	3711	6	12	15	11	20	24
CNS	Hydro	5159	6148	7481	1487	1783	2172	16	16	17	15	14	14
IEA-NPS	Coal	10016	10335		2143	2238		38	26		30	18	
IEA-NPS	Gas	7517	9071		2334	2740		23	22		24	22	
IEA-NPS	Nuclear	3253	3726		464	518		10	9		6	4	
IEA-NPS	Wind	3157	4690		1250	1707		4	12		7	14	
IEA-NPS	Solar PV	2197	3839		1589	2540		2	9		6	20	
IEA-NPS	Hydro	5330	6179		1604	1839		16	15		18	15	
IEA-SDS	Coal	4878	1982		1633	1119			5			8	
IEA-SDS	Gas	6830	5358		2103	2406			14			16	
IEA-SDS	Nuclear	3888	4960		542	678			13			5	
IEA-SDS	Wind	4355	7730		1712	2819			21			19	
IEA-SDS	Solar PV	3268	6409		2346	4240			17			29	
IEA-SDS	Hydro	5722	6900		1738	2096			19			14	

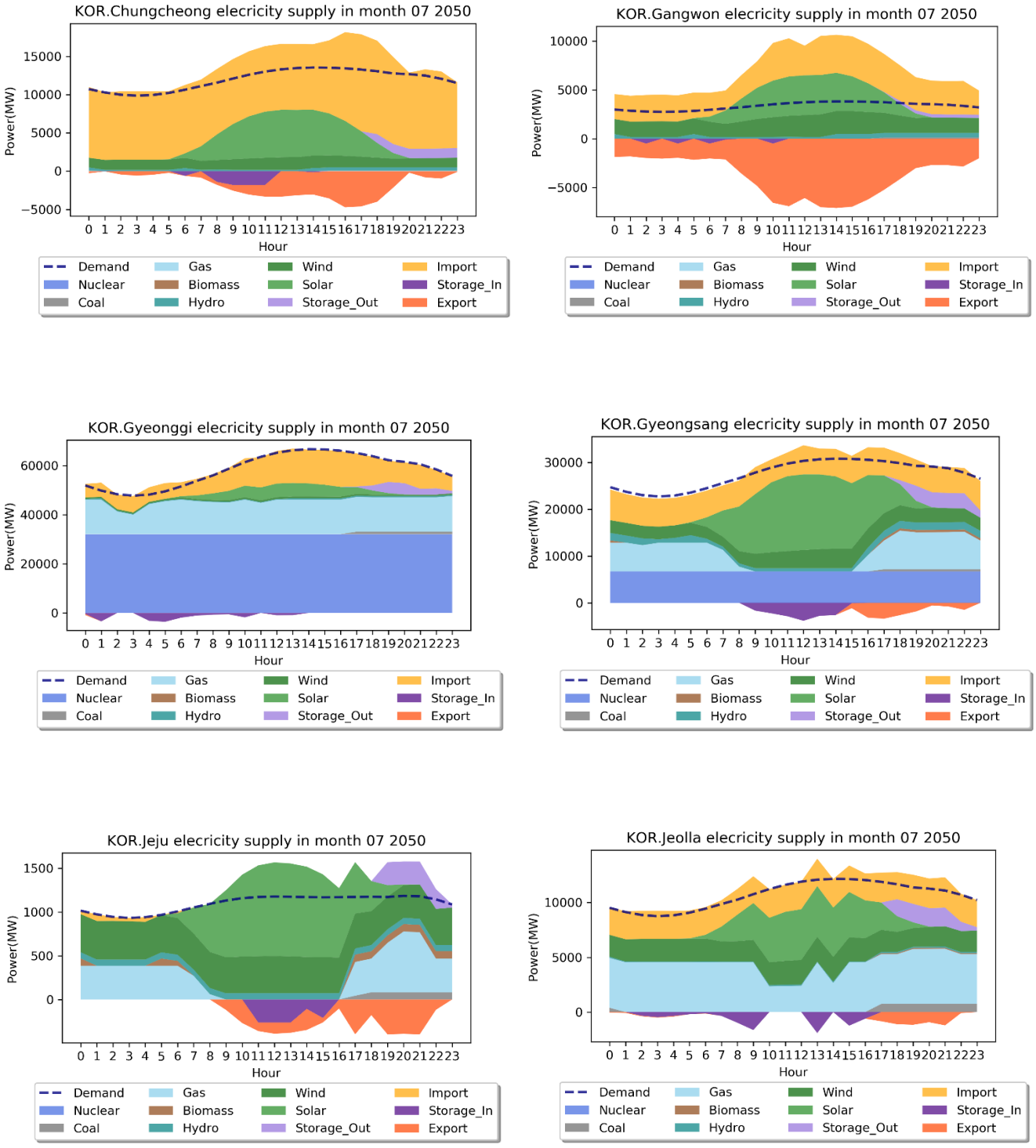


Figure 36. The electricity supply and flow of the zones in South Korea in July of 2050 in MCP scenario.

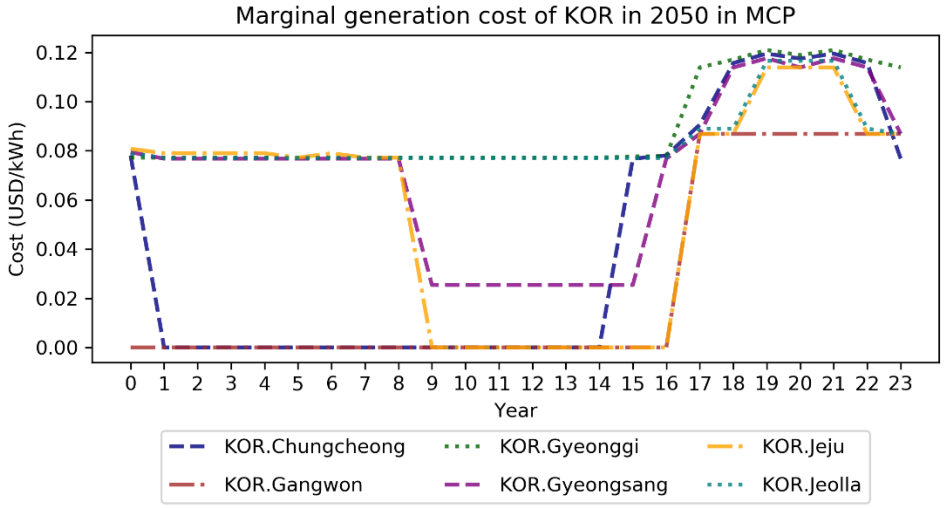


Figure 37. The zonal market price of the zones in South Korea in July of 2050 in MCP scenario.

To examine the influence of interconnection in an integrated regional market, this work runs the models with separate country instances for 10 countries in South African Power Pool (SAPP). Each country is treated as one independent market. The outputs compared with the integral SAPP market are summarized in Table 25. The electricity trading is minimum when the countries are modelled independently[38]. It is clear that integral market instance can accommodate higher penetration of renewable energy, resulting in reduced emissions. The overall cost of the integral market is only slightly less, as lower cost might be expected. This is probably because the electricity import cost in set at 0.3 USD/kWh for the independent country instance. The overall cost in independent instances can be higher if electricity import is not enabled. The independent country instances require more flexible units such as gas power plant and battery storage system. Generally the results support the assumption that an integral regional system can utilize the resources more efficiently than separate independent systems.

[38] Individual country (or market) instance can import electricity from other market with high cost to prevent infeasible solution. See equation (4.1).

Table 25. The model result of South African Power Pool in 2050 in HCS scenario.

Integ. – Integral market model instance; indep. – Independent country model instance.

		AGO		BWA		LSO		MOZ		MWI		NAM		SWZ		ZAF		ZMB		ZWE	
Model instance		Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.	Integ.	Indep.
Electricity Demand	TWh	90.76	90.76	37.66	37.66	7.47	7.47	144.92	144.92	19.32	19.32	40.75	40.75	14.51	14.51	458.79	458.79	122.79	122.79	74.09	74.09
Electricity Supply	TWh	86.21	91.54	38.01	38.36	7.49	7.70	120.21	145.01	25.16	19.92	53.18	43.58	6.42	14.51	509.39	469.16	108.68	123.24	81.09	74.99
Electricity Spilled	TWh	0.37	0.62	0.00	0.05	0.00	0.05	2.27	0.00	0.00	0.27	0.00	0.87	0.00	0.00	0.93	1.58	0.00	0.00	0.00	0.00
Electricity Import	TWh	15.03	0.02	12.20	0.00	46.24	0.00	54.89	0.21	11.90	0.01	12.72	0.01	24.62	0.00	55.36	0.00	20.02	0.00	16.32	0.54
Electricity Export	TWh	9.42	0.00	11.96	0.60	46.26	0.18	25.43	0.00	17.69	0.21	23.05	0.45	16.53	0.01	100.53	0.64	5.62	0.08	22.69	1.07
Renewable Gen.	%	86.30	85.10	98.70	91.50	92.70	92.30	77.50	51.20	128.10	96.70	128.00	101.50	44.30	78.90	86.30	84.20	81.50	87.40	103.80	95.10
CO2 Emission	M.T	-0.99	-1.69	0.10	-0.58	0.00	-0.21	-1.16	-0.74	-2.54	0.32	0.17	0.21	-0.34	0.22	2.47	4.32	-2.90	-2.18	-2.88	-1.35
Annual Cost	B.USD	5.72	7.22	2.52	2.84	0.41	0.49	8.03	11.64	1.75	1.38	2.50	2.15	0.54	1.19	33.34	30.60	7.62	9.11	5.60	5.28
Capacity - Coal	GW	0.00	0.00	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04	1.04	0.37	0.37	0.00	0.00
Capacity - Gas	GW	4.49	6.58	1.95	1.12	0.70	0.24	3.19	3.59	0.48	0.58	0.92	1.11	1.79	0.50	38.87	15.07	1.99	2.21	0.93	1.69
Capacity - Oil	GW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity - Nuclear	GW	0.26	0.93	0.10	0.35	0.10	0.10	0.69	9.13	0.00	0.10	0.10	0.40	0.00	0.45	14.98	12.76	0.98	1.91	0.70	0.27
Capacity - Biomass	GW	0.10	0.20	0.00	0.00	0.00	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.20	0.20	0.30	0.22	0.10	0.10	0.20	0.10
Capacity - BECCS	GW	1.31	1.90	0.00	0.39	0.00	0.10	0.82	0.91	0.86	0.00	0.00	0.00	0.10	0.00	0.12	0.00	1.20	0.87	1.06	0.58
Capacity - Pump Hydro	GW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.73	2.73	0.00	0.00	0.00	0.00
Capacity - Battery storage	GW	1.57	3.70	0.62	1.63	0.00	0.17	2.62	4.07	0.31	0.35	0.57	0.56	0.11	0.29	5.98	6.32	4.29	7.48	1.38	2.26
Capacity - Hydropower	GW	14.33	9.85	0.00	0.07	0.46	0.46	29.23	8.61	1.58	1.98	0.19	0.19	0.81	0.72	7.44	9.61	6.66	8.45	1.49	3.01
Capacity - Wind	GW	1.88	3.80	11.64	7.26	1.62	1.50	6.60	11.37	5.27	3.98	13.68	9.79	1.46	2.96	99.08	83.48	15.53	15.43	19.86	15.87
Capacity - PV	GW	10.41	14.30	2.47	5.77	0.00	0.00	5.41	10.79	1.77	1.32	0.00	0.96	0.00	1.46	22.36	34.42	18.10	19.54	8.98	8.90

This work differentiates the type of reserves services in an electricity system. As in several models, the reserve capacity is modelled by adding a capacity margin. This work implements primary, secondary and tertiary reserve services corresponding to difference response time in dispatch operation. The provision of the services depends on a generation unit's ramp capability. The two modelling approaches may produce different capacity mix. To investigate this issue, the models are modified to use the capacity margin and are applied a margin of 9% in both the ED and CE models.

Table 26 compares the results of the two approaches for South Korea in 2050 in MCP scenario. In this case the results are almost identical except for gas and battery storage. When modelled with reserve services, additional capacity of flexible gas power plant and battery storage system are needed. The generation from gas power plants is also higher in order to operate at spinning state, and this causes higher emission and costs. Although the difference is not significant, it does change the generation and capacity mix in a system.

Table 26. The results of South Korea in 2050 in MCP scenario modelled with reserve services and capacity margin.

RS – reserve services; CM – capacity margin.

	Demand	Supply	Spilled	Import	Export	Renewable Gen.	Emission	Carbon Sequest.	Ann. Var. Cost	Ann. Fixed Cost	
	TWh	TWh	TWh	TWh	TWh	%	M.Tonnes	M.Tonnes	B.USD	B.USD	
RS	966.2	969.2	1.7	3.9	0.0	51.6	51.6	0.0	20.9	100.7	
CM	966.2	956.7	1.4	16.3	0.0	51.7	46.2	0.0	19.9	100.3	
Capacity (GW)	Coal	Gas	Nuclear	Biomass	PHS	Battery Storage	Hydropower	Wind	Offshore Wind	PV	Other Renewables
RS	2.8	39.1	45.9	0.8	0.0	17.1	3.7	62.3	104.5	76.1	1.2
CM	2.8	32.3	45.9	0.7	0.0	13.4	3.7	62.3	104.5	76.1	1.2
Generation (TWh)	Coal	Gas	Nuclear	Biomass			Hydropower	Wind	Offshore Wind	PV	Other Renewables
RS	4.9	130.6	336.3	1.9			11.9	99.4	263.0	113.6	8.4
CM	4.0	118.4	336.1	2.8			11.8	99.4	263.0	113.6	8.4

4.3.3 Summary

This work aims to investigate possible development of electricity sector at global scale using the materials produced in the previous works. This work integrates dispatchable generation technologies as well as flexibility measures, such as storage and interconnection. A framework with optimization

models is developed to estimate capacity and generation mix of all types of generation technologies. In the core of the framework, an electricity dispatch (ED) model and a capacity expansion (CE) model are developed. The model instances are created based on pre-defined regional integral markets which consist of several countries. The ED model performs 24 hours intraday dispatch for each calendar month. The CE model performs 5-year step iterations from base year 2015 to 2050. Another 12 time-slices are selected dynamically to test system reliability in the CE model. There are 1,070 representative zones in this work. In each terrestrial zone, the available options for expansion can range from 30 to 90. Four scenarios are proposed to investigate possible future development. They are reference scenario (REF), high carbon price scenario (HCS), optimal CRE mix scenario (MCP) and carbon neutral scenario (CNS). In HCS, higher carbon cost is applied. The MCP is building on the optimal CRE capacity mix in every country proposed previously. In CNS, constraints are applied to ensure net zero emissions in 2050 for electricity sector.

The resulting generation and capacity mix in the scenarios do not differ notably. The generation from renewables reaches between 70% and 75% in 2050, and wind power becomes the most important energy source. For dispatchable technologies, higher share of low emission nuclear and CCS presents in HCS and CNS scenarios. Compared with REF scenario, conventional fossil fuel plants are replaced by nuclear and CCS in HCS due to higher carbon cost. BECCS becomes cost competitive from 2040 and drives the global emissions down to negative. In MCP, the capacity mix is based on the optimal capacity mix of CRE in every country. Although the share of renewable generation is almost the same as HCS and CNS, this scenario demonstrates higher level of self-sufficiency and better efficiency in utilizing dispatchable sources. This result reflects on the objectives of MCP, i.e. finding an efficient balance among total cost, zonal residual load variation and CRE portfolio output variation. In CNS scenario, the result is similar to REF scenario before 2035, but changes significantly thereafter driven by the emissions target. More renewables, nuclear and CCS are installed in the last periods.

All the scenarios demonstrate different degree of decarbonization. In REF scenario, the global carbon dioxide emissions from electricity sector can reduce to 4,000 $MtCO_2$ per year in 2050. The emissions in MCP scenario is only 9% less than REF scenario, while CNS scenario is set to reach zero in 2050. The emissions in HCS scenario can be negative in 2050 making it the most aggressive reduction pathway. Its emissions peaks at 2040 and the cumulative emissions is around 160 Gt. Keeping the emissions at this level may increase the possibility to reach 1.5°C or 2°C global warming target. However, further study is needed to investigate the interaction with other sectors. In sum, the

results suggest that higher carbon cost could be the most effective way to curb the emissions in electricity sector. The penetration of renewable can reach at least 70% thanks to the declining cost and the improving system flexibility. Further emissions reduction can be achieved through more nuclear and CCS installation.

Examples are presented to show the dispatch operation and energy flow in the zones. The system integration at wider international market level has shown to utilize the resources more efficiently than independent country. To the author's knowledge, this study used the most detailed spatial granularity at global scale when compared with other studies and models. This could capture the space-time variability of renewable output in the systems.

The main contributions of this work are: First, it is one of the few studies that proposes possible electricity sector decarbonization development at global scale. The results can be useful reference for stakeholders related with electricity sector transition in the world. Second, this work used relatively high temporal and spatial granularity in the models, which is intended to capture the variability of VREs. Third, flexibility measures, including storage, interconnection and reserve services, are considered in the models. This is particularly important for systems with large share of VRE. In addition, this work tests system reliability with 12 extreme energy supply and demand cases for each iteration in planning phase. This also aims to capture the flexibility requirements in a system when the share of VRE is high.

The main limits of this work are: First, the models are formulated in linear programming problems. They cannot perfectly capture certain technical constraints over generator's operation. Second, the capacity planning performs with a period of 5-years foresight. This may not produce solutions of optimal investment in the long run. Third, this study does not take into account heat supply and demand. There exists a flexibility in adjusting electricity and heat generation in CHP or adjusting demand in end-use sectors. Lately, the projection of electricity demand is fixed and demand management measures are not modelled. This, again, can underestimate the flexibility in a system.

5. Key results and contributions

The goal of this research is to assess future decarbonization scenarios of the electricity sector in the world, with a particular focus on renewable energy integration. This has been achieved through a series of interconnected works. The first work is to assess the global technical and capacity potential for wind and solar power technologies with consistent approaches. The second part is to develop a novel approach to find the optimal climate-related energy mix in every country. The final part is to assess possible pathways for future electricity sector decarbonization drawing on all the materials produced from the first and second works.

5.1 Key results

In the assessment of global wind and solar energy potential, the latest datasets at the time of writing are used, and a wide range of constraints are considered. Information from OpenStreetMap (OSM) is used to support the geospatial assessment. MERRA-2 datasets are used for temporal capacity factor (CF) estimation, while energy resource maps from GWA and GSA are used to improve the spatial resolution in the assessment. The resulting data are hourly CF profiles for each technology in multiple output tranches, and the results cover 731 terrestrial zones and 339 offshore zones in 171 countries/districts in the world.

In this work, the accuracy of the land cover map is improved with information from the OSM. Although only a fraction of global land cover has been updated, the influence on the following assessment is important especially for the expanded urban area. Analyses on comparing the eligibility masks produced with existing wind turbine and solar power sites locations demonstrate high accuracy of the suitable development area identified. While the eligible area for onshore wind development accounts for 32.7% of global terrestrial area, 83.7% of existing wind turbines are located inside the eligible area identified in this study. The accuracy is even higher when comparing existing solar PV sites and the eligible area proposed. The analyses has thereby proven that OSM provides more reliable geographic information and that the accuracy of satellite-based land cover map can be an issue. Validation of the estimated CF has also been carried out by comparing with historical records in European countries. The result shows very high correlation in most countries.

In general, the capacity and energy potentials reported in this work are relatively conservative compared with other studies, stemming from stricter and arguably more realistic social impact

restrictions, permafrost areas, road access and minimum CF requirements. It has been acknowledged that the parameters used have decisive influence on the estimated potential. The global energy potentials of onshore and offshore wind are around 211,000 and 216,000TWh/y; fixed-tilt and one-axis tracking utility-scale PV are 836,000 and 981,000TWh/y; and the CSP is 587,000 TWh/y. The potentials are significantly higher than the global power demand and also can satisfy the total primary energy demand. Each CF tranche class of a technology in a zone demonstrates a unique temporal output pattern. Higher CF class may not guarantee more production at all time. Therefore, it is crucial to consider the characteristics of space-time variability of VREs in an electricity system model.

Before the development of a full scale electricity sector model, mathematical models are formulated to investigate the optimal climate-related energy (CRE, i.e. wind, solar and water) mix in the power system of every country. This work particularly looks into the output complementarity of all available CRE options in a country. The models are developed with the objectives of minimizing cost, residual load variation and portfolio output variation. Each model is applied with constraints on capacity limit, system balance, transmission, hydropower dispatch, energy curtailment and CRE target. A compromise programming model that incorporates all the three objectives is developed. This research regards the solution from this multi-objectives model as the proposed optimal renewable mix in a country. All the models run with aggregated CF and demand profile of 288 time-slices for 1,070 representative zones in 171 countries/districts. The modelling scenario is set to investigate the optimal CRE mix in 2040 with the generation targets at 30%, 50% and 70% in the countries. In addition, this work further estimates the required data of monthly hydropower output and power demand profile in the zones.

The CF covariance matrices of all available CRE options in a country are produced. Each element in the matrices represents the covariance of a pair of options, and the matrices are calculated at two temporal frequencies. By observing the resulting matrices, it is confirmed that output complementarity exits for wind and solar technologies at sub-country level at hourly and daily time frequencies. Wind power demonstrates persistent variability patterns at all the time scale, while the variability of solar power can be severe at hourly level but relatively stable at daily scale.

The results suggest that the proposed mix can be good reference for policy makers since it can effectively find the optimal balance among the three objective values. For instance, 10% more investment on the CRE deployment in the EU countries can significantly reduce residual load variation and portfolio output variation by a wide range. When the CRE target is low, a relatively higher share

of solar and hydropower can be found in the solutions. However, wind power becomes crucial in higher CRE share systems while solar energy is bounded at around 50% of capacity share. Any higher solar energy penetration can cause serious energy spill during daytime hours and increase the residual load variation. Moreover, the results show that higher CRE penetration, up to 70%, may be attainable in most countries.

This research explores possible development for global electricity systems with respect to several scenarios, and pays particular attention to the increasing share of renewables in modern power systems. A framework with optimization models is developed to estimate the mix of capacity and generation in regional markets throughout the time horizon. In the core of this framework, an electricity dispatch (ED) model and a capacity expansion (CE) model are developed. The constraints in the models include power balance, transmission, hydropower operation, storage operation, reserve requirements, capacity addition and VRE targets. A regional market can consist of several zones and countries. Four scenarios are proposed to investigate possible future development. They are reference scenario (REF), high carbon price scenario (HCS), optimal CRE mix scenario (MCP) and carbon neutral scenario (CNS).

The results show that even in base reference scenario the global emission from electricity sector can be reduced significantly. In these scenarios, the generation from renewables reaches between 70% and 75% in 2050 and wind power makes up the largest share. The increasing share of low emission nuclear and CCS only appear in the high carbon cost scenario and the carbon neutral scenario. The high carbon cost scenario demonstrates the most promising emissions reduction pathway. With BECCS becoming cost competitive in the last periods of the analysis, emissions from the electricity sector become negative. This is the only scenario that shows an emission peak in the time horizon. On the other hand, the results also prove that the proposed optimal CRE mix can reduce reliance on dispatchable thermal units and storage systems with a moderate compromise on total cost. This is expected since the optimal mix incorporates objectives of minimum residual load variation and portfolio output variation. In the carbon neutral scenario, the pathway is similar to the reference scenario before 2035, but changes significantly thereafter, driven by the emissions constraint. More renewables, nuclear and CCS are installed in the final periods, causing a severe increase in costs.

The effectiveness of interconnection is promoted in this work. Examples are shown to demonstrate how the energy dispatch and flow works efficiently between the zones in a market. A

scenario without international transmission is also performed as a counterexample to show how an integrated market can utilize resources more efficiently than separate independent systems. Moreover, this work differentiates the required reserve services in an electricity system instead of using a simple capacity margin in capturing system reliability. The results show that when modelled with the common three tiers of reserves, more flexible gas power plants and storage systems are needed.

5.2 Main contributions

The main contributions of this research are summarized as below:

- This research generates data of VREs potentials at subnational level with hourly CF estimation, categorized into CF tranche classes. The data is available for 1,070 terrestrial and offshore zones. The data can be essential inputs for regional or global ESMs that are striving to improve modelling resolution.
- This research proves that the information from OSM can be used to improve the quality of renewable energy assessment. To the author's knowledge, there is no other study that has made this effort at global scale prior to this research.
- This research supports the claim in several studies that the global wind and solar energy potentials are significantly higher than the power demand, and also are enough to serve the total primary energy demand.
- This research calculates the energy output covariance matrices of all available CRE options in every country. The matrices reveal the overall output complementary of each pair of the options. This is also the first attempt that has been made, to the author's knowledge, in this field to generate the covariance matrices for every country.
- A novel multi-objective model is proposed to estimate the optimal CRE mix in a country. This mathematical model is developed with the objectives of minimizing cost, residual load variation and portfolio output variation. The results suggest that the proposed optimal mix can effectively minimize the objectives simultaneously.
- The proposed optimal CRE mix can be useful reference for stakeholders of electricity system development as the optimal mix has been proven to reduce reliance on dispatchable thermal units and storage systems with a moderate compromise on total cost.

- This is one of the few researches that estimates possible electricity sector development at global scale. The results can be a useful reference for any stakeholders involved in energy transition. The key message is: the outlook of electricity sector decarbonization is promising even in a “business as usual” scenario. In addition to renewables, this research highlights the role of nuclear and CCS technologies in the scenarios of aggressive decarbonization.
- The electricity sector modelling is carried out with relatively higher spatial granularity in an effort to capture local VRE output characteristics. Measures for improving system flexibility, including storage operation, interconnection and reserve services, are considered in the models. This inclusion is crucial for systems with large share of VRE.

5.3 Potential contributions to international climate policy debate

The spatial granularity of existing global IAMs are ESMs tend to be at regional or country level. This may not well capture the renewable output characteristics at sub-country or local level. With a focus on renewable integration, this research assesses several decarbonisation scenarios with relatively high spatial granularity, while main measures for improving system flexibility are integrated in the models including hydropower dispatch, storage operation, interconnection and reserve services. Therefore, the results may be particularly useful for policy makers or stakeholders in a country, especially for those less studied in the literatures. The scenarios tell when and where a specific renewable technology need to be deployed to reach the decarbonization target. All data and codes are released to the public. The model can be tailored to regions or countries with different spatial representation, not limited to the 1,070 representative zones.

The correlation and covariance tables of power output from variable renewable energies in a country can be valuable information. The data reveals the overall complementarity of all available renewable options at different time frequency. The result suggest that the best portfolio does not always consist with top output tranches of each technology. A technology can be instable at hourly frequency but regarded as stable at daily frequency. These characteristics are important in developing a reliable electricity system. Also, the correlation and covariance tables of the portfolio output is calculated against zonal demand profile. This also provides crucial information in developing the optimal portfolio in the long run.

In the decarbonization scenario analysis, one key message is that carbon price is an effective tool in reducing the emissions. This research does not answer whether the 1.5°C or 2°C target is achievable

since this research only covers electricity supply and demand, yet this research provides another set of decarbonization pathways. To reach the 1.5°C target, other studies suggest more drastic decline of the emissions in electricity sector between 2020 and 2030. This implies that the required carbon price has to be much higher than the HCS in this study, and given that regional power generation resource can be integrated.

Overall, this research has brought together novel GIS-based approaches for assessment of renewables potentials, combined this with energy mix optimization that promotes easier integration of renewables, and then assessed sub-country level transition pathways to low carbon electricity systems. The combination of these research efforts underlines the increasing importance of renewables in modern power systems, their importance as a cornerstone of broader system decarbonization, and the fact that they are now part of the baseline mix of technologies expected in the future, which is a marked difference over how they were perceived as an expensive and problematic technology only a few decades ago.

5.4 Future works and research direction

This research covers several topics in this field of study. Models are developed to support this research and several methods have been used to prepare the necessary data. There are possible improvements and future research directions.

- Improving the accuracy of land cover information can have a decisive influence on the renewable potential assessment. This can be done by updating the latest information from the OSM or change the land cover map if more accurate one exists.
- The zonal electricity demand profile is based on the approach described in Section 3.2. The profile and the future projection can be replaced whenever more credible data exists. Note that this research requires sub-country demand profile. Historical hourly data of a country from platform such as ENTSO-E has to be split into zonal basis accordingly.
- A complete and free global existing power plant database can be helpful in improving the quality of this research. The database has to specify the location of the power plants so that the existing plants can be allocated to the corresponding zones.
- It is possible to upgrade the models with higher spatial granularity since hourly generation and demand profiles have already been produced. For small market region, it can be done with minor changes on the scripts given that most of the model configurations are set in external

files. However, for large market region, the computational resource is still the major concern when increasing temporal resolution.

- This research has performed four scenarios to investigate future decarbonization pathways. There are several other factors can influence future energy transition, such as the cost assumptions of specific technology or fuel price projection. For example, new scenarios can be based on different cost assumptions. A more aggressive scenario of 100% renewable electricity supply can also be implemented. The solutions can be important reference to the global climate change research groups.
- The exclusion of heat supply and demand is a weakness of this research. For example, CHP plants offers good flexibility in adjusting heat and power generation. To integrate heat generation and consumption, the models need substantial alternations.
- The flaw of optimization based model is that it assumes perfect conditions throughout the time horizon. In reality, new political instruments, new market rules, imperfect market competition, unbalanced information, investor's strategy and so on can all contribute to imperfect and changing investment decisions. To capture the interaction of different roles in a market or system, an agent-based modelling structure offers this possibility. In doing so, the economic dispatch model would only need minor modifications, but the capacity expansion model would require fundamental changes to capture investment behavior of the agents.
- Although the source code of the electricity sector model is released to the public, it may be difficult to use directly since a few of the configurations are hard-coded. A future work would be converting the mode into Python package which can be used more easily without modifying the code. All settings and data can be imported from plain files.

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Appendix A: Supplementary files

All the datasets mentioned in this thesis can be obtained from the following link under a Creative Commons Attribution license.

https://doi.org/10.5281/zenodo.3457084

Data Package 1: The main output datasets

File 1: Definition of the zones in this study

File 2: Statistics on land cover pixels updated from OSM

File 3: Validation of the eligibility masks with existing sites

File 4: Validation of the estimated CF profile for EU countries

File 5: Summary of the available area, technical potential and capacity potential in this study

File 6: Aggregation of the estimated 10-year hourly CF into 288 month-hour profile

File 7: The projection of electricity demand profile for each zone in 288 month-hour profile

File 8: The overall aggregated output covariance matrices for each country

Data Package 2: The estimated 10-year hourly capacity factor of all available technologies and capacity factor tranches in every zone in the world

Data Package 3: The solutions of optimal climate-related energy mix with different objectives in global electricity systems

Data Package 4: The modelling results of electricity sector decarbonization pathways by country/district

Data Package 5: Python scripts of the electricity sector decarbonization modelling framework

Appendix B: Spatial representation of country/district and zones.

Table B.1. List of country/district in this research.

(Market group: **ASEAN** - Association of Southeast Asian Nations; **CAM** – Central America; **CAPP** - Central African Power Pool; **CAPS** - Central Asia Power System; **COMELEC** - North African Power Pool; **EAPP** - East African Power Pool; **MENA** - Middle East and North Africa; **NA** – North America; **SAARC** - South Asian Association for Regional Cooperation; **SAM** – South America; **SAPP** - South African Power Pool; **WAPP** - West African Power Pool;)

Country/District	Code	Market group*	Techno-economic Cost Group	Carbon price group SDS
Afghanistan	AFG	CAPS	Middle East	SDS_NonOECD
Albania	ALB	Europe	Europe	SDS_NonOECD
Algeria	DZA	COMELEC	Africa	SDS_NonOECD
Angola	AGO	SAPP	Africa	SDS_NonOECD
Argentina	ARG	SAM	Brazil	SDS_NonOECD
Armenia	ARM	Eurasia	Russia	SDS_NonOECD
Australia	AUS	AUS	Europe	SDS_OECD
Austria	AUT	Europe	Europe	SDS_OECD
Azerbaijan	AZE	Eurasia	Russia	SDS_NonOECD
Bahrain	BHR	MENA	Middle East	SDS_NonOECD
Bangladesh	BGD	SAARC	India	SDS_NonOECD
Belarus	BLR	Eurasia	Russia	SDS_NonOECD
Belgium	BEL	Europe	Europe	SDS_OECD
Belize	BLZ	CAM	Brazil	SDS_NonOECD
Benin	BEN	WAPP	Africa	SDS_NonOECD
Bhutan	BTN	SAARC	India	SDS_NonOECD
Bolivia	BOL	SAM	Brazil	SDS_NonOECD
Bosnia and Herz.	BIH	Europe	Russia	SDS_NonOECD
Botswana	BWA	SAPP	Africa	SDS_NonOECD
Brazil	BRA	SAM	Brazil	SDS_NonOECD
Brunei	BRN	ASEAN	India	SDS_NonOECD
Bulgaria	BGR	Europe	Russia	SDS_NonOECD
Burkina Faso	BFA	WAPP	Africa	SDS_NonOECD
Burundi	BDI	EAPP	Africa	SDS_NonOECD
Côte d'Ivoire	CIV	WAPP	Africa	SDS_NonOECD
Cambodia	KHM	ASEAN	India	SDS_NonOECD
Cameroon	CMR	CAPP	Africa	SDS_NonOECD
Canada	CAN	NA	United States	SDS_OECD
Cayenne	GUF	SAM	Brazil	SDS_NonOECD
Central African Rep.	CAF	CAPP	Africa	SDS_NonOECD
Chad	TCD	CAPP	Africa	SDS_NonOECD
Chile	CHL	SAM	Brazil	SDS_OECD
China	CHN	CHN	China	SDS_NonOECD
Colombia	COL	SAM	Brazil	SDS_NonOECD
Congo	COG	CAPP	Africa	SDS_NonOECD
Costa Rica	CRI	CAM	Brazil	SDS_NonOECD
Croatia	HRV	Europe	Europe	SDS_NonOECD
Cuba	CUB	CUB	Brazil	SDS_NonOECD
Cyprus	CYP	Europe	Europe	SDS_NonOECD
Czechia	CZE	Europe	Europe	SDS_OECD
Dem. Rep. Congo	COD	CAPP	Africa	SDS_NonOECD
Denmark	DNK	Europe	Europe	SDS_OECD
Djibouti	DJI	EAPP	Africa	SDS_NonOECD
Dominican Rep.	DOM	DOM	Brazil	SDS_NonOECD
Ecuador	ECU	SAM	Brazil	SDS_NonOECD
Egypt	EGY	MENA	Middle East	SDS_NonOECD
El Salvador	SLV	CAM	Brazil	SDS_NonOECD
Eq. Guinea	GNQ	CAPP	Africa	SDS_NonOECD
Eritrea	ERI	EAPP	Africa	SDS_NonOECD
Estonia	EST	Europe	Russia	SDS_OECD
Ethiopia	ETH	EAPP	Africa	SDS_NonOECD
Fiji	FJI	FJI	United States	SDS_NonOECD
Finland	FIN	Europe	Europe	SDS_OECD
France	FRA	Europe	Europe	SDS_OECD
Gabon	GAB	CAPP	Africa	SDS_NonOECD
Gambia	GMB	WAPP	Africa	SDS_NonOECD
Georgia	GEO	Eurasia	Russia	SDS_NonOECD
Germany	DEU	Europe	Europe	SDS_OECD
Ghana	GHA	WAPP	Africa	SDS_NonOECD
Greece	GRC	Europe	Europe	SDS_OECD
Guatemala	GTM	CAM	Brazil	SDS_NonOECD
Guinea	GIN	WAPP	Africa	SDS_NonOECD
Guinea-Bissau	GNB	WAPP	Africa	SDS_NonOECD
Guyana	GUY	SAM	Brazil	SDS_NonOECD
Haiti	HTI	HTI	Brazil	SDS_NonOECD
Honduras	HND	CAM	Brazil	SDS_NonOECD
Hungary	HUN	Europe	Europe	SDS_OECD
Iceland	ISL	ISL	Europe	SDS_OECD
India	IND	SAARC	India	SDS_NonOECD
Indonesia	IDN	ASEAN	India	SDS_NonOECD
Iran	IRN	MENA	Middle East	SDS_NonOECD
Iraq	IRQ	MENA	Middle East	SDS_NonOECD
Ireland	IRL	Europe	Europe	SDS_OECD
Israel	ISR	MENA	Middle East	SDS_OECD
Italy	ITA	Europe	Europe	SDS_OECD
Jamaica	JAM	JAM	Brazil	SDS_NonOECD
Japan	JPN	JPN	Japan	SDS_OECD
Jordan	JOR	MENA	Middle East	SDS_NonOECD
Kazakhstan	KAZ	CAPS	Russia	SDS_NonOECD

Country/District	Code	Market group*	Techno-economic Cost Group	Carbon price group SDS
Kenya	KEN	EAPP	Africa	SDS_NonOECD
Kosovo	XKX	Europe	Russia	SDS_NonOECD
Kuwait	KWT	MENA	Middle East	SDS_NonOECD
Kyrgyzstan	KGZ	CAPS	Russia	SDS_NonOECD
Laos	LAO	ASEAN	India	SDS_NonOECD
Latvia	LVA	Europe	Russia	SDS_OECD
Lebanon	LBN	MENA	Middle East	SDS_NonOECD
Lesotho	LSO	SAPP	Africa	SDS_NonOECD
Liberia	LBR	WAPP	Africa	SDS_NonOECD
Libya	LBY	COMELEC	Africa	SDS_NonOECD
Lithuania	LTU	Europe	Russia	SDS_OECD
Luxembourg	LUX	Europe	Europe	SDS_OECD
Macedonia	MKD	Europe	Russia	SDS_NonOECD
Madagascar	MDG	MDG	Africa	SDS_NonOECD
Malawi	MWI	SAPP	Africa	SDS_NonOECD
Malaysia	MYS	ASEAN	India	SDS_NonOECD
Mali	MLI	WAPP	Africa	SDS_NonOECD
Malta	MLT	Europe	Europe	SDS_NonOECD
Mauritania	MRT	COMELEC	Africa	SDS_NonOECD
Mauritius	MUS	MUS	Africa	SDS_NonOECD
Mexico	MEX	NA	United States	SDS_OECD
Moldova	MDA	Europe	Russia	SDS_NonOECD
Mongolia	MNG	MNG	Russia	SDS_NonOECD
Montenegro	MNE	Europe	Russia	SDS_NonOECD
Morocco	MAR	COMELEC	Africa	SDS_NonOECD
Mozambique	MOZ	SAPP	Africa	SDS_NonOECD
Myanmar	MMR	ASEAN	India	SDS_NonOECD
Namibia	NAM	SAPP	Africa	SDS_NonOECD
Nepal	NPL	SAARC	India	SDS_NonOECD
Netherlands	NLD	Europe	Europe	SDS_OECD
New Zealand	NZL	NZL	Europe	SDS_OECD
Nicaragua	NIC	CAM	Brazil	SDS_NonOECD
Niger	NER	WAPP	Africa	SDS_NonOECD
Nigeria	NGA	WAPP	Africa	SDS_NonOECD
North Korea	PRK	PRK	India	SDS_NonOECD
Norway	NOR	Europe	Europe	SDS_OECD
Oman	OMN	MENA	Middle East	SDS_NonOECD
Pakistan	PAK	SAARC	India	SDS_NonOECD
Palestine	PSE	MENA	Middle East	SDS_NonOECD
Panama	PAN	CAM	Brazil	SDS_NonOECD
Papua New Guinea	PNG	PNG	India	SDS_NonOECD
Paraguay	PRY	SAM	Brazil	SDS_NonOECD
Peru	PER	SAM	Brazil	SDS_NonOECD
Philippines	PHL	ASEAN	India	SDS_NonOECD
Poland	POL	Europe	Europe	SDS_OECD
Portugal	PRT	Europe	Europe	SDS_OECD
Puerto Rico	PRI	CAM	United States	SDS_NonOECD
Qatar	QAT	MENA	Middle East	SDS_NonOECD
Romania	ROU	Europe	Russia	SDS_NonOECD
Russia	RUS	Eurasia	Russia	SDS_NonOECD
Rwanda	RWA	EAPP	Africa	SDS_NonOECD
S. Sudan	SSD	EAPP	Africa	SDS_NonOECD
Saudi Arabia	SAU	MENA	Middle East	SDS_NonOECD
Senegal	SEN	WAPP	Africa	SDS_NonOECD
Serbia	SRB	Europe	Russia	SDS_NonOECD
Sierra Leone	SLE	WAPP	Africa	SDS_NonOECD
Singapore	SGP	ASEAN	Japan	SDS_NonOECD
Slovakia	SVK	Europe	Europe	SDS_OECD
Slovenia	SVN	Europe	Europe	SDS_OECD
Somalia	SOM	EAPP	Africa	SDS_NonOECD
South Africa	ZAF	SAPP	Africa	SDS_NonOECD
South Korea	KOR	KOR	Japan	SDS_OECD
Spain	ESP	Europe	Europe	SDS_OECD
Sri Lanka	LKA	SAARC	India	SDS_NonOECD
Sudan	SDN	EAPP	Africa	SDS_NonOECD
Suriname	SUR	SAM	Africa	SDS_NonOECD
Swaziland	SWZ	SAPP	Africa	SDS_NonOECD
Sweden	SWE	Europe	Europe	SDS_OECD
Switzerland	CHE	Europe	Europe	SDS_OECD
Syria	SYR	MENA	Africa	SDS_NonOECD
Taiwan	TWN	TWN	China	SDS_NonOECD
Tajikistan	TJK	CAPS	Russia	SDS_NonOECD
Tanzania	TZA	EAPP	Africa	SDS_NonOECD
Thailand	THA	ASEAN	India	SDS_NonOECD
Timor-Leste	TLS	TLS	India	SDS_NonOECD
Togo	TGO	WAPP	Africa	SDS_NonOECD
Trinidad and Tobago	TTO	TTO	Brazil	SDS_NonOECD
Tunisia	TUN	COMELEC	Africa	SDS_NonOECD
Turkey	TUR	MENA	Middle East	SDS_OECD
Turkmenistan	TKM	CAPS	Russia	SDS_NonOECD
Uganda	UGA	EAPP	Africa	SDS_NonOECD
Ukraine	UKR	Eurasia	Russia	SDS_NonOECD
United Arab Emirates	ARE	MENA	Middle East	SDS_NonOECD
United Kingdom	GBR	Europe	Europe	SDS_OECD
United States of America	USA	NA	United States	SDS_OECD
Uruguay	URY	SAM	Brazil	SDS_NonOECD
Uzbekistan	UZB	CAPS	Russia	SDS_NonOECD
Venezuela	VEN	SAM	Brazil	SDS_NonOECD
Vietnam	VNM	ASEAN	India	SDS_NonOECD
Yemen	YEM	MENA	Middle East	SDS_NonOECD
Zambia	ZMB	SAPP	Africa	SDS_NonOECD
Zimbabwe	ZWE	SAPP	Africa	SDS_NonOECD

Appendix C: Summary of renewable potentials

Table C.1. Aggregated renewable capacity potential and average CF in the countries/districts.

The table below is aggregated capacity potential in the countries/districts. Low energy production tranche in each technology is excluded. (ONW – onshore wind; OFW – offshore wind; PV-FT – fixed tilt PV; PV-TK – one-axis tracking PV; PV-DT – distributed PV)

Technology	ONW	ONW	OFW	OFW	PV-FT	PV-FT	PV-TK	PV-TK	PV-DT	PV-DT	CSP-6h	CSP-6h	CSP-9h	CSP-9h	Hydro
Country/ District	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential
	GW	%	GW	%	GW	%	GW	%	GW	%	GW	%	GW	%	GW
	CF>0.18	CF>0.18	CF>0.18	CF>0.18	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.25	CF>0.25	CF>0.25	CF>0.25	
AFG	379.6	0.355	0.0	0.000	4561.0	0.205	4561.0	0.249	9.7	0.184	1628.1	0.308	1302.5	0.385	87.0
AGO	40.1	0.199	36.3	0.411	3395.9	0.203	3395.9	0.225	7.9	0.190	1392.7	0.357	1114.2	0.447	97.9
ALB	18.6	0.263	30.9	0.218	33.6	0.161	33.6	0.193	2.5	0.155	0.0	0.000	0.0	0.000	6.1
ARE	217.6	0.224	83.4	0.201	1310.3	0.210	1310.3	0.243	13.1	0.200	959.4	0.318	767.5	0.398	0.0
ARG	4568.6	0.307	3869.3	0.460	18045.9	0.194	18045.9	0.236	42.3	0.175	9122.3	0.325	7298.8	0.404	121.4
ARM	10.0	0.232	0.0	0.000	89.9	0.168	89.9	0.201	4.2	0.158	0.0	0.000	0.0	0.000	1.7
AUS	8602.8	0.263	7244.2	0.300	51446.3	0.205	51446.3	0.244	56.6	0.166	35735.5	0.396	28588.4	0.492	15.9
AUT	43.1	0.266	0.0	0.000	70.2	0.128	70.2	0.152	14.0	0.120	0.0	0.000	0.0	0.000	14.9
AZE	27.4	0.299	191.5	0.313	336.0	0.156	336.0	0.184	20.1	0.144	0.0	0.000	0.0	0.000	3.9
BDI	0.6	0.215	0.0	0.000	73.9	0.181	73.9	0.190	0.8	0.183	0.0	0.000	0.0	0.000	1.0
BEL	17.6	0.281	5.8	0.394	21.1	0.113	21.1	0.133	19.9	0.105	0.0	0.000	0.0	0.000	0.3
BEN	5.2	0.198	1.5	0.184	451.9	0.182	451.9	0.193	6.2	0.171	0.0	0.000	0.0	0.000	1.4
BFA	66.7	0.193	0.0	0.000	944.8	0.196	944.8	0.213	6.8	0.195	0.0	0.000	0.0	0.000	0.1
BGD	0.8	0.192	70.0	0.187	150.3	0.169	150.3	0.186	8.8	0.156	0.0	0.000	0.0	0.000	14.2
BGR	64.5	0.229	59.1	0.257	120.5	0.149	120.5	0.178	18.5	0.139	0.0	0.000	0.0	0.000	5.7
BHR	0.9	0.262	36.6	0.253	7.2	0.203	7.2	0.231	0.9	0.197	2.3	0.297	1.8	0.372	0.0
BIH	30.2	0.283	0.0	0.000	113.6	0.146	113.6	0.175	3.0	0.130	0.0	0.000	0.0	0.000	12.6
BLR	256.9	0.231	0.0	0.000	176.6	0.114	176.6	0.136	41.8	0.106	0.0	0.000	0.0	0.000	0.9
BLZ	0.0	0.200	2.7	0.196	30.6	0.178	30.6	0.193	0.4	0.177	0.0	0.000	0.0	0.000	1.3
BOL	179.7	0.260	0.0	0.000	4749.2	0.223	4749.2	0.257	9.0	0.198	1565.1	0.481	1252.1	0.598	179.7
BRA	1560.5	0.234	2930.4	0.301	30210.3	0.186	30210.3	0.204	116.0	0.177	3930.4	0.321	3144.3	0.402	607.5
BRN	0.0	0.000	0.0	0.000	2.9	0.165	2.9	0.169	0.4	0.167	0.0	0.000	0.0	0.000	0.1
BTN	0.0	0.207	0.0	0.000	1.7	0.153	1.7	0.172	0.1	0.145	0.0	0.000	0.0	0.000	32.7
BWA	522.4	0.240	0.0	0.000	3816.1	0.215	3816.1	0.254	4.2	0.204	2908.3	0.376	2326.6	0.471	0.1
CAF	13.4	0.204	0.0	0.000	650.1	0.192	650.1	0.205	2.9	0.187	57.6	0.308	46.1	0.384	15.6
CAN	2517.3	0.279	5790.7	0.404	3279.1	0.139	3284.0	0.168	47.7	0.130	0.0	0.000	146.6	0.290	532.8
CHE	8.8	0.261	0.0	0.000	45.8	0.132	45.8	0.156	9.2	0.124	0.0	0.000	0.0	0.000	17.1
CHL	263.8	0.392	1212.5	0.485	4732.3	0.238	4732.3	0.286	13.5	0.191	1642.4	0.485	1313.9	0.603	79.5
CHN	5869.2	0.290	3666.6	0.310	34931.8	0.170	35049.2	0.204	494.2	0.137	2673.3	0.270	4207.6	0.319	1474.7
CIV	1.4	0.209	0.0	0.000	676.4	0.177	676.4	0.187	10.7	0.165	0.0	0.000	0.0	0.000	9.6
CMR	28.6	0.223	0.0	0.000	525.0	0.188	525.0	0.200	16.7	0.183	0.0	0.000	0.0	0.000	71.4
COD	13.1	0.224	0.0	0.000	1809.6	0.174	1809.6	0.182	23.0	0.176	9.8	0.305	7.8	0.381	360.4
COG	0.1	0.205	0.0	0.000	485.5	0.160	485.5	0.163	1.4	0.162	0.0	0.000	0.0	0.000	87.5
COL	43.5	0.328	90.5	0.453	2291.6	0.176	2291.6	0.183	11.5	0.176	63.5	0.334	50.8	0.416	313.9
CRI	18.1	0.364	31.9	0.348	68.3	0.172	68.3	0.181	2.0	0.176	0.0	0.318	0.0	0.397	21.6
CUB	54.4	0.214	174.8	0.217	238.5	0.192	238.5	0.213	8.2	0.187	22.5	0.299	18.0	0.374	0.1
CYP	1.3	0.204	10.7	0.199	56.9	0.193	56.9	0.232	1.7	0.185	10.2	0.315	8.1	0.394	0.1
CZE	56.8	0.230	0.0	0.000	74.0	0.119	74.0	0.141	20.6	0.112	0.0	0.000	0.0	0.000	1.2
DEU	344.2	0.272	142.3	0.445	425.5	0.115	425.5	0.136	121.1	0.108	0.0	0.000	0.0	0.000	15.9
DJI	51.1	0.374	21.6	0.356	362.3	0.204	362.3	0.225	0.2	0.198	118.0	0.324	94.4	0.404	4.0
DNK	88.5	0.336	410.8	0.443	71.3	0.106	71.3	0.130	5.0	0.102	0.0	0.000	0.0	0.000	0.0
DOM	12.7	0.254	25.5	0.283	98.6	0.193	98.6	0.213	5.3	0.189	9.6	0.333	7.7	0.416	0.6
DZA	3209.9	0.328	51.0	0.253	18094.7	0.209	18094.7	0.248	12.6	0.176	13509.0	0.328	10807.2	0.410	1.8
ECU	6.6	0.292	0.1	0.182	394.9	0.147	394.9	0.150	6.8	0.160	0.0	0.326	0.0	0.406	50.6
EGY	1413.0	0.318	158.9	0.299	9034.4	0.221	9034.4	0.263	15.8	0.199	6761.8	0.361	5409.4	0.451	44.4
ERI	146.8	0.315	289.6	0.276	1009.0	0.206	1009.0	0.229	2.1	0.206	245.6	0.320	196.5	0.397	0.8
ESP	504.6	0.241	299.6	0.278	1505.5	0.176	1505.5	0.214	40.1	0.161	129.6	0.287	103.7	0.358	18.7
EST	64.3	0.241	151.8	0.384	65.6	0.107	65.6	0.132	0.3	0.102	0.0	0.000	0.0	0.000	0.4
ETH	338.4	0.264	0.0	0.000	5388.3	0.201	5388.3	0.222	41.8	0.199	1614.7	0.335	1291.7	0.419	128.0
FIN	203.4	0.233	361.6	0.371	0.2	0.109	0.2	0.133	0.0	0.102	0.0	0.000	0.0	0.000	5.4
FJI	4.6	0.244	75.2	0.227	24.2	0.159	24.2	0.175	0.4	0.148	0.0	0.000	0.0	0.000	1.3
FRA	706.4	0.273	603.3	0.368	1142.6	0.134	1142.6	0.159	114.6	0.124	1.4	0.254	1.6	0.315	26.1
GAB	0.0	0.191	0.0	0.000	117.9	0.154	117.9	0.155	1.2	0.158	0.0	0.000	0.0	0.000	30.0
GBR	306.1	0.360	2342.4	0.455	323.9	0.106	846.9	0.115	24.1	0.103	0.0	0.000	0.0	0.000	3.6
GEO	29.2	0.277	2.9	0.202	96.0	0.150	96.0	0.177	6.8	0.140	0.0	0.000	0.0	0.000	14.8
GHA	13.5	0.212	4.6	0.186	631.5	0.179	631.5	0.190	19.0	0.167	0.0	0.000	0.0	0.000	3.8
GIN	8.7	0.213	0.0	0.000	628.8	0.190	628.8	0.203	7.9	0.185	0.0	0.000	0.0	0.000	15.6
GMB	0.1	0.184	1.0	0.185	23.0	0.193	23.0	0.209	1.9	0.191	0.0	0.000	0.0	0.000	0.1
GNB	0.1	0.186	6.1	0.198	55.3	0.189	55.3	0.203	0.6	0.188	0.0	0.000	0.0	0.000	0.5
GNQ	0.0	0.000	0.0	0.000	14.1	0.158	14.1	0.161	0.4	0.159	0.0	0.000	0.0	0.000	3.7
GRC	91.5	0.289	432.9	0.322	311.0	0.171	311.0	0.204	13.6	0.160	1.4	0.281	1.1	0.351	5.5
GTM	11.6	0.273	0.7	0.199	195.3	0.188	195.3	0.204	4.0	0.190	2.4	0.340	1.9	0.424	44.1
GUF	0.0	0.000	152.4	0.262	3.1	0.176	3.1	0.184	0.5	0.180	0.0	0.000	0.0	0.000	2.7
GUY	16.7	0.217	157.4	0.277	166.3	0.182	166.3	0.189	1.0	0.184	0.0	0.000	0.0	0.000	21.3
HND	18.7	0.294	209.3	0.268	221.5	0.181	221.5	0.195	2.3	0.184	0.2	0.343	0.2	0.429	11.8
HRV	41.0	0.275	195.1	0.234	106.9	0.149	106.9	0.179	7.4	0.133	0.0	0.000	0.0	0.000	7.7
HTI	9.3	0.261	5.7	0.235	127.0	0.198	127.0	0.218	3.0	0.197	23.0	0.338	18.4	0.422	1.0
HUN	126.2	0.212	0.0	0.000	83.9	0.136	83.9	0.162	22.5	0.126	0.0	0.000	0.0	0.000	1.3

Technology	ONW	ONW	OFW	OFW	PV-FT	PV-FT	PV-TK	PV-TK	PV-DT	PV-DT	CSP-6h	CSP-6h	CSP-9h	CSP-9h	Hydro
Country/ District	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential
	GW	%	GW	%	GW	%	GW	%	GW	%	GW	%	GW	%	GW
	CF>0.18	CF>0.18	CF>0.18	CF>0.18	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.25	CF>0.25	CF>0.25	CF>0.25	
IDN	16.3	0.228	1781.0	0.270	3411.5	0.160	3411.5	0.164	69.2	0.167	12.3	0.331	9.9	0.414	364.9
IND	725.8	0.224	1357.5	0.229	5437.4	0.184	5437.4	0.209	143.2	0.173	51.7	0.299	41.3	0.374	748.2
IRL	134.2	0.420	882.3	0.477	118.4	0.103	669.4	0.112	0.1	0.101	0.0	0.000	0.0	0.000	0.7
IRN	2848.3	0.283	408.2	0.222	21152.9	0.207	21152.9	0.249	42.5	0.185	9437.6	0.303	7550.1	0.379	77.2
IRQ	951.7	0.312	5.2	0.296	5120.1	0.198	5120.1	0.235	18.4	0.181	3170.4	0.299	2536.4	0.374	27.5
ISL	189.4	0.381	922.4	0.453	0.0	0.000	0.0	0.000	0.0	0.000	0.0	0.000	0.0	0.000	14.2
ISR	17.6	0.227	0.0	0.000	186.5	0.214	186.5	0.256	6.5	0.192	92.9	0.373	74.3	0.466	0.2
ITA	200.1	0.239	315.1	0.235	277.5	0.163	277.5	0.196	60.4	0.147	0.6	0.273	0.4	0.341	30.4
JAM	2.4	0.246	70.8	0.285	15.0	0.187	15.0	0.204	1.9	0.187	0.7	0.310	0.5	0.388	0.7
JOR	166.0	0.259	0.0	0.000	1142.9	0.220	1142.9	0.267	3.1	0.202	822.3	0.389	657.8	0.486	0.2
JPN	154.2	0.244	1467.8	0.300	189.7	0.135	189.7	0.155	91.8	0.138	0.0	0.000	0.0	0.000	38.1
KAZ	3484.8	0.317	515.6	0.355	14993.1	0.151	14993.1	0.183	38.3	0.138	0.0	0.000	0.2	0.294	24.4
KEN	268.6	0.322	75.6	0.296	3527.0	0.194	3527.0	0.204	17.2	0.188	658.8	0.336	527.1	0.420	16.8
KGZ	6.8	0.241	0.0	0.000	535.8	0.170	535.8	0.204	13.5	0.154	8.0	0.254	17.7	0.310	27.1
KHM	6.7	0.241	2.8	0.219	257.4	0.174	257.4	0.185	2.8	0.176	0.0	0.000	0.0	0.000	18.1
KOR	28.7	0.243	1047.0	0.295	65.7	0.151	65.7	0.175	13.5	0.142	0.0	0.000	0.0	0.000	3.7
KWT	48.6	0.359	54.0	0.297	290.2	0.200	290.2	0.232	5.6	0.192	236.6	0.302	189.3	0.377	0.0
LAO	89.5	0.254	0.0	0.000	688.2	0.163	688.2	0.177	2.1	0.163	0.0	0.000	0.0	0.000	66.9
LBN	6.7	0.235	2.7	0.201	38.1	0.197	38.1	0.239	2.4	0.183	1.6	0.355	1.3	0.443	2.0
LBR	0.0	0.197	0.0	0.000	154.2	0.165	154.2	0.171	2.2	0.163	0.0	0.000	0.0	0.000	14.7
LBY	1665.4	0.339	545.4	0.278	9616.7	0.212	9616.7	0.253	10.7	0.196	7661.5	0.339	6129.2	0.423	0.0
LKA	33.5	0.246	135.6	0.291	129.6	0.177	129.6	0.185	4.8	0.179	0.0	0.000	0.0	0.000	3.5
LSO	12.7	0.258	0.0	0.000	60.2	0.208	60.2	0.253	5.6	0.199	0.4	0.360	0.3	0.450	1.9
LTU	77.4	0.266	28.0	0.394	99.7	0.110	99.7	0.132	6.3	0.102	0.0	0.000	0.0	0.000	0.5
LUX	1.1	0.224	0.0	0.000	2.7	0.116	2.7	0.136	0.9	0.109	0.0	0.000	0.0	0.000	0.0
LVA	90.9	0.246	109.1	0.391	133.3	0.108	133.3	0.131	1.6	0.102	0.0	0.000	0.0	0.000	1.0
MAR	1263.2	0.370	612.1	0.425	8180.2	0.210	8180.2	0.251	12.1	0.188	4878.6	0.339	3902.9	0.424	2.2
MDA	78.4	0.235	0.0	0.000	6.5	0.138	6.5	0.164	9.9	0.127	0.0	0.000	0.0	0.000	0.4
MDG	357.8	0.292	256.8	0.360	2004.1	0.202	2004.1	0.229	3.8	0.194	22.0	0.377	17.6	0.471	102.9
MEX	362.6	0.245	1428.7	0.254	9804.9	0.212	9804.9	0.249	73.9	0.200	4730.7	0.381	3784.6	0.475	110.0
MKD	9.1	0.231	0.0	0.000	48.6	0.156	48.6	0.187	2.1	0.146	0.0	0.000	0.0	0.000	1.1
MLI	618.4	0.282	0.0	0.000	4996.6	0.204	4996.6	0.227	9.0	0.196	1304.7	0.316	1043.8	0.395	7.3
MLT	0.1	0.216	108.9	0.246	0.1	0.186	0.1	0.222	0.3	0.177	0.0	0.000	0.0	0.000	0.0
MMR	17.5	0.236	35.5	0.192	1314.0	0.171	1314.0	0.191	15.3	0.169	0.0	0.000	0.0	0.000	264.8
MNE	10.1	0.284	19.1	0.231	40.4	0.150	40.4	0.180	0.7	0.144	0.0	0.000	0.0	0.000	6.1
MNG	1229.0	0.317	0.0	0.000	8706.6	0.184	8706.6	0.230	7.3	0.158	3334.7	0.270	4669.2	0.321	7.4
MOZ	42.4	0.212	376.6	0.224	2081.1	0.189	2081.1	0.213	10.1	0.182	201.0	0.300	160.8	0.375	100.6
MRT	555.3	0.366	154.4	0.433	3548.8	0.204	3548.8	0.231	3.4	0.198	1108.2	0.331	886.6	0.414	0.2
MUS	2.1	0.259	13.8	0.329	1.3	0.169	1.3	0.192	0.9	0.178	0.0	0.000	0.0	0.000	0.0
MWI	24.9	0.231	0.0	0.000	76.0	0.195	76.0	0.216	4.1	0.191	1.0	0.308	0.8	0.385	7.9
MYS	0.2	0.213	15.0	0.189	639.5	0.161	639.5	0.163	16.2	0.161	0.0	0.000	0.0	0.000	57.6
NAM	1235.5	0.246	812.3	0.423	9059.1	0.227	9059.1	0.269	3.7	0.215	6112.6	0.425	4890.1	0.531	9.2
NER	723.0	0.266	0.0	0.000	4172.7	0.208	4172.7	0.233	3.7	0.201	1203.8	0.332	963.1	0.415	3.2
NGA	545.3	0.220	0.1	0.183	2569.4	0.184	2569.4	0.196	41.5	0.175	0.0	0.000	0.0	0.000	61.8
NIC	79.8	0.307	340.1	0.276	302.0	0.173	302.0	0.186	2.6	0.183	2.0	0.324	1.6	0.405	6.4
NLD	42.2	0.295	158.5	0.440	112.9	0.109	112.9	0.130	17.0	0.104	0.0	0.000	0.0	0.000	0.3
NOR	260.0	0.364	1319.9	0.425	51.4	0.104	82.8	0.123	0.4	0.101	0.0	0.000	0.0	0.000	43.5
NPL	0.1	0.197	0.0	0.000	29.4	0.169	29.4	0.194	6.6	0.161	0.0	0.000	0.0	0.000	163.0
NZL	306.1	0.318	1386.1	0.380	1551.3	0.140	1551.3	0.168	11.2	0.135	11.1	0.261	12.6	0.322	26.9
OMN	639.8	0.290	223.9	0.359	4837.2	0.218	4837.2	0.252	6.9	0.205	3546.0	0.348	2836.8	0.435	0.0
PAK	625.7	0.282	278.7	0.237	5716.5	0.205	5716.5	0.243	23.7	0.173	1738.4	0.320	1390.7	0.399	163.7
PAN	24.9	0.265	77.0	0.222	116.6	0.173	116.6	0.180	2.1	0.171	0.0	0.000	0.0	0.000	11.8
PER	45.9	0.249	335.3	0.268	3877.5	0.214	3877.5	0.238	12.6	0.188	642.8	0.391	514.3	0.490	233.5
PHL	108.5	0.269	735.0	0.258	637.3	0.165	637.3	0.172	13.8	0.168	0.0	0.000	0.0	0.000	38.0
PNG	8.3	0.251	393.5	0.281	182.0	0.165	182.0	0.170	2.1	0.164	0.0	0.000	0.0	0.000	240.6
POL	410.0	0.262	127.1	0.393	346.7	0.116	346.7	0.137	49.4	0.108	0.0	0.000	0.0	0.000	3.9
PRI	0.5	0.218	26.1	0.244	4.6	0.193	4.6	0.212	4.8	0.184	0.5	0.330	0.4	0.412	0.4
PRK	93.5	0.259	181.5	0.266	36.2	0.151	36.2	0.178	7.1	0.140	0.0	0.000	0.0	0.000	8.5
PRT	74.2	0.217	104.6	0.289	297.1	0.173	297.1	0.210	12.7	0.159	4.4	0.285	3.5	0.357	5.9
PRY	158.7	0.210	0.0	0.000	1648.6	0.177	1648.6	0.201	7.0	0.174	89.9	0.287	71.9	0.359	16.5
PSE	1.9	0.206	0.0	0.000	41.6	0.203	41.6	0.243	2.6	0.195	4.1	0.339	3.3	0.423	0.0
QAT	38.1	0.287	154.2	0.218	225.9	0.206	225.9	0.238	2.9	0.197	168.9	0.308	135.1	0.385	0.0
ROU	150.5	0.228	114.6	0.286	259.4	0.137	259.4	0.163	58.1	0.130	0.0	0.000	0.0	0.000	8.4
RUS	6560.3	0.271	7080.6	0.345	7999.4	0.129	8001.1	0.155	230.6	0.116	0.0	0.000	108.8	0.281	594.4
RWA	0.2	0.206	0.0	0.000	21.4	0.175	21.4	0.181	1.5	0.175	0.0	0.000	0.0	0.000	1.0
SAU	4161.1	0.282	329.3	0.237	26428.7	0.217	26428.7	0.255	28.0	0.206	18428.9	0.348	14743.1	0.435	0.0
SDN	1057.4	0.312	73.8	0.264	6654.6	0.212	6654.6	0.241	19.2	0.207	3887.9	0.325	3110.3	0.406	57.0
SEN	85.7	0.196	59.3	0.236	1036.7	0.195	1036.7	0.213	6.7	0.193	0.0	0.000	0.0	0.000	0.4
SGP	0.0	0.000	0.0	0.000	0.1	0.151	0.1	0.152	1.3	0.152	0.0	0.000	0.0	0.000	0.0
SLE	0.2	0.218	0.0	0.000	181.0	0.173	181.0	0.182	2.4	0.171	0.0	0.000	0.0	0.000	12.3
SLV	6.4	0.242	1.6	0.203	17.4	0.206	17.4	0.225	1.5	0.200	0.2	0.357	0.2	0.446	3.2
SOM	487.2	0.307	374.8	0.423	4209.9	0.203	4209.9	0.222	3.7	0.205	1615.8	0.358	1292.7	0.448	1.5
SRB	83.7	0.220	0.0	0.000	127.3	0.141	127.3	0.167	8.8	0.131	0.0	0.000	0.0	0.000	4.6
SSD	3.6	0.234	0.0	0.000	2708.1	0.187	2708.1	0.201	6.5	0.189	38.9	0.310	31.1	0.387	15.6
SUR	0.0	0.000	229.8	0.304	13.9	0.182	13.9	0.190	0.8	0.181	0.0	0.000	0.0	0.000	10.5
SVK	29.9	0.230	0.0	0.000	30.8	0.126	30.8	0.151	10.5	0.119	0.0	0.000	0.0	0.000	2.4
SVN	5.3	0.242	0.6	0.215	21.1	0.136	21.1	0.162	2.4	0.126	0.0	0.000	0.0	0.000	3.4
SWE	249.3	0.249	636.5	0.376	101.4	0.107	101.8	0.130	3.1	0.103	0.0	0.000	0.0	0.000	20.2
SWZ	12.2	0.217	0.0	0.000	59.3	0.178	59.3	0.208	0.3	0.169	0.7	0.284	0.6	0.355	1.9
SYR	482.8	0.287	4.3	0.232	2762.6	0.202	2762.6	0.245	17.7	0.187	2067.9	0.331	1654.3	0.414	5.5
TCD	234.3	0.265	0.0	0.000	2106.9	0.204	2106.9	0.226	7.1	0.201	406.0	0.318	324.8	0.397	4.7
TGO	1.5	0.206	0.7	0.183	156.8	0.178	156.8	0.188	4.7	0.175	0.0	0.000	0.0	0.000	0.4

Technology	ONW	ONW	OFW	OFW	PV-FT	PV-FT	PV-TK	PV-TK	PV-DT	PV-DT	CSP-6h	CSP-6h	CSP-9h	CSP-9h	Hydro
Country/ District	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential	Avg CF	Potential
	GW	%	GW	%	GW	%	GW	%	GW	%	GW	%	GW	%	GW
	CF>0.18	CF>0.18	CF>0.18	CF>0.18	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.10	CF>0.25	CF>0.25	CF>0.25	CF>0.25	
THA	86.3	0.226	16.2	0.188	712.6	0.169	712.6	0.180	24.8	0.171	0.0	0.000	0.0	0.000	12.8
TJK	13.6	0.279	0.0	0.000	252.0	0.173	252.0	0.206	6.2	0.162	1.5	0.299	1.2	0.373	38.3
TKM	409.2	0.311	194.4	0.284	2802.0	0.178	2802.0	0.212	6.3	0.168	6.9	0.266	5.5	0.332	22.1
TLS	6.4	0.252	0.0	0.185	43.2	0.183	43.2	0.196	0.4	0.189	0.0	0.313	0.0	0.391	1.2
TTO	0.3	0.252	112.6	0.295	3.4	0.184	3.4	0.196	0.9	0.182	0.0	0.000	0.0	0.000	0.0
TUN	468.5	0.318	382.6	0.283	1968.1	0.200	1968.1	0.240	7.0	0.177	1402.7	0.310	1122.2	0.388	0.5
TUR	575.6	0.250	196.2	0.285	2500.2	0.177	2500.2	0.214	52.3	0.159	98.7	0.294	79.5	0.367	88.7
TWN	3.5	0.274	281.2	0.362	12.7	0.152	12.7	0.166	8.0	0.150	0.0	0.000	0.0	0.000	15.4
TZA	235.4	0.266	4.3	0.189	2148.5	0.193	2148.5	0.204	23.0	0.192	277.0	0.337	221.6	0.422	26.3
UGA	2.7	0.217	0.0	0.000	495.5	0.193	495.5	0.202	12.2	0.188	93.5	0.325	74.8	0.406	5.0
UKR	1201.3	0.261	363.6	0.310	265.4	0.128	265.4	0.152	129.7	0.121	0.0	0.000	0.0	0.000	4.8
URY	308.2	0.211	375.9	0.350	1595.4	0.176	1595.4	0.209	4.8	0.167	817.3	0.287	653.8	0.358	2.4
USA	9246.9	0.293	6109.3	0.352	40001.3	0.183	40007.2	0.221	612.3	0.161	14332.3	0.323	12126.8	0.398	362.3
UZB	405.8	0.317	0.0	0.000	2692.9	0.177	2692.9	0.214	35.3	0.161	89.3	0.260	71.4	0.325	9.6
VEN	237.5	0.273	495.3	0.365	2785.7	0.186	2785.7	0.199	13.5	0.187	131.6	0.335	105.2	0.417	116.2
VNM	128.5	0.272	1618.0	0.284	689.8	0.149	689.8	0.157	14.7	0.151	0.0	0.000	0.0	0.000	40.8
XKX	5.1	0.249	0.0	0.000	12.6	0.149	12.6	0.177	1.2	0.140	0.0	0.000	0.0	0.000	0.6
YEM	684.7	0.284	226.4	0.292	5555.9	0.223	5555.9	0.255	5.1	0.211	2713.0	0.374	2170.4	0.467	0.0
ZAF	1862.9	0.252	1104.1	0.389	13240.5	0.209	13240.5	0.253	36.3	0.187	7396.8	0.391	5917.5	0.488	19.2
ZMB	113.8	0.220	0.0	0.000	1520.9	0.207	1520.9	0.232	8.1	0.202	391.0	0.327	312.8	0.409	104.5
ZWE	176.4	0.218	0.0	0.000	1625.3	0.205	1625.3	0.238	4.8	0.200	760.0	0.341	608.0	0.427	20.3

Appendix D: Summary of optimal CRE mix by country/district

Table D.1. Aggregated output results of model CP in 70% CRE target.

(**RLV** – zonal average of standard deviation of residual load variation; **POV** – zonal average of standard deviation of portfolio output variation)

Country/ District	Zones	Annual Demand	CRE Supply	Spilled Energy	Annual Cost	RLV.	POV.	Total Capacity	Onshore Wind	Offshore Wind	PV	CSP	Hydropower
	Terrestrial + offshore	GWh	GWh	GWh	M.USD /year	MW	MW	MW	MW	MW	MW	MW	MW
AFG	5+0	12059	8646	131	407	49	160	2626	894	0	790	0	943
AGO	4+2	47856	34393	572	2252	279	356	13017	2682	839	4763	91	4642
ALB	1+1	8725	6187	78	302	142	235	2001	969	0	531	0	501
ARE	2+2	233475	166228	1623	15367	2805	9236	69995	56340	554	2031	11071	0
ARG	8+3	241691	172643	891	7878	206	2258	50341	14716	0	11643	0	23982
ARM	1+0	10007	7004	0	399	192	130	2539	592	0	1026	0	921
AUS	7+6	330222	239546	4855	13851	736	3653	80287	35240	3065	28225	0	13757
AUT	3+0	68054	47961	0	2312	321	653	13314	2881	0	2642	0	7791
AZE	3+1	32820	23097	0	1295	140	488	7545	2137	0	2486	0	2922
BDI	1+0	1727	1219	10	66	58	13	434	72	0	104	0	258
BEL	2+1	91444	64660	297	4434	857	4059	31608	16552	2174	12579	0	304
BEN	1+1	6278	4572	177	310	150	99	1929	576	37	675	0	641
BFA	2+0	7505	6108	787	458	135	220	3075	1666	0	1311	0	98
BGD	7+1	123543	90554	3571	5323	718	1472	48272	10905	0	23167	0	14200
BGR	3+2	41909	29413	0	1958	229	766	11217	3848	0	3448	0	3921
BHR	1+1	58463	42128	798	5523	1620	3162	17143	977	13058	1263	1845	0
BIH	1+0	15794	11060	0	548	312	245	3224	832	0	261	0	2131
BLR	6+0	54556	38274	1	3109	113	2334	17778	12619	0	4266	0	893
BLZ	1+1	770	580	40	43	16	8	242	7	51	78	0	106
BOL	5+0	14681	10433	44	429	56	253	3128	1181	0	824	0	1124
BRA	15+9	852260	603685	861	29856	1014	3686	204966	32522	0	62544	0	109901
BRN	1+1	8625	6699	604	2418	262	536	6711	0	4950	1626	0	135
BTN	1+0	6613	6020	1389	293	296	60	2568	46	0	1249	0	1273
BWA	2+0	19857	14096	129	988	176	440	4980	2892	0	1193	750	145
CAF	2+0	920	670	23	37	11	7	231	35	0	72	0	124
CAN	7+4	608036	446595	14909	23914	1631	6086	120200	54519	132	8273	0	57276
CHE	1+0	65174	48100	2430	2338	1345	350	11510	1691	0	0	0	9819
CHL	5+4	124604	91925	3948	4646	399	615	27683	4636	0	6049	440	16558
CHN	36+9	9475425	7035245	278335	330628	19089	146014	2651685	1685817	32811	494628	0	438429
CIV	3+2	34169	25141	989	1366	280	192	9192	1258	0	3318	0	4616
CMR	4+1	32862	24555	1163	1256	158	192	8080	1329	0	2524	0	4227
COD	9+1	41282	30203	801	1324	71	63	7465	487	0	277	0	6701
COG	2+1	4523	3422	180	182	35	15	1152	219	0	257	0	675
COL	7+2	96663	68702	193	2664	174	400	16393	1914	0	1048	0	13430
CRI	1+2	17575	12734	432	513	272	308	3655	1123	0	848	29	1655
CUB	3+4	29685	21034	40	1971	231	1362	8710	4032	3464	791	346	77
CYP	1+1	6053	4275	38	459	126	331	2266	1819	19	107	272	50
CZE	2+0	60960	42880	83	2782	522	2271	20537	11678	0	7619	0	1240
DEU	12+2	576014	409644	2810	26112	908	16543	186348	77204	10119	83152	0	15873
DJI	1+1	2142	1559	61	78	39	31	507	147	0	119	0	242
DNK	2+3	34355	24790	632	1415	164	1424	8700	4487	1404	2806	0	3
DOM	3+1	28553	20188	67	1475	173	862	7141	3624	881	1040	993	603
DZA	5+1	105418	75497	835	3618	297	1835	22518	12688	0	8038	0	1792
ECU	5+2	42631	31471	1328	1592	141	113	11049	1849	5	2692	0	6504
EGY	7+4	324127	233615	2837	12065	727	5281	74121	36786	0	30123	3309	3903
ERI	1+1	1886	1349	29	61	22	31	395	170	0	100	0	125
ESP	8+4	259667	186919	2834	11263	696	3736	71061	20359	2150	29598	270	18683
EST	1+1	7668	5422	52	368	68	286	2178	1196	0	626	0	356
ETH	6+0	47237	33883	325	1674	205	388	10640	3628	0	2860	0	4152
FIN	5+3	87808	62704	185	4146	194	2837	21694	16035	0	250	0	5409
FJI	1+1	1294	938	32	52	12	31	325	110	0	95	0	120
FRA	12+7	475519	340574	2346	19380	691	8803	133324	53197	0	54045	0	26082
GAB	1+1	10522	7893	522	821	247	96	4846	1429	603	1657	0	1157
GBR	12+8	338907	241026	1022	12599	541	10368	96138	46936	1776	43828	0	3598
GEO	1+1	18453	13152	236	576	453	190	3327	796	0	26	0	2504
GHA	2+1	49129	35006	467	2396	474	608	15920	5392	0	6773	0	3755
GIN	2+1	5284	3805	75	241	58	101	1570	612	0	476	0	482
GMB	1+1	1267	935	43	136	28	40	591	167	240	125	0	59
GNB	1+1	182	129	1	13	4	6	82	56	0	14	0	13
GNQ	1+2	2244	1653	82	65	28	2	407	5	0	46	0	356
GRC	6+3	56833	40486	489	2161	196	1007	13960	4433	165	5541	0	3820
GTM	3+1	17124	12245	203	572	152	251	4196	962	0	1355	0	1879
GUF	1+1	1678	1252	76	70	53	12	493	0	28	224	0	241
GUY	1+1	1491	1092	48	52	29	13	371	67	0	95	0	208
HND	4+1	14568	10825	542	557	73	137	3677	577	47	1082	92	1879
HRV	2+1	22701	16067	1	822	155	320	5538	1112	0	2152	0	2273
HTI	1+1	755	552	24	24	8	13	161	48	0	35	5	73
HUN	3+0	40503	28596	134	1948	245	1528	14208	7763	0	5121	0	1324
IDN	12+7	515965	391175	26449	25046	1222	4313	166350	37971	9932	50977	917	66553

Country/ District	Zones	Annual Demand	CRE Supply	Spilled Energy	Annual Cost	RLV.	POV.	Total Capacity	Onshore Wind	Offshore Wind	PV	CSP	Hydropo wer
	Terrestrial + offshore	GWh	GWh	GWh	M.USD /year	MW	MW	MW	MW	MW	MW	MW	MW
IND	23+7	3609531	2696893	125952	165596	4004	36072	1352187	546360	9173	468602	0	328053
IRL	2+2	28055	19745	49	886	154	865	6452	3138	0	2636	0	677
IRN	7+3	443675	323081	8233	16322	1025	3738	104644	32501	0	38721	0	33423
IRQ	5+1	74798	53532	786	2980	314	1255	20178	8394	0	8027	0	3757
ISL	1+1	19550	13904	213	568	111	389	3047	1530	0	0	0	1518
ISR	3+1	114289	84642	4085	12011	1154	4355	48922	23276	12785	9153	3536	173
ITA	9+10	321720	232566	5447	13197	593	3713	82284	18503	0	33561	0	30219
JAM	1+1	5590	3992	79	254	91	98	1358	395	0	310	125	529
JOR	3+0	33898	24197	257	1264	272	897	8506	4916	0	3393	0	196
JPN	9+14	982525	703786	5461	70318	2874	21504	307242	62445	77609	129103	0	38085
KAZ	9+1	127039	91714	2051	5262	207	1308	29088	11186	0	6356	0	11547
KEN	6+1	45032	33143	1324	1423	114	316	8946	1637	0	1439	0	5870
KGZ	3+0	19721	14467	525	789	152	146	4777	857	0	927	0	2994
KHM	4+1	12677	8994	70	424	95	170	3605	818	0	1384	0	1403
KOR	6+6	774004	573431	24197	83897	5161	38192	291432	77934	130631	79177	0	3690
KWT	1+1	91006	64846	1222	4726	1346	3817	21197	15978	0	1229	3989	0
LAO	3+0	10782	7582	12	270	35	211	2153	1039	0	427	0	687
LBN	1+1	34899	24774	306	2823	967	1409	10610	5609	2017	0	1886	1097
LBR	1+1	222	170	15	12	8	2	81	14	0	33	0	33
LBY	3+1	20557	14698	195	661	94	322	4194	2431	0	1763	0	0
LKA	5+1	29862	20995	20	1016	94	263	7533	1155	0	2852	0	3526
LSO	1+0	4335	3034	0	145	90	117	891	492	0	68	0	331
LTU	1+1	13822	9847	161	727	89	554	4011	2505	80	929	0	497
LUX	1+0	6962	0	0	0	0	0	0	0	0	0	0	0
LVA	1+1	9559	6727	33	436	97	226	2497	1037	0	447	0	1013
MAR	5+5	62931	44843	237	2055	166	1086	12515	7523	0	3911	0	1081
MDA	1+0	6733	4715	0	350	77	239	1883	1112	0	359	0	412
MDG	3+3	7966	5843	203	252	37	75	1599	367	0	400	0	832
MEX	9+7	472945	338738	2980	20084	1338	4344	122928	39588	0	43080	0	40260
MKD	1+0	9806	6890	27	454	205	273	2622	1218	0	772	0	632
MLI	4+0	11494	8140	40	495	79	125	3253	875	0	1184	0	1194
MLT	1+1	3128	2234	17	381	82	196	1047	83	755	209	0	0
MMR	6+3	34077	24516	358	1140	169	336	9937	2700	0	4153	0	3084
MNE	1+1	3964	2840	65	149	72	95	933	309	0	301	0	323
MNG	4+0	10260	7217	20	359	61	182	2151	1101	0	672	0	378
MOZ	5+3	76411	55450	1111	3635	342	823	23044	8071	0	6483	0	8490
MRT	1+1	6295	4511	107	225	73	108	1342	616	0	411	81	234
MUS	1+1	15761	11372	228	1226	331	732	4318	873	2414	1031	0	0
MWI	2+0	11204	7872	0	452	104	152	2908	1146	0	694	0	1068
MYS	6+4	337157	262924	23600	37456	1721	7160	160461	9363	68962	53497	0	28640
NAM	3+2	21488	15219	2	777	103	323	4640	2113	300	1201	0	1025
NER	3+0	5540	4076	151	231	40	76	1459	453	0	485	3	519
NGA	10+1	142542	102235	1225	5883	360	1079	38396	8308	0	13772	0	16316
NIC	3+2	6331	4457	0	178	34	108	1259	412	0	262	0	585
NLD	4+2	115390	82434	1091	5578	488	4737	36268	14196	6036	15767	0	269
NOR	5+4	123957	88305	330	3599	445	2014	19097	10278	0	0	0	8819
NPL	5+0	9910	7418	431	458	79	143	3856	1396	0	1223	0	1238
NZL	2+2	61153	44718	1918	2107	367	1040	13804	3811	0	4574	0	5418
OMN	2+2	60771	43894	846	2187	449	1269	13519	8595	0	4547	374	3
PAK	7+2	226050	164524	4490	6802	843	2106	57286	14452	0	23620	0	19214
PAN	2+2	15917	11284	0	491	131	242	3505	1038	0	809	0	1658
PER	6+5	78884	58479	2446	2713	212	294	16909	3036	0	3781	0	10092
PHL	9+7	172479	123707	2100	5432	483	1440	40907	6177	0	15101	0	19630
PNG	1+1	8564	5995	0	230	116	20	1484	129	0	42	0	1313
POL	5+1	143038	101720	783	6872	511	4226	46566	19761	3060	19878	0	3867
PRI	1+1	22820	16294	172	2275	373	855	6498	510	4107	960	569	352
PRK	4+3	19760	14002	8	538	55	377	4304	1682	0	1067	0	1555
PRT	2+2	51267	36824	828	2124	430	1198	15207	6474	0	5627	0	3106
PRY	2+0	19719	13906	85	754	92	146	5046	778	0	879	0	3390
PSE	1+1	12286	8720	69	1959	329	708	6095	1929	3494	280	346	46
QAT	1+1	76464	54236	679	4499	1975	3763	18639	13479	1996	0	3164	0
ROU	7+1	63664	44796	0	2925	149	915	15663	5350	0	3143	0	7171
RUS	17+8	911290	664134	15777	44748	1096	8716	236743	103319	0	57397	0	76026
RWA	1+0	3659	2683	121	160	101	31	1005	153	0	327	0	525
SAU	6+3	615369	438553	3412	26448	1882	8258	141114	100537	733	31156	8688	0
SDN	5+1	60111	42716	154	2252	202	503	14559	3742	0	5877	0	4941
SEN	3+2	19153	13908	340	1399	170	482	5856	1247	2684	1509	0	417
SGP	1+1	120857	0	0	0	0	0	0	0	0	0	0	0
SLE	1+1	926	687	39	53	27	24	359	169	0	128	0	62
SLV	1+1	10690	7494	11	364	260	196	2766	741	0	957	0	1068
SOM	3+3	1818	1306	24	73	13	19	430	149	0	123	0	159
SRB	3+0	40055	28199	0	1894	227	643	10592	3036	0	3095	0	4462
SSD	1+0	3943	2854	95	163	85	30	1070	267	0	296	0	507
SUR	1+1	3688	2682	96	153	104	21	988	0	69	413	0	507
SVK	2+0	27273	19135	0	1188	206	704	7929	3450	0	2595	0	1884
SVN	1+1	14311	10021	0	520	174	148	3441	471	0	1305	0	1665
SWE	4+5	139726	101417	1865	5718	675	2767	28873	15467	0	2035	0	11371
SWZ	1+0	8414	5890	0	370	192	168	2463	908	0	805	0	749
SYR	4+1	27252	19212	3	974	131	495	6498	2473	0	2366	0	1659
TCD	2+0	1136	806	8	45	11	14	288	91	0	89	0	108
TGO	1+1	6880	5021	193	494	126	138	2468	943	517	563	0	445
THA	7+3	444803	315632	688	28825	1473	16242	226255	202534	0	10918	0	12803
TJK	4+0	23184	16843	393	980	170	273	5897	1577	0	1273	0	3047

Country/ District	Zones	Annual Demand	CRE Supply	Spilled Energy	Annual Cost	RLV.	POV.	Total Capacity	Onshore Wind	Offshore Wind	PV	CSP	Hydropo wer
	Terrestrial + offshore	GWh	GWh	GWh	M.USD /year	MW	MW	MW	MW	MW	MW	MW	MW
TKM	3+1	23234	16523	80	877	91	397	5466	2036	0	1956	0	1474
TLS	1+1	318	231	8	10	7	6	82	27	0	26	0	29
TTO	1+1	18089	13019	206	1545	458	601	5429	291	4026	1112	0	1
TUN	3+2	32448	23244	356	1154	169	768	7607	3965	0	3101	0	541
TUR	8+4	317821	231473	5982	11879	625	3464	74569	19401	0	23936	0	31232
TWN	4+4	360606	255328	2	23104	1784	11024	84891	4011	44792	20670	0	15418
TZA	7+2	29828	21279	247	1040	63	283	6750	1908	0	1906	0	2937
UGA	4+0	16681	12393	659	602	73	84	3924	390	0	1014	0	2520
UKR	7+2	176048	123759	7	9100	346	4999	52834	32010	0	15997	0	4827
URY	1+1	19648	14167	414	841	137	336	5532	1873	0	1299	0	2360
USA	51+21	4569802	3314719	66210	252664	2023	46547	1342608	504361	90940	529687	1231	216388
UZB	5+0	86567	61080	0	3670	382	1310	22707	7051	0	9192	0	6464
VEN	6+4	133787	98621	3473	4373	289	1244	30714	7238	0	8565	0	14910
VNM	8+5	364996	262851	4199	13211	939	3754	104009	26525	0	39857	0	37628
XKX	1+0	6838	4797	9	312	106	234	1677	963	0	303	0	411
YEM	6+2	6545	4662	33	193	22	113	1212	898	0	313	0	0
ZAF	9+4	322795	229106	255	13229	749	3745	80590	30017	148	31207	0	19218
ZMB	2+0	65054	45791	36	2764	831	773	17944	5264	0	6286	0	6395
ZWE	2+0	39067	27399	20	1604	415	734	10655	4429	0	3446	0	2780

Appendix E: Summary of the model results in four scenarios at global scale

Data Item	Unit	Scenario	2015	2020	2025	2030	2035	2040	2045	2050
Electricity Demand	TWh	REF	22185	25355	28213	31421	34648	37810	40778	43434
Electricity Demand	TWh	HCS	22185	25355	28213	31421	34648	37810	40778	43434
Electricity Demand	TWh	MCP	22185	25355	28213	31421	34648	37810	40778	43434
Electricity Demand	TWh	CNS	22185	25355	28213	31421	34648	37810	40778	43434
Electricity Supply	TWh	REF	22485	25619	28575	31942	35342	38744	41794	44583
Electricity Supply	TWh	HCS	22485	25621	28561	31955	35492	38860	41923	44635
Electricity Supply	TWh	MCP	22485	25619	28573	31913	35308	38622	41757	44633
Electricity Supply	TWh	CNS	22485	25619	28575	31941	35363	38711	41667	44667
Electricity Spilled	TWh	REF	109	83	90	100	147	230	204	247
Electricity Spilled	TWh	HCS	109	85	102	116	200	201	196	211
Electricity Spilled	TWh	MCP	109	83	97	103	161	201	245	331
Electricity Spilled	TWh	CNS	109	83	90	104	157	183	244	292
Electricity Import	TWh	REF	1018	1126	1942	3087	3649	4333	4981	5591
Electricity Import	TWh	HCS	1018	1122	1357	2241	3166	4173	5018	5763
Electricity Import	TWh	MCP	1018	1126	1750	2656	3030	3532	4213	5013
Electricity Import	TWh	CNS	1018	1126	1942	2992	3375	4100	5231	5689
Electricity Export	TWh	REF	1099	1171	2011	3190	3776	4487	5155	5780
Electricity Export	TWh	HCS	1099	1168	1412	2324	3289	4344	5221	5989
Electricity Export	TWh	MCP	1099	1171	1816	2749	3139	3663	4369	5189
Electricity Export	TWh	CNS	1099	1171	2011	3091	3494	4239	5124	5822
Carbon Emission	M.Ton	REF	9767	10254	9547	7167	6268	4961	4724	4006
Carbon Emission	M.Ton	HCS	9767	10141	8519	5092	3109	564	-435	-1580
Carbon Emission	M.Ton	MCP	9767	10254	9013	6406	5181	4113	3940	3451
Carbon Emission	M.Ton	CNS	9767	10254	9531	6923	5436	3929	2394	160
Carbon Sequestration	M.Ton	REF	0	0	0	0	0	0	0	0
Carbon Sequestration	M.Ton	HCS	0	0	0	0	254	922	1664	2520
Carbon Sequestration	M.Ton	MCP	0	0	0	0	0	0	0	0
Carbon Sequestration	M.Ton	CNS	0	0	0	0	11	84	185	1216
Annual Variable Cost	B.USD	REF	590	816	896	817	790	724	773	751
Annual Variable Cost	B.USD	HCS	590	829	1049	880	728	522	534	514
Annual Variable Cost	B.USD	MCP	590	816	854	733	661	596	638	637
Annual Variable Cost	B.USD	CNS	590	816	896	799	711	621	592	581
Annual Fixed Cost	B.USD	REF	1142	1049	1146	1245	1421	1590	1708	1893
Annual Fixed Cost	B.USD	HCS	1142	1052	1215	1458	1765	1992	2123	2246
Annual Fixed Cost	B.USD	MCP	1142	1049	1254	1449	1721	1963	2078	2201
Annual Fixed Cost	B.USD	CNS	1142	1049	1147	1269	1520	1749	1998	2250
Fuel Consumption Coal	PJ	REF	76139	75571	65511	37102	30052	21256	18555	14770
Fuel Consumption Coal	PJ	HCS	76139	73642	56768	27306	17492	4467	3048	2422
Fuel Consumption Coal	PJ	MCP	76139	75571	62898	35106	26699	19618	17203	13470
Fuel Consumption Coal	PJ	CNS	76139	75571	65321	35980	27560	19710	7458	3356
Fuel Consumption Gas	PJ	REF	33983	48430	54506	62736	59961	52504	52832	46425
Fuel Consumption Gas	PJ	HCS	33983	49669	50920	42246	29342	18806	16597	12489
Fuel Consumption Gas	PJ	MCP	33983	48430	49381	52539	46261	40165	41158	38732
Fuel Consumption Gas	PJ	CNS	33983	48430	54530	60276	49522	38204	33289	18740
Fuel Consumption Oil	PJ	REF	8927	5253	3947	1830	777	4	0	0
Fuel Consumption Oil	PJ	HCS	8927	5253	3947	1824	772	0	0	0
Fuel Consumption Oil	PJ	MCP	8927	5253	3947	1828	777	4	0	0
Fuel Consumption Oil	PJ	CNS	8927	5253	3947	1831	776	4	0	0
Fuel Consumption Uranium	PJ	REF	32810	30280	24867	32286	34629	39288	41918	43434
Fuel Consumption Uranium	PJ	HCS	32810	30270	24774	45917	52638	74199	79020	80349
Fuel Consumption Uranium	PJ	MCP	32810	30280	24868	28784	28080	27993	28675	30129
Fuel Consumption Uranium	PJ	CNS	32810	30280	24863	32589	35066	43393	51315	57977
Fuel Consumption Biomass	PJ	REF	3904	3901	3905	3897	3890	3887	3886	3898
Fuel Consumption Biomass	PJ	HCS	3904	3901	3905	3892	3931	9464	16099	25321
Fuel Consumption Biomass	PJ	MCP	3904	3901	3902	3896	3888	3884	3885	3887
Fuel Consumption Biomass	PJ	CNS	3904	3901	3913	3906	4180	4416	6577	19468
Capacity - Coal	GW	REF	3315	2617	2632	1902	1909	1458	1187	804
Capacity - Coal	GW	HCS	3315	2618	2629	1887	1887	1424	1135	649
Capacity - Coal	GW	MCP	3315	2617	2626	1893	1899	1442	1175	784
Capacity - Coal	GW	CNS	3315	2617	2629	1890	1890	1427	1141	655
Capacity - Coal CCS	GW	REF	0	0	0	0	0	0	0	0
Capacity - Coal CCS	GW	HCS	0	0	0	0	15	25	29	29
Capacity - Coal CCS	GW	MCP	0	0	0	0	0	0	0	0
Capacity - Coal CCS	GW	CNS	0	0	0	0	0	11	14	14
Capacity - Gas	GW	REF	2485	2464	2389	2683	2502	2392	2476	2702
Capacity - Gas	GW	HCS	2485	2492	2281	2417	2037	1722	1582	1689
Capacity - Gas	GW	MCP	2485	2464	2291	2508	2280	2228	2382	2632
Capacity - Gas	GW	CNS	2485	2464	2390	2662	2433	2317	2450	2745
Capacity - Gas CCS	GW	REF	0	0	0	0	0	0	0	0
Capacity - Gas CCS	GW	HCS	0	0	0	0	53	91	146	165
Capacity - Gas CCS	GW	MCP	0	0	0	0	0	0	0	0

Data Item	Unit	Scenario	2015	2020	2025	2030	2035	2040	2045	2050
Capacity - Gas CCS	GW	CNS	0	0	0	0	2	3	23	39
Capacity - Oil	GW	REF	708	404	404	258	175	98	12	0
Capacity - Oil	GW	HCS	708	404	404	258	175	98	12	0
Capacity - Oil	GW	MCP	708	404	404	258	175	98	12	0
Capacity - Oil	GW	CNS	708	404	404	258	175	98	12	0
Capacity - Nuclear	GW	REF	409	348	289	379	410	469	506	528
Capacity - Nuclear	GW	HCS	409	348	289	561	661	919	987	1004
Capacity - Nuclear	GW	MCP	409	348	289	340	335	338	351	377
Capacity - Nuclear	GW	CNS	409	348	289	383	416	518	622	711
Capacity - Biomass	GW	REF	107	126	129	125	122	121	119	118
Capacity - Biomass	GW	HCS	107	126	129	125	123	121	115	116
Capacity - Biomass	GW	MCP	107	126	129	125	122	120	114	115
Capacity - Biomass	GW	CNS	107	126	129	125	132	175	244	363
Capacity - BECCS	GW	REF	0	0	0	0	0	0	0	0
Capacity - BECCS	GW	HCS	0	0	0	0	1	103	259	477
Capacity - BECCS	GW	MCP	0	0	0	0	0	0	0	0
Capacity - BECCS	GW	CNS	0	0	0	0	1	1	7	258
Capacity - Pump Hydro Storage	GW	REF	86	86	86	86	86	86	86	83
Capacity - Pump Hydro Storage	GW	HCS	86	86	86	86	86	86	86	83
Capacity - Pump Hydro Storage	GW	MCP	86	86	86	86	86	86	86	83
Capacity - Pump Hydro Storage	GW	CNS	86	86	86	86	86	86	86	83
Capacity - Battery Storage	GW	REF	0	23	82	143	197	390	509	653
Capacity - Battery Storage	GW	HCS	0	23	85	153	235	501	711	911
Capacity - Battery Storage	GW	MCP	0	23	85	147	202	365	470	636
Capacity - Battery Storage	GW	CNS	0	23	82	143	208	395	601	994
Capacity - Hydropower	GW	REF	1116	1227	1291	1425	1561	1763	1898	2047
Capacity - Hydropower	GW	HCS	1116	1227	1390	1611	1821	1884	1948	1992
Capacity - Hydropower	GW	MCP	1116	1227	1269	1373	1499	1639	1824	1951
Capacity - Hydropower	GW	CNS	1116	1227	1291	1487	1611	1783	1970	2172
Capacity - Wind	GW	REF	408	610	1263	2105	2906	3873	4435	5010
Capacity - Wind	GW	HCS	408	614	1470	2674	3985	4888	5262	5552
Capacity - Wind	GW	MCP	408	610	1477	2647	3804	5046	5585	6198
Capacity - Wind	GW	CNS	408	610	1264	2172	3295	4365	5290	5819
Capacity - Offshore Wind	GW	REF	13	24	24	23	21	11	0	5
Capacity - Offshore Wind	GW	HCS	13	24	24	27	35	29	18	28
Capacity - Offshore Wind	GW	MCP	13	24	116	212	307	398	396	399
Capacity - Offshore Wind	GW	CNS	13	24	24	27	34	26	40	70
Capacity - PV	GW	REF	211	487	615	1133	1717	2307	2855	3814
Capacity - PV	GW	HCS	211	487	894	1463	2015	2433	3013	3590
Capacity - PV	GW	MCP	211	487	920	1617	2324	2946	3383	3930
Capacity - PV	GW	CNS	211	487	627	1140	1873	2517	3097	3711
Capacity - Other Renewables	GW	REF	15	23	130	170	207	227	229	232
Capacity - Other Renewables	GW	HCS	15	23	131	173	209	226	229	232
Capacity - Other Renewables	GW	MCP	15	23	129	175	222	253	262	266
Capacity - Other Renewables	GW	CNS	15	23	130	170	207	226	229	231
Generation - Coal	TWh	REF	7976	7935	6906	3961	3232	2309	2031	1757
Generation - Coal	TWh	HCS	7976	7732	5994	2902	1736	275	91	31
Generation - Coal	TWh	MCP	7976	7935	6625	3744	2868	2120	1879	1596
Generation - Coal	TWh	CNS	7976	7935	6884	3832	2951	2026	697	293
Generation - Coal CCS	TWh	REF	0	0	0	0	0	0	0	0
Generation - Coal CCS	TWh	HCS	0	0	0	0	107	179	204	198
Generation - Coal CCS	TWh	MCP	0	0	0	0	0	0	0	0
Generation - Coal CCS	TWh	CNS	0	0	0	0	0	78	101	66
Generation - Gas	TWh	REF	4891	6903	7891	9176	8858	7836	7882	6927
Generation - Gas	TWh	HCS	4891	7090	7346	6155	3891	2130	1536	980
Generation - Gas	TWh	MCP	4891	6903	7129	7654	6815	5979	6132	5781
Generation - Gas	TWh	CNS	4891	6903	7894	8822	7303	5666	4545	2583
Generation - Gas CCS	TWh	REF	0	0	0	0	0	0	0	0
Generation - Gas CCS	TWh	HCS	0	0	0	0	369	562	793	751
Generation - Gas CCS	TWh	MCP	0	0	0	0	0	0	0	0
Generation - Gas CCS	TWh	CNS	0	0	0	0	18	18	135	176
Generation - Oil	TWh	REF	696	410	308	143	61	0	0	0
Generation - Oil	TWh	HCS	696	410	308	142	60	0	0	0
Generation - Oil	TWh	MCP	696	410	308	143	61	0	0	0
Generation - Oil	TWh	CNS	696	410	308	143	61	0	0	0
Generation - Nuclear	TWh	REF	2758	2557	2115	2774	2980	3384	3612	3743
Generation - Nuclear	TWh	HCS	2758	2556	2107	3949	4532	6392	6809	6923
Generation - Nuclear	TWh	MCP	2758	2557	2115	2472	2416	2411	2471	2596
Generation - Nuclear	TWh	CNS	2758	2557	2115	2800	3018	3737	4421	4996
Generation - Biomass	TWh	REF	317	318	318	318	318	318	317	318
Generation - Biomass	TWh	HCS	317	318	318	317	318	321	328	328
Generation - Biomass	TWh	MCP	317	318	318	318	317	317	317	318
Generation - Biomass	TWh	CNS	317	318	319	318	339	357	505	655
Generation - BECCS	TWh	REF	0	0	0	0	0	0	0	0
Generation - BECCS	TWh	HCS	0	0	0	0	4	571	1285	2330
Generation - BECCS	TWh	MCP	0	0	0	0	0	0	0	0
Generation - BECCS	TWh	CNS	0	0	0	0	3	5	43	1284
Generation - Hydropower	TWh	REF	3945	4264	4479	4952	5413	6090	6555	7039
Generation - Hydropower	TWh	HCS	3945	4264	4817	5558	6246	6498	6742	6917

Data Item	Unit	Scenario	2015	2020	2025	2030	2035	2040	2045	2050
Generation - Hydropower	TWh	MCP	3945	4264	4400	4774	5200	5662	6302	6715
Generation - Hydropower	TWh	CNS	3945	4264	4479	5159	5577	6148	6799	7481
Generation - Wind	TWh	REF	1461	2196	4542	7397	9949	13029	14695	16396
Generation - Wind	TWh	HCS	1461	2214	5158	9076	13085	15906	17074	17974
Generation - Wind	TWh	MCP	1461	2196	4946	8342	11372	14388	16112	18061
Generation - Wind	TWh	CNS	1461	2196	4543	7619	11206	14504	17174	18661
Generation - Offshore Wind	TWh	REF	51	96	96	93	83	47	0	19
Generation - Offshore Wind	TWh	HCS	51	96	96	107	140	113	67	105
Generation - Offshore Wind	TWh	MCP	51	96	342	597	846	1076	1067	1073
Generation - Offshore Wind	TWh	CNS	51	96	96	107	134	103	147	262
Generation - PV	TWh	REF	307	802	1036	1969	3031	4180	5140	6815
Generation - PV	TWh	HCS	307	803	1522	2571	3578	4393	5477	6570
Generation - PV	TWh	MCP	307	802	1533	2722	3969	5053	5809	6803
Generation - PV	TWh	CNS	307	802	1052	1981	3341	4524	5550	6662
Generation - Other Renewables	TWh	REF	89	142	890	1171	1430	1573	1591	1611
Generation - Other Renewables	TWh	HCS	89	142	899	1189	1445	1567	1585	1614
Generation - Other Renewables	TWh	MCP	89	142	861	1157	1458	1643	1701	1735
Generation - Other Renewables	TWh	CNS	89	142	890	1171	1427	1565	1584	1608

Appendix F: Summary of the model results by country/district in four scenarios

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
AFG	Carbon Emission	MT	0.4	0.4	0.2	0.1	0.3	0.2	0	0	0.2	0	0.2	0.2	0.1	0.1
AFG	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFG	Ann. Cost	B.USD	0.1	0.2	0.3	0.6	0.9	0.4	0.7	1	0.4	0.7	1	0.3	0.6	0.9
AFG	Ann. Demand	TWh	4.7	6	8.8	12.1	15.7	8.8	12.1	15.7	8.8	12.1	15.7	8.8	12.1	15.7
AFG	Ann. Supply	TWh	1.3	1.9	6.6	16.1	25.2	6.6	16.5	25	7.3	16.6	25.9	6.6	16.1	25.6
AFG	Ann. Import	TWh	3.6	4.4	4.2	2.7	2.4	4.1	4.3	3.9	4.2	1.7	2	4.2	2.7	4.2
AFG	Ann. Export	TWh	0	0	1.8	6	11	1.5	8.1	12.2	2.4	5.6	11.3	1.8	6	13.2
AFG	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFG	Gen. Gas	TWh	0	0.3	0.2	0.1	0.6	0.2	0	0.1	0.2	0.1	0.4	0.2	0.1	0.2
AFG	Gen. Nuclear	TWh	0	0	0	0	0	0	1.2	1.2	0	0	0	0	0	0.6
AFG	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFG	Gen. Hydro	TWh	0.9	1.2	0.5	0.4	0.4	0.5	0.4	0.4	0.5	0.4	0.4	0.5	0.4	0.4
AFG	Gen. Wind	TWh	0	0	5.7	15.5	24.2	5.6	14.7	23.3	5.7	14.4	23.4	5.7	15.5	24.4
AFG	Gen. PV	TWh	0	0.2	0.2	0.1	0	0.2	0.1	0	0.7	1.7	1.7	0.2	0.1	0
AGO	Carbon Emission	MT	5.2	5.5	6.1	4.8	7.3	5.5	2	-1	6	4.5	6.7	6.1	4.8	1.7
AGO	Carbon Sequester	MT	0	0	0	0	0	0	0	3.5	0	0	0	0	0	3.6
AGO	Ann. Cost	B.USD	0.9	1.5	2.6	3.7	6.4	2.8	3.1	5.7	2.8	4.1	6.7	2.6	3.7	6.7
AGO	Ann. Demand	TWh	9.3	13.1	27.5	52.6	90.8	27.5	52.6	90.8	27.5	52.6	90.8	27.5	52.6	90.8
AGO	Ann. Supply	TWh	9.3	16.8	32.9	56.8	100.5	32	48.1	86.2	34	59.7	102	32.9	56.8	100.7
AGO	Ann. Import	TWh	0	0	0.4	3.7	6.1	0.2	10.1	15	0.3	3.3	5.8	0.4	3.8	7.1
AGO	Ann. Export	TWh	0	0	3.1	6.8	13.2	2.4	4.9	9.4	2.6	6.1	11.5	3.1	6.8	14.8
AGO	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AGO	Gen. Gas	TWh	1.8	5.1	10.1	12.5	19.3	8.6	5	6.8	9.5	11.4	17.9	10.1	12.5	14.2
AGO	Gen. Nuclear	TWh	0	0	0	0	0	0.4	1.2	1.2	0	0	0	0	0	0
AGO	Gen. CCS	TWh	0	0	0	0	0	0	0	4	0	0	0	0	0	4.1
AGO	Gen. Hydro	TWh	3.2	8.7	18	33.6	57.6	15.9	29	48.7	16.8	31	54.9	18	33.6	57.9
AGO	Gen. Wind	TWh	0	0	1.1	2.1	2.1	2.1	2.1	4.2	3.9	7.8	7.9	1.1	2.1	2.1
AGO	Gen. PV	TWh	0	0.1	2.4	8.6	21.6	3.6	10.9	21.3	2.2	9.1	21.1	2.4	8.6	22.5
ALB	Carbon Emission	MT	0	0	0	0	0	0	0	-1.2	0	0	0	0	0	-0.9
ALB	Carbon Sequester	MT	0	0	0	0	0	0	0	1.2	0	0	0	0	0	0.9
ALB	Ann. Cost	B.USD	0.4	0.5	0.7	0.9	1.3	0.7	1	1.3	0.7	0.8	1.2	0.7	1	1.4
ALB	Ann. Demand	TWh	6.6	7.2	8.4	9.8	11.2	8.4	9.8	11.2	8.4	9.8	11.2	8.4	9.8	11.2
ALB	Ann. Supply	TWh	5.9	6.9	11.3	18	23.7	11.3	17.9	23.5	11.2	16.4	22.1	11.3	17.9	23.1
ALB	Ann. Import	TWh	1.9	2	2.7	2.3	3.6	6.2	8.8	9.2	2.9	2.4	2.7	2.5	2.7	2.9
ALB	Ann. Export	TWh	1.2	1.6	5.6	10.5	16.1	9.1	16.9	21.6	5.4	9	13.7	5.4	10.9	14.8
ALB	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ALB	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ALB	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ALB	Gen. CCS	TWh	0	0	0	0	0	0	0	1.5	0	0	0	0	0	1.1
ALB	Gen. Hydro	TWh	5.9	6.9	6.9	5.5	8.9	6.9	8.6	8.6	6.9	3.8	8.5	6.9	7.8	10.1
ALB	Gen. Wind	TWh	0	0	4.4	9.3	9.3	4.4	9.3	9.3	4	9.3	9.3	4.4	9.3	9.3
ALB	Gen. PV	TWh	0	0	0	3.1	5.5	0	0	4.2	0.3	3.3	4.3	0	0.8	2.7
ARE	Carbon Emission	MT	48.3	55.3	48.4	13	12.7	20.2	6.5	5.8	39.2	12.2	8.4	48.4	13	8.5
ARE	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1
ARE	Ann. Cost	B.USD	10.2	11.3	16.7	16.3	17.3	17.8	17.1	17.5	17.8	21.6	21.9	16.7	16.3	17.1
ARE	Ann. Demand	TWh	119	135.6	186.1	250.2	295.3	186.1	250.2	295.3	186.1	250.2	295.3	186.1	250.2	295.3
ARE	Ann. Supply	TWh	119.2	140.4	190.2	196	205.3	186.1	197.3	192.2	191.9	233.9	242.4	190.2	196	202.4
ARE	Ann. Import	TWh	0	0.4	0.4	58.7	99.2	0.5	56	107.4	0.1	22.4	72.5	0.4	58.7	106.4
ARE	Ann. Export	TWh	0.2	5.1	4.5	3.9	8.2	0.5	2.7	3.6	5.8	5.2	15.2	4.5	3.9	9.9
ARE	Gen. Coal	TWh	2.9	2.9	2.9	1.8	0.7	1.2	0	0	2.9	1.8	0.5	2.9	1.8	0
ARE	Gen. Gas	TWh	114.8	136.2	117.8	28.2	30	49.1	16.8	14.6	94.3	26.9	20.8	117.8	28.2	23.8
ARE	Gen. Nuclear	TWh	0	0	55.6	73.5	67.3	112.4	105.5	96.6	39.9	62.2	51.4	55.6	73.5	62.3
ARE	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.2
ARE	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ARE	Gen. Wind	TWh	0	0	12.5	42.2	42.2	12.5	12.5	20	41.3	100.5	105	12.5	42.2	42.2
ARE	Gen. PV	TWh	0.2	1	1	50.1	64.8	10.6	62.3	61	1.5	10.9	33.1	1	50.1	72.5
ARG	Carbon Emission	MT	63.1	58.7	18.2	0.7	0.1	13.4	0.3	0	17.1	0.7	0.2	18.3	0.6	0
ARG	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ARG	Ann. Cost	B.USD	11.2	11.2	11.3	14	19.4	11	14.2	19.2	11.2	13.3	18.6	11.3	14	18.7
ARG	Ann. Demand	TWh	142.6	159.9	208.5	265.9	326.8	208.5	265.9	326.8	208.5	265.9	326.8	208.5	265.9	326.8
ARG	Ann. Supply	TWh	144.8	150.4	188.1	301.4	414.4	177.1	307	408.2	185.8	289.1	397.8	188.2	301.3	404.9
ARG	Ann. Import	TWh	5	12.3	36.4	15.3	15.8	47.7	22.7	25.4	39.4	22.7	19.5	36.6	16.5	18.7
ARG	Ann. Export	TWh	6.4	1.6	13	44.7	93.8	12.9	56.7	97	13.8	38.8	81.3	13.3	45.6	87.8
ARG	Gen. Coal	TWh	30.9	40	1.6	0.1	0.1	0.6	0	0	1.3	0.2	0.2	1.6	0.1	0
ARG	Gen. Gas	TWh	54.3	49.5	38.4	1.5	0	28.4	0.8	0	36.3	1.5	0.1	38.5	1.4	0
ARG	Gen. Nuclear	TWh	13.1	10.2	5.5	3.9	4.1	5.2	3.2	3.3	5.5	4	4.5	5.5	3.8	3.7
ARG	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ARG	Gen. Hydro	TWh	27.4	37.3	36.4	59.7	69	36.4	64.2	71.1	36.4	35.7	69.1	36.4	59.9	69.4
ARG	Gen. Wind	TWh	1	6.2	88.5	201.8	301.8	87.3	203.3	288.2	81.8	200.5	276.7	88.5	201	288.3
ARG	Gen. PV	TWh	0	1	1	7.4	12.3	1	8.5	18.7	8	20.3	20.3	1	8	16.5
ARM	Carbon Emission	MT	0.8	0.8	0.2	0.2	0	0.5	0.1	0	0.1	0.1	0	0.4	0	0
ARM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ARM	Ann. Cost	B.USD	0.7	0.6	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.5	0.4	0.5	0.6
ARM	Ann. Demand	TWh	5.9	6.8	8.7	11	13.6	8.7	11	13.6	8.7	11	13.6	8.7	11	13.6
ARM	Ann. Supply	TWh	9.1	6.9	6.7	7.3	7.6	8.9	7.9	8.6	7.8	9.4	9.2	7.6	8.1	8.2
ARM	Ann. Import	TWh	0	0.1	2.4	4.4	6.6	1.1	4.4	6.5	1.4	1.9	4.8	1.8	4.1	8.4
ARM	Ann. Export	TWh	3.1	0.2	0.4	0.8	0.6	1.2	1.1	1.3	0.5	0.3	0.4	0.6	1.2	2.8
ARM	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ARM	Gen. Gas	TWh	2.1	2.2	0.6	0.6	0	1.2	0.2	0	0.4	0.2	0	0.9	0.1	0
ARM	Gen. Nuclear	TWh	2.4	0	0	0	0	0	0	0	0	0	0	0	0	0
ARM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ARM	Gen. Hydro	TWh	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
ARM	Gen. Wind	TWh	0	0	0	0.6	1.5	1.5	1.5	2.5	0.7	1.7	1.7	0.6	1.5	1.5
ARM	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.6	1.5	1.5	0.1	0.1	0
AUS	Carbon Emission	MT	139.9	133.9	58.4	17.4	8.1	33.4	4.6	4.2	58.5	18.2	7.9	58.4	17.5	2.1
AUS	Carbon Sequester	MT	0	0	0	0	0	0	0	1.4	0	0	0	0	0	1.7
AUS	Ann. Cost	B.USD	21.8	22.9	19.3	22	25.3	21.9	22.9	26.1	19.4	22.4	25.6	19.3	22	25.1
AUS	Ann. Demand	TWh	235.4	242.9	303.5	367.9	435.5	303.5	367.9	435.5	303.5	367.9	435.5	303.5	367.9	435.5
AUS	Ann. Supply	TWh	235.6	243.6	305.7	374.7	446.2	305.4	377.7	449	306.3	376.4	446.9	305.7	374.6	455.6

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
AUS	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUS	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUS	Gen. Coal	TWh	138	133.4	54.5	16.1	0	12.8	0.1	0	54.5	16.7	0	54.5	16.4	0
AUS	Gen. Gas	TWh	39.5	35.1	20	9.6	22.2	58	12.4	11.5	20.6	10.2	21.6	20	9.2	11
AUS	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUS	Gen. CCS	TWh	0	0	0	0	0	0	0	3.4	0	0	0	0	0	2.1
AUS	Gen. Hydro	TWh	26.9	24.5	14.9	14	13.6	14.6	14.3	14.8	14.9	12.1	13.6	14.9	14	15.9
AUS	Gen. Wind	TWh	15.9	23.6	112.3	233.8	277.8	120.3	247	290.6	110.4	226.5	277.1	112.3	233.8	292.5
AUS	Gen. PV	TWh	8	20.1	64.6	63.5	95.4	60.1	66.4	91.6	66.5	73.4	97.5	64.6	63.5	97
AUT	Carbon Emission	MT	11.1	42.7	254.6	228.4	114.6	51.7	19.2	11.4	195.3	156.2	97.5	249.4	127.1	23
AUT	Carbon Sequester	MT	0	0	0	0	0	0	5.4	11.2	0	0	0	0	0	4.8
AUT	Ann. Cost	B.USD	5.6	9.5	39.1	43.3	32.8	16.5	14.2	14.9	31.5	31.9	27.2	38.6	30.6	19.2
AUT	Ann. Demand	TWh	66.3	68.8	70.6	74.1	78.9	70.6	74.1	78.9	70.6	74.1	78.9	70.6	74.1	78.9
AUT	Ann. Supply	TWh	93.3	188.4	770.6	693.9	405.7	227.4	155	151.3	607.5	492.8	337.2	759.2	431.5	168.7
AUT	Ann. Import	TWh	18.8	0.8	0	2.5	53	13.3	54	65.3	0	2.9	14.7	0	34.9	85.3
AUT	Ann. Export	TWh	45.5	120.4	699.9	622.1	379	169.7	134.1	136.7	536.8	421.4	272.4	688.5	391.9	174.3
AUT	Gen. Coal	TWh	3.4	1.4	0	0	0	0	0	0	0	0	0	0	0	0
AUT	Gen. Gas	TWh	20.9	111.8	701.1	629	315.7	140.7	51.7	29.6	537.2	429.9	268.3	686.6	349.9	62.5
AUT	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUT	Gen. CCS	TWh	0	0	0	0	0	0	13.6	28.3	0	0	0	0	0	12
AUT	Gen. Hydro	TWh	57.1	59.7	50.6	38	38	50.6	49.6	49.6	50.6	38	38	50.6	38	50.3
AUT	Gen. Wind	TWh	7.6	10.4	13.9	23.1	24.7	24.7	24.7	24.7	13.9	18.8	24.7	17.1	24.7	24.7
AUT	Gen. PV	TWh	1.1	1.8	1.8	0.7	24.1	8.2	12.2	15.8	2.5	3	3	1.8	15.8	15.8
AZE	Carbon Emission	MT	6.8	6.2	3.3	0.5	0.1	3.5	0.2	0	3.3	0.2	0.1	3.2	0	0
AZE	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AZE	Ann. Cost	B.USD	1.6	1.6	1.6	2.1	3	2.3	2.8	3.2	1.5	1.8	2.6	1.9	2.5	3.5
AZE	Ann. Demand	TWh	21.7	24.9	32.1	40.4	50.1	32.1	40.4	50.1	32.1	40.4	50.1	32.1	40.4	50.1
AZE	Ann. Supply	TWh	20.1	19.7	20.4	35.3	54.9	30.7	46.3	57.6	19.1	29.3	48	25.8	39.9	57.8
AZE	Ann. Import	TWh	2.5	5.3	12.3	7.2	6.1	4.3	3	7.3	13.1	11.5	6.7	7.9	4.9	6.5
AZE	Ann. Export	TWh	0.8	0	0.5	1.9	10.5	2.5	8.3	14.2	0	0.2	4.3	1.4	4	13.6
AZE	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AZE	Gen. Gas	TWh	16	14.8	7.9	1.4	0.1	8.3	0.5	0.1	8	0.6	0.1	7.6	0.1	0
AZE	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AZE	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AZE	Gen. Hydro	TWh	3.8	4.3	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
AZE	Gen. Wind	TWh	0	0.3	5.6	22.3	31.3	15.5	30.2	31.3	2.8	18.2	31.3	11.3	25.8	29.9
AZE	Gen. PV	TWh	0	0.1	0.1	4.9	16.8	0.1	8.9	19.5	1.6	3.9	9.8	0.1	6.5	20.4
BDI	Carbon Emission	MT	0	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.3	0.2	0.2	0.3	0.2	0.1
BDI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BDI	Ann. Cost	B.USD	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
BDI	Ann. Demand	TWh	0.3	0.4	0.9	1.7	3	0.9	1.7	3	0.9	1.7	3	0.9	1.7	3
BDI	Ann. Supply	TWh	0.2	0.6	1.3	1.7	1.8	1.2	1.6	1.4	1.5	1.8	1.8	1.5	1.7	1.5
BDI	Ann. Import	TWh	0.1	0	0.1	0.3	2.7	0.3	0.8	4.2	0.1	0.4	2.5	0.1	0.3	2.5
BDI	Ann. Export	TWh	0	0.2	0.6	0.3	1.5	0.6	0.6	2.5	0.7	0.4	1.4	0.7	0.3	1.1
BDI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BDI	Gen. Gas	TWh	0	0.3	0.5	0.5	0.6	0.4	0.3	0.3	0.6	0.4	0.4	0.7	0.5	0.2
BDI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BDI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BDI	Gen. Hydro	TWh	0.2	0.2	0.7	1	1	0.7	1	0.8	0.7	1	1	0.7	1	1
BDI	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.2	0.2	0	0	0
BDI	Gen. PV	TWh	0	0.1	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2
BEL	Carbon Emission	MT	9.3	5.7	2.8	0	0	3	0.1	0	2.8	0	0	2.8	0	0
BEL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BEL	Ann. Cost	B.USD	7.7	7.1	3.5	2.7	2.3	5.6	4.1	3.2	4.6	5.1	5.1	3.5	2.7	2.4
BEL	Ann. Demand	TWh	87.9	91.2	93.6	98.3	104.6	93.6	98.3	104.6	93.6	98.3	104.6	93.6	98.3	104.6
BEL	Ann. Supply	TWh	78	70.1	26.3	24.4	21.6	56.4	43	30.8	44.5	57.3	57.1	26.3	24.4	21.9
BEL	Ann. Import	TWh	15	25.3	68.4	74.2	104.3	46.4	101.3	123.6	49.4	43.4	69.8	68.5	81.4	115.1
BEL	Ann. Export	TWh	4.9	4	0.8	0	21.2	9.1	45.3	48.9	0.1	2	21.8	0.9	7.3	32.3
BEL	Gen. Coal	TWh	3.1	0	0	0	0	0	0	0	0	0	0	0	0	0
BEL	Gen. Gas	TWh	17.2	15.3	7.6	0	0	8	0.2	0	7.6	0	0	7.6	0	0
BEL	Gen. Nuclear	TWh	43.9	36.8	0	0	0	0	0	0	0	0	0	0	0	0
BEL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BEL	Gen. Hydro	TWh	0.1	0.4	0.4	0.4	0.2	0.4	0.4	0.2	0.4	0.4	0.2	0.4	0.4	0.2
BEL	Gen. Wind	TWh	6.5	9.5	9.1	17.9	16.3	38.9	36.4	25.5	22.7	40.2	40.2	9.1	17.9	16.3
BEL	Gen. PV	TWh	3.1	4.1	4.1	1	0	4.1	1	0	8.7	11.7	11.7	4.1	1	0
BEN	Carbon Emission	MT	0.2	0.6	0.4	0.7	0.4	0.4	0.2	-0.3	0.7	0.4	0.3	0.4	0.7	-3
BEN	Carbon Sequester	MT	0	0	0	0	0	0	0	0.5	0	0	0	0	0	3.2
BEN	Ann. Cost	B.USD	0.1	0.1	0.2	0.4	0.6	0.2	0.4	0.9	0.3	0.3	0.6	0.2	0.4	0.9
BEN	Ann. Demand	TWh	1.2	1.7	3.6	6.9	11.9	3.6	6.9	11.9	3.6	6.9	11.9	3.6	6.9	11.9
BEN	Ann. Supply	TWh	0.3	1.4	3	5	9.3	2.8	6	12.6	3.9	4.2	8	3	5	9.8
BEN	Ann. Import	TWh	1.8	2.5	1.2	10.8	20	1.7	16.8	29.2	0.5	7.1	18.5	1.2	10.8	18.9
BEN	Ann. Export	TWh	0.9	2.2	0.6	8.9	17.3	0.9	15.9	29.9	0.8	4.4	14.6	0.6	8.9	16.8
BEN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BEN	Gen. Gas	TWh	0	1.1	1	1.9	1.1	0.8	0.4	0.6	1.8	0.9	0.9	1	1.9	0.5
BEN	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BEN	Gen. CCS	TWh	0	0	0	0	0	0	0	0.6	0	0	0	0	0	3.6
BEN	Gen. Hydro	TWh	0.1	0.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
BEN	Gen. Wind	TWh	0	0	0	0	0	0	0.4	0.4	0.3	1	1	0	0	0
BEN	Gen. PV	TWh	0	0.1	0.6	1.8	6.9	0.6	3.9	9.7	0.3	0.9	4.8	0.6	1.8	4.3
BFA	Carbon Emission	MT	0	0.5	0.7	0.4	0.7	0.3	0.2	-0.4	0.7	0.3	1	0.7	0.4	-3.7
BFA	Carbon Sequester	MT	0	0	0	0	0	0	0	0.6	0	0	0	0	0	3.8
BFA	Ann. Cost	B.USD	0	0.1	0.3	0.5	1	0.4	0.5	1.1	0.3	0.6	1.2	0.3	0.5	1.3
BFA	Ann. Demand	TWh	1.3	1.9	3.9	7.5	12.9	3.9	7.5	12.9	3.9	7.5	12.9	3.9	7.5	12.9
BFA	Ann. Supply	TWh	0	1.7	3.6	5.9	13.2	4.3	6.3	14	3.7	6.6	15.6	3.6	5.9	14.2
BFA	Ann. Import	TWh	1.3	1.1	0.7	3.7	8	0.8	3.6	6.9	0.6	4	7.4	0.7	3.7	6.3
BFA	Ann. Export	TWh	0	0.9	0.3	2	8.2	1.1	2.3	7.8	0.3	3	10	0.3	2	7.5
BFA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BFA	Gen. Gas	TWh	0	1.4	1.9	1.1	1.8	0.8	0.6	0.7	1.9	0.9	2.5	1.9	1.1	0.3
BFA	Gen. Nuclear	TWh	0	0	0	1.2	1.1	0.9	0.9	0.9	0	0.7	0.7	0	1.2	1.2
BFA	Gen. CCS	TWh	0	0	0	0	0	0	0	0.7	0	0	0	0	0	4.3
BFA	Gen. Hydro	TWh	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
BFA	Gen. Wind	TWh	0	0	0.3	0.4	0.4	0.4	0.4	0.4	0.8	2.6	2.6	0.3	0.4	0.4
BFA	Gen. PV	TWh	0	0.1	1.2	3.1	9.7	2.1	4.3	11.3	0.9	2.2	9.7	1.2	3.1	7.5
BGD	Carbon Emission	MT	27.4	31.9	9.2	3.9	2.2	10.9	4.4	1	9.3	3.8	2.3	9.2	3.9	0.1
BGD	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGD	Ann. Cost	B.USD	4.4	5.8	5.4	4.8	5.2	7	8.6	9.5	5.7	6	6.9	5.4	4.8	9.3

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
BGD	Ann. Demand	TWh	53.4	67.6	99.4	135.9	177.4	99.4	135.9	177.4	99.4	135.9	177.4	99.4	135.9	177.4
BGD	Ann. Supply	TWh	53.7	67.8	65.8	69.6	93.4	87.1	121.3	141.1	69	86.1	122.2	65.8	69.8	124
BGD	Ann. Import	TWh	0	0	34	68.1	93.5	18.6	20.5	41.8	30.7	52.1	74.5	34	67.9	58.7
BGD	Ann. Export	TWh	0	0	0	0.4	7.7	5.7	5.7	4.5	0	1	17.8	0	0.4	3.9
BGD	Gen. Coal	TWh	3.7	3.7	0.7	0.1	0	0.7	0	0	0.7	0.1	0	0.7	0.1	0
BGD	Gen. Gas	TWh	41.8	57.2	15.7	9.7	5.7	19.9	10.9	2.3	16	9.7	5.9	15.7	9.7	0
BGD	Gen. Nuclear	TWh	0	0	16	15.2	15.5	17	62.6	73.6	16	15.2	15.3	16	15.2	30.3
BGD	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGD	Gen. Hydro	TWh	0.7	0.7	15.3	21.1	21.1	21.1	21.1	21.1	14.1	21.1	21.1	15.3	21.1	21.1
BGD	Gen. Wind	TWh	0	0	0	0	1.3	1	1	1	3.5	9.4	9.6	0	0	1.3
BGD	Gen. PV	TWh	0.2	0.4	15.7	23.5	50	24.8	25.7	43.6	16.3	30.7	70.5	15.7	23.7	62.7
BGR	Carbon Emission	MT	14.7	11.6	1.5	0.8	0.9	0.6	0.1	0.1	1.5	0.8	0.9	1.5	0.4	-0.5
BGR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.8
BGR	Ann. Cost	B.USD	4.5	3.8	2.7	1.2	1.4	3.3	2.3	2.4	3	1.8	1.9	2.7	1.3	1.8
BGR	Ann. Demand	TWh	31.3	34.2	39.9	46.3	53	39.9	46.3	53	39.9	46.3	53	39.9	46.3	53
BGR	Ann. Supply	TWh	43.4	40.4	31.9	13.4	16.7	37.8	25.6	25.9	35.3	22.2	23.4	31.7	15.3	19.1
BGR	Ann. Import	TWh	0.1	1.7	10.9	43.2	52.7	8.6	28.4	38.9	8.2	31.2	41.3	11.2	42	50.3
BGR	Ann. Export	TWh	12.2	7.7	2.7	10	15.9	6.3	7.3	11.4	3.5	6.8	11.3	2.9	10.6	15.8
BGR	Gen. Coal	TWh	15.7	13.2	1.6	0.8	0.9	0.3	0	0	1.4	0.8	0.9	1.5	0.5	0.3
BGR	Gen. Gas	TWh	1.4	0	0	0	0	0.7	0	0.1	0.2	0	0	0	0	0
BGR	Gen. Nuclear	TWh	15.4	15.4	15.3	0	0	15.4	9.7	10.1	14.6	0	1.1	15.3	0	2.1
BGR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1
BGR	Gen. Hydro	TWh	7.5	8.2	10.1	7.4	7.4	10.1	7.4	7.4	10.1	7.4	7.4	10.1	7.4	7.4
BGR	Gen. Wind	TWh	1.8	2	3.3	5.2	8.5	9.8	8.5	8.5	5.5	9.6	9.6	3.3	7.5	8.6
BGR	Gen. PV	TWh	1.4	1.5	1.5	0.1	0.1	1.5	0.1	0	3.3	4.5	4.5	1.5	0.1	0
BHR	Carbon Emission	MT	11.1	12.4	5.4	2.9	3.1	3.2	2.1	0.6	7.2	3.2	2.4	5.4	2.9	3.3
BHR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
BHR	Ann. Cost	B.USD	2.3	2.6	3.5	3.3	3.6	3.8	3.8	3.1	4.6	6.4	6.2	3.5	3.3	3.9
BHR	Ann. Demand	TWh	28.5	32.4	44.5	59.8	70.6	44.5	59.8	70.6	44.5	59.8	70.6	44.5	59.8	70.6
BHR	Ann. Supply	TWh	28.5	32.1	44.3	36.5	35.8	44.4	40.8	27.2	41.7	50.8	50.1	44.3	36.5	36.4
BHR	Ann. Import	TWh	0	0.4	0.3	23.4	34.9	0.2	19.2	43.7	3.2	12.8	27.8	0.3	23.4	34.4
BHR	Ann. Export	TWh	0.1	0.1	0.1	0	0.1	0.2	0.2	0.3	0	0	0	0.1	0	0.2
BHR	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BHR	Gen. Gas	TWh	28.5	32	13.9	7.4	7.4	8.2	5.4	1.5	18.7	8.4	6	13.9	7.4	9
BHR	Gen. Nuclear	TWh	0	0	29.7	22.9	22.2	27.2	23.8	20.6	6.6	7.8	6.1	29.7	22.9	18.7
BHR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
BHR	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BHR	Gen. Wind	TWh	0	0	0.5	0.5	0.5	0.9	0.9	0.8	13.9	27.5	29.1	0.5	0.5	0.5
BHR	Gen. PV	TWh	0	0.1	0.1	5.7	5.6	8.1	10.8	4.3	0.8	2.3	4.1	0.1	5.7	7.8
BIH	Carbon Emission	MT	6.5	5.7	0.1	0	0	0.1	0	-2.8	0.1	0	0	0.1	0	-1.9
BIH	Carbon Sequester	MT	0	0	0	0	0	0	0	2.8	0	0	0	0	0	1.9
BIH	Ann. Cost	B.USD	1.1	1.1	0.9	1.4	1.4	0.9	1.4	1.7	0.9	1.4	1.4	0.9	1.4	1.8
BIH	Ann. Demand	TWh	12	13.1	15.2	17.7	20.2	15.2	17.7	20.2	15.2	17.7	20.2	15.2	17.7	20.2
BIH	Ann. Supply	TWh	14.1	13.2	14.7	24.5	24.4	15	24.4	27.7	14.6	24.7	24.7	14.7	24.5	26.7
BIH	Ann. Import	TWh	3.4	7.9	18.1	22.3	24.9	11.2	12.1	15.6	16.1	16.9	24.3	18.3	20.2	19.9
BIH	Ann. Export	TWh	5.5	8	17.5	29	29.1	11	18.9	23.1	15.5	24	28.8	17.8	27	26.4
BIH	Gen. Coal	TWh	7.4	6.5	0	0	0	0	0	0	0	0	0	0	0	0
BIH	Gen. Gas	TWh	0	0	0.2	0	0	0.2	0	0	0.2	0	0	0.2	0	0
BIH	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BIH	Gen. CCS	TWh	0	0	0	0	0	0	0	3.4	0	0	0	0	0	2.3
BIH	Gen. Hydro	TWh	6.7	6.3	11.9	12.1	12.1	12.1	12.1	12.1	11.9	12.1	12.1	11.9	12.1	12.1
BIH	Gen. Wind	TWh	0	0.2	2.4	12.4	12.4	2.7	12.4	12.4	2.4	12.4	12.4	2.4	12.4	12.4
BIH	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.2	0.4	0.4	0.1	0.1	0
BLR	Carbon Emission	MT	9.9	8.8	0.3	0.4	0.2	0.2	0.1	-6.2	0.2	0	0.2	0.2	0.1	-10.6
BLR	Carbon Sequester	MT	0	0	0	0	0	0	0	6.3	0	0	0	0	0	10.6
BLR	Ann. Cost	B.USD	2.2	2	1.5	1.8	2.5	2.2	3.7	5.3	2.4	3.8	4.1	2.3	4.2	6.8
BLR	Ann. Demand	TWh	34	39.1	50.3	63.4	78.6	50.3	63.4	78.6	50.3	63.4	78.6	50.3	63.4	78.6
BLR	Ann. Supply	TWh	25.4	23.4	18.9	22.1	30	28.6	48.4	65.1	29.1	45.8	48.6	30.4	50.4	68.5
BLR	Ann. Import	TWh	8.9	16.1	32.6	43	49.9	23	17.3	16.9	23.1	19.7	31.8	21.1	14	10.5
BLR	Ann. Export	TWh	0.2	0	0.6	0.8	0.5	1	1.9	3.1	1.5	1.8	1.3	1	0.7	0.2
BLR	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BLR	Gen. Gas	TWh	25.1	22.3	0.5	0.7	0.3	0.3	0	0	0.3	0	0.2	0.3	0	0
BLR	Gen. Nuclear	TWh	0	0	17.1	17.9	20.1	24.8	44.7	53.9	16.5	16.5	17.2	26.5	44.5	45.4
BLR	Gen. CCS	TWh	0	0	0	0	0	0	0	7.6	0	0	0	0	0	12.8
BLR	Gen. Hydro	TWh	0	0.4	0.8	0.8	0.9	0.7	0.7	0.7	0.4	0.7	0.8	0.8	0.8	0.8
BLR	Gen. Wind	TWh	0.1	0.3	0.3	2.5	8.6	2.6	2.8	2.8	9.9	24.3	26.2	2.6	2.8	3.5
BLR	Gen. PV	TWh	0	0.2	0.2	0.1	0	0.2	0.1	0	1.8	4.3	4.1	0.2	0.1	0
BLZ	Carbon Emission	MT	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-0.4
BLZ	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
BLZ	Ann. Cost	B.USD	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
BLZ	Ann. Demand	TWh	0.4	0.5	0.6	0.8	0.9	0.6	0.8	0.9	0.6	0.8	0.9	0.6	0.8	0.9
BLZ	Ann. Supply	TWh	0.4	0.5	0.6	0.5	0.5	0.5	0.6	0.8	0.8	0.9	0.8	0.6	0.5	0.9
BLZ	Ann. Import	TWh	0	0	0.1	0.3	0.5	0.2	0.3	0.3	0	0.1	0.3	0.1	0.3	0.2
BLZ	Ann. Export	TWh	0	0	0.1	0	0	0.1	0	0.2	0.2	0.2	0.2	0.1	0	0.1
BLZ	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BLZ	Gen. Gas	TWh	0.1	0.1	0.3	0.2	0.3	0.2	0.2	0.3	0.2	0.3	0.4	0.3	0.2	0
BLZ	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BLZ	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.5
BLZ	Gen. Hydro	TWh	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
BLZ	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0	0	0
BLZ	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0.2	0.2	0.3	0.2	0.1	0.1	0.1
BOL	Carbon Emission	MT	3.5	3.1	1.2	0	0.1	1.1	0	0	1.1	0.1	0.1	1.2	0	0
BOL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOL	Ann. Cost	B.USD	0.7	0.8	0.8	1	1.4	0.8	1	1.4	0.8	1.1	1.5	0.8	1	1.4
BOL	Ann. Demand	TWh	8.6	9.7	12.6	16.1	19.8	12.6	16.1	19.8	12.6	16.1	19.8	12.6	16.1	19.8
BOL	Ann. Supply	TWh	8.7	9.9	12.8	22.5	33.3	12.7	22.6	33.3	13	23.1	34	12.8	22.5	35.2
BOL	Ann. Import	TWh	0	0	8.8	12.5	17	15.4	20.4	23.4	9	12.7	15.4	8.8	12.5	18.2
BOL	Ann. Export	TWh	0	0	8.4	17.8	28.9	14.6	25.5	34.9	8.8	18.6	28.1	8.4	17.8	31.8
BOL	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOL	Gen. Gas	TWh	6.7	6.1	2.1	0.1	0.2	1.9	0	0.1	2.1	0.2	0.2	2.1	0.1	0.1
BOL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOL	Gen. Hydro	TWh	1.6	3	2.7	2.4	2.3	2.7	2.4	2.3	2.7	2.4	2.3	2.7	2.4	2.3
BOL	Gen. Wind	TWh	0	0.2	3.5	4	5.9	3.5	3.7	5.9	3.6	4.5	4.3	3.5	4	6.3
BOL	Gen. PV	TWh	0	0.3	0.3	0.3	0.1	0.3	0.3	0	0.7	1.6	1.6	0.3	0.3	0.4
BRA	Carbon Emission	MT	76.3	72.6	43.8	19.6	22.8	35.7	10.8	4.5	41.1	20.5	25.4	43.8	20	1
BRA	Carbon	MT	0	0	0	0	0	0	0	4	0	0	0	0	0	11.1

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
	Sequester															
BRA	Ann. Cost	B.USD	35.8	42.3	50.4	56	67.2	52.5	56.7	69.2	51	56.8	68.9	50.4	56.1	67.6
BRA	Ann. Demand	TWh	562	639.1	788.9	974.2	1174.8	788.9	974.2	1174.8	788.9	974.2	1174.8	788.9	974.2	1174.8
BRA	Ann. Supply	TWh	536.1	640	804.8	940.1	1108.4	829.6	941.9	1121.4	809.4	942.1	1125	804.8	940.7	1106.3
BRA	Ann. Import	TWh	42.4	27	27	61.5	96.1	27.5	71.5	96.2	28.8	60	84.2	27	61.9	98.5
BRA	Ann. Export	TWh	4.1	4.9	25.7	13.1	12.1	49.8	22	23.3	31.3	13.8	16.8	25.7	13.9	12.2
BRA	Gen. Coal	TWh	36.2	28.3	14.5	5.9	4.7	11.3	1	0.1	14	6	5.1	14.5	5.8	0.5
BRA	Gen. Gas	TWh	66.9	86.1	62.3	38.4	49.6	49.3	26.4	22.5	57	40.7	55.9	62.3	39.6	31.3
BRA	Gen. Nuclear	TWh	14.5	13.3	14.2	8	7.8	11.8	6.4	6	13.8	8.4	7.8	14.2	7.9	6.4
BRA	Gen. CCS	TWh	0	0	0	0	0	0	0	4.9	0	0	0	0	0	13.5
BRA	Gen. Hydro	TWh	335.5	388.5	432.4	459.7	522.6	439.3	454.8	500.4	421.6	441.9	516.1	432.4	460.2	511.6
BRA	Gen. Wind	TWh	37.3	76.5	202.6	301.7	348.4	245.5	326.4	400.7	203.7	294.9	350.9	202.6	301.2	367.7
BRA	Gen. PV	TWh	0	4.5	17.2	71.3	120.3	10.8	72	132.2	37.7	95.3	134.3	17.2	71	116.9
BRN	Carbon Emission	MT	1.9	3.2	0.7	0.7	0.7	0.7	0	-0.3	0.7	0.6	0.4	0.8	0.7	0
BRN	Carbon Sequester	MT	0	0	0	0	0	0	0	0.3	0	0	0	0	0	0
BRN	Ann. Cost	B.USD	0.3	0.4	0.3	0.3	0.2	0.4	0.3	0.3	1.3	2.2	2.1	0.3	0.3	0.2
BRN	Ann. Demand	TWh	3.9	4.9	7.3	9.9	13	7.3	9.9	13	7.3	9.9	13	7.3	9.9	13
BRN	Ann. Supply	TWh	3.9	4.9	2.9	4.2	3.3	5.4	4.6	4	5.2	7.6	7.3	2.9	4.2	2.5
BRN	Ann. Import	TWh	0	0	4.7	5.7	9.7	3.4	6.7	9.5	2.6	3.8	7	4.7	5.7	10.5
BRN	Ann. Export	TWh	0	0	0	0	0	1.2	0.9	0.5	0	0.2	0.2	0	0	0
BRN	Gen. Coal	TWh	0	1.8	0.3	0.8	0.8	0	0	0	0.3	0.7	0.4	0.4	0.8	0
BRN	Gen. Gas	TWh	3.9	3.1	0.7	0	0	1.3	0.1	0.1	0.7	0	0	0.7	0	0
BRN	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BRN	Gen. CCS	TWh	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0
BRN	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BRN	Gen. Wind	TWh	0	0	0	0	0	0	0	0	1.5	3	3	0	0	0
BRN	Gen. PV	TWh	0	0	0.9	2.5	1.6	3.1	3.6	2.6	1.4	2.7	2.7	0.9	2.5	1.6
BTN	Carbon Emission	MT	0	0	0	0	0	0	0	-0.6	0	0	0	0	0	-0.4
BTN	Carbon Sequester	MT	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0.4
BTN	Ann. Cost	B.USD	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.7
BTN	Ann. Demand	TWh	2.6	3.3	4.8	6.6	8.6	4.8	6.6	8.6	4.8	6.6	8.6	4.8	6.6	8.6
BTN	Ann. Supply	TWh	5.2	5.2	5.2	5.6	5.6	5.8	8.3	9.4	5.9	6.8	6.8	5.2	5.6	8.9
BTN	Ann. Import	TWh	1.8	1.3	1.9	3.5	5	1.7	1.3	1.6	1.9	2.5	3.4	1.9	3.5	2
BTN	Ann. Export	TWh	3.7	3.2	2.3	2.5	2	2.7	3	2.4	2.9	2.6	1.5	2.3	2.5	2.3
BTN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTN	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTN	Gen. Nuclear	TWh	0	0	0	0	0	0.6	2.8	3.5	0	0	0	0	0	0.9
BTN	Gen. CCS	TWh	0	0	0	0	0	0	0	0.7	0	0	0	0	0	0.5
BTN	Gen. Hydro	TWh	5.2	5.2	5.2	5.4	5.3	5.2	5.2	5	5.2	5.2	5.2	5.2	5.4	5.2
BTN	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTN	Gen. PV	TWh	0	0	0	0.3	0.3	0	0.3	0.3	0.6	1.5	1.6	0	0.3	0.3
BWA	Carbon Emission	MT	6.1	6.8	1.9	0.4	0.4	1.2	0	0.1	1.8	0.4	0.4	1.9	0.4	0.2
BWA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BWA	Ann. Cost	B.USD	0.4	0.6	0.7	1.3	2.7	0.7	1.1	2.5	0.8	1.5	2.9	0.7	1.3	2.7
BWA	Ann. Demand	TWh	3.8	5.4	11.4	21.8	37.7	11.4	21.8	37.7	11.4	21.8	37.7	11.4	21.8	37.7
BWA	Ann. Supply	TWh	6.1	6.9	9.4	19	40.9	9	16	38	9.6	20.8	42.7	9.4	19	40.8
BWA	Ann. Import	TWh	0.5	0.8	3.3	7.6	12.7	3.6	9.5	12.2	3	6.4	11.2	3.3	7.5	11.4
BWA	Ann. Export	TWh	2.7	2.3	1.4	4.7	15.6	1.2	3.5	12	1.2	5.2	15.6	1.4	4.6	14
BWA	Gen. Coal	TWh	6	6.7	1.6	0.3	0.4	1.1	0	0	1.4	0.3	0.3	1.6	0.3	0.1
BWA	Gen. Gas	TWh	0	0	0.7	0.3	0.2	0	0.1	0.2	0.8	0.2	0.2	0.7	0.3	0.3
BWA	Gen. Nuclear	TWh	0	0	0	0	0	0.7	0.6	0.7	0	0	0	0	0	0
BWA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BWA	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BWA	Gen. Wind	TWh	0	0	5.8	15.1	37	3.4	8.9	31.6	5.5	15.4	37.4	5.8	15.1	37
BWA	Gen. PV	TWh	0	0.1	1.3	3.4	3.4	3.7	6.4	5.6	1	2.3	2.3	1.3	3.4	3.4
CAF	Carbon Emission	MT	0.1	0.1	0.1	0.3	0.3	0.1	0.2	0.2	0.1	0.3	0.3	0.1	0.3	0.1
CAF	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAF	Ann. Cost	B.USD	0	0	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.1
CAF	Ann. Demand	TWh	0.2	0.2	0.5	0.9	1.6	0.5	0.9	1.6	0.5	0.9	1.6	0.5	0.9	1.6
CAF	Ann. Supply	TWh	0.2	0.2	1.1	2.1	2.2	1.1	1.9	2.4	1.3	2.2	2.2	1.1	2.1	1.9
CAF	Ann. Import	TWh	0	0	0.7	1.1	2.6	0.6	0.7	1.1	0.6	0.6	3.1	0.7	1.1	3.1
CAF	Ann. Export	TWh	0	0	1.2	2.2	3.2	1.2	1.6	1.9	1.3	1.8	3.7	1.2	2.2	3.5
CAF	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAF	Gen. Gas	TWh	0	0.1	0.3	0.8	0.8	0.3	0.4	0.5	0.2	0.7	0.7	0.3	0.8	0.2
CAF	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAF	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAF	Gen. Hydro	TWh	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0	0.1	0.1	0.3
CAF	Gen. Wind	TWh	0	0	0	0.1	0.1	0	0.3	0.6	0.1	0.1	0.2	0	0.1	0.4
CAF	Gen. PV	TWh	0	0	0	0	0	0	0	0.1	0.2	0.2	0.2	0	0	0.1
CAN	Carbon Emission	MT	92.8	134.1	113.6	58.2	22.4	98.1	20.3	2.9	112.8	75.6	34.8	110.7	50	9
CAN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	2.2
CAN	Ann. Cost	B.USD	41.5	43.2	42.3	44.1	48.8	46.6	45.4	54.4	42.2	45	53.7	42.1	49.2	61.4
CAN	Ann. Demand	TWh	577.2	614.7	651.2	697.6	756	651.2	697.6	756	651.2	697.6	756	651.2	697.6	756
CAN	Ann. Supply	TWh	645.7	715.8	757.7	851	954.3	730.8	798.3	1027.6	751.7	818.8	986.8	753.3	876.8	1059.2
CAN	Ann. Import	TWh	18.9	13.7	12	12.7	5.1	45.1	58	42.4	28.2	25.9	17.9	19.9	18.6	8
CAN	Ann. Export	TWh	86.4	108.1	113.7	139.1	194.6	119.9	150.8	294.5	123.3	142.5	242.9	115.6	195.9	296.5
CAN	Gen. Coal	TWh	56.1	65.3	6.6	0.1	0	3.3	0	0	7.6	0.9	0.2	5.9	0.3	0
CAN	Gen. Gas	TWh	93.5	169.9	275.2	160.4	61.8	250.5	56	7.7	269.5	206.3	95.3	270.7	137.2	24.5
CAN	Gen. Nuclear	TWh	105.2	81.8	20.9	0	0	20.9	0	0	20.9	0	0	20.9	0	0
CAN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	5.6
CAN	Gen. Hydro	TWh	329.4	333	290.9	225.4	185	290.9	213.8	323.7	290.9	207.7	204.1	290.9	203.7	269.8
CAN	Gen. Wind	TWh	44.6	50.6	134.8	427.8	629.5	136.6	498.2	614.1	129.7	363.2	609.6	135.9	493.6	666
CAN	Gen. PV	TWh	3	3.9	3.9	0.9	41.5	3.9	1.1	52.1	8.4	10.5	47.5	3.9	13	58.6
CHE	Carbon Emission	MT	0.3	0.3	0.1	0	0	0.1	0	0	0.1	0	0	0.1	0	0
CHE	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHE	Ann. Cost	B.USD	6	5.7	4.4	4.3	4.7	4.9	4.7	4.6	4.4	4.3	4.3	4.4	4.4	4.3
CHE	Ann. Demand	TWh	62.2	64.5	66.2	69.6	74	66.2	69.6	74	66.2	69.6	74	66.2	69.6	74
CHE	Ann. Supply	TWh	85.4	82.5	71.9	72.1	81	80.7	79.2	76.9	71.9	72.2	72	71.9	74.3	71.8
CHE	Ann. Import	TWh	20.6	6.5	44.9	44.4	66.2	28.1	67.4	83.6	35.8	36.1	33.6	44.1	63.3	91.2
CHE	Ann. Export	TWh	43.9	24.4	50.5	46.9	73.2	42.6	77.1	86.5	41.5	38.7	31.5	49.7	68.1	89
CHE	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHE	Gen. Gas	TWh	0.5	0.4	0.2	0	0	0.2	0	0	0.2	0	0	0.2	0	0
CHE	Gen. Nuclear	TWh	22.7	14.9	0	0	0	0	0	0	0	0	0	0	0	0
CHE	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHE	Gen. Hydro	TWh	58.6	62.1	62.1	62.1	61.1	62.1	62.1	61.1	62.1	62.1	61.1	62.1	62.1	61.1
CHE	Gen. Wind	TWh	0.2	0.5	3.1	4.7	6.9	6.9	6.9	6.9	3.1	4.8	6.9	3.1	6.9	6.9
CHE	Gen. PV	TWh	1.7	2.9	2.3	1.2	9.1	7.4	6.3	5.1	2.3	1.2	0	2.3	1.2	0

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
CHL	Carbon Emission	MT	32	32.6	15.4	0.3	0.3	3.9	0	0	13.1	0.4	0.5	15.7	0.3	0.1
CHL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHL	Ann. Cost	B.USD	5.7	6.7	6.4	6	7.1	5.8	5.8	7	6.3	6.4	7.4	6.4	6	7
CHL	Ann. Demand	TWh	70.7	79.3	103.4	131.8	162.1	103.4	131.8	162.1	103.4	131.8	162.1	103.4	131.8	162.1
CHL	Ann. Supply	TWh	70.8	79.4	95.2	118.4	142.8	84.2	115.6	138.7	93.4	124.4	142.9	95.6	118.6	143.1
CHL	Ann. Import	TWh	0	0	12.4	26.5	36.8	23	32.7	40.8	14.4	23.4	38.1	12.7	27.8	38.1
CHL	Ann. Export	TWh	0	0	3.9	12.5	16.9	3.1	15.7	16.6	3.4	15.4	18.4	4	14	18.4
CHL	Gen. Coal	TWh	29.7	31.2	15.3	0.3	0.3	3.2	0	0	12.9	0.4	0.6	15.5	0.3	0.1
CHL	Gen. Gas	TWh	8.6	7.6	0.1	0	0	0	0	0	0.1	0	0	0.3	0	0
CHL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHL	Gen. Hydro	TWh	22.3	22.6	22.7	29	36.7	21.4	27.5	39.5	23.5	31.6	40.7	22.7	29.2	35.4
CHL	Gen. Wind	TWh	3.2	7.1	19.5	18.5	28.7	19.5	18.4	29	20.1	20.8	30.1	19.5	18.6	30.8
CHL	Gen. PV	TWh	1.2	5.3	7	12.6	19.2	6.9	11.8	12.3	6.5	11.9	11.9	7	12.5	19
CHN	Carbon Emission	MT	3164.8	3646.6	1948.6	1326.5	1011.4	1837.5	-268.5	-1265.7	1930.8	1303.1	962.7	1948.6	1326.5	-34.1
CHN	Carbon Sequester	MT	0	0	0	0	0	0	520.7	1297.5	0	0	0	0	0	446.1
CHN	Ann. Cost	B.USD	286.3	420.7	520.5	565.5	577.9	592.4	583.7	557	527.7	585.3	586.8	520.5	565.5	585.7
CHN	Ann. Demand	TWh	5373.1	6823.3	8861.2	10346.4	10974.5	8861.2	10346.4	10974.5	8861.2	10346.4	10974.5	8861.2	10346.4	10974.5
CHN	Ann. Supply	TWh	5421.6	6866.9	9069.2	10729.7	11410.8	9072.6	10778.1	11363.8	9033.5	10645.4	11387.3	9069.2	10729.7	11400.5
CHN	Ann. Import	TWh	0	0	0	0	5.7	0	0	0	0	0	4.8	0	0	21
CHN	Ann. Export	TWh	15.8	0.1	0.2	2.1	2.5	0.2	12.5	9.1	0.2	3.4	7.4	0.2	2.1	2.8
CHN	Gen. Coal	TWh	3478.2	4017.9	2164.7	1487	1189.9	1977.7	206.3	12.3	2145.4	1465.7	1167.6	2164.7	1487	261.2
CHN	Gen. Gas	TWh	119.2	105.9	50.2	25.2	195.7	194.6	188.7	47.5	49.6	20.3	96.3	50.2	25.2	491.9
CHN	Gen. Nuclear	TWh	242.4	320	1341.8	1392.3	1409	1365.6	1742.1	1728.1	1293.4	1281.9	1248.5	1341.8	1392.3	1439.9
CHN	Gen. CCS	TWh	0	0	0	0	0	0	565.2	1474.2	0	0	0	0	0	532.7
CHN	Gen. Hydro	TWh	972	1156.2	1611.5	1749.5	1803.8	1609.1	1631.6	1590.5	1532	1673.6	1731.8	1611.5	1749.5	1783.9
CHN	Gen. Wind	TWh	498.6	906.4	3264.5	4874.1	5335	3282.5	5283	5294.8	3329.3	4993.9	5759.6	3264.5	4874.1	5416.4
CHN	Gen. PV	TWh	69.3	315.3	474	927.9	1207.9	473.6	894.8	950.6	536.8	935.9	1113.7	474	927.9	1201.6
CIV	Carbon Emission	MT	2.6	2.5	3.8	5.9	9.6	2.4	3.2	-2.9	3.4	3.9	9.4	3.8	5.9	1.3
CIV	Carbon Sequester	MT	0	0	0	0	0	0	0	6.9	0	0	0	0	0	5
CIV	Ann. Cost	B.USD	0.5	0.6	1.2	2.5	4.8	1.3	2.3	4.4	1.3	2.6	4.8	1.2	2.5	4.7
CIV	Ann. Demand	TWh	6.6	9.4	19.6	37.6	64.8	19.6	37.6	64.8	19.6	37.6	64.8	19.6	37.6	64.8
CIV	Ann. Supply	TWh	9	10.1	19.4	36.9	63.7	18.5	33.2	53.6	19.1	37.9	63	19.4	36.9	60.2
CIV	Ann. Import	TWh	0.2	0.6	0.8	1.2	2.3	1.7	5.3	12.2	1	1.1	3.2	0.8	1.2	5
CIV	Ann. Export	TWh	2.5	1.4	0.6	0.5	1	0.5	0.8	0.7	0.4	1.3	1.1	0.6	0.5	0.3
CIV	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CIV	Gen. Gas	TWh	5.9	5.6	10	15.9	25.9	6.3	8.8	10.9	9.1	10.3	25.3	10	15.9	16.9
CIV	Gen. Nuclear	TWh	0	0	0	2.7	7.3	2.6	3.6	5.9	0	3.2	4.7	0	2.7	10.1
CIV	Gen. CCS	TWh	0	0	0	0	0	0	0	7.9	0	0	0	0	0	5.7
CIV	Gen. Hydro	TWh	2.7	4.1	9.3	18.1	18.1	9.4	18.1	18.1	8.2	18.1	18.1	9.3	18.1	18.1
CIV	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.5	1.8	1.8	0	0	0
CIV	Gen. PV	TWh	0	0.1	0.1	0.1	12.3	0.1	2.6	10.9	1.2	4.4	13.1	0.1	0.1	9
CMR	Carbon Emission	MT	1.8	2.7	2.1	3.1	4.8	2	0.9	0.7	1.6	1.9	3.8	2.1	3.1	-1
CMR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	3
CMR	Ann. Cost	B.USD	0.5	0.7	1.1	1.6	2.6	1.1	1.6	2.7	1	1.6	2.5	1.1	1.6	3
CMR	Ann. Demand	TWh	6.4	9	18.9	36.1	62.3	18.9	36.1	62.3	18.9	36.1	62.3	18.9	36.1	62.3
CMR	Ann. Supply	TWh	5.3	8.5	16.5	27.7	43.7	16.6	30.3	54.8	15.4	27.2	42.9	16.5	27.7	53.1
CMR	Ann. Import	TWh	1.2	0.7	4	11.4	23	4	12.4	21.1	4.9	11.8	23.8	4	11.4	18.7
CMR	Ann. Export	TWh	0	0.1	1.4	2.4	3.4	1.5	4.1	11	1.1	2.3	3.1	1.4	2.4	6.9
CMR	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CMR	Gen. Gas	TWh	1.5	4.9	4.3	8	12.8	4.2	2.4	1.8	3	5.1	9.9	4.3	8	5.3
CMR	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CMR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	3.4
CMR	Gen. Hydro	TWh	2.8	2.8	8.4	15.4	24.1	8.5	22.6	38	7.3	13.6	23.9	8.4	15.4	35.7
CMR	Gen. Wind	TWh	0	0	1.6	2.2	3.3	1.6	3.3	6.4	1.8	3	3.7	1.6	2.2	3.3
CMR	Gen. PV	TWh	0	0.1	0.1	0.1	1.7	0.1	0.1	6.8	1.2	3.7	3.7	0.1	0.1	3.5
COD	Carbon Emission	MT	1.4	1.4	1.6	3	4.4	1.5	1.3	1.2	1.5	3.1	4.3	1.6	3	0
COD	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1.7
COD	Ann. Cost	B.USD	0.7	0.8	1.5	2.7	4.9	1.5	2.9	4.8	1.5	2.7	4.8	1.5	2.7	4.6
COD	Ann. Demand	TWh	8	11.3	23.7	45.4	78.3	23.7	45.4	78.3	23.7	45.4	78.3	23.7	45.4	78.3
COD	Ann. Supply	TWh	11.5	12.1	27.3	56.4	106.1	27.2	63.9	109.4	27.4	54.7	103.5	27.3	56.4	99.8
COD	Ann. Import	TWh	1.9	1.4	0.9	1.6	2.8	0.9	2.9	5.4	0.9	1.2	2.9	0.9	1.6	4.7
COD	Ann. Export	TWh	2.8	0.7	3	11.4	28.1	2.9	18.5	29.4	3.1	9.5	25.4	3.1	11.4	23.4
COD	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COD	Gen. Gas	TWh	0.1	0.3	2.9	7.5	11.4	2.7	3.1	2.8	2.8	7.9	11	2.9	7.5	4.5
COD	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COD	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.9
COD	Gen. Hydro	TWh	10	10.4	22.5	46.8	92.7	22.2	58.7	102.8	22.5	44.2	90	22.5	46.8	90.4
COD	Gen. Wind	TWh	0	0	1.5	1.8	1.8	1.8	1.8	3.4	1.5	2	2	1.5	1.8	2.6
COD	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0.2	0.3	0.5	0.4	0.1	0.1	0
COG	Carbon Emission	MT	0.7	0.7	0.3	0.5	0.3	0.3	0.3	0	0.3	0.5	0.3	0.3	0.5	-0.1
COG	Carbon Sequester	MT	0	0	0	0	0	0	0	0.2	0	0	0	0	0	0.2
COG	Ann. Cost	B.USD	0.2	0.2	0.2	0.4	0.5	0.2	0.3	0.5	0.2	0.4	0.6	0.2	0.4	0.5
COG	Ann. Demand	TWh	0.9	1.2	2.6	5	8.6	2.6	5	8.6	2.6	5	8.6	2.6	5	8.6
COG	Ann. Supply	TWh	2.3	2.3	2.6	7.1	11.8	2.7	6.5	11.6	2.8	7.3	12	2.6	7.1	11.7
COG	Ann. Import	TWh	0.5	0.5	3.3	10.5	25.9	3.4	14.9	21	3.2	8.7	23.3	3.3	10.5	20.1
COG	Ann. Export	TWh	1.9	1.4	3.2	12.5	28.7	3.3	16	23.4	3.3	10.9	26.5	3.3	12.5	22.8
COG	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COG	Gen. Gas	TWh	1.4	1.4	0.5	1.1	0.8	0.5	0.5	0.3	0.5	1	0.7	0.5	1.1	0.4
COG	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COG	Gen. CCS	TWh	0	0	0	0	0	0	0	0.2	0	0	0	0	0	0.3
COG	Gen. Hydro	TWh	0.8	0.8	2.1	6.1	11.1	2.1	6.1	11	2.1	5.8	10.8	2.1	6.1	11.1
COG	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0	0.1	0.1	0	0	0
COG	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.1	0.3	0.3	0	0	0
COL	Carbon Emission	MT	14.4	13.3	3	1.3	1.4	2.8	0.7	0.4	3.1	1.1	1.6	3	1.3	0.1
COL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COL	Ann. Cost	B.USD	3.7	4	4.6	5.2	5.8	4.7	5.3	5.9	4.6	5.3	5.8	4.6	5.2	5.7
COL	Ann. Demand	TWh	57	63.9	83.4	106.3	130.7	83.4	106.3	130.7	83.4	106.3	130.7	83.4	106.3	130.7
COL	Ann. Supply	TWh	72.3	73.4	104.5	128.4	142.4	104.3	127.6	142.1	105.1	130.3	139.4	104.5	128.4	142.8
COL	Ann. Import	TWh	0	0.5	8.4	13.6	21.2	7.6	13.5	18.3	7.7	11.5	18.8	8.4	13.7	23.3

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
COL	Ann. Export	TWh	13.2	8.2	22.9	30.9	30	24.1	29.8	25.8	22.8	31.8	24	22.9	30.9	32.5
COL	Gen. Coal	TWh	11	10.3	2.6	1.3	1.2	2.4	0.4	0.1	2.6	1.1	1.4	2.6	1.3	0
COL	Gen. Gas	TWh	10.3	9.3	0.6	0.2	0.5	0.7	0.5	0.7	0.9	0.1	0.5	0.6	0.2	0.2
COL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COL	Gen. Hydro	TWh	49.3	52	82.4	101.9	101.8	84	101.4	101.6	81.9	101.9	101.5	82.4	101.9	101.7
COL	Gen. Wind	TWh	0.1	0.1	17.2	20.7	34.7	15.6	20.9	34.9	17.4	21.1	30.1	17.2	20.7	36.3
COL	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.8	1.8	1.6	0.1	0.1	0.2
CRI	Carbon Emission	MT	0.1	0.1	0	0	0	0	0	0	0	0	0	0	0	0
CRI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRI	Ann. Cost	B.USD	0.5	0.7	1.1	1.3	1.4	1.1	1.4	1.4	1.1	1.2	1.4	1.1	1.3	1.4
CRI	Ann. Demand	TWh	10.4	11.6	15.2	19.3	23.8	15.2	19.3	23.8	15.2	19.3	23.8	15.2	19.3	23.8
CRI	Ann. Supply	TWh	10	12.8	26.4	34	33.7	27.2	34.8	33.9	25.9	28.9	34.9	26.4	34	33.7
CRI	Ann. Import	TWh	2.6	3.1	1.2	0.9	1.7	1.9	3.2	3.3	1.3	1.6	2.9	1.2	1	1.8
CRI	Ann. Export	TWh	2.2	3.6	11.4	15.1	11	12.5	17.3	12.6	11	10.7	12.7	11.4	15.1	10.9
CRI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRI	Gen. Gas	TWh	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0
CRI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRI	Gen. Hydro	TWh	6.8	8.3	8.3	7	6	8.3	7	6	8.3	7	6	8.3	7	6
CRI	Gen. Wind	TWh	1.3	2.6	16.3	20.6	20.6	17.1	20.6	20.6	15.4	18.5	20.6	16.3	20.6	20.6
CRI	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0.2	0.5	1.2	1.2	0.1	0.1	0
CUB	Carbon Emission	MT	13.8	10.7	6.9	4.2	3.8	3.7	0.8	-3	6	3.5	3	6.9	4.2	0.3
CUB	Carbon Sequester	MT	0	0	0	0	0	0	0	3.4	0	0	0	0	0	1.5
CUB	Ann. Cost	B.USD	2.4	2.3	2.5	2.8	3.5	2.8	2.9	3.6	2.9	3.4	4.1	2.5	2.8	3.6
CUB	Ann. Demand	TWh	17.8	20.9	25.9	32.7	40.8	25.9	32.7	40.8	25.9	32.7	40.8	25.9	32.7	40.8
CUB	Ann. Supply	TWh	17.8	20.9	25.9	32.8	41	26	32.7	40.8	26	33.2	41.1	25.9	32.8	40.9
CUB	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CUB	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CUB	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CUB	Gen. Gas	TWh	4.6	14.9	13.1	11.2	10.2	4.6	2.2	1.2	10.4	9.5	8	13.1	11.2	4.8
CUB	Gen. Nuclear	TWh	0	0	0	4.9	9.5	4.9	15.4	20	0	1.7	7.4	0	4.9	14.8
CUB	Gen. CCS	TWh	0	0	0	0	0	0	0	4.2	0	0	0	0	0	1.8
CUB	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CUB	Gen. Wind	TWh	0	0	3.7	9.2	10.3	10.3	10.4	8.8	7.7	15	16.9	3.7	9.2	10.3
CUB	Gen. PV	TWh	0	0.2	6.6	7.1	10.6	3.8	4.3	6.3	4.7	5.4	7.3	6.6	7.1	8.8
CYP	Carbon Emission	MT	3.1	1.9	1.3	1.2	1.3	1.3	0.2	-0.2	1	0.6	0.7	1.3	1.2	-0.1
CYP	Carbon Sequester	MT	0	0	0	0	0	0	0	0.3	0	0	0	0	0	0.4
CYP	Ann. Cost	B.USD	0.6	0.5	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.7	0.5	0.5	0.7
CYP	Ann. Demand	TWh	4.3	4.7	5.5	6.3	7.3	5.5	6.3	7.3	5.5	6.3	7.3	5.5	6.3	7.3
CYP	Ann. Supply	TWh	4.3	4.7	5.5	6.4	7.5	5.6	6.5	7.3	5.5	6.5	7.4	5.5	6.4	7.6
CYP	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CYP	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CYP	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CYP	Gen. Gas	TWh	0.8	3.3	2.8	3.4	3.7	2.6	0.6	0.2	1.9	1.6	1.8	2.8	3.4	0.8
CYP	Gen. Nuclear	TWh	0	0	0	0	0	0	1.4	2	0	0	0	0	0	0.6
CYP	Gen. CCS	TWh	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0.5
CYP	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CYP	Gen. Wind	TWh	0.2	0.3	0.3	0.1	0	0.3	0.6	0.6	1.3	2.6	2.6	0.3	0.1	0
CYP	Gen. PV	TWh	0.1	0.3	2.1	2.9	3.8	2.3	4	4.3	1.5	1.5	2.2	2.1	2.9	5.7
CZE	Carbon Emission	MT	8	2.5	1.2	0	0	1	0	0	1.1	0	0	1.1	0	-0.4
CZE	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
CZE	Ann. Cost	B.USD	6.6	5.7	3.4	3.3	2.3	3.7	4.3	3.1	4.3	5	3.3	3.4	3.3	3.3
CZE	Ann. Demand	TWh	58.4	60.6	62.2	65.3	69.5	62.2	65.3	69.5	62.2	65.3	69.5	62.2	65.3	69.5
CZE	Ann. Supply	TWh	49.2	44.7	27.6	28.9	25.4	32.7	41.7	34.6	41.9	53.5	37.3	27.5	28.9	35.4
CZE	Ann. Import	TWh	15.9	16.1	35.5	37.1	49	30.2	37	50	21.1	13.5	37.4	35.5	37.6	45.5
CZE	Ann. Export	TWh	6.6	0.2	0.9	0.6	4.9	0.7	13.3	14.9	0.7	1.7	5.2	0.8	1.2	11.2
CZE	Gen. Coal	TWh	8.6	2.4	1.1	0	0	0.9	0	0	1	0	0	1	0	0
CZE	Gen. Gas	TWh	1.7	1.5	0.8	0	0	0.8	0	0	0.8	0	0	0.8	0	0
CZE	Gen. Nuclear	TWh	30.9	30.9	15.8	15.8	0	15.8	12.5	0	15.8	15.8	0	15.8	15.8	0
CZE	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.5
CZE	Gen. Hydro	TWh	2	3.8	3.8	3.8	3.3	3.8	3.8	3.3	3.8	3.8	3.3	3.8	3.8	3.3
CZE	Gen. Wind	TWh	0.8	1	1	6.3	6.3	6.3	22.5	28.3	11.9	23.5	23.5	1	6.3	28.3
CZE	Gen. PV	TWh	2.2	2.2	2.2	0.1	12.8	2.2	0.1	0	5.7	7.5	7.5	2.2	0.1	0
DEU	Carbon Emission	MT	192.2	163.3	49.5	0.1	0	46.2	0.1	0	49.1	0.6	0.5	48.9	0.1	-0.2
DEU	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
DEU	Ann. Cost	B.USD	58.3	60	36.2	30.1	33.2	49.6	38.3	36.5	42.4	38.1	41	36.2	34.9	40.5
DEU	Ann. Demand	TWh	546.2	566.8	582	611.2	650.4	582	611.2	650.4	582	611.2	650.4	582	611.2	650.4
DEU	Ann. Supply	TWh	571.2	581.4	301.4	278.7	353.1	478.4	404.3	397.5	394.7	382.9	454.3	301.7	359.1	455.5
DEU	Ann. Import	TWh	68.9	61.8	502.5	469.8	353.7	143.3	286.7	345.6	353	309.2	237	494.2	303.8	298.9
DEU	Ann. Export	TWh	93	72.9	205.5	125.2	47.3	32	66.8	82.6	153.9	72.3	33.8	197.4	40.9	93.6
DEU	Gen. Coal	TWh	201.5	173.3	53.2	0	0	49.1	0	0	52.7	0.7	0.6	52.4	0	0
DEU	Gen. Gas	TWh	47.5	36	10.9	0	0	10.9	0.1	0	10.9	0	0	10.9	0	0
DEU	Gen. Nuclear	TWh	86.3	86.3	0	0	0	0	0	0	0	0	0	0	0	0
DEU	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
DEU	Gen. Hydro	TWh	26.6	21.8	34	36.4	36.4	40.3	40.2	44.1	34.3	36.4	36.4	34.3	36.4	44.1
DEU	Gen. Wind	TWh	131.1	177.4	117.6	196.6	271.3	292.6	320	316.9	178	225	299.6	118.4	276.9	375.1
DEU	Gen. PV	TWh	40.8	49	46.8	8.3	8.3	46.8	8.3	1.2	79.9	84.1	81.5	46.8	8.3	0
DJI	Carbon Emission	MT	0.8	0.7	0.4	0	0	0.4	0	0	0.4	0	0	0.4	0	0
DJI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DJI	Ann. Cost	B.USD	0.1	0.2	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2
DJI	Ann. Demand	TWh	0.4	0.5	1.1	2.1	3.7	1.1	2.1	3.7	1.1	2.1	3.7	1.1	2.1	3.7
DJI	Ann. Supply	TWh	0.8	0.8	1.1	2.5	4.6	1.4	3	5.1	1.5	3.3	5.5	1.1	2.5	4.6
DJI	Ann. Import	TWh	0	0	0	0.8	0.5	0	0.4	0.5	0.4	0.7	0.7	0	0.8	0.7
DJI	Ann. Export	TWh	0.5	0.2	0.1	1.1	1.4	0.3	1.3	2	0.7	1.8	2.5	0.1	1.1	1.6
DJI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DJI	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DJI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DJI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DJI	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DJI	Gen. Wind	TWh	0	0	0	1.2	1.2	0.2	1.4	1.4	0.2	0.7	0.7	0	1.2	1.2
DJI	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.1	0.2	0.2	0	0	0
DNK	Carbon Emission	MT	2.3	3	0.2	0	0	0.2	0	0	0.2	0	0	0.2	0	0
DNK	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DNK	Ann. Cost	B.USD	3.8	3.7	3.3	4.4	5.7	3.9	5	6.3	3.3	4.3	5.6	3.3	4.4	5.8
DNK	Ann. Demand	TWh	33.8	35.1	36	37.8	40.3	36	37.8	40.3	36	37.8	40.3	36	37.8	40.3

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
DNK	Ann. Supply	TWh	26	29.6	39.4	69.8	96.3	50.3	80.7	107.3	38	63.7	90.6	39.4	69.8	96.7
DNK	Ann. Import	TWh	19.4	34.1	43	13.6	14.4	18.9	36.6	53.2	38.1	21.7	14.5	41.4	19.2	56.9
DNK	Ann. Export	TWh	11.2	28.5	46.3	45.3	70.2	33	79	119.6	39.9	47.5	64.1	44.6	50.9	112.7
DNK	Gen. Coal	TWh	2	2.9	0	0	0	0	0	0	0	0	0	0	0	0
DNK	Gen. Gas	TWh	1.4	1.2	0.6	0	0	0.6	0	0	0.6	0	0	0.6	0	0
DNK	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DNK	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DNK	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DNK	Gen. Wind	TWh	18.9	21.5	35.2	66.5	93.3	46.1	77.4	104.3	32.8	58.1	84.9	35.2	66.5	93.3
DNK	Gen. PV	TWh	0.7	1	0.6	0.3	0	0.6	0.3	0	1.6	2.7	2.6	0.6	0.3	0
DOM	Carbon Emission	MT	12.5	12.5	5.2	3.4	4.5	3.1	0.6	-1.5	5.1	3.1	3.7	5.2	3.4	0.3
DOM	Carbon Sequester	MT	0	0	0	0	0	0	0	1.9	0	0	0	0	0	2
DOM	Ann. Cost	B.USD	1.6	2.1	2.1	2.3	3	2.2	2.4	3	2.2	2.6	3.2	2.1	2.3	3.1
DOM	Ann. Demand	TWh	17.1	20.1	24.9	31.4	39.2	24.9	31.4	39.2	24.9	31.4	39.2	24.9	31.4	39.2
DOM	Ann. Supply	TWh	17.1	20.2	24.9	31.6	39.6	24.9	31.4	39.3	24.9	31.7	39.6	24.9	31.6	39.2
DOM	Ann. Import	TWh	0	0	0	0	0	0	0.1	0	0	0	0.1	0	0	0.1
DOM	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	Gen. Coal	TWh	4.7	4.9	0.3	0	0	0	0	0	0.2	0	0	0.3	0	0
DOM	Gen. Gas	TWh	3.6	7.1	8.5	9.1	12	3.7	1.5	1	8.2	8.1	9.8	8.5	9.1	6.1
DOM	Gen. Nuclear	TWh	0	0	0	2.3	2.9	5.1	13.2	16.3	0	0.7	2.8	0	2.3	9.1
DOM	Gen. CCS	TWh	0	0	0	0	0	0	0	2.3	0	0	0	0	0	2.4
DOM	Gen. Hydro	TWh	1.1	1.1	1.1	1.1	1.6	1.1	1.1	1.7	1.1	1.1	1.6	1.1	1.1	1.4
DOM	Gen. Wind	TWh	0.3	1.1	8.9	12.6	12.5	11.4	12.6	12.5	8.6	14.9	14.8	8.9	12.6	12.9
DOM	Gen. PV	TWh	0.1	0.3	4.3	6.4	10.7	1.8	2.9	5.5	3.4	3.7	7.5	4.3	6.4	7.2
DZA	Carbon Emission	MT	21	23.7	14.8	3.6	2.4	6.5	0.7	0.8	14.8	3.4	2	14.8	3.6	1.2
DZA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
DZA	Ann. Cost	B.USD	4.3	5	5.6	6.3	6	6.1	7.1	7.2	5.7	6.2	6.5	5.6	6.3	6.1
DZA	Ann. Demand	TWh	55.8	63.6	87.3	117.4	138.5	87.3	117.4	138.5	87.3	117.4	138.5	87.3	117.4	138.5
DZA	Ann. Supply	TWh	55.4	63.4	87.7	133.2	141.6	88.1	132.7	145.4	87.8	124.1	150.1	87.7	133.2	144.2
DZA	Ann. Import	TWh	0.5	0.2	0.4	2.3	14.1	0.8	1.8	11.6	0.6	9.3	10.4	0.4	2.2	13.8
DZA	Ann. Export	TWh	0	0	0.2	14.2	12.9	0.7	14.8	16	0.6	12.6	17.2	0.2	14.1	14.1
DZA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DZA	Gen. Gas	TWh	53.9	61.1	38.7	9.5	6.3	16.6	1.9	2	38.7	9	5.2	38.7	9.5	4.2
DZA	Gen. Nuclear	TWh	0	0	0	0	0	22.4	14.2	13.1	0	0	0	0	0	0
DZA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
DZA	Gen. Hydro	TWh	0.7	0.7	0.4	0.4	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.6
DZA	Gen. Wind	TWh	0	0	26	54.1	63.4	26	45.5	57.1	27.4	61.8	66.8	26	54.1	63.1
DZA	Gen. PV	TWh	0.1	0.9	0.9	4.6	6.7	0.9	6.2	8.4	5.3	13.2	13.2	0.9	4.6	11.4
ECU	Carbon Emission	MT	7.5	4.3	1.3	0.2	0.4	1.3	0.2	0.3	1.3	0.1	0.6	1.3	0.2	0.1
ECU	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECU	Ann. Cost	B.USD	1.8	2.1	2	2.1	2.2	2.1	2.2	2.4	2.1	2.2	2.7	2	2.1	2.2
ECU	Ann. Demand	TWh	25.2	28.2	36.8	46.9	57.6	36.8	46.9	57.6	36.8	46.9	57.6	36.8	46.9	57.6
ECU	Ann. Supply	TWh	22.4	32	37.4	47.4	48.8	39.1	49.3	51.3	38.8	43.2	53.7	37.4	47.5	49.6
ECU	Ann. Import	TWh	12.9	8.4	16.4	21.2	28.3	14.6	19.4	27.8	15.1	22.7	22.3	16.4	21.2	27.2
ECU	Ann. Export	TWh	9.7	9.8	14.9	20.5	18.8	14.7	20.7	20.8	14.9	17.3	17.7	14.9	20.6	18.5
ECU	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECU	Gen. Gas	TWh	2.5	1.5	0.8	0.5	0.8	0.8	0.4	0.6	0.8	0.2	1.4	0.8	0.5	0.4
ECU	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECU	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECU	Gen. Hydro	TWh	12.8	26.2	26.4	37.6	38.9	27.7	39	39.1	26.2	29.6	39	26.4	37.7	39
ECU	Gen. Wind	TWh	0.1	0.1	3.8	3.9	3.8	4.1	4.2	3.9	4.3	5.1	5	3.8	3.9	4.6
ECU	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	2	1.3	2.9	2.9	0.1	0.1	0
EGY	Carbon Emission	MT	72.3	77.8	40	6.5	3.9	24.7	3.2	1.3	39.8	3.3	1.8	40	6.5	3.7
EGY	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EGY	Ann. Cost	B.USD	12.8	16.5	17.8	20.2	23.7	20.8	24.3	28.2	18.5	20.6	23.9	17.8	20.2	23.9
EGY	Ann. Demand	TWh	169.6	193.1	265.1	356.5	420.7	265.1	356.5	420.7	265.1	356.5	420.7	265.1	356.5	420.7
EGY	Ann. Supply	TWh	146.6	172	268.8	413.5	528.1	292.2	448.6	563.3	264.2	386.3	520.8	268.8	413.5	529.3
EGY	Ann. Import	TWh	26.6	23.4	6	24.1	22.2	4.1	6.3	7.4	6.9	19.9	31	6	23.9	24.8
EGY	Ann. Export	TWh	0	0	4.6	64.6	108.8	26.9	85.4	133	1.9	33.5	107.7	4.6	64.3	112.3
EGY	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EGY	Gen. Gas	TWh	113.7	136.2	87.6	17.1	10.2	47.1	8.2	3.2	87.2	8.7	4.7	87.6	17.1	9.8
EGY	Gen. Nuclear	TWh	0	0	21.5	16.6	13.1	84.9	67.1	40.6	17.3	12.4	8	21.5	16.6	12.3
EGY	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EGY	Gen. Hydro	TWh	0.4	0.6	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1
EGY	Gen. Wind	TWh	3.6	7	143	361.9	465.7	143	345.6	455.6	120.7	291.5	431.4	143	361.9	465.9
EGY	Gen. PV	TWh	0	2.5	2.5	10.4	31.7	2.9	20.2	56.7	20.7	55.2	58.4	2.5	10.4	33.3
ERI	Carbon Emission	MT	0.4	0.3	0.3	0	0	0.2	0	0	0.3	0	0.1	0.3	0	0
ERI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ERI	Ann. Cost	B.USD	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2
ERI	Ann. Demand	TWh	0.4	0.5	1.1	2.1	3.6	1.1	2.1	3.6	1.1	2.1	3.6	1.1	2.1	3.6
ERI	Ann. Supply	TWh	0.4	0.5	1.5	2.6	4.7	1	2.6	4.7	1.6	3	5.4	1.5	2.6	4.7
ERI	Ann. Import	TWh	0	0	0	1	1.1	0.1	1.1	1.5	0.5	1.7	1.8	0	1	1.3
ERI	Ann. Export	TWh	0	0	0.4	1.5	2.3	0	1.7	2.6	0.9	2.7	3.6	0.4	1.6	2.4
ERI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ERI	Gen. Gas	TWh	0	0.1	0.5	0.1	0.1	0	0.1	0.1	0.3	0.1	0.2	0.5	0.1	0.1
ERI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ERI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ERI	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ERI	Gen. Wind	TWh	0	0	0	0.3	0.3	0	0	0	0.2	0.7	0.7	0	0.6	0.6
ERI	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.1	0.2	0.2	0.1	0.1	0
ESP	Carbon Emission	MT	61.3	47.4	17.9	8.5	1.8	11.9	2.1	1	16.6	6.4	1.9	17.4	3.7	0
ESP	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESP	Ann. Cost	B.USD	27.1	26.1	22.4	22.7	22.7	24.3	24.4	24.4	22.2	21.9	21.1	22.3	22.4	23.4
ESP	Ann. Demand	TWh	259.8	269.6	276.8	290.7	309.4	276.8	290.7	309.4	276.8	290.7	309.4	276.8	290.7	309.4
ESP	Ann. Supply	TWh	276.2	271.9	294.9	354.6	418	320.3	378	434.4	287.6	325.9	360.3	294.9	350.3	416.4
ESP	Ann. Import	TWh	10.5	7	9.7	14.6	26.2	10.3	24.9	24.3	12.5	16.2	23.4	11.1	21.7	27.5
ESP	Ann. Export	TWh	25.5	7.4	24.1	72.3	120.9	48.6	100.6	135	20	45.3	64.4	25.5	72.7	120.6
ESP	Gen. Coal	TWh	42.3	33.7	6.7	1	1.6	3.4	0	0.4	6.3	0.5	1.6	6.6	0	0
ESP	Gen. Gas	TWh	39.5	34.2	30.2	20.2	0.6	21.8	5.7	1.1	27.5	15.9	0.7	29.3	10	0
ESP	Gen. Nuclear	TWh	43.6	53.8	0	0	0	0	0	0	0	0	0	0	0	0
ESP	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESP	Gen. Hydro	TWh	52.4	53	34.6	33.3	17.6	40.7	33.3	17.6	34.6	34	18.6	34.6	33.3	18.9
ESP	Gen. Wind	TWh	70.4	73.8	117.4	145	194	134.6	190	206.8	120.5	152.9	212.9	117.4	155.2	212.9
ESP	Gen. PV	TWh	7.6	7.8	80.6	133.6	186.1	94.8	128.2	191	73	100.2	107.5	81.7	130.5	167
EST	Carbon Emission	MT	0.7	0.6	0.3	0	0	0.2	0	0	0.3	0	0	0.3	0	0
EST	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
EST	Ann. Cost	B.USD	0.6	0.5	0.5	0.5	0.6	0.7	0.8	0.7	0.5	0.6	0.6	0.5	0.6	0.8
EST	Ann. Demand	TWh	7.7	8	8.2	8.6	9.2	8.2	8.6	9.2	8.2	8.6	9.2	8.2	8.6	9.2
EST	Ann. Supply	TWh	2.4	2.7	3.2	2.9	7.4	5.4	8.6	8.5	3.6	4.6	6.4	3.2	4.7	8.9
EST	Ann. Import	TWh	5.6	5.9	11.2	7.1	3.8	3.8	2.6	4.5	8.9	4.5	5	11.2	4.5	4.4
EST	Ann. Export	TWh	0.3	0.6	6.2	1.3	2	1	2.6	3.8	4.3	0.4	2.2	6.2	0.5	4.1
EST	Gen. Coal	TWh	0.6	0.5	0.3	0	0	0.2	0	0	0.3	0	0	0.3	0	0
EST	Gen. Gas	TWh	0.3	0.2	0	0	0	0	0	0	0	0	0	0	0	0
EST	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EST	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EST	Gen. Hydro	TWh	0	0.2	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
EST	Gen. Wind	TWh	0.9	1.1	1.7	1.7	6.3	4	7.4	7.4	1.8	2.8	4.7	1.7	3.5	7.4
EST	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.3	0.6	0.6	0.1	0.1	0
ETH	Carbon Emission	MT	3.3	2.1	2.2	1.7	2.6	1.8	1.2	1.1	2.2	1.2	2.6	2.2	1.6	-0.2
ETH	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1.4
ETH	Ann. Cost	B.USD	1.2	1.3	1.8	2.3	3.4	1.9	2.3	3.4	1.9	2.6	3.7	1.8	2.3	3.5
ETH	Ann. Demand	TWh	9.1	12.9	27.1	52	89.6	27.1	52	89.6	27.1	52	89.6	27.1	52	89.6
ETH	Ann. Supply	TWh	17.3	18.8	31.8	48.5	73.8	32	46.8	73.3	31.6	51.5	75.3	31.8	48.4	74.5
ETH	Ann. Import	TWh	0.6	0.5	0.1	4.7	15.9	0.3	6.3	16.6	0.4	4.2	14.7	0.1	4.8	15.4
ETH	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ETH	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ETH	Gen. Gas	TWh	0	3.9	5.1	4.5	7.1	4.1	3.2	2.9	5.1	3.3	7	5.1	4.4	3.3
ETH	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ETH	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6
ETH	Gen. Hydro	TWh	12.5	12.6	12.6	12.2	13.6	12.6	12.2	13.2	12.8	12.3	13.6	12.6	12.2	13.3
ETH	Gen. Wind	TWh	1.2	1.2	1.7	1.2	6.8	1.5	1	6.4	4	11.6	14.5	1.7	1.2	6.6
ETH	Gen. PV	TWh	0	0.1	0.1	0.1	1.5	0.1	0.1	2.8	1.4	5.1	5.1	0.1	0.1	1.9
FIN	Carbon Emission	MT	10.7	5.6	3.3	0.2	0	1.2	0	0	3.5	0	0	3.1	0	0
FIN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIN	Ann. Cost	B.USD	6.3	6.5	5.7	5.4	5.8	6.2	5.6	6	6	6.1	6.1	5.6	5.7	6.3
FIN	Ann. Demand	TWh	82.7	85.8	88.1	92.5	98.4	88.1	92.5	98.4	88.1	92.5	98.4	88.1	92.5	98.4
FIN	Ann. Supply	TWh	56.1	59.9	49.9	50.2	59.5	59.4	53.7	60.3	55.2	60.2	62.9	49.8	54.6	60.5
FIN	Ann. Import	TWh	31.4	30.4	39.8	45.5	44	32.8	43.5	43.8	34.9	37.7	41.9	40	43.1	43.9
FIN	Ann. Export	TWh	2.5	2.7	0.1	0.5	2.4	1.9	1.5	2.7	0.4	3	3.9	0.1	2.3	3.3
FIN	Gen. Coal	TWh	9.5	3.6	1.8	0	0	1	0	0	1.7	0	0	1.8	0	0
FIN	Gen. Gas	TWh	4	5.7	4.5	0.4	0	0.7	0	0	5.1	0	0	4.1	0	0
FIN	Gen. Nuclear	TWh	20	25	11.9	11.9	11.5	11.7	8.8	6.3	11.9	11.7	11.1	11.9	11.7	7
FIN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIN	Gen. Hydro	TWh	12.5	12	10.6	9.9	10.1	10.6	10.2	12.3	10.6	9.9	7.6	10.6	10.5	11
FIN	Gen. Wind	TWh	2.8	6.3	13.9	20.8	30.6	28.1	27.4	34.6	18.5	31.3	36.9	14.1	25.1	34
FIN	Gen. PV	TWh	0	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.2	0.3	0.3	0.1	0.1	0.2
FJI	Carbon Emission	MT	0.3	0.2	0.1	0	0	0.1	0	0	0.1	0	0	0.1	0	0
FJI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Ann. Cost	B.USD	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
FJI	Ann. Demand	TWh	0.8	0.9	1.1	1.3	1.5	1.1	1.3	1.5	1.1	1.3	1.5	1.1	1.3	1.5
FJI	Ann. Supply	TWh	0.8	1	1.2	1.4	1.9	1.2	1.4	1.9	1.2	1.7	1.8	1.2	1.4	1.9
FJI	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FJI	Gen. Hydro	TWh	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
FJI	Gen. Wind	TWh	0	0.2	0.2	0.2	0	0.2	0.2	0	0.2	0.3	0.5	0.2	0.2	0
FJI	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.1	0.2	0.2	0.1	0.1	0
FRA	Carbon Emission	MT	15.7	14.6	2.8	0.1	0.1	3.3	0.1	0	2.8	0.3	0.1	2.8	0	0
FRA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FRA	Ann. Cost	B.USD	56.8	52.1	28	26.8	36.4	36.2	40.1	43.1	29.5	28.6	36	28.4	32.2	42.6
FRA	Ann. Demand	TWh	464.6	482.1	495.1	519.9	553.3	495.1	519.9	553.3	495.1	519.9	553.3	495.1	519.9	553.3
FRA	Ann. Supply	TWh	598.4	579.1	381.6	440	623.1	515.1	645	704.2	406.4	457.6	593.7	389.3	534.4	722.4
FRA	Ann. Import	TWh	16.6	12.1	145.1	187	183.5	95.6	190	228.3	118.7	154.6	145.5	137.4	162.2	218.9
FRA	Ann. Export	TWh	145.7	102.1	24.7	98.7	239.9	108.8	298	356.2	23.1	83.9	174.8	24.6	168.1	365.9
FRA	Gen. Coal	TWh	9	9.7	0	0	0	0	0	0	0	0	0	0	0	0
FRA	Gen. Gas	TWh	14.9	13.3	6.7	0.3	0.1	8	0.3	0	6.8	0.6	0.1	6.6	0	0
FRA	Gen. Nuclear	TWh	436.2	399.9	95.9	11.6	9.8	93.3	5.4	5	96	11.3	10.2	95.8	10.7	5.1
FRA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FRA	Gen. Hydro	TWh	90.7	87	75.9	76.3	72.9	77.3	76.3	67.4	75.9	76.1	72.4	75.9	76.3	69.1
FRA	Gen. Wind	TWh	31.7	50.1	137.8	239.1	414.5	262	473.9	519.8	147	253.9	389.3	144.8	321.7	522.9
FRA	Gen. PV	TWh	9.4	13.6	24.9	72.7	85.7	34.3	49.6	72.6	40.2	75.6	81.7	25.6	85.7	85.7
GAB	Carbon Emission	MT	0.7	0.7	0.4	0.4	1.2	0.4	0.1	0.2	0.4	0.4	1.5	0.4	0.4	-0.1
GAB	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
GAB	Ann. Cost	B.USD	0.2	0.2	0.3	0.4	0.7	0.4	0.3	0.8	0.5	0.9	1.2	0.3	0.4	0.7
GAB	Ann. Demand	TWh	2.1	2.9	6.2	11.8	20.3	6.2	11.8	20.3	6.2	11.8	20.3	6.2	11.8	20.3
GAB	Ann. Supply	TWh	2.3	2.8	6.1	7.3	10.5	6.1	6.3	15.8	6.2	8.8	13.1	6.1	7.3	12.6
GAB	Ann. Import	TWh	0.1	0.2	1.7	5.2	10.7	1.7	7.4	10.3	1.4	3.7	8	1.7	5.2	10.9
GAB	Ann. Export	TWh	0.3	0.1	1.6	0.7	0.6	1.6	1	2.5	1.3	0.6	0.6	1.6	0.7	1
GAB	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAB	Gen. Gas	TWh	0.9	1.3	0.8	0.9	3.3	0.8	0.2	0.4	0.8	1	4	0.8	0.9	0.5
GAB	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAB	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
GAB	Gen. Hydro	TWh	1.2	1.4	5.2	6.2	7.1	5.2	6	15.2	4.5	4.7	6	5.2	6.2	11.6
GAB	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.3	1	1	0	0	0
GAB	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.5	1.9	1.9	0.1	0.1	0
GBR	Carbon Emission	MT	99.8	78.2	6.2	0	0	6.2	0	0	6.2	0	0	6.2	0	0
GBR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GBR	Ann. Cost	B.USD	31	30.4	29.1	28	29.6	29.3	32.3	32.8	29.4	30.1	31.5	29.1	30	31.1
GBR	Ann. Demand	TWh	336.3	349	358.3	376.3	400.5	358.3	376.3	400.5	358.3	376.3	400.5	358.3	376.3	400.5
GBR	Ann. Supply	TWh	321.5	323.8	395.4	427.3	485.4	396.4	505.6	529	395.3	441.3	499.9	395.6	468.3	507.6
GBR	Ann. Import	TWh	18.4	29	28.7	58.6	77.4	43.7	77.4	95.1	28.1	58.5	72.7	28.6	57.7	97.5
GBR	Ann. Export	TWh	1.7	0.1	55.5	99	148.8	71.2	188	205.5	55	112.5	158.6	55.6	136.8	182.2
GBR	Gen. Coal	TWh	77.6	60.1	0	0	0	0	0	0	0	0	0	0	0	0
GBR	Gen. Gas	TWh	75.4	67	16.3	0	0	16.3	0	0	16.3	0	0	16.3	0	0
GBR	Gen. Nuclear	TWh	60.8	47.8	9.9	11.2	10	10.9	5.6	4.6	9.8	11.2	8.7	10.1	10.5	5.9
GBR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GBR	Gen. Hydro	TWh	6.6	9.1	9.1	9.1	4.7	9.2	9.2	4.7	9.1	9.1	4.7	9.1	9.1	4.7
GBR	Gen. Wind	TWh	71.7	106.5	326.9	383	450.9	327	466.9	500	312.4	361.9	427.5	326.9	424.8	477.5
GBR	Gen. PV	TWh	9	13.2	13.2	4.1	0	13.2	4.1	0	27.8	39.3	39.3	13.2	4.1	0
GEO	Carbon Emission	MT	0.7	0.8	0	0	0	0.1	0	0	0	0	0	0	0	0

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
GEO	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GEO	Ann. Cost	B.USD	0.7	0.7	0.9	1.2	1.2	0.9	1.2	1.2	0.9	1.2	1.2	0.9	1.3	1.4
GEO	Ann. Demand	TWh	10.6	12.2	15.6	19.7	24.4	15.6	19.7	24.4	15.6	19.7	24.4	15.6	19.7	24.4
GEO	Ann. Supply	TWh	11.8	13.9	20.2	28.3	28.3	20.4	28.3	28.3	20.4	28.4	28.4	20.3	28.7	28.6
GEO	Ann. Import	TWh	3.1	0.7	6.7	4.3	8	3.1	4.8	13.8	7.1	5	5.7	3.9	3	9.6
GEO	Ann. Export	TWh	4.3	2.5	11.3	12.7	11.9	7.6	13.4	17.7	11.9	13.7	9.7	8.4	11.8	12.3
GEO	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GEO	Gen. Gas	TWh	1.8	2	0	0	0	0.2	0	0	0	0	0	0.1	0	0
GEO	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GEO	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GEO	Gen. Hydro	TWh	10	11.7	19.2	21.7	21.7	19.2	21.7	21.7	19	21.7	21.7	19.2	21.7	21.7
GEO	Gen. Wind	TWh	0	0.2	1	6.6	6.6	1	6.6	6.6	1.2	6.6	6.6	1	6.6	6.6
GEO	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0	0	0
GHA	Carbon Emission	MT	2.6	2.9	5.8	10.3	13.4	3.6	3.6	-2.9	5	8.1	11.5	5.8	10.3	4.2
GHA	Carbon Sequester	MT	0	0	0	0	0	0	0	6.3	0	0	0	0	0	5.3
GHA	Ann. Cost	B.USD	0.7	0.9	2	3.7	6.8	2	3.4	6.5	2	4.2	6.9	2	3.7	7.3
GHA	Ann. Demand	TWh	9.5	13.5	28.2	54	93.2	28.2	54	93.2	28.2	54	93.2	28.2	54	93.2
GHA	Ann. Supply	TWh	10.6	11.4	28.2	48.3	86.5	26.9	43	79.3	27.7	53.9	87.9	28.2	48.3	90.8
GHA	Ann. Import	TWh	0	2	0.5	6.1	8.9	1.4	13.3	19.6	0.8	1.4	7.8	0.5	6.1	6.9
GHA	Ann. Export	TWh	1.1	0	0.4	0.3	1.9	0.1	2.3	5.5	0.3	1.2	2.2	0.4	0.3	4
GHA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GHA	Gen. Gas	TWh	3.7	4.5	14.5	27.5	36.2	8.6	9.8	9.1	12.6	21.6	31.1	14.5	27.5	25.6
GHA	Gen. Nuclear	TWh	0	0	0	2.8	8.6	3.7	12.6	24.3	0	2.9	11.4	0	2.8	12.4
GHA	Gen. CCS	TWh	0	0	0	0	0	0	0	7.2	0	0	0	0	0	6
GHA	Gen. Hydro	TWh	6	6	11.9	11.9	11.9	10.9	10.9	11.9	10	11.9	11.9	11.9	11.9	11.9
GHA	Gen. Wind	TWh	0	0	0.9	2.6	5.8	2.6	2.6	3.9	2.6	8.8	8.8	0.9	2.6	2.6
GHA	Gen. PV	TWh	0	0.1	0.5	3.4	24.1	0.9	7.1	23	2.3	8.7	24.8	0.5	3.4	32
GIN	Carbon Emission	MT	0.4	0.4	0.5	0.6	0.6	0.3	0.1	-1	0.5	0.4	0.6	0.5	0.6	0.3
GIN	Carbon Sequester	MT	0	0	0	0	0	0	0	1.1	0	0	0	0	0	0
GIN	Ann. Cost	B.USD	0.2	0.2	0.2	0.5	0.7	0.3	0.5	0.8	0.3	0.5	0.7	0.2	0.5	0.5
GIN	Ann. Demand	TWh	0.9	1.3	2.8	5.3	9.1	2.8	5.3	9.1	2.8	5.3	9.1	2.8	5.3	9.1
GIN	Ann. Supply	TWh	1.6	1.8	2.8	6.6	9.2	3.3	6.6	11.1	3.3	6.1	9.5	2.8	6.6	7.6
GIN	Ann. Import	TWh	0	0	0.6	0.7	2.9	0.9	1.2	3.8	0.4	1.6	3.1	0.6	0.7	4.3
GIN	Ann. Export	TWh	0	0	0.6	2	2.9	1.4	2.5	5.7	1	2.3	3.3	0.6	2	2.7
GIN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GIN	Gen. Gas	TWh	0	0.3	1	1.5	1.7	0.4	0.4	0.5	0.9	1.1	1.7	1	1.5	0.8
GIN	Gen. Nuclear	TWh	0	0	0	0.7	1.5	1	1.7	1.7	0	0.7	0.7	0	0.7	0.7
GIN	Gen. CCS	TWh	0	0	0	0	0	0	0	1.3	0	0	0	0	0	0
GIN	Gen. Hydro	TWh	1.1	1.1	1.3	3	4.9	1.3	1.3	3.7	1.3	1.7	4.6	1.3	3	4.6
GIN	Gen. Wind	TWh	0	0	0.3	1.2	1.2	0.3	3	3	0.6	1.7	1.7	0.3	1.2	1.4
GIN	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.2	0.9	0.4	0.8	0.7	0.1	0.1	0
GMB	Carbon Emission	MT	0.2	0.2	0.4	0.1	0.2	0.1	0.1	-0.4	0.3	0.2	0.2	0.4	0.1	-0.5
GMB	Carbon Sequester	MT	0	0	0	0	0	0	0	0.5	0	0	0	0	0	0.6
GMB	Ann. Cost	B.USD	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.1	0.2
GMB	Ann. Demand	TWh	0.2	0.3	0.7	1.3	2.2	0.7	1.3	2.2	0.7	1.3	2.2	0.7	1.3	2.2
GMB	Ann. Supply	TWh	0.2	0.3	0.9	1.2	1.5	1	1.4	2.2	1	2	1.8	0.9	1.2	1.9
GMB	Ann. Import	TWh	0	0	0	0.1	0.7	0	0.1	0.2	0	0	0.6	0	0.1	0.3
GMB	Ann. Export	TWh	0	0	0.2	0.1	0	0.4	0.2	0.2	0.4	0.7	0.2	0.2	0.1	0
GMB	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GMB	Gen. Gas	TWh	0	0.1	0.7	0.3	0.4	0	0.4	0.3	0.5	0.5	0.4	0.7	0.3	0.2
GMB	Gen. Nuclear	TWh	0	0	0	0.8	0.7	0.7	0.7	0.7	0	0.7	0.7	0	0.8	0.7
GMB	Gen. CCS	TWh	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0.7
GMB	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GMB	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.2	0.5	0.5	0	0	0
GMB	Gen. PV	TWh	0	0.1	0.1	0.2	0.4	0.2	0.3	0.6	0.2	0.3	0.2	0.1	0.2	0.3
GNB	Carbon Emission	MT	0	0	0.2	0.1	0.1	0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0
GNB	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNB	Ann. Cost	B.USD	0	0	0.1	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	0.1
GNB	Ann. Demand	TWh	0	0	0.1	0.2	0.3	0.1	0.2	0.3	0.1	0.2	0.3	0.1	0.2	0.3
GNB	Ann. Supply	TWh	0	0.1	0.7	0.5	1.3	1	1.2	1.3	0.7	0.8	0.9	0.7	0.5	1.1
GNB	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0.1	0	0	0.1
GNB	Ann. Export	TWh	0	0	0.6	0.3	1.1	0.9	1	1	0.6	0.6	0.7	0.6	0.3	0.8
GNB	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNB	Gen. Gas	TWh	0	0	0.5	0.2	0.2	0	0.1	0.2	0.3	0.4	0.3	0.5	0.2	0
GNB	Gen. Nuclear	TWh	0	0	0	0	0.7	0.7	0.7	0.7	0	0	0	0	0	0.7
GNB	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNB	Gen. Hydro	TWh	0	0	0.1	0.3	0.4	0.1	0.1	0.1	0.1	0.1	0.4	0.1	0.3	0.3
GNB	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0	0	0
GNB	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.2	0.3	0.2	0.2	0.1	0.1	0.1	0.1
GNQ	Carbon Emission	MT	0.5	0.4	0.3	0.1	0.2	0.3	0.1	0.1	0.2	0.1	0.2	0.3	0.1	0
GNQ	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNQ	Ann. Cost	B.USD	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.2	0.3	0.1	0.1	0.2
GNQ	Ann. Demand	TWh	0.4	0.6	1.2	2.2	3.9	1.2	2.2	3.9	1.2	2.2	3.9	1.2	2.2	3.9
GNQ	Ann. Supply	TWh	1.4	1.2	1.7	3.3	5.7	1.7	3.3	5.5	1.8	3.5	6	1.7	3.3	5.4
GNQ	Ann. Import	TWh	0.3	0.3	1.2	0.4	0.3	1.2	0.7	1.5	1	0.4	0.3	1.2	0.4	0.8
GNQ	Ann. Export	TWh	1.3	0.9	1.8	1.5	2	1.8	1.7	3	1.7	1.7	2.3	1.8	1.5	1.9
GNQ	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNQ	Gen. Gas	TWh	0.9	0.7	0.5	0.3	0.4	0.5	0.3	0.2	0.4	0.3	0.4	0.5	0.3	0.1
GNQ	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNQ	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNQ	Gen. Hydro	TWh	0.6	0.6	1.3	3.1	5.3	1.3	3.1	5.3	1.3	3.1	5.4	1.3	3.1	5.3
GNQ	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GNQ	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0	0	0
GRC	Carbon Emission	MT	22.7	16.8	3.6	1.9	0.1	2.3	0.9	0.1	3.7	1.8	0.1	3.6	1.1	-0.6
GRC	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.6
GRC	Ann. Cost	B.USD	5.3	5.3	4.4	5.3	5.8	4.4	5.4	6.3	4.3	4.8	5.2	4.4	5.3	5.9
GRC	Ann. Demand	TWh	57.4	59.5	61.1	64.2	68.3	61.1	64.2	68.3	61.1	64.2	68.3	61.1	64.2	68.3
GRC	Ann. Supply	TWh	51.2	53	69.5	99.8	119.5	67.5	99.8	120.4	68.1	86.6	102.8	69.4	100.8	114.1
GRC	Ann. Import	TWh	7.3	8.1	4.1	4.3	5.7	11.3	9.1	11.6	3.9	3.8	5.8	4.4	5.2	8.7
GRC	Ann. Export	TWh	1.1	1	11.7	38.9	55.8	16.8	42.2	61.2	9.8	25.2	39.2	11.8	40.6	53
GRC	Gen. Coal	TWh	18.6	14.3	1.2	0.6	0	0.2	0	0	1.2	0.6	0	1.2	0.4	0
GRC	Gen. Gas	TWh	6.8	6.1	6	3.7	0.2	4.9	2.5	0.1	6.1	3.4	0.3	5.8	2.1	0
GRC	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRC	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.8
GRC	Gen. Hydro	TWh	9.3	10.5	7.2	6.3	4	7.2	6.3	4	7.2	6.3	4	7.2	6.3	4.3
GRC	Gen. Wind	TWh	8.9	15.9	40	50.6	51.3	46.9	51.3	51.7	42	52	52	40	51.3	51.7

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
GRC	Gen. PV	TWh	3.9	4	14.5	38.5	64	7.7	39.5	64.8	11	24	46.6	14.5	40.5	57.3
GTM	Carbon Emission	MT	4.7	5.1	2.4	1.8	1.8	1.6	0.9	0.8	2	1.4	1.3	2.4	1.8	-0.3
GTM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1.3
GTM	Ann. Cost	B.USD	1.2	1.5	1.2	1.3	1.6	1.2	1.2	1.5	1.2	1.3	1.6	1.2	1.3	1.8
GTM	Ann. Demand	TWh	9.8	11	14.3	18.2	22.4	14.3	18.2	22.4	14.3	18.2	22.4	14.3	18.2	22.4
GTM	Ann. Supply	TWh	11	13.2	11.9	13.5	20.1	11.1	12	16.7	11.7	14.3	20.1	11.9	13.5	18.7
GTM	Ann. Import	TWh	0	0.7	3.1	5.5	4.6	5.1	7.7	7.2	3.8	4.8	5.2	3.1	5.6	4.4
GTM	Ann. Export	TWh	1.2	2.9	0.7	0.7	2.3	1.8	1.4	1.4	1.2	0.8	2.8	0.7	0.8	0.7
GTM	Gen. Coal	TWh	3.8	4.5	1.5	0.5	0.6	0.8	0	0	1.6	0.8	0.7	1.5	0.5	0
GTM	Gen. Gas	TWh	0	0	1.5	3.5	3.2	1.1	2.2	2.1	0.1	1.9	1.8	1.5	3.5	2.9
GTM	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GTM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6
GTM	Gen. Hydro	TWh	3.8	5.4	5.4	5.4	9.2	5.4	5.4	6	5.4	5.4	9.4	5.4	5.4	5.9
GTM	Gen. Wind	TWh	0.3	0.5	1.4	1.8	4.2	1.6	2	4.2	1.6	2.6	4.7	1.4	1.8	4.2
GTM	Gen. PV	TWh	0.2	0.3	0.3	0.9	1.5	0.3	0.8	2.6	1.1	2.2	2.1	0.3	0.9	2.1
GUF	Carbon Emission	MT	0.3	0.4	0.2	0.2	0.3	0.2	0.1	0.1	0.2	0.1	0.3	0.2	0.1	0.2
GUF	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUF	Ann. Cost	B.USD	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2
GUF	Ann. Demand	TWh	0.9	1	1.3	1.7	2.1	1.3	1.7	2.1	1.3	1.7	2.1	1.3	1.7	2.1
GUF	Ann. Supply	TWh	0.9	1.2	1.3	1.1	1.5	1.3	1.2	1.4	1.4	1.5	1.9	1.3	1.1	1.5
GUF	Ann. Import	TWh	0	0	0.1	0.6	0.7	0.3	0.5	0.8	0.1	0.4	0.5	0.1	0.7	0.7
GUF	Ann. Export	TWh	0	0	0.1	0.1	0.2	0.2	0.1	0.2	0	0.1	0.4	0.1	0.1	0.2
GUF	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUF	Gen. Gas	TWh	0.4	0.7	0.5	0.4	0.8	0.4	0.3	0.4	0.4	0.3	0.7	0.5	0.3	0.6
GUF	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUF	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUF	Gen. Hydro	TWh	0.4	0.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
GUF	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0	0	0
GUF	Gen. PV	TWh	0.1	0.1	0.1	0.1	0	0.1	0.1	0.1	0.2	0.4	0.4	0.1	0.1	0.1
GUY	Carbon Emission	MT	0.7	0.6	0.3	0.1	0.1	0.3	0.1	0.1	0.3	0.1	0.1	0.3	0.1	0
GUY	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUY	Ann. Cost	B.USD	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
GUY	Ann. Demand	TWh	0.8	0.9	1.2	1.5	1.8	1.2	1.5	1.8	1.2	1.5	1.8	1.2	1.5	1.8
GUY	Ann. Supply	TWh	0.8	0.9	0.8	0.6	0.5	0.8	0.8	0.8	0.9	1	0.9	0.8	0.6	0.6
GUY	Ann. Import	TWh	0	0	1.4	4.4	8.5	2.1	4.1	10.7	1.5	3	6	1.4	4.5	11.5
GUY	Ann. Export	TWh	0	0	1	3.5	7.2	1.7	3.4	9.7	1.2	2.5	5.1	1	3.6	10.2
GUY	Gen. Coal	TWh	0.2	0.2	0.1	0.1	0	0.1	0	0	0.1	0.1	0	0.1	0.1	0
GUY	Gen. Gas	TWh	0	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.1
GUY	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUY	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GUY	Gen. Hydro	TWh	0	0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
GUY	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.3	0.3	0	0	0
GUY	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.1	0.2	0.2	0.1	0.1	0
HND	Carbon Emission	MT	3.5	2.6	1.2	0.5	1.2	1	0.8	1.5	1.2	1	1.1	1.2	0.5	0.4
HND	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
HND	Ann. Cost	B.USD	0.8	1	0.8	0.7	1	0.9	0.8	1.3	0.9	0.9	1.1	0.8	0.7	1
HND	Ann. Demand	TWh	8.6	9.6	12.6	16	19.7	12.6	16	19.7	12.6	16	19.7	12.6	16	19.7
HND	Ann. Supply	TWh	8.2	8.9	10.4	11.1	17	12.2	12.3	16.8	9.9	12.9	15.9	10.4	11.1	15.4
HND	Ann. Import	TWh	1.8	3.4	11.6	16.8	16.2	12	20.8	18.9	10.8	12.8	18.9	11.6	16.9	16
HND	Ann. Export	TWh	1.5	2.5	9.3	11.7	12.9	11.4	16.8	15.2	8	9.6	14.6	9.3	11.8	11.4
HND	Gen. Coal	TWh	0.1	0.1	0.1	0	0	0	0	0	0.1	0	0	0.1	0	0
HND	Gen. Gas	TWh	0	0.1	0.9	1.3	3.1	0.4	2.1	4.1	0.8	2.8	2.9	0.9	1.3	1.8
HND	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HND	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
HND	Gen. Hydro	TWh	2.4	2.7	2.7	2.7	2.5	2.7	2.7	1.7	2.7	2.7	0.9	2.7	2.7	3.1
HND	Gen. Wind	TWh	0.7	1.4	4	4.7	9.2	5	5	8.9	2.9	3.1	8	4	4.7	8
HND	Gen. PV	TWh	0.7	0.9	0.9	0.2	0	0.9	0.2	0	1.5	1.7	1.5	0.9	0.2	0
HRV	Carbon Emission	MT	1.9	1.6	0	0	0	0	0	0	0	0	0	0	0	0
HRV	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HRV	Ann. Cost	B.USD	0.9	0.9	1	1.8	2.6	1.2	2.1	2.8	1.1	1.6	2.4	1	1.8	2.6
HRV	Ann. Demand	TWh	17.5	19.1	22.3	25.8	29.6	22.3	25.8	29.6	22.3	25.8	29.6	22.3	25.8	29.6
HRV	Ann. Supply	TWh	12.4	13.2	19.1	37	52.5	23.1	40.9	56.4	19.9	32.1	47.6	19.1	36.9	52.5
HRV	Ann. Import	TWh	9.7	18.8	36.5	26.9	25.8	15.9	9.8	16.1	29.6	22.6	25.4	36.3	23.5	21.2
HRV	Ann. Export	TWh	4.6	12.9	33.3	37.9	48.5	16.6	24.5	42.6	27.1	28.6	43.2	33.2	34.4	43.9
HRV	Gen. Coal	TWh	1.7	1.5	0	0	0	0	0	0	0	0	0	0	0	0
HRV	Gen. Gas	TWh	0.9	0.8	0	0	0	0	0	0	0	0	0	0	0	0
HRV	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HRV	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HRV	Gen. Hydro	TWh	7.7	7.7	3.4	4.2	15.3	3.4	15.3	15.3	3.4	4.4	15.3	3.4	6.2	15.3
HRV	Gen. Wind	TWh	1.8	2.8	15.4	16.7	16.7	16.2	16.7	16.7	15	16.7	16.7	15.4	16.7	16.7
HRV	Gen. PV	TWh	0.1	0.1	0.1	16	20.3	3.3	8.7	24.3	1.3	10.8	15.4	0.1	13.9	20.2
HTI	Carbon Emission	MT	0.7	0.5	0.3	0	0	0.3	0	0	0.2	0	0	0.3	0	0
HTI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HTI	Ann. Cost	B.USD	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
HTI	Ann. Demand	TWh	0.5	0.5	0.7	0.8	1	0.7	0.8	1	0.7	0.8	1	0.7	0.8	1
HTI	Ann. Supply	TWh	0.9	1	0.8	0.9	1.1	0.8	0.9	1.3	1.2	1	1.1	0.8	0.9	1.1
HTI	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HTI	Ann. Export	TWh	0	0	0	0	0.1	0	0	0.2	0.5	0.2	0	0	0	0.1
HTI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HTI	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0.1	0	0	0
HTI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HTI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HTI	Gen. Hydro	TWh	0.2	0.4	0.4	0.2	0.2	0.4	0.2	0.2	0.4	0.2	0.2	0.4	0.2	0.2
HTI	Gen. Wind	TWh	0	0	0	0.6	0.8	0	0.6	1	0.2	0.5	0.5	0	0.6	0.8
HTI	Gen. PV	TWh	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
HUN	Carbon Emission	MT	7	4.7	0.5	0.1	0	0.5	0	0	0.5	0.1	0	0.5	0	-0.3
HUN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
HUN	Ann. Cost	B.USD	2.8	2.8	1	1.2	2.4	1.8	2.5	3	1.6	2.1	2.9	1	2.5	3.4
HUN	Ann. Demand	TWh	41.3	42.9	44	46.2	49.2	44	46.2	49.2	44	46.2	49.2	44	46.2	49.2
HUN	Ann. Supply	TWh	27.1	25.4	9.1	14.6	42	22.6	34.3	46.5	17.1	26	43.2	9.1	38.5	52.6
HUN	Ann. Import	TWh	17.1	19.1	62.1	72.5	63	30.6	31.6	38.1	48.1	54.4	53.7	61.6	50	47.6
HUN	Ann. Export	TWh	2.7	1.2	26.6	40.3	55.3	9	19.4	35.1	20.8	33.7	47.3	26.1	41.8	50.5
HUN	Gen. Coal	TWh	6.3	3.9	0	0	0	0	0	0	0	0	0	0	0	0
HUN	Gen. Gas	TWh	3.8	3.4	1.5	0.3	0	1.5	0.1	0	1.4	0.2	0	1.5	0	0
HUN	Gen. Nuclear	TWh	14.2	14.2	0	0	0	0	0	0	0	0	0	0	0	0
HUN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
HUN	Gen. Hydro	TWh	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.2	0.4	0.4	0.2	0.4	0.4
HUN	Gen. Wind	TWh	0.9	1	1	1	1	1	9.5	9.5	7	13.8	13.6	1	1	9.3
HUN	Gen. PV	TWh	0.2	0.9	0.7	7.2	34.9	14	18.6	30.9	2.8	5.8	23.4	0.7	31.4	36.6
IDN	Carbon Emission	MT	145.2	150.8	160.5	115.9	129.4	59.4	20.8	-50.6	141.7	89.8	109.7	160.4	116	70.8
IDN	Carbon Sequester	MT	0	0	0	0	0	0	0	72.3	0	0	0	0	0	0.4
IDN	Ann. Cost	B.USD	15	18.1	31.6	46.5	64	31.2	45.8	62.1	32.5	47.9	65.9	31.6	46.5	64.2
IDN	Ann. Demand	TWh	222	280.7	413.1	564.6	736.9	413.1	564.6	736.9	413.1	564.6	736.9	413.1	564.6	736.9
IDN	Ann. Supply	TWh	222.1	280.8	604.6	907.9	1195.5	518.1	870.2	1116.1	567	831.1	1156.1	604.5	908.3	1189.3
IDN	Ann. Import	TWh	0	0	1.4	1.1	0.9	6.5	3.9	2.1	2	1.2	0.3	1.4	1.1	0.7
IDN	Ann. Export	TWh	0	0	192.1	336.3	444.8	107.2	298	371.9	155.5	258.3	401.5	192.1	336.7	440.2
IDN	Gen. Coal	TWh	105.8	90.1	13	4.9	0.1	12.6	0.2	0	13	3.5	0.4	12.9	4.9	0
IDN	Gen. Gas	TWh	71.1	147.9	377.5	290.9	342.6	114.7	53	40	327.2	226.2	289.2	377.5	291.1	187.5
IDN	Gen. Nuclear	TWh	0	0	0	0	0	122	162.2	181.5	0	0	0	0	0	99.2
IDN	Gen. CCS	TWh	0	0	0	0	0	0	0	91.5	0	0	0	0	0	0.4
IDN	Gen. Hydro	TWh	20	22.1	101.1	360	479.9	154.7	431.9	485.9	92.9	313.5	477.6	101.1	360.1	536.9
IDN	Gen. Wind	TWh	0	0.3	6.7	11.4	14.7	7.3	15.2	25.1	20.7	50.7	52.4	6.7	11.4	24.1
IDN	Gen. PV	TWh	0	0.1	12.8	116.8	232.2	14.9	82.8	166.4	27.5	113	208.1	12.8	116.8	214.4
IND	Carbon Emission	MT	816.7	844.6	812.1	788.7	743	617.5	301	-236.8	768.3	715.7	700.6	812.2	788.5	85.2
IND	Carbon Sequester	MT	0	0	0	0	0	0	2.2	406.6	0	0	0	0	0	250.8
IND	Ann. Cost	B.USD	89.7	117.7	179.3	251.5	315	206.2	284.7	335.5	184.6	263.3	323.9	179.3	251.5	334.7
IND	Ann. Demand	TWh	1134.2	1528.9	2707.3	3986.3	4985.3	2707.3	3986.3	4985.3	2707.3	3986.3	4985.3	2707.3	3986.3	4985.3
IND	Ann. Supply	TWh	1191.6	1546.7	2778.8	4070.3	5083.3	2771.9	4009.1	4984.4	2774.8	4043.5	5035.7	2778.9	4070.2	4988.9
IND	Ann. Import	TWh	4	3.8	20.6	96.9	198	28.6	164.2	260.3	16.8	72	177.8	20.6	97.1	232.1
IND	Ann. Export	TWh	4.5	4.1	86.3	145.3	221.2	69.4	138.5	198	75.8	96.7	162	86.3	145.3	172
IND	Gen. Coal	TWh	825.9	672	316.6	121.3	51.4	332.1	51.4	10.8	319.5	123.3	50.9	316.7	121.3	0
IND	Gen. Gas	TWh	74	487.9	1315	1781.8	1833.7	767.6	650.6	307.8	1193.8	1583.6	1724.2	1315.2	1781.4	887.8
IND	Gen. Nuclear	TWh	47.3	56.7	84	47.3	40.9	79.7	774.1	936.4	84.5	47	40.5	83.7	46.9	289
IND	Gen. CCS	TWh	0	0	0	0	0	0	5.3	520.2	0	0	0	0	0	292.7
IND	Gen. Hydro	TWh	126	133.8	120.1	373.1	901.1	334.5	782.4	792.6	120.1	332.6	776.8	120.1	373.2	1111.8
IND	Gen. Wind	TWh	77.3	112.2	312.1	536.5	656.6	489.7	634.1	693.7	436.7	845.5	889.2	312.1	536.6	729.2
IND	Gen. PV	TWh	8.7	52.1	602	1187.1	1579.3	740.2	1094.5	1717.6	591.3	1088.1	1534.6	602.1	1187.4	1616
IRL	Carbon Emission	MT	8.8	7.7	0.6	0	0	0.6	0	0	0.6	0	0	0.6	0	0
IRL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRL	Ann. Cost	B.USD	2.1	2.5	2.1	2.7	3.2	2.1	2.6	3.1	2.1	2.8	3.3	2.1	2.7	3.2
IRL	Ann. Demand	TWh	27	28.1	28.8	30.2	32.2	28.8	30.2	32.2	28.8	30.2	32.2	28.8	30.2	32.2
IRL	Ann. Supply	TWh	27.2	35.3	38.5	57.8	74.3	38.5	57.8	74.3	38.7	58	75.1	38.5	57.8	74.3
IRL	Ann. Import	TWh	1.7	0	16.2	30.8	29.9	30.7	35.5	35.4	17.3	31.7	31.1	16.1	31.1	31.6
IRL	Ann. Export	TWh	1.8	7	25.9	57.8	71.4	40.4	62.8	76.8	27.1	59.2	73.5	25.8	58.3	73.1
IRL	Gen. Coal	TWh	5.7	4.9	0.1	0	0	0.1	0	0	0.1	0	0	0.1	0	0
IRL	Gen. Gas	TWh	9.3	8.3	1.2	0	0	1.2	0	0	1.2	0	0	1.2	0	0
IRL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRL	Gen. Hydro	TWh	0.4	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.6	1.1	1.1	1.1
IRL	Gen. Wind	TWh	11.1	20.4	35.6	56.4	72.9	35.6	56.4	72.9	34.8	54.4	72	35.6	56.4	72.9
IRL	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	1.1	2.2	2.2	0.1	0.1	0
IRN	Carbon Emission	MT	96.6	117.2	66.2	28.4	19.1	26.5	6.4	3.1	69.2	25.5	15.2	66.2	28.4	7.4
IRN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRN	Ann. Cost	B.USD	21.9	22.6	24.4	27	30.9	27.1	30	35	25.2	27.7	29.6	24.4	27	30.2
IRN	Ann. Demand	TWh	234.3	266.8	366.2	492.5	581.2	366.2	492.5	581.2	366.2	492.5	581.2	366.2	492.5	581.2
IRN	Ann. Supply	TWh	240.1	264.3	356.2	509	665.1	362.4	513.4	681.8	356.4	504.1	649.8	356.2	509	654.1
IRN	Ann. Import	TWh	3.8	6.6	17.7	19.8	21	13.9	13.2	7.6	17.4	28.7	40.1	17.7	19.7	24
IRN	Ann. Export	TWh	8.1	3.6	1.9	17.3	78.9	3	18.8	87.1	2.3	22.8	78.5	1.9	17.3	71.1
IRN	Gen. Coal	TWh	0	56.4	47.2	28.8	22.2	5.6	0	3.1	49.7	26.7	18	47.2	28.8	7.4
IRN	Gen. Gas	TWh	173.5	148.7	56.3	11.7	1.2	43.3	16.6	1.2	59.1	8.6	0.4	56.3	11.7	2.4
IRN	Gen. Nuclear	TWh	4.9	7.4	11.6	9.3	7.8	72.2	67.8	38.6	6.3	5.2	3.7	11.6	9.3	7.2
IRN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRN	Gen. Hydro	TWh	30.5	36.1	36	53.6	48.4	34.7	34.7	67.8	34.7	47	41.8	36	53.6	48.4
IRN	Gen. Wind	TWh	0.7	1.9	199.2	396	536.9	200.4	369.2	509.6	175.8	349.3	515.8	199.2	396	539.3
IRN	Gen. PV	TWh	0	0.6	0.6	10	49.2	0.6	25.4	61.8	25.2	67.7	70.8	0.6	10	49
IRQ	Carbon Emission	MT	41.3	33.3	20.6	3.6	1.5	16.9	3.1	0.7	20	2.3	0.8	20.6	3.6	0.2
IRQ	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1.2
IRQ	Ann. Cost	B.USD	8.4	8.9	9	5.6	6.1	9	5.9	3.8	9	6	5.6	9	5.6	6.4
IRQ	Ann. Demand	TWh	39.1	44.6	61.2	82.3	97.1	61.2	82.3	97.1	61.2	82.3	97.1	61.2	82.3	97.1
IRQ	Ann. Supply	TWh	59.5	55.1	74.3	69.5	114.7	64.7	70.7	70.7	73	73.8	109.5	74.3	69.5	115
IRQ	Ann. Import	TWh	3.5	3.3	6.6	45.9	104.4	20.1	46.9	109.1	5.2	67.7	128	6.6	45.9	100.1
IRQ	Ann. Export	TWh	23.4	13.4	19.2	30.8	119.3	23.1	33.9	81	16.4	57	136.8	19.2	30.8	115.4
IRQ	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRQ	Gen. Gas	TWh	15.2	21.5	21.1	9.4	3.6	11.5	8.2	1.8	19.6	5.9	2	21.1	9.4	3.7
IRQ	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IRQ	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.4
IRQ	Gen. Hydro	TWh	7	7	6.3	5.2	0	6.3	5.2	0	6.3	5.2	0	6.3	5.2	0
IRQ	Gen. Wind	TWh	0	0	33.6	54.9	102.7	33.6	57.4	65.8	28.9	49.4	92.1	33.6	54.9	105.5
IRQ	Gen. PV	TWh	0	0.1	0.1	0.1	8.4	0.1	0.1	3.2	5	13.4	15.4	0.1	0.1	3.8
ISL	Carbon Emission	MT	4.6	1.1	0.6	0.2	0.2	0.3	0.2	0	0.6	0.2	0.2	0.6	0.2	0
ISL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISL	Ann. Cost	B.USD	1.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1	0.9	0.9	0.9
ISL	Ann. Demand	TWh	18.5	19.2	19.7	20.7	22.1	19.7	20.7	22.1	19.7	20.7	22.1	19.7	20.7	22.1
ISL	Ann. Supply	TWh	18.5	19.8	20.2	21.4	22.8	20.6	21.3	23.3	20.2	21.3	22.6	20.2	21.4	23.4
ISL	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISL	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISL	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISL	Gen. Gas	TWh	0	3	1.6	0.6	0.5	0.7	0.6	0	1.6	0.6	0.6	1.6	0.6	0
ISL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISL	Gen. Hydro	TWh	8.9	9.2	7.2	5.6	5.6	7.2	5.6	5.6	7.2	5.6	5.6	7.2	5.6	5.6
ISL	Gen. Wind	TWh	0	0	2.9	4.9	5.5	4.6	5.8	7.1	2.9	5.7	6.4	2.9	4.9	6.9
ISL	Gen. PV	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISR	Carbon Emission	MT	43.2	60	18.4	2.1	0.1	4.7	0.5	0	17.5	1.7	0	18.4	2.1	-0.8
ISR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.8
ISR	Ann. Cost	B.USD	5	6.3	5	4.4	3.4	4	3	0.8	8.4	11.3	9.9	5	4.4	3.6
ISR	Ann. Demand	TWh	57.1	65.1	89.3	120.1	141.7	89.3	120.1	141.7	89.3	120.1	141.7	89.3	120.1	141.7
ISR	Ann. Supply	TWh	62.1	76.8	57.6	55.6	50	38.7	33.1	12.2	69.2	76	77.7	57.6	55.6	51.1
ISR	Ann. Import	TWh	0	0	43.4	125.8	159.2	54.1	107.4	157.2	27.2	73.2	125.8	43.4	125.5	159.7

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
ISR	Ann. Export	TWh	4.8	11.4	11.1	56	61.9	2.9	19.1	24.7	6.5	23.1	49	11.1	55.6	65.4
ISR	Gen. Coal	TWh	35.2	55.5	6.6	0	0	1.4	0	0	5.8	0	0	6.6	0	0
ISR	Gen. Gas	TWh	25	18.5	30.8	5.4	0.2	8.7	1.3	0	30.5	4.3	0	30.9	5.4	0.1
ISR	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1
ISR	Gen. Hydro	TWh	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
ISR	Gen. Wind	TWh	0.1	0.1	3.2	3.2	3.1	3.2	3.2	2.9	19.9	43.9	49	3.2	3.2	3.1
ISR	Gen. PV	TWh	1.5	2.2	16.6	46.7	46.4	25.1	28.3	8.9	8.4	16.7	17.6	16.6	46.7	46.1
ITA	Carbon Emission	MT	68.6	55	22.4	3.2	0.1	19.2	2.5	0	22.3	4.5	0.3	21.4	1.1	-2.5
ITA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	2.5
ITA	Ann. Cost	B.USD	27.7	26.2	22.3	18.8	20.3	29.3	24.6	23.9	22.7	19.3	19.1	22.4	21.8	24.1
ITA	Ann. Demand	TWh	318.1	330.1	338.9	355.9	378.7	338.9	355.9	378.7	338.9	355.9	378.7	338.9	355.9	378.7
ITA	Ann. Supply	TWh	261.7	266.2	224	233.9	307.6	328.7	321.7	340.6	231.1	241.1	271.5	227.3	296.9	340.2
ITA	Ann. Import	TWh	62.4	71.3	130.3	153.1	169.8	56.4	119.6	143.4	122.8	130.3	134.5	127	150.4	170.5
ITA	Ann. Export	TWh	5.1	5.9	9.6	24.3	90	41.7	78.8	97.6	9.3	9.5	19.7	9.6	83.5	122.1
ITA	Gen. Coal	TWh	41.2	32.5	17.1	1.7	0	12	0	0	16.9	2.4	0	16.1	0.8	0
ITA	Gen. Gas	TWh	83.5	72.6	21	4.9	0.2	24.3	6.6	0	21.4	6.9	0.6	20.7	1.1	0
ITA	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ITA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	3.1
ITA	Gen. Hydro	TWh	66	75.4	71.8	72.2	71.9	72.3	72.2	71.8	71.8	72.2	71.9	71.8	72.2	71.9
ITA	Gen. Wind	TWh	28.2	32.9	38	65.9	69.1	76.2	93.2	93.1	44.2	70.2	77.1	40.9	67	98.6
ITA	Gen. PV	TWh	26.9	29.2	49.4	63.4	141.3	118.3	125.5	152.8	50.3	63.9	97	51.2	130.2	142.8
JAM	Carbon Emission	MT	2.7	1.8	0.9	0.5	0.7	0.5	0.1	-0.3	0.9	0.5	0.7	0.9	0.5	-0.1
JAM	Carbon Sequester	MT	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0.4
JAM	Ann. Cost	B.USD	0.5	0.4	0.4	0.5	0.6	0.4	0.5	0.6	0.4	0.5	0.6	0.4	0.5	0.7
JAM	Ann. Demand	TWh	3.3	3.9	4.9	6.1	7.7	4.9	6.1	7.7	4.9	6.1	7.7	4.9	6.1	7.7
JAM	Ann. Supply	TWh	3.4	3.9	4.9	6.1	7.7	4.9	6.1	7.7	4.9	6.1	7.7	4.9	6.1	7.7
JAM	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JAM	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JAM	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JAM	Gen. Gas	TWh	0.2	1.8	1.7	1.4	1.9	0.7	0.4	0.1	1.6	1.3	1.8	1.7	1.4	0.9
JAM	Gen. Nuclear	TWh	0	0	0	0.7	1.5	0.7	2.1	3	0	0.7	1.5	0	0.7	1.5
JAM	Gen. CCS	TWh	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0.5
JAM	Gen. Hydro	TWh	0.1	0.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.9
JAM	Gen. Wind	TWh	0.1	0.6	1.3	2	2	1.6	2	2	1.3	2	2	1.3	2	2.2
JAM	Gen. PV	TWh	0	0.1	0.9	1.2	1.6	0.9	0.9	1.3	0.8	1	1.4	0.9	1.2	1.6
JOR	Carbon Emission	MT	9.8	9.3	1.7	0	0.1	1.7	0	0	1.7	0	0	1.7	0	-0.1
JOR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
JOR	Ann. Cost	B.USD	1.8	2.2	1.7	1.7	1.9	2.3	2.5	3.2	1.7	2	1.7	1.7	1.7	2
JOR	Ann. Demand	TWh	17.8	20.3	27.9	37.5	44.2	27.9	37.5	44.2	27.9	37.5	44.2	27.9	37.5	44.2
JOR	Ann. Supply	TWh	14.9	22.4	20.9	28.4	36.5	27.2	36.9	56.4	20.8	32.8	35.4	20.9	28.4	36.7
JOR	Ann. Import	TWh	32.5	24.3	48.2	72	87.9	25.5	41.3	57.9	37.8	70.1	98.8	48.2	72	87.3
JOR	Ann. Export	TWh	28.6	25.8	41.2	62.3	79.6	24.7	40.4	68	30.6	65	89.1	41.2	62.3	79.1
JOR	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JOR	Gen. Gas	TWh	7.3	14.8	0	0	0.2	0	0	0	0	0	0	0	0	0.2
JOR	Gen. Nuclear	TWh	0	0	0	0	0	6.4	6.1	4.4	0	0	0	0	0	0
JOR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
JOR	Gen. Hydro	TWh	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
JOR	Gen. Wind	TWh	0.3	2	17.2	26.5	26.5	17	16.7	23	14.9	25.3	28.2	17.2	26.5	26.5
JOR	Gen. PV	TWh	0.1	1.8	1.8	1.8	9.6	1.8	14	28.8	3.9	7.4	7.1	1.8	1.8	9.1
JPN	Carbon Emission	MT	446.4	319.9	312.3	90.4	13.5	118.8	7.9	1.6	238.3	75.6	42.3	312.3	90.4	6.9
JPN	Carbon Sequester	MT	0	0	0	0	0	0	0	4	0	0	0	0	0	1.2
JPN	Ann. Cost	B.USD	112.2	97.6	95.8	96.2	99.1	107.7	99.3	100.4	107.6	118.8	118.6	95.8	96.2	99.9
JPN	Ann. Demand	TWh	1001	991.8	1008.3	1036.1	1068.2	1008.3	1036.1	1068.2	1008.3	1036.1	1068.2	1008.3	1036.1	1068.2
JPN	Ann. Supply	TWh	1001.3	995.6	1010.2	1037	1069.5	1008.6	1037	1069.6	1015	1043.8	1075.8	1010.2	1037	1069.4
JPN	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JPN	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JPN	Gen. Coal	TWh	303.3	241.6	288.8	94.9	6.2	92.2	0.1	0	229.5	68.7	10.1	288.8	94.9	3
JPN	Gen. Gas	TWh	308.7	268.6	163.6	29.4	21.1	103.4	19.1	1.3	107.9	48.1	95	163.6	29.4	13.7
JPN	Gen. Nuclear	TWh	120.2	241.1	246.6	605.3	715.9	466.8	677.5	731.4	170.1	260	302.5	246.6	605.3	719.7
JPN	Gen. CCS	TWh	0	0	0	0	0	0	0	10.1	0	0	0	0	0	1.4
JPN	Gen. Hydro	TWh	110.9	111.1	147.6	147.4	145	147.6	147.5	145	147.6	147.5	145	147.6	147.4	145
JPN	Gen. Wind	TWh	9.1	13	14.3	16.4	18.3	37.3	32.5	9.5	164.8	307.5	307.4	14.3	16.4	17.5
JPN	Gen. PV	TWh	43.1	74.8	73.1	68.8	91.9	83.9	87.6	103.3	117.8	141.7	145.7	73.1	68.8	98.4
KAZ	Carbon Emission	MT	45.1	52.4	47.8	26	17.8	31.6	7.3	-0.2	44	24.3	15.7	47.8	26	7.1
KAZ	Carbon Sequester	MT	0	0	0	0	0	0	1.1	5.3	0	0	0	0	0	0.8
KAZ	Ann. Cost	B.USD	4.3	6.1	9.2	11.2	13.8	9.2	11	13.2	9.1	10.8	14.1	9.2	11.2	13.6
KAZ	Ann. Demand	TWh	77	88.5	113.8	143.5	177.9	113.8	143.5	177.9	113.8	143.5	177.9	113.8	143.5	177.9
KAZ	Ann. Supply	TWh	70.7	114	168	200	241.7	139.4	181.1	226.9	163	186.5	242.5	168	200	243.8
KAZ	Ann. Import	TWh	7.1	1.3	1.7	4.3	5.4	3.6	12	13.7	2.3	5	5.7	1.7	4.3	8.4
KAZ	Ann. Export	TWh	0.4	26.7	55.7	60.4	68.5	29	48.2	60.3	51.4	47.7	69.7	55.7	60.4	73
KAZ	Gen. Coal	TWh	32.6	14.7	1.6	0	0	1.6	0	0	1.6	0	0	1.6	0	0
KAZ	Gen. Gas	TWh	29.1	89.3	117.5	68.9	47.2	74.1	19.3	7.7	106.6	64.4	41.2	117.5	68.9	21.1
KAZ	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KAZ	Gen. CCS	TWh	0	0	0	0	0	0	2.6	9	0	0	0	0	0	1
KAZ	Gen. Hydro	TWh	8.7	9.1	6.9	8.3	7.4	7.5	7.1	4.6	6.5	7.4	6.4	6.9	8.3	6.5
KAZ	Gen. Wind	TWh	0.3	0.5	41.7	122.5	186.8	55.9	151.9	204.1	44.7	106	186.1	41.7	122.5	213.3
KAZ	Gen. PV	TWh	0.1	0.4	0.4	0.3	0.3	0.4	0.3	1.6	3.7	8.8	8.8	0.4	0.3	2
KEN	Carbon Emission	MT	1.6	0.8	1	0.4	0.6	0.7	0.1	0.1	0.7	0.4	0.6	1.1	0.5	0.3
KEN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KEN	Ann. Cost	B.USD	0.7	0.8	1.2	2.2	3.6	1.1	2.2	3.7	1.1	2.3	3.8	1.2	2.2	3.7
KEN	Ann. Demand	TWh	8.7	12.3	25.8	49.5	85.4	25.8	49.5	85.4	25.8	49.5	85.4	25.8	49.5	85.4
KEN	Ann. Supply	TWh	11.9	13	25.1	61.3	110.3	24.5	62.5	112.3	24.9	62.1	111.4	25.4	61.8	110.3
KEN	Ann. Import	TWh	0.4	0	1.5	0.8	3	2	1.1	2.4	1.9	1.4	2.3	1.6	0.7	3.2
KEN	Ann. Export	TWh	1.9	0.6	0.7	12	26.6	0.5	13.5	27.7	0.8	13.3	26.8	0.9	12.5	26.7
KEN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KEN	Gen. Gas	TWh	0	0	1.6	1	1.4	0.7	0.3	0.3	0.8	1	1.5	1.7	1.3	0.7
KEN	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KEN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KEN	Gen. Hydro	TWh	3	3.2	2.9	1.6	0.8	2.9	1.6	0.6	2.9	1.6	0.6	2.9	1.6	0.6
KEN	Gen. Wind	TWh	1.9	2.1	10.6	21.6	69.8	10.6	22.1	72.9	10.9	22.3	68.8	10.7	22.2	70.3
KEN	Gen. PV	TWh	0.1	0.2	0.2	0.1	0	0.2	0.1	0	0.9	2.1	2.1	0.2	0.1	0
KGZ	Carbon Emission	MT	3.7	2.8	1.3	0	0	0.9	0	-0.9	1.1	0	0.1	1.3	0	-1.5
KGZ	Carbon Sequester	MT	0	0	0	0	0	0	0	0.9	0	0	0	0	0	1.5

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
KGZ	Ann. Cost	B.USD	0.9	0.9	1.1	1.5	1.6	1.2	1.1	1.6	1.1	1.7	1.5	1.1	1.5	1.7
KGZ	Ann. Demand	TWh	11.7	13.5	17.3	21.8	27.1	17.3	21.8	27.1	17.3	21.8	27.1	17.3	21.8	27.1
KGZ	Ann. Supply	TWh	16.9	16	19.4	32.1	33.3	22.1	22.1	30.7	19.6	32.7	28.3	19.4	32.1	31.4
KGZ	Ann. Import	TWh	0.3	1.1	2.9	5	13.5	2.8	12.2	15.7	2.5	2.8	12	2.9	5	14.2
KGZ	Ann. Export	TWh	5.4	3.5	4.7	14.5	19.5	7.4	11.7	18.9	4.5	12.9	13	4.7	14.5	18.2
KGZ	Gen. Coal	TWh	4.2	3.1	1.4	0	0	1	0	0	1.3	0	0	1.4	0	0
KGZ	Gen. Gas	TWh	0.1	0.2	0.2	0	0.1	0.2	0	0	0.1	0	0.1	0.2	0	0
KGZ	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KGZ	Gen. CCS	TWh	0	0	0	0	0	0	0	1.1	0	0	0	0	0	1.9
KGZ	Gen. Hydro	TWh	12.5	12.7	17.7	32.1	31.9	20.9	20.4	23.1	16.8	29.1	24.6	17.7	32.1	25.1
KGZ	Gen. Wind	TWh	0	0	0	0	0	0	0.2	0.5	0.8	2	2	0	0	0.5
KGZ	Gen. PV	TWh	0	0	0	0	1.4	0	1.5	5.9	0.6	1.5	1.5	0	0	3.9
KHM	Carbon Emission	MT	3	3.6	2.4	1.2	1	1.6	0.2	0.1	2.4	1.1	1.6	2.4	1.2	0.4
KHM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KHM	Ann. Cost	B.USD	0.4	0.6	0.6	0.8	1	0.6	0.8	0.9	0.6	0.8	1.2	0.6	0.8	1.1
KHM	Ann. Demand	TWh	5.5	6.9	10.2	13.9	18.2	10.2	13.9	18.2	10.2	13.9	18.2	10.2	13.9	18.2
KHM	Ann. Supply	TWh	6.1	8.3	8.8	14.3	17.4	8.2	13.3	15.4	9.1	14.6	20.2	8.8	14.3	18.1
KHM	Ann. Import	TWh	0.6	0.1	13.4	19.8	15.6	10.6	21.3	20	11.8	29.2	19.5	13.4	19.7	15.5
KHM	Ann. Export	TWh	1.1	1.4	11.7	19.5	14.3	8.3	20.1	16.7	10.4	28.8	20.9	11.7	19.5	15
KHM	Gen. Coal	TWh	3	3.6	2.4	1.2	0.9	1.4	0.1	0	2.4	1.1	1	2.4	1.2	0.1
KHM	Gen. Gas	TWh	0	0	0	0.1	0.2	0.3	0.3	0.3	0	0.1	1.7	0	0.1	1
KHM	Gen. Nuclear	TWh	0	0	0	0.6	0.6	0	0.5	0.7	0	0	0	0	0.6	1.1
KHM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KHM	Gen. Hydro	TWh	2.9	4.3	4.3	6.3	8.7	4.3	8.4	8.7	4.3	5.1	8.7	4.3	6.3	8.7
KHM	Gen. Wind	TWh	0	0	1.9	5.2	6.3	1.9	3.2	4.9	1.4	5.5	6.1	1.9	5.2	6.4
KHM	Gen. PV	TWh	0	0.2	0.2	0.2	0	0.2	0.2	0	0.8	2.1	1.9	0.2	0.2	0
KOR	Carbon Emission	MT	232.2	239.3	231.5	77.6	22.6	74.7	15.4	2.9	175	86.6	51.6	231.5	77.6	6.6
KOR	Carbon Sequester	MT	0	0	0	0	0	0	0	1.3	0	0	0	0	0	1.1
KOR	Ann. Cost	B.USD	42.8	47.9	60.4	72.4	86.7	67.7	75.9	87.3	80	112	121.6	60.4	72.4	87.4
KOR	Ann. Demand	TWh	522.3	538.8	673.4	816.3	966.2	673.4	816.3	966.2	673.4	816.3	966.2	673.4	816.3	966.2
KOR	Ann. Supply	TWh	523.5	540.6	674.4	817	965.6	674	816.6	966.6	679.3	823.2	969.2	674.4	817	966
KOR	Ann. Import	TWh	0	0	0	0.1	1	0	0	0.1	0	1.9	3.9	0	0.1	0.6
KOR	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOR	Gen. Coal	TWh	215.2	236.9	222.3	77.6	5.2	65.3	2.1	0.7	184.5	73.5	4.9	222.3	77.6	4.6
KOR	Gen. Gas	TWh	101.7	82.3	101.4	30.6	47.6	47.1	34.9	3.1	42.5	62.8	130.6	101.4	30.6	7.4
KOR	Gen. Nuclear	TWh	170.7	181.5	305.4	609.2	797.6	453.1	679.7	837.9	187.4	203.8	336.3	305.4	609.2	833.1
KOR	Gen. CCS	TWh	0	0	0	0	0	0	0	3.4	0	0	0	0	0	1.3
KOR	Gen. Hydro	TWh	19.3	19	18.6	16.9	11.8	18.6	16.9	11.8	18.6	16.9	11.9	18.6	16.9	11.8
KOR	Gen. Wind	TWh	2.3	4.2	3.8	3.1	2.5	6.5	5.8	5.7	188.6	362.4	362.5	3.8	3.1	4.8
KOR	Gen. PV	TWh	4.8	11.2	11.9	69.3	91.4	72.3	67.6	95	46.6	94.2	113.6	11.9	69.3	94.1
KWT	Carbon Emission	MT	39.2	30.9	18.5	4.3	2.1	10.4	3.2	1.2	18.4	4	2.8	18.5	4.3	1.3
KWT	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1
KWT	Ann. Cost	B.USD	7	6.6	7.6	7.4	7.4	8.3	8.3	7.6	8	7	7.6	7.6	7.4	7.4
KWT	Ann. Demand	TWh	52.5	59.8	82.1	110.4	130.3	82.1	110.4	130.3	82.1	110.4	130.3	82.1	110.4	130.3
KWT	Ann. Supply	TWh	53.2	59.1	82.1	110	131.1	83.1	111.1	118.8	82.1	87.8	117.5	82.1	110	126
KWT	Ann. Import	TWh	0	0.7	0.4	7.6	68.3	0.8	6.5	50.7	0.3	25.6	68.4	0.4	7.6	65
KWT	Ann. Export	TWh	0.6	0	0.4	6.4	69.2	1.8	7.1	39.2	0.2	1.8	54.5	0.4	6.4	60.5
KWT	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KWT	Gen. Gas	TWh	20.6	44.9	30.7	11.4	5.5	10.1	8.4	3.1	30.7	10.7	7.3	30.7	11.4	5.9
KWT	Gen. Nuclear	TWh	0	0	0	0	0	21.6	19.2	13.1	0	0	0	0	0	0
KWT	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.1
KWT	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KWT	Gen. Wind	TWh	0	0.2	44.3	90.8	111.9	44.3	83.3	98.2	39.8	64.6	97.3	44.3	90.8	105
KWT	Gen. PV	TWh	0	0.1	0.1	7.8	13.8	0.1	0.1	4.4	0.7	2	2.4	0.1	7.8	13.9
LAO	Carbon Emission	MT	11.9	19.2	10.9	8.7	6.7	4.5	1.2	0.3	10.3	7.9	6.6	10.9	8.7	1.5
LAO	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LAO	Ann. Cost	B.USD	1.4	2.2	2.1	2.1	2.1	2	1.8	1.8	2.1	2.2	2.2	2.1	2.1	1.8
LAO	Ann. Demand	TWh	4.2	5.4	7.9	10.8	14.1	7.9	10.8	14.1	7.9	10.8	14.1	7.9	10.8	14.1
LAO	Ann. Supply	TWh	27.1	39.4	31.7	32.1	32.8	26.6	30.5	34.3	32.7	34.9	35.5	31.7	32.1	28.7
LAO	Ann. Import	TWh	0	0	13.1	35.8	47.3	11.4	28.3	30.4	7.7	27.7	37.8	13.1	35.8	37.9
LAO	Ann. Export	TWh	22.5	33.6	36.8	57	66	30.1	47.9	50.5	32.3	51.7	59.2	36.8	57.1	52.5
LAO	Gen. Coal	TWh	12.7	20.2	11.9	9.4	7.2	4.8	1.2	0.3	11.2	8.6	7	11.9	9.4	0.7
LAO	Gen. Gas	TWh	0	0	0	0	0.1	0.2	0.1	0.2	0	0	0.2	0	0	2.2
LAO	Gen. Nuclear	TWh	0	0	0.6	0.6	0.6	1.7	1.6	2	0.7	0.6	0.6	0.6	0.6	0.6
LAO	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LAO	Gen. Hydro	TWh	14.4	19.1	19.1	19.1	18.1	19.1	19.1	18.1	19.1	19.1	18.1	19.1	19.1	18.1
LAO	Gen. Wind	TWh	0	0	0	2.9	6.8	0.6	8.3	13.6	1.4	6	9	0	2.9	7
LAO	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.3	0.7	0.7	0.1	0.1	0
LBN	Carbon Emission	MT	13	6.5	0.9	0	0.1	0.7	0	0	0.9	0	0	0.9	0	0.1
LBN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBN	Ann. Cost	B.USD	1.9	1.5	0.9	1.3	1.3	2.2	2.4	2	1.3	2.3	2.2	0.9	1.3	1.2
LBN	Ann. Demand	TWh	18.3	20.8	28.5	38.4	45.3	28.5	38.4	45.3	28.5	38.4	45.3	28.5	38.4	45.3
LBN	Ann. Supply	TWh	14.2	7.9	12.1	17.4	17.9	24.6	29.5	21.3	11.4	19.6	22	12.1	17.4	15.3
LBN	Ann. Import	TWh	4.8	14.3	20.4	35.2	50.7	15.9	27.9	44.4	21.2	35.9	52.2	20.4	35.2	43.6
LBN	Ann. Export	TWh	0.7	1.3	4	12.9	23.3	11.9	19	20.3	4	14.1	26.5	4	12.9	13.6
LBN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBN	Gen. Gas	TWh	0	0.5	1.9	0	0.2	1.2	0	0	1.8	0	0	1.9	0	0.1
LBN	Gen. Nuclear	TWh	0	0	4.4	3.5	2.9	13.1	14.1	10.5	0.7	0.5	0.4	4.4	3.5	2.8
LBN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBN	Gen. Hydro	TWh	0.7	0.6	0.8	0.7	0.7	0.9	0.8	0.8	0.6	0.5	0.5	0.8	0.7	0.7
LBN	Gen. Wind	TWh	0	0	1.6	1.6	0	1.6	1.6	1	5.8	12.9	15.5	1.6	1.6	0
LBN	Gen. PV	TWh	0	0.1	3.2	11.7	14.2	7.6	12.9	9.1	0.1	0.1	0	3.2	11.7	11.6
LBR	Carbon Emission	MT	0	0	0	0.1	0.1	0	0	0	0	0	0.1	0	0.1	0
LBR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBR	Ann. Cost	B.USD	0	0	0	0.1	0.1	0	0	0.1	0	0	0.1	0	0.1	0
LBR	Ann. Demand	TWh	0	0.1	0.1	0.2	0.4	0.1	0.2	0.4	0.1	0.2	0.4	0.1	0.2	0.4
LBR	Ann. Supply	TWh	0.2	0.5	0.5	0.6	0.7	0.5	0.5	1.2	0.5	0.5	0.9	0.5	0.6	0.7
LBR	Ann. Import	TWh	0	0	0.1	0.1	0.1	0.2	0.1	0.4	0.1	0.1	0.1	0.1	0.1	0.1
LBR	Ann. Export	TWh	0.2	0.4	0.4	0.5	0.5	0.6	0.4	1.2	0.5	0.4	0.6	0.4	0.5	0.4
LBR	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBR	Gen. Gas	TWh	0	0	0	0.1	0.3	0	0	0	0	0	0.3	0	0.1	0.1
LBR	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0.7	0	0	0	0	0	0
LBR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBR	Gen. Hydro	TWh	0.2	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.6
LBR	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBR	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.1	0.1	0.1	0.1	0.1	0
LBY	Carbon Emission	MT	19	6.7	3	0.3	0.2	1.8	0	0	3	0	0.1	3	0.3	0.1

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
LBY	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBY	Ann. Cost	B.USD	3.1	1.6	1.3	1	1.1	1.4	1.2	1.3	1.3	1.1	1.2	1.3	1	1.2
LBY	Ann. Demand	TWh	10.8	12.2	16.8	22.6	26.7	16.8	22.6	26.7	16.8	22.6	26.7	16.8	22.6	26.7
LBY	Ann. Supply	TWh	28.4	12.8	16.9	23.7	28.5	16.9	23.3	27.4	16.9	25.1	30.1	16.9	23.7	29.3
LBY	Ann. Import	TWh	0	0	0	0.7	0.8	0.1	0.1	0.4	0	0.6	0.7	0	0.7	0.8
LBY	Ann. Export	TWh	17.5	0.6	0	1.6	2.4	0.1	0.7	1	0	2.9	3.7	0	1.6	3.2
LBY	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBY	Gen. Gas	TWh	15.3	9.7	7.3	0.7	0.4	4.1	0	0.1	7.5	0	0.3	7.3	0.7	0.3
LBY	Gen. Nuclear	TWh	0	0	0	0	0	3.4	1.6	1.5	0	0	0	0	0	0
LBY	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBY	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LBY	Gen. Wind	TWh	0	0	0	6.9	9.1	0	4.9	8.4	3.3	8.7	11.3	0	6.9	9.7
LBY	Gen. PV	TWh	0	0.1	0.1	0.7	3.5	0.1	1.5	2.2	1.3	3.2	3.2	0.1	0.7	4
LKA	Carbon Emission	MT	5.8	8.2	3	1.2	1	2.5	0.6	-3.4	3.1	0.9	1	3	1.2	-3.2
LKA	Carbon Sequester	MT	0	0	0	0	0	0	0	3.5	0	0	0	0	0	3.2
LKA	Ann. Cost	B.USD	0.9	1.1	1.4	1.7	1.9	1.6	2	2.5	1.4	1.8	1.9	1.4	1.7	3
LKA	Ann. Demand	TWh	12.6	15.9	23.4	32	41.7	23.4	32	41.7	23.4	32	41.7	23.4	32	41.7
LKA	Ann. Supply	TWh	12.6	16	23.5	36.1	40.3	24.8	38.5	46.7	24	37.2	40.1	23.5	36.1	51.7
LKA	Ann. Import	TWh	0	0	1.8	3.1	7.6	1.9	1.7	2	1.5	2.5	7.2	1.8	3.1	1.2
LKA	Ann. Export	TWh	0	0	1.7	6.5	4.9	2.9	7.6	6.9	1.8	7.3	4.6	1.7	6.5	11
LKA	Gen. Coal	TWh	4.3	7.9	2.8	1.3	1.1	2.2	0.5	0	2.9	1	1.1	2.8	1.3	0
LKA	Gen. Gas	TWh	0	0	0	0	0	0	0.2	0	0	0	0	0	0	0
LKA	Gen. Nuclear	TWh	0	0	0	0	0	1.8	3.8	7.7	0	0	0	0	0	1.3
LKA	Gen. CCS	TWh	0	0	0	0	0	0	0	4	0	0	0	0	0	3.7
LKA	Gen. Hydro	TWh	6	6.2	6.4	6.9	6.5	7.5	6.9	6.5	6.4	6.9	6.5	6.4	6.9	6.5
LKA	Gen. Wind	TWh	0.5	0.7	12.4	25.7	25.5	12.5	25.5	25.4	12.4	25.6	25.4	12.4	25.7	25.5
LKA	Gen. PV	TWh	0.1	0.3	1.4	2.2	7.1	0.4	1.5	2.9	1.8	3.8	7	1.4	2.2	12.8
LSO	Carbon Emission	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LSO	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LSO	Ann. Cost	B.USD	0	0	0.1	0.3	0.4	0.2	0.3	0.4	0.1	0.3	0.4	0.1	0.3	0.4
LSO	Ann. Demand	TWh	0.8	1.1	2.3	4.3	7.5	2.3	4.3	7.5	2.3	4.3	7.5	2.3	4.3	7.5
LSO	Ann. Supply	TWh	0.2	0.3	2.1	5.6	8.1	2.7	6.6	7.5	2.1	5.7	7.4	2.1	5.6	7.4
LSO	Ann. Import	TWh	0.5	0.7	20	36.9	34.5	19.8	29.4	46.2	18.9	24.8	37.9	20	35.8	31.8
LSO	Ann. Export	TWh	0	0	19.8	38.2	35.2	20.2	31.7	46.3	18.7	26.2	37.8	19.8	37.1	31.7
LSO	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LSO	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LSO	Gen. Nuclear	TWh	0	0	0	0	0	0.6	0.5	0.6	0	0	0	0	0	0
LSO	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LSO	Gen. Hydro	TWh	0.2	0.2	0.2	1.4	1.4	0.2	0.4	1.4	0.2	1.4	1.4	0.2	1.4	1.4
LSO	Gen. Wind	TWh	0	0	1.7	4.2	5.2	1.7	5.6	5.6	1.7	4.1	5.2	1.7	4.2	5.2
LSO	Gen. PV	TWh	0	0.1	0.1	0.1	1.5	0.1	0.1	0	0.1	0.2	0.8	0.1	0.1	0.8
LTU	Carbon Emission	MT	0.6	0.5	0.2	0.2	0	0.2	0	0	0.2	0	0	0.2	0	0
LTU	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LTU	Ann. Cost	B.USD	0.7	0.6	0.6	0.5	0.3	0.6	0.5	0.6	0.8	0.9	0.8	0.6	0.4	0.5
LTU	Ann. Demand	TWh	12	13.1	15.3	17.7	20.3	15.3	17.7	20.3	15.3	17.7	20.3	15.3	17.7	20.3
LTU	Ann. Supply	TWh	6.4	6.6	5.8	4.6	3.4	5.8	4.5	7.8	7.8	10.4	10	5.8	4	7.3
LTU	Ann. Import	TWh	8.3	9.8	27	27.3	22.4	16.9	16.9	17.8	21.1	13.6	16.1	27	23	16.3
LTU	Ann. Export	TWh	2.7	3.3	17.5	14.1	5.5	7.4	3.7	5.4	13.6	6.1	5.8	17.5	9.3	3.3
LTU	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LTU	Gen. Gas	TWh	1.5	1.4	0.6	0.6	0	0.6	0	0	0.6	0	0	0.6	0	0
LTU	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LTU	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LTU	Gen. Hydro	TWh	3.4	3.4	3.4	3.4	3.1	3.4	3.4	3.1	3.4	3.4	3.1	3.4	3.4	3.1
LTU	Gen. Wind	TWh	1.2	1.4	1.4	0.2	0	1.4	0.8	4.4	3.1	5.8	5.8	1.4	0.2	3.9
LTU	Gen. PV	TWh	0.1	0.1	0.1	0.1	0	0.1	0.1	0	0.4	0.9	0.9	0.1	0.1	0
LUX	Carbon Emission	MT	0.2	0.2	0.1	0	0	0.1	0	0	0.1	0	0	0.1	0	-0.1
LUX	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
LUX	Ann. Cost	B.USD	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LUX	Ann. Demand	TWh	6.6	6.8	7	7.4	7.8	7	7.4	7.8	7	7.4	7.8	7	7.4	7.8
LUX	Ann. Supply	TWh	0.9	0.9	0.5	0.2	0.2	0.5	0.2	0.2	0.5	0.2	0.2	0.5	0.2	0.4
LUX	Ann. Import	TWh	7.2	6.3	28	8.7	8.8	6.8	9.8	11.2	22.7	9.5	10.3	28.2	7.4	10.9
LUX	Ann. Export	TWh	1.5	0.3	21.4	1.5	1.2	0.3	2.6	3.5	16.1	2.4	2.6	21.7	0.3	3.5
LUX	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LUX	Gen. Gas	TWh	0.6	0.6	0.3	0	0	0.3	0	0	0.3	0	0	0.3	0	0
LUX	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LUX	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
LUX	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LUX	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LUX	Gen. PV	TWh	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LVA	Carbon Emission	MT	0.8	0.7	0	0	0	0	0	0	0	0	0	0	0	0
LVA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LVA	Ann. Cost	B.USD	0.6	0.6	0.3	0.3	0.5	0.3	0.6	0.6	0.4	0.5	0.5	0.3	0.3	0.7
LVA	Ann. Demand	TWh	7	7.6	8.9	10.3	11.8	8.9	10.3	11.8	8.9	10.3	11.8	8.9	10.3	11.8
LVA	Ann. Supply	TWh	8.1	8	3.5	3.5	6.9	3.5	7.8	8.4	4.5	6	6	3.5	3.5	8.9
LVA	Ann. Import	TWh	2.6	3.2	17	13.7	6.5	7.5	4.4	6.2	13.2	6.1	7.2	16.9	9.2	5
LVA	Ann. Export	TWh	3.7	3.6	11.6	6.8	1.6	2.1	1.9	2.8	8.8	1.7	1.4	11.5	2.3	2.1
LVA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LVA	Gen. Gas	TWh	2.1	1.8	0	0	0	0	0	0	0	0	0	0	0	0
LVA	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LVA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LVA	Gen. Hydro	TWh	5.4	5.4	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
LVA	Gen. Wind	TWh	0.2	0.3	0.1	0.1	3.6	0.1	4.5	5.1	1	2.2	2.2	0.1	0.1	5.5
LVA	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.2	0.4	0.4	0.1	0.1	0
MAR	Carbon Emission	MT	19.9	22.6	8.5	1.5	1.9	5.6	0.4	0.1	8.5	1.2	1.8	8.5	1.5	0.3
MAR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAR	Ann. Cost	B.USD	2.7	3.3	3.7	3.5	4.2	4	3.5	4	3.7	3.6	3.8	3.7	3.5	4.2
MAR	Ann. Demand	TWh	33.2	37.8	51.9	69.8	82.4	51.9	69.8	82.4	51.9	69.8	82.4	51.9	69.8	82.4
MAR	Ann. Supply	TWh	33.8	38.2	53	65	87.6	52.9	60	75.7	52.9	68	79.5	53	65	89.7
MAR	Ann. Import	TWh	0	0	0	10.3	10	0.6	13.2	14.4	0.6	9.8	14	0	10.3	11.1
MAR	Ann. Export	TWh	0.5	0.2	0.5	3.5	12.5	0.7	2.3	6.7	0.7	5.7	8.2	0.5	3.4	15.3
MAR	Gen. Coal	TWh	17.3	21.2	5.8	0.1	1.9	4.1	0	0	6.1	0.1	1.7	5.8	0.1	0.3
MAR	Gen. Gas	TWh	4.4	4	6.8	3.7	0	3.3	1.1	0.2	6.1	2.9	0	6.8	3.7	0
MAR	Gen. Nuclear	TWh	0	0	0	0	0	5	3.5	3.2	0	0	0	0	0	0
MAR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAR	Gen. Hydro	TWh	3.8	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
MAR	Gen. Wind	TWh	5.1	5.5	32.7	49.3	63.8	32.7	42.4	52.2	30.9	50.3	58.3	32.7	49.3	65.2

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
MAR	Gen. PV	TWh	1	1	1	5	15.6	1	6.2	13.9	3.5	7.8	13.1	1	5	17.9
MDA	Carbon Emission	MT	2.2	0.6	0.1	0	0	0.1	0	0	0.1	0	0	0.1	0	0
MDA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDA	Ann. Cost	B.USD	0.8	0.6	0.1	0.2	0.4	0.4	0.5	0.7	0.1	0.3	0.4	0.4	0.5	0.9
MDA	Ann. Demand	TWh	5	5.5	6.4	7.5	8.5	6.4	7.5	8.5	6.4	7.5	8.5	6.4	7.5	8.5
MDA	Ann. Supply	TWh	4.6	1.7	0.6	2	4.8	6	6.6	8.8	1.8	3.2	5.5	6	6.7	11.3
MDA	Ann. Import	TWh	0.5	3.9	5.9	5.5	6.7	0.5	1.9	2.9	4.6	4.7	3.9	0.5	0.9	1.9
MDA	Ann. Export	TWh	0	0.2	0	0.1	2.9	0.1	1.1	3.2	0	0.5	0.9	0.1	0.2	4.6
MDA	Gen. Coal	TWh	0	0.1	0	0	0	0	0	0	0	0	0	0	0	0
MDA	Gen. Gas	TWh	4.3	1.4	0.2	0	0	0.2	0	0	0.2	0	0	0.2	0	0
MDA	Gen. Nuclear	TWh	0	0	0	0	0	3.8	4.6	4.6	0	0	0	3.8	4.6	4.5
MDA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDA	Gen. Hydro	TWh	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
MDA	Gen. Wind	TWh	0	0	0	1.6	1.6	1.6	1.6	1.6	1	2.3	2.3	1.6	1.6	1.6
MDA	Gen. PV	TWh	0	0.1	0.1	0.1	2.8	0.1	0.1	2.2	0.2	0.5	2.7	0.1	0.1	4.6
MDG	Carbon Emission	MT	0.7	1	0.2	0.1	0.2	0	0	0.1	0.2	0.1	0.2	0.2	0.1	-0.1
MDG	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
MDG	Ann. Cost	B.USD	0.1	0.2	0.2	0.4	0.6	0.3	0.4	0.7	0.3	0.4	0.6	0.2	0.4	0.7
MDG	Ann. Demand	TWh	1.4	2	4.2	8	13.7	4.2	8	13.7	4.2	8	13.7	4.2	8	13.7
MDG	Ann. Supply	TWh	1.4	2	4.2	8.3	14.4	4.2	8.2	14.2	4.2	8.5	14.3	4.2	8.3	14.3
MDG	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDG	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDG	Gen. Coal	TWh	0.7	0.8	0	0	0	0	0	0	0	0	0	0	0	0
MDG	Gen. Gas	TWh	0.1	0.4	0.4	0.3	0.5	0	0.1	0.1	0.4	0.2	0.5	0.4	0.3	0.3
MDG	Gen. Nuclear	TWh	0	0	0	0	0	0.6	0.7	0.6	0	0	0	0	0	0
MDG	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
MDG	Gen. Hydro	TWh	0.7	0.7	0.7	2.2	3.7	0.7	1.3	2.6	0.7	1.9	3.5	0.7	2.2	3.3
MDG	Gen. Wind	TWh	0	0	2.1	4.4	8.6	1.8	4.9	9.2	2	4.7	8.7	2.1	4.4	8.6
MDG	Gen. PV	TWh	0	0.1	0.1	0.3	0.7	0.1	0.2	0.7	0.3	0.9	0.9	0.1	0.3	0.9
MEX	Carbon Emission	MT	113.4	95.6	19.9	0.5	1.9	12.3	1.1	1.6	15	2.3	1.4	17.2	1	1
MEX	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEX	Ann. Cost	B.USD	22.2	22.3	16.1	24.6	30.7	16.4	26.9	41.3	15.9	23.6	31.7	16	27.4	39.1
MEX	Ann. Demand	TWh	287.2	338.3	417.7	527.6	659.2	417.7	527.6	659.2	417.7	527.6	659.2	417.7	527.6	659.2
MEX	Ann. Supply	TWh	277	271.4	311.7	557.5	671.2	304.3	530.6	789.5	304.5	480	627.4	309.6	537.3	679.8
MEX	Ann. Import	TWh	14.2	74.4	118.2	58.2	66.2	132.3	75.7	60.1	128.9	85.5	83.3	120.3	55.9	62.5
MEX	Ann. Export	TWh	0	0	1	62.3	59	6.9	62.1	164.6	1.2	19.4	31.4	1	53.2	68.7
MEX	Gen. Coal	TWh	43.4	40.3	13.8	0.4	0	5.7	0	0	10.2	1.2	0	10.9	0.2	0
MEX	Gen. Gas	TWh	140.3	125.3	14.6	0.5	4	15.6	3	4.2	11	2.5	2.8	15.1	2	2.3
MEX	Gen. Nuclear	TWh	11.7	11.7	11.7	0	0	11.2	0	0	11.7	0	0	11.7	0	0
MEX	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEX	Gen. Hydro	TWh	38.1	38.9	31.1	44	62	31.2	79.3	79.3	31.1	42.1	66.5	31.1	79.3	79.6
MEX	Gen. Wind	TWh	13.2	28.1	70.4	202.6	210.2	68.8	188.6	188.5	76.7	182.3	203.2	70.3	194.7	235.5
MEX	Gen. PV	TWh	0.3	5.6	48.2	191.6	278.2	49.7	140.9	403.4	41.6	132.1	237.1	48.6	142.1	230.9
MKD	Carbon Emission	MT	2.9	3.1	0.2	0	0	0.2	0	-0.6	0.2	0	0	0.2	0	-0.6
MKD	Carbon Sequester	MT	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0.6
MKD	Ann. Cost	B.USD	0.5	0.6	0.2	0.2	0.2	0.3	0.4	0.5	0.3	0.4	0.4	0.2	0.2	0.4
MKD	Ann. Demand	TWh	7.5	8.2	9.5	11	12.6	9.5	11	12.6	9.5	11	12.6	9.5	11	12.6
MKD	Ann. Supply	TWh	5.7	6.2	2.5	2.3	2.8	4.7	5.5	5.9	3.8	5.5	5.3	2.5	3	5
MKD	Ann. Import	TWh	1.8	1.9	8.3	15.2	22.6	5.9	13.9	14.6	6.9	9.8	16.7	8.2	16.3	20.8
MKD	Ann. Export	TWh	0	0	1.1	6.5	12.8	1.1	8.4	7.9	1	4.2	9.3	0.9	8.3	13.2
MKD	Gen. Coal	TWh	3.1	3.5	0	0	0	0	0	0	0	0	0	0	0	0
MKD	Gen. Gas	TWh	0.1	0.1	0.3	0	0	0.3	0	0	0.3	0	0	0.3	0	0
MKD	Gen. Nuclear	TWh	0	0	0	0	0	0	1.1	0.9	0	0	0	0	0	0
MKD	Gen. CCS	TWh	0	0	0	0	0	0	0	0.8	0	0	0	0	0	0.7
MKD	Gen. Hydro	TWh	2.2	2.3	1.5	1.5	1.3	1.5	1.5	1.3	1.5	1.5	1.3	1.5	1.5	1.3
MKD	Gen. Wind	TWh	0.1	0.1	0.7	0.7	1.5	2.8	2.8	2.8	1.6	3	2.9	0.7	1.5	2.8
MKD	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.5	1	1	0.1	0.1	0
MLI	Carbon Emission	MT	0	0.7	1	0.8	1	0.4	0.4	0.5	0.8	0.5	1	1	0.8	0.5
MLI	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MLI	Ann. Cost	B.USD	0.1	0.2	0.4	1	1.7	0.5	1.1	1.8	0.5	1	1.7	0.4	1	1.6
MLI	Ann. Demand	TWh	2	2.9	6	11.5	19.8	6	11.5	19.8	6	11.5	19.8	6	11.5	19.8
MLI	Ann. Supply	TWh	0.9	2.7	6.4	15.5	27.4	6.3	15.9	26.8	6.6	15.8	28	6.4	15.5	26.4
MLI	Ann. Import	TWh	1.8	0.5	0.2	0.5	2.9	0.6	0.4	3.5	0.2	0.3	1.9	0.2	0.5	3.3
MLI	Ann. Export	TWh	0.6	0.3	0.5	4.3	10	0.9	4.7	10.1	0.7	4.4	9.5	0.5	4.3	9.3
MLI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MLI	Gen. Gas	TWh	0	1.7	2.7	2.1	2.6	1.1	1.1	1.3	2.2	1.4	2.8	2.7	2.1	1.3
MLI	Gen. Nuclear	TWh	0	0	0	1.5	2.2	1.5	2.9	2.9	0	1.4	1.4	0	1.5	1.5
MLI	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MLI	Gen. Hydro	TWh	0.8	0.8	0.8	0.8	1.3	0.8	0.8	0.5	0.8	0.8	1.1	0.8	0.8	0.5
MLI	Gen. Wind	TWh	0	0	1.9	10.2	20.5	1.9	10.2	21.3	1.9	9.3	19.8	1.9	10.2	22
MLI	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.6	1.8	1.8	0.1	0.1	0
MLT	Carbon Emission	MT	0.9	0.7	0.1	0	0.1	0.1	0.3	0.1	0.1	0	0.1	0.1	0	-0.2
MLT	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
MLT	Ann. Cost	B.USD	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.4	0.4	0.1	0.1	0.1
MLT	Ann. Demand	TWh	2.3	2.5	3	3.4	3.9	3	3.4	3.9	3	3.4	3.9	3	3.4	3.9
MLT	Ann. Supply	TWh	1.1	1	0.3	0.2	0.5	0.3	0.9	0.5	1.1	1.6	2	0.3	0.2	0.4
MLT	Ann. Import	TWh	1.2	1.5	2.6	3.3	3.5	2.7	2.6	3.4	1.9	2	2.1	2.6	3.3	3.6
MLT	Ann. Export	TWh	0	0	0	0	0	0.1	0.1	0	0	0	0	0	0	0.1
MLT	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MLT	Gen. Gas	TWh	0.1	0	0	0	0.2	0	0.7	0.3	0	0	0.3	0	0	0
MLT	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MLT	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
MLT	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MLT	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.7	1.4	1.4	0	0	0
MLT	Gen. PV	TWh	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.2	0.2	0.2
MMR	Carbon Emission	MT	4.4	5.3	4.2	2.2	1.8	2.4	0.6	0.5	4.1	1.6	1.4	4.2	2.2	0.6
MMR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MMR	Ann. Cost	B.USD	1	1.3	1.7	2.3	3	1.8	2.4	2.7	1.8	2.3	3.1	1.7	2.3	2.7
MMR	Ann. Demand	TWh	14.7	18.6	27.4	37.5	48.9	27.4	37.5	48.9	27.4	37.5	48.9	27.4	37.5	48.9
MMR	Ann. Supply	TWh	16.1	19.2	27	42.8	56.1	28.2	45.1	52.8	27.8	43.7	59.2	27	42.7	53.3
MMR	Ann. Import	TWh	0	0	2.9	4.8	6	3	4.3	6.7	2	2.5	4.3	2.9	4.8	7.2
MMR	Ann. Export	TWh	0	0	2.3	9.6	12.6	3.5	11.4	10	2.1	8.3	14.1	2.3	9.6	10.9
MMR	Gen. Coal	TWh	1.4	1.5	1.1	0.7	0.2	0.5	0	0	1.1	0.6	0.2	1.1	0.7	0
MMR	Gen. Gas	TWh	5.3	7.4	7.1	3.9	4.1	3.7	1.4	1.2	6.6	2.7	2.9	7.1	3.9	1.5
MMR	Gen. Nuclear	TWh	0	0	0.8	1.5	5	2.8	3.5	3.4	0.7	1.6	5	0.8	1.5	4.6
MMR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
MMR	Gen. Hydro	TWh	9.3	9.8	9.8	14.8	20.6	9.8	17.7	20.4	9.8	12.8	20.6	9.8	14.8	20.5
MMR	Gen. Wind	TWh	0	0	5.7	13.1	14.2	6.1	13.6	14.2	5.1	12.1	14.3	5.7	13.1	14.3
MMR	Gen. PV	TWh	0	0.2	0.3	0.3	3.6	0.3	0.3	5.1	2.1	5.7	8	0.3	0.3	3.8
MNE	Carbon Emission	MT	1.1	0.9	0	0	0	0	0	-0.5	0	0	0	0	0	-0.3
MNE	Carbon Sequester	MT	0	0	0	0	0	0	0	0.5	0	0	0	0	0	0.3
MNE	Ann. Cost	B.USD	0.2	0.3	0.2	0.4	0.5	0.3	0.4	0.6	0.2	0.4	0.5	0.2	0.4	0.5
MNE	Ann. Demand	TWh	2.9	3.2	3.8	4.4	5	3.8	4.4	5	3.8	4.4	5	3.8	4.4	5
MNE	Ann. Supply	TWh	3.4	3.8	4.7	7.7	9.1	5.3	8.2	10.1	4.7	7.7	9.4	4.7	7.6	9.4
MNE	Ann. Import	TWh	0.3	0.9	9.8	7.5	10	3.7	6.2	7.3	6	4.2	7.6	9.3	5.9	4.8
MNE	Ann. Export	TWh	0.8	1.5	10.7	10.8	14.1	5.2	10	12.5	6.7	7.5	12	10.2	9.2	9.3
MNE	Gen. Coal	TWh	1.2	1.1	0	0	0	0	0	0	0	0	0	0	0	0
MNE	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MNE	Gen. Nuclear	TWh	0	0	0	0	0	0.6	0.5	0.5	0	0	0	0	0	0
MNE	Gen. CCS	TWh	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0.4
MNE	Gen. Hydro	TWh	2.2	2.2	3.7	4.3	4.3	2.7	4.3	4.3	3.6	4.3	4.3	3.7	4.3	4.3
MNE	Gen. Wind	TWh	0	0.5	0.9	3.3	4.8	1.9	3.3	4.8	0.9	3	4.7	0.9	3.3	4.8
MNE	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.2	0.4	0.4	0.1	0.1	0
MNG	Carbon Emission	MT	5	5.5	0.5	0.2	0.1	0.1	0	0	0.2	0.1	0.1	0.5	0.2	-0.1
MNG	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
MNG	Ann. Cost	B.USD	0.4	0.6	0.6	0.7	0.7	0.6	0.7	0.7	0.6	0.7	0.7	0.6	0.7	0.8
MNG	Ann. Demand	TWh	5.9	7.4	9.7	11.3	12	9.7	11.3	12	9.7	11.3	12	9.7	11.3	12
MNG	Ann. Supply	TWh	5.9	7.5	9.7	11.4	12.2	9.7	11.3	12.1	9.7	11.4	12.1	9.7	11.4	12.1
MNG	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MNG	Ann. Export	TWh	0	0	0	0.1	0.1	0	0	0.1	0	0.1	0.1	0	0.1	0.1
MNG	Gen. Coal	TWh	5.4	5.9	0	0	0	0	0	0	0	0	0	0	0	0
MNG	Gen. Gas	TWh	0	0	1.3	0.5	0.3	0.2	0.1	0.1	0.4	0.3	0.3	1.3	0.5	0.1
MNG	Gen. Nuclear	TWh	0	0	1.9	1.5	1.2	3	2.5	2.2	2.2	1.8	1.7	1.9	1.5	1.4
MNG	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
MNG	Gen. Hydro	TWh	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
MNG	Gen. Wind	TWh	0.2	1.2	6.2	8.5	9.2	6	8.1	8.9	6.3	7.9	8.8	6.2	8.5	9.4
MNG	Gen. PV	TWh	0	0.1	0.1	0.8	1.1	0.3	0.5	0.8	0.7	1.3	1.3	0.1	0.8	1.1
MOZ	Carbon Emission	MT	1.3	2.9	4.4	2.9	8.3	2.3	1.5	-1.2	4.9	3.4	7.5	4.4	2.9	1.7
MOZ	Carbon Sequester	MT	0	0	0	0	0	0	0	2.7	0	0	0	0	0	2.3
MOZ	Ann. Cost	B.USD	0.7	0.9	2.9	5.3	9.3	3	4.6	8	3.1	6	9.6	2.9	5.3	9
MOZ	Ann. Demand	TWh	14.8	20.9	43.8	84.1	144.9	43.8	84.1	144.9	43.8	84.1	144.9	43.8	84.1	144.9
MOZ	Ann. Supply	TWh	8.2	12.8	44.6	84.2	139.6	43.3	70.4	120.2	46.2	92.5	143.4	44.6	84.2	135.8
MOZ	Ann. Import	TWh	8.5	9.3	10.6	25.5	38.5	7.2	27.2	54.9	8.6	19.5	36.6	10.6	25.3	42.7
MOZ	Ann. Export	TWh	1.5	0.8	10.2	22.7	28.5	6.1	11.5	25.4	9.9	25.6	30.1	10.2	22.5	28.7
MOZ	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MOZ	Gen. Gas	TWh	2	6.6	11.7	7.8	22.4	5.9	3.9	4.2	13.1	9	20.2	11.7	7.8	10.9
MOZ	Gen. Nuclear	TWh	0	0	0	0	0	4.5	3.7	3.8	0	0	0	0	0	0
MOZ	Gen. CCS	TWh	0	0	0	0	0	0	0	3.1	0	0	0	0	0	2.6
MOZ	Gen. Hydro	TWh	6.2	6	28.2	59.8	83.8	24	45.1	82.8	24.3	57.9	85	28.2	59.8	86.3
MOZ	Gen. Wind	TWh	0	0	4.6	9.5	12	7	9.7	15.9	6.2	15.4	16.3	4.6	9.5	18.7
MOZ	Gen. PV	TWh	0	0.1	0.1	7.1	21.6	1.9	7.9	10.6	2.6	10.1	21.9	0.1	7.1	17.5
MRT	Carbon Emission	MT	0.5	0.6	0.4	0.1	0.2	0.1	0	0.1	0.2	0.1	0.2	0.4	0.1	0.1
MRT	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MRT	Ann. Cost	B.USD	0.1	0.2	0.2	0.3	0.5	0.2	0.3	0.5	0.2	0.3	0.5	0.2	0.3	0.5
MRT	Ann. Demand	TWh	1.1	1.6	3.3	6.3	10.9	3.3	6.3	10.9	3.3	6.3	10.9	3.3	6.3	10.9
MRT	Ann. Supply	TWh	1.1	1.6	3.2	6	10.2	3.2	5.8	10.5	3.1	5	9.7	3.2	6	10.4
MRT	Ann. Import	TWh	0	0	0.1	0.7	1	0	0.5	0.7	0.2	1.7	1.6	0.1	0.7	0.9
MRT	Ann. Export	TWh	0	0	0	0.3	0.3	0	0.1	0.3	0	0.4	0.4	0	0.3	0.4
MRT	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MRT	Gen. Gas	TWh	0.8	1.1	0.9	0.3	0.5	0.3	0.1	0.2	0.6	0.2	0.5	0.9	0.3	0.4
MRT	Gen. Nuclear	TWh	0	0	0	0	0	0.6	0.4	0.3	0	0	0	0	0	0
MRT	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MRT	Gen. Hydro	TWh	0	0.1	0.1	0.3	0.4	0.1	0.3	0.3	0.1	0.2	0.4	0.1	0.3	0.4
MRT	Gen. Wind	TWh	0.2	0.2	2	4.8	8	2	4.4	8.3	1.9	3.4	7.2	2	4.8	8.1
MRT	Gen. PV	TWh	0.1	0.2	0.2	0.7	1.4	0.2	0.7	1.4	0.3	0.7	1.3	0.2	0.7	1.6
MUS	Carbon Emission	MT	2.6	3	2.8	0.8	0.8	0.5	0.2	-0.2	1.7	1.4	1	2.8	0.8	0
MUS	Carbon Sequester	MT	0	0	0	0	0	0	0	0.3	0	0	0	0	0	0.2
MUS	Ann. Cost	B.USD	0.3	0.5	0.8	1.4	2.5	0.8	1.5	2.5	1	1.9	2.8	0.8	1.4	2.6
MUS	Ann. Demand	TWh	3	4.2	8.8	16.9	29.2	8.8	16.9	29.2	8.8	16.9	29.2	8.8	16.9	29.2
MUS	Ann. Supply	TWh	3	4.2	8.8	16.9	29.2	8.8	16.9	29.2	8.9	17	29.3	8.8	16.9	29.2
MUS	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUS	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUS	Gen. Coal	TWh	1.8	2	0.2	0	0	0.2	0	0	0.3	0	0	0.2	0	0
MUS	Gen. Gas	TWh	0	0.9	6.5	2.1	2.1	0.6	0.5	0.1	3.3	3.7	2.6	6.5	2.1	0.2
MUS	Gen. Nuclear	TWh	0	0	0	10.7	21.9	4.9	12.6	23.5	0	2.8	15.3	0	10.7	23.4
MUS	Gen. CCS	TWh	0	0	0	0	0	0	0	0.5	0	0	0	0	0	0.5
MUS	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUS	Gen. Wind	TWh	0	0.2	1.5	2.4	2.4	2.4	2.4	2.4	4.4	8.6	8.3	1.5	2.4	2.4
MUS	Gen. PV	TWh	0	0.1	0.2	1.4	2.4	0.3	1	2.4	0.4	1.6	2.9	0.2	1.4	2.4
MWI	Carbon Emission	MT	0	0.4	0.4	0.3	0.4	0.2	0.2	-2.5	0.3	0.2	0.2	0.4	0.3	-1.1
MWI	Carbon Sequester	MT	0	0	0	0	0	0	0	2.7	0	0	0	0	0	1.3
MWI	Ann. Cost	B.USD	0.1	0.2	0.4	1	1.5	0.3	1	1.7	0.4	1	1.4	0.4	1	1.7
MWI	Ann. Demand	TWh	2	2.8	5.8	11.2	19.3	5.8	11.2	19.3	5.8	11.2	19.3	5.8	11.2	19.3
MWI	Ann. Supply	TWh	0.9	2.2	5.9	14.5	22.4	5.2	15.2	25.2	5.7	14.5	21.7	5.9	14.5	22.5
MWI	Ann. Import	TWh	1.1	0.6	1.3	3.7	7.4	1.2	4.8	11.9	1	2.2	8.4	1.3	3.6	10
MWI	Ann. Export	TWh	0.1	0	1.3	6.9	10.4	0.5	8.7	17.7	0.8	5.5	10.6	1.3	6.8	13.2
MWI	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MWI	Gen. Gas	TWh	0	1	1.1	0.7	0.9	0.4	0.4	0.4	0.7	0.4	0.5	1.1	0.7	0.7
MWI	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MWI	Gen. CCS	TWh	0	0	0	0	0	0	0	3.1	0	0	0	0	0	1.5
MWI	Gen. Hydro	TWh	0.9	1.1	1.1	1.1	4.1	1.1	1.1	4.4	1.1	1.7	3.6	1.1	1.1	2.8
MWI	Gen. Wind	TWh	0	0	3.6	12.6	12.9	3.6	13.6	13.8	3.5	11.4	12.9	3.6	12.6	12.9
MWI	Gen. PV	TWh	0	0.1	0.1	0.1	4.5	0.1	0.1	3.5	0.4	1.1	4.5	0.1	0.1	4.5
MYS	Carbon Emission	MT	88.5	142.5	25.5	10.2	7.2	17.1	0.4	-22.8	28.7	9.6	5.2	25.6	10.2	-9.9
MYS	Carbon Sequester	MT	0	0	0	0	0	0	0	23.3	0	0	0	0	0	9.9
MYS	Ann. Cost	B.USD	9.6	12.6	10.9	11.3	12.8	12.3	10.4	14.2	23.4	34.8	34.6	10.9	11.3	12.8
MYS	Ann. Demand	TWh	140.4	177.6	261.3	357.2	466.1	261.3	357.2	466.1	261.3	357.2	466.1	261.3	357.2	466.1
MYS	Ann. Supply	TWh	145.5	200	182.4	211.9	248.2	196.8	193.2	255.1	207.1	256.6	291.2	182.4	211.6	227.2
MYS	Ann. Import	TWh	0	0	186.5	329.6	436	137.2	316.6	404.7	151	263.7	402.5	186.5	329.9	443.1
MYS	Ann. Export	TWh	5	21.9	104.2	177.1	204.4	70.1	138.8	183.6	93.1	148.2	200.7	104.2	177.1	192.6
MYS	Gen. Coal	TWh	67.8	126.4	22.9	10.9	7.9	12.6	0	0	26.1	10.2	5.7	22.9	11	0
MYS	Gen. Gas	TWh	53.6	47	8.5	0	0	12	1.1	1.2	8.5	0	0	8.5	0	0

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
MYS	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MYS	Gen. CCS	TWh	0	0	0	0	0	0	0	27.2	0	0	0	0	0	11.6
MYS	Gen. Hydro	TWh	22	25.2	48.5	48.5	49	48.5	48.5	49	48.5	48.5	48.9	48.5	48.5	49
MYS	Gen. Wind	TWh	0	0	0	0	0	0	0	0	27.9	57.3	57.3	0	0	0
MYS	Gen. PV	TWh	0.3	0.6	52.1	102.2	141.2	73.5	93.3	127.8	45.8	90.3	129.2	52.1	101.9	115.3
NAM	Carbon Emission	MT	0.9	1.6	1.2	0.3	0.2	0.5	0.3	0.2	1.1	0.3	0.2	1.2	0.3	0.2
NAM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NAM	Ann. Cost	B.USD	0.1	0.3	0.6	1.3	2.3	0.6	1.4	2.5	0.6	1.4	2.4	0.6	1.3	2.4
NAM	Ann. Demand	TWh	4.2	5.9	12.3	23.6	40.8	12.3	23.6	40.8	12.3	23.6	40.8	12.3	23.6	40.8
NAM	Ann. Supply	TWh	1.6	3.9	11	28.5	51.9	10.1	29.7	53.2	11.1	28.9	52.4	11	28.5	51.8
NAM	Ann. Import	TWh	2.7	2.1	3.8	6.2	9.7	3.8	9.3	12.7	3.8	4.4	8.6	3.8	6.2	8.4
NAM	Ann. Export	TWh	0	0	2.3	9.9	19.2	1.3	14.2	23	2.2	8.6	18.4	2.3	9.9	17.9
NAM	Gen. Coal	TWh	0.9	0.9	0.4	0	0	0.3	0	0	0.5	0	0	0.4	0	0
NAM	Gen. Gas	TWh	0	1.9	1.9	0.8	0.6	0.5	0.7	0.4	1.7	0.9	0.5	1.9	0.8	0.5
NAM	Gen. Nuclear	TWh	0	0	0	0	0	0.6	0.6	0.6	0	0	0	0	0	0
NAM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NAM	Gen. Hydro	TWh	0.6	0.9	0.9	0.5	0.5	0.9	0.5	0.5	0.9	0.5	0.5	0.9	0.5	0.5
NAM	Gen. Wind	TWh	0	0	7.5	27	50.8	7.5	27.8	51.6	7.3	25.2	49	7.5	27	50.8
NAM	Gen. PV	TWh	0.1	0.2	0.2	0.1	0	0.2	0.1	0	0.8	2.3	2.3	0.2	0.1	0
NER	Carbon Emission	MT	0.8	1.3	0.6	0.1	0.3	0.4	0.1	0.2	0.4	0.1	0.4	0.6	0.1	0.1
NER	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NER	Ann. Cost	B.USD	0.1	0.2	0.3	0.4	0.7	0.3	0.4	0.7	0.3	0.4	0.8	0.3	0.4	0.6
NER	Ann. Demand	TWh	1.2	1.7	3.5	6.7	11.6	3.5	6.7	11.6	3.5	6.7	11.6	3.5	6.7	11.6
NER	Ann. Supply	TWh	0.8	2.5	4.3	8.9	16	3.9	8.7	15.6	4.6	10.1	17.4	4.3	8.9	15.4
NER	Ann. Import	TWh	0.8	0.1	0.1	0.1	1.4	0.5	0.2	1.5	0.1	0.3	1.3	0.1	0.1	1.9
NER	Ann. Export	TWh	0.3	0.9	0.9	2.3	5.8	0.8	2.1	5.5	1.1	3.7	7.1	0.9	2.3	5.6
NER	Gen. Coal	TWh	0.6	0.5	0	0	0	0	0	0	0	0	0	0	0	0
NER	Gen. Gas	TWh	0	1.7	1.5	0.4	0.8	0.7	0.2	0.5	0.9	0.3	0.9	1.5	0.4	0.2
NER	Gen. Nuclear	TWh	0	0	0	0	0	0.7	0.7	0.6	0	0	0	0	0	0
NER	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NER	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NER	Gen. Wind	TWh	0	0	0	1.7	8.6	0	1.3	8.2	0.8	2.2	9	0	1.7	8.6
NER	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.3	0.9	0.9	0.1	0.1	0
NGA	Carbon Emission	MT	9.3	13.3	14.3	13.2	21.8	8.8	5.2	7.7	13.1	13.8	20.4	14.3	13.2	8.1
NGA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	2.9
NGA	Ann. Cost	B.USD	2.6	3.3	5.9	10.8	18.5	6.1	12	19.6	5.8	10.7	18.3	5.9	10.8	16.8
NGA	Ann. Demand	TWh	27.8	39.3	82.3	157.7	271.9	82.3	157.7	271.9	82.3	157.7	271.9	82.3	157.7	271.9
NGA	Ann. Supply	TWh	30.9	41.6	85.1	165.6	277.8	83.6	174.9	289.1	83.2	159.7	274.8	85.1	165.6	258.7
NGA	Ann. Import	TWh	0	0.2	0.6	3.1	12	0.6	1.5	12.9	1	3.8	12	0.6	3.1	29.2
NGA	Ann. Export	TWh	2.3	2	1	9.3	15	1.3	16.6	25.1	0.2	4.4	12.1	1	9.3	13
NGA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NGA	Gen. Gas	TWh	23.9	34.5	37.6	34.7	59	23.5	13.9	20.8	34.6	36.2	55.3	37.6	34.7	30
NGA	Gen. Nuclear	TWh	0	0	0	0	0	12.6	13.6	13.2	0	0	0	0	0	2.6
NGA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	3.3
NGA	Gen. Hydro	TWh	7	7	35.1	73.4	103.1	29.7	54.5	87.8	28.7	64.2	103.1	35.1	73.4	103.3
NGA	Gen. Wind	TWh	0	0	8.8	45.4	87.9	14.3	79.5	129.7	11.2	36.3	84.1	8.8	45.4	93.1
NGA	Gen. PV	TWh	0	0.1	0.1	8.5	24.4	0.1	10	34.4	5.2	19.6	28.8	0.1	8.5	22.7
NIC	Carbon Emission	MT	1.8	1.2	0.6	0	0.1	0.4	0.2	0.4	0.5	0.3	0.5	0.6	0	0
NIC	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NIC	Ann. Cost	B.USD	0.4	0.5	0.5	0.6	0.7	0.5	0.7	0.9	0.5	0.7	0.9	0.5	0.6	0.7
NIC	Ann. Demand	TWh	3.7	4.2	5.5	7	8.6	5.5	7	8.6	5.5	7	8.6	5.5	7	8.6
NIC	Ann. Supply	TWh	3.3	4.2	7.3	12.4	17.5	7.1	12.9	18.7	7.3	13.4	19.1	7.3	12.4	17.3
NIC	Ann. Import	TWh	2.6	3.4	9.8	11.7	7.9	10.2	15.5	10.2	9.1	6.8	9.1	9.8	11.7	8.2
NIC	Ann. Export	TWh	2.2	3.4	11.6	17.2	16.6	11.8	21.5	20	11	13.3	19.3	11.6	17.1	16.7
NIC	Gen. Coal	TWh	0.2	0.2	0.1	0	0	0	0	0	0.1	0	0	0.1	0	0
NIC	Gen. Gas	TWh	0.1	0	0.2	0.1	0.3	0	0.5	1	0	0.8	1.5	0.2	0.1	0.1
NIC	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NIC	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NIC	Gen. Hydro	TWh	0.2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
NIC	Gen. Wind	TWh	0.9	0.9	4.6	10.3	14.8	4.7	10.6	15.3	4.6	10.2	14.7	4.6	10.3	14.7
NIC	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.4	0.6	0.5	0.1	0.1	0
NLD	Carbon Emission	MT	44.5	39.8	16.5	0.2	0	12.9	0	0	15.5	0.5	0.4	15.9	0	0
NLD	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NLD	Ann. Cost	B.USD	8	8.2	6.3	5.9	5	9.5	6.6	5.5	7.8	7.8	8	6.3	5.9	5
NLD	Ann. Demand	TWh	112.9	117.2	120.3	126.3	134.4	120.3	126.3	134.4	120.3	126.3	134.4	120.3	126.3	134.4
NLD	Ann. Supply	TWh	95.4	89	54.4	58.7	53	92.4	67.3	61.9	73.2	78.5	93.1	53.9	58.5	53.1
NLD	Ann. Import	TWh	27.9	38.6	91.5	81.8	108.2	41.9	125.6	143.7	74.9	64.9	80.5	93.9	92.4	119.5
NLD	Ann. Export	TWh	9.8	10	24.9	13.1	25.6	13.2	64.4	69.8	27	15.7	36.5	26.8	23.3	37.2
NLD	Gen. Coal	TWh	37.3	33.7	14	0.2	0	9.6	0	0	13	0.6	0.5	13.3	0	0
NLD	Gen. Gas	TWh	35.1	31.1	13.1	0	0	13.2	0	0	13	0	0	13.1	0	0
NLD	Gen. Nuclear	TWh	3.6	0	0	0	0	0	0	0	0	0	0	0	0	0
NLD	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NLD	Gen. Hydro	TWh	0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
NLD	Gen. Wind	TWh	14	15.5	20.1	51.2	48.8	62.2	60	57.7	35.6	59	73.8	20.1	51.2	48.8
NLD	Gen. PV	TWh	1.5	4.5	3.1	3.1	0	3.1	3.1	0	7.4	14.6	14.6	3.1	3.1	0
NOR	Carbon Emission	MT	1	1	0.2	0	0	0.2	0	0	0.2	0	0	0.2	0	0
NOR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOR	Ann. Cost	B.USD	7.2	8	9.1	11.9	13.1	9.2	11.9	13.1	9.2	11.9	13.1	9.1	11.9	13.1
NOR	Ann. Demand	TWh	123.8	128.4	131.9	138.5	147.4	131.9	138.5	147.4	131.9	138.5	147.4	131.9	138.5	147.4
NOR	Ann. Supply	TWh	151	161.1	205.4	281.1	314.1	205.4	281.1	314.1	205.6	281.2	314	205.4	281.1	314.1
NOR	Ann. Import	TWh	13.9	9	0	1.1	3.9	3.9	9.5	13.6	0.2	0	3	0	0.4	15.2
NOR	Ann. Export	TWh	32.2	34.2	68.6	139.6	166	72.7	147.6	174.7	69.2	139	164.4	68.6	139.4	176.5
NOR	Gen. Coal	TWh	0.1	0.1	0	0	0	0	0	0	0	0	0	0	0	0
NOR	Gen. Gas	TWh	2	2.1	0.3	0	0	0.3	0	0	0.3	0	0	0.3	0	0
NOR	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOR	Gen. Hydro	TWh	144.6	146.9	116.9	91.2	113.6	116.9	82.1	113.6	116.9	93.5	113.5	116.9	82.1	113.6
NOR	Gen. Wind	TWh	4	11.6	87.9	189.5	200.2	87.9	198.7	200.2	88.1	187.4	200.3	87.9	198.6	200.2
NOR	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.1	0.1	0	0.1	0.1	0
NPL	Carbon Emission	MT	0	0	0	0	0	0	0.2	-3.3	0	0	0.1	0	0	-1.5
NPL	Carbon Sequester	MT	0	0	0	0	0	0	0	3.3	0	0	0	0	0	1.5
NPL	Ann. Cost	B.USD	0.1	0.2	0.2	0.4	0.6	0.3	0.8	1	0.3	0.5	0.7	0.2	0.4	1.9
NPL	Ann. Demand	TWh	4.3	5.4	8	10.9	14.2	8	10.9	14.2	8	10.9	14.2	8	10.9	14.2
NPL	Ann. Supply	TWh	2.4	3.5	4.1	8.4	11.3	5	13.1	17.7	4.8	9.2	12.7	4.1	8.4	18.5
NPL	Ann. Import	TWh	2.5	2.6	4.5	12.5	35.1	4.2	62.9	91.6	3.9	5.7	19.8	4.5	12.6	51.5
NPL	Ann. Export	TWh	0.4	0.7	0.6	9.6	30.9	1.2	63	92	0.7	3.8	17.6	0.6	9.7	54.1

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
NPL	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPL	Gen. Gas	TWh	0	0	0	0	0.1	0	0.4	0.1	0	0	0.2	0	0	0
NPL	Gen. Nuclear	TWh	0	0	0	0	0	0.7	4.4	5.2	0	0	0	0	0	0
NPL	Gen. CCS	TWh	0	0	0	0	0	0	0	3.9	0	0	0	0	0	1.7
NPL	Gen. Hydro	TWh	2.4	3.4	3.4	3.6	6.2	3.4	3.4	2.8	3.4	3.4	6.2	3.4	3.6	4.9
NPL	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.5	1.1	1.1	0	0	0
NPL	Gen. PV	TWh	0	0.1	0.4	2.6	2.8	0.3	2.7	3.7	0.9	2.6	3	0.4	2.6	2.7
NZL	Carbon Emission	MT	6.4	7	1.6	0.9	0.5	1.4	0.5	0.4	1.5	0.8	0.6	1.6	0.9	0.4
NZL	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
NZL	Ann. Cost	B.USD	2.5	2.6	2.6	3.1	3.6	2.7	3.1	3.7	2.6	3.2	3.7	2.6	3.1	3.7
NZL	Ann. Demand	TWh	42.3	43.7	54.6	66.1	78.3	54.6	66.1	78.3	54.6	66.1	78.3	54.6	66.1	78.3
NZL	Ann. Supply	TWh	42.7	44	54.9	67	81.3	55.1	68.3	81.8	55	68.1	81.6	54.9	67	81.2
NZL	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NZL	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NZL	Gen. Coal	TWh	4.9	5.6	0	0	0	0	0	0	0	0	0	0	0	0
NZL	Gen. Gas	TWh	5.3	5	4.3	2.4	1.3	3.6	1.1	1	3.8	2	1.4	4.3	2.4	1.2
NZL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NZL	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
NZL	Gen. Hydro	TWh	22.1	22.3	11.8	8.7	7.4	11.8	8.7	7.4	11.8	8.7	7.9	11.8	8.7	7.4
NZL	Gen. Wind	TWh	3.2	3.4	12.9	28.2	44.6	13.7	29.9	44.8	11.1	25.8	40.7	12.9	28.2	44.5
NZL	Gen. PV	TWh	0.1	0.1	0.1	1.9	2.2	0.1	2.8	2.7	2.6	5.9	5.8	0.1	1.9	2.2
OMN	Carbon Emission	MT	12.7	12.2	5.3	1.9	0.1	4	1.1	0	8.1	1.6	0.2	5.3	1.9	0.1
OMN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OMN	Ann. Cost	B.USD	2.6	2.6	3.3	4.3	5.2	3.6	4.6	5.6	3.4	4.1	4.9	3.3	4.3	5.2
OMN	Ann. Demand	TWh	31.7	36.1	49.6	66.7	78.7	49.6	66.7	78.7	49.6	66.7	78.7	49.6	66.7	78.7
OMN	Ann. Supply	TWh	31.7	31.4	50	86.7	122.2	50.6	88.6	127.8	47.8	78.5	120.8	50	86.7	121.4
OMN	Ann. Import	TWh	0.1	4.9	0.7	2.6	7.8	0.5	1.6	6.3	2.3	2.5	7.4	0.7	2.7	8.6
OMN	Ann. Export	TWh	0	0	0.2	19.4	46.7	0.5	20	50.9	0	11.9	44.2	0.2	19.4	46.7
OMN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OMN	Gen. Gas	TWh	31.1	31.2	13.6	5	0.1	10.5	2.8	0	21	4.1	0.4	13.6	5	0.1
OMN	Gen. Nuclear	TWh	0	0	9.6	7.3	6.3	13.3	11.3	10.1	0	0	0	9.6	7.3	5.2
OMN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OMN	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OMN	Gen. Wind	TWh	0	0	26.7	74.4	115.9	26.7	74.4	117.8	23.3	65.1	110.8	26.7	74.4	115.9
OMN	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	3.1	8.1	8.5	0.1	0.1	0
PAK	Carbon Emission	MT	46.2	48.8	14.8	2.7	1.7	13.6	1.9	1.6	14.9	2.2	1.7	14.8	2.7	-0.2
PAK	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
PAK	Ann. Cost	B.USD	8.7	11.6	9.2	10.7	15.4	9.7	11.8	16.7	9.3	10.7	15.5	9.2	10.7	17.3
PAK	Ann. Demand	TWh	97.8	123.6	181.9	248.7	324.5	181.9	248.7	324.5	181.9	248.7	324.5	181.9	248.7	324.5
PAK	Ann. Supply	TWh	98.2	124.7	160.2	282.3	423.6	161.5	300.3	446.3	160.7	282.8	425.1	160.2	282.3	434.3
PAK	Ann. Import	TWh	0	0	41.3	53.9	74.1	40.5	48	56.1	35.5	31.2	54	41.3	53.9	71.8
PAK	Ann. Export	TWh	0	0	17	82.8	162.1	17.4	92.2	166.2	12.1	60.9	144.8	17	82.8	170.9
PAK	Gen. Coal	TWh	5.9	12.8	5.5	2.7	1.8	3.5	1.3	0.8	5.6	2	1.7	5.5	2.7	0
PAK	Gen. Gas	TWh	21.5	24	8.3	0.4	0.2	10.2	1.6	1.6	8.6	0.6	0.3	8.3	0.4	0
PAK	Gen. Nuclear	TWh	10.9	15.8	30.6	28.9	28.6	30.1	29	28.8	30.5	28.7	28.5	30.6	28.9	28.3
PAK	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
PAK	Gen. Hydro	TWh	25.9	32	32	32	31.2	32	32	31.2	32	32	31.2	32	32	31.2
PAK	Gen. Wind	TWh	2.2	8.5	71.8	211.9	359.6	73.8	230.9	383.1	62.3	180.5	324.6	71.8	211.9	361.1
PAK	Gen. PV	TWh	0.7	6	6	6.3	2.3	6	5.3	0	15.8	39.1	39.1	6	6.3	1.9
PAN	Carbon Emission	MT	3.1	3.1	1.4	0.4	0.7	0.9	0.1	0.3	1.2	0.6	0.9	1.4	0.4	-0.2
PAN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
PAN	Ann. Cost	B.USD	0.8	0.9	0.8	0.8	1	0.8	0.8	1.1	0.8	0.8	1	0.8	0.8	1
PAN	Ann. Demand	TWh	9.4	10.5	13.7	17.5	21.5	13.7	17.5	21.5	13.7	17.5	21.5	13.7	17.5	21.5
PAN	Ann. Supply	TWh	10.7	11.5	12.4	15.3	18.5	11.9	17.1	19.5	12.3	14.3	18.1	12.4	15.3	19.2
PAN	Ann. Import	TWh	0	0.9	2	3.1	3.8	3.3	2.8	3.6	2.4	4.2	4.5	2	3.2	3.3
PAN	Ann. Export	TWh	1.3	1.2	0.5	0.6	0.5	0.6	1.7	1.3	0.5	0.7	0.8	0.5	0.7	0.7
PAN	Gen. Coal	TWh	1.3	1.9	0.8	0.2	0.5	0.5	0	0	0.7	0.5	0.8	0.8	0.2	0
PAN	Gen. Gas	TWh	0	0.2	0.6	0.4	0.7	0.2	0.2	0.6	0.4	0.4	0.4	0.6	0.4	0.3
PAN	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PAN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
PAN	Gen. Hydro	TWh	6.2	6.5	6.5	5.5	4.8	6.5	5.5	4.8	6.5	5.5	4.8	6.5	5.5	5
PAN	Gen. Wind	TWh	1	1.2	3.8	3.8	7.4	4	6	8.8	3.8	3.8	5.8	3.8	3.8	8.2
PAN	Gen. PV	TWh	0.1	0.2	0.2	0.2	0	0.2	0.2	0	0.5	1.1	1.1	0.2	0.2	0
PER	Carbon Emission	MT	9.9	8.5	2.1	1	1.9	2.1	0.3	0.4	1.8	0.8	1.1	2.1	1	0.7
PER	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PER	Ann. Cost	B.USD	2.6	3	3.5	3.8	4.8	3.6	3.9	4.7	3.5	3.9	4.7	3.5	3.8	4.4
PER	Ann. Demand	TWh	46.5	52.2	68.1	86.8	106.7	68.1	86.8	106.7	68.1	86.8	106.7	68.1	86.8	106.7
PER	Ann. Supply	TWh	37.5	47.5	68.8	77.8	99.3	69.9	81.4	101.6	67.6	79.4	99.4	68.8	77.6	100.1
PER	Ann. Import	TWh	9.3	8.9	12	21.1	24.7	12.6	22.5	28	12.9	20.4	24.4	12	21.3	25
PER	Ann. Export	TWh	0	0.5	9.5	8.6	12.9	9.9	13.2	18	9.9	9.7	12.6	9.5	8.6	14.1
PER	Gen. Coal	TWh	2.2	1.9	0.6	0	0	0.6	0	0	0.6	0	0	0.6	0	0
PER	Gen. Gas	TWh	19.4	16.6	3.2	2	4.9	3.1	0.7	0.8	2.4	1.5	2.9	3.2	2.1	1.9
PER	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PER	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PER	Gen. Hydro	TWh	13.7	24.9	28	32	42.2	28.5	34.8	42.2	23.7	29.8	42.2	28	32.2	42.2
PER	Gen. Wind	TWh	1	2.4	7.1	11.1	14	7.9	12.8	14.6	8.4	12.3	16.3	7.1	10.8	15.3
PER	Gen. PV	TWh	0.3	0.8	0.8	3.7	9.1	0.8	3.9	15	3.3	6.9	9	0.8	3.5	11.8
PHL	Carbon Emission	MT	40.7	48.3	17.6	6.7	10.2	12.5	1.8	-13.8	16.4	6.2	8.5	17.6	6.8	-11.4
PHL	Carbon Sequester	MT	0	0	0	0	0	0	0	15.2	0	0	0	0	0	14.4
PHL	Ann. Cost	B.USD	5.5	7.2	7.2	8.8	12.1	8.2	9.4	12.7	7.1	8.9	11.8	7.2	8.8	12.9
PHL	Ann. Demand	TWh	74	93.5	137.6	188.1	245.5	137.6	188.1	245.5	137.6	188.1	245.5	137.6	188.1	245.5
PHL	Ann. Supply	TWh	74.2	94	135	192.6	253	140.2	198.2	250.2	133.8	192.9	250.4	135	192.7	252
PHL	Ann. Import	TWh	0	0	10.2	11.5	12.2	3.3	18	14.2	11.6	12.8	20.5	10.2	11.4	13
PHL	Ann. Export	TWh	0	0	0	4.1	4.4	1.8	9.3	8.6	0	3.8	4.9	0	4.1	6.7
PHL	Gen. Coal	TWh	32.3	41.6	13.7	6.2	4.5	7.6	1	0	12.5	5.6	3.6	13.7	6.2	0.7
PHL	Gen. Gas	TWh	14.2	12.9	10.8	1.9	15.3	12.5	2.2	3	10.4	2	13.1	10.8	1.9	5.6
PHL	Gen. Nuclear	TWh	0	0	0	0	0.5	9.6	7.3	16.9	0	0	0.4	0	0	0
PHL	Gen. CCS	TWh	0	0	0	0	0	0	0	17.7	0	0	0	0	0	16.8
PHL	Gen. Hydro	TWh	12.2	12.2	25.7	50.7	59.4	24.2	53.7	59.2	24.1	48.1	59.4	25.7	50.5	59.4
PHL	Gen. Wind	TWh	2	2.3	52.5	72.7	90.4	52.2	77	90.4	52.8	72	90.4	52.5	72.8	90.7
PHL	Gen. PV	TWh	1.1	1.4	2.2	17.6	39.2	2.1	13.5	19.1	8.2	21.6	39.7	2.2	17.7	34.9
PNG	Carbon Emission	MT	1.7	1.6	0.5	0	0.1	0.5	0	0.1	0.5	0	0.1	0.5	0	-0.1
PNG	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
PNG	Ann. Cost	B.USD	0.3	0.4	0.4	0.4	0.5	0.4	0.4	0.5	0.4	0.4	0.5	0.4	0.4	0.5
PNG	Ann. Demand	TWh	3.4	4.3	6.3	8.6	11.2	6.3	8.6	11.2	6.3	8.6	11.2	6.3	8.6	11.2
PNG	Ann. Supply	TWh	3.4	4.3	6.3	8.6	11.2	6.3	8.6	11.2	6.3	8.6	11.2	6.3	8.6	11.2

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
PNG	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PNG	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PNG	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PNG	Gen. Gas	TWh	0.5	2	0.4	0.1	0.2	0.4	0.1	0.2	0.4	0.1	0.2	0.4	0.1	0
PNG	Gen. Nuclear	TWh	0	0	0.6	0.3	0.3	0.6	0.3	0.3	0.6	0.3	0.3	0.6	0.3	0.3
PNG	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
PNG	Gen. Hydro	TWh	1.1	1.1	2.4	2.6	4.4	2.4	2.6	4.4	2.4	2.6	4.4	2.4	2.6	4.4
PNG	Gen. Wind	TWh	0	0	2.1	2.3	2.2	2.1	2.3	2.2	2.1	2.3	2.2	2.1	2.3	2.2
PNG	Gen. PV	TWh	0	0.1	0.1	0.2	0.9	0.1	0.2	0.9	0.1	0.2	0.9	0.1	0.2	0.9
POL	Carbon Emission	MT	48.1	59.9	103.9	103.5	61	38.8	9.6	7.4	74.5	58.8	46.7	103.3	68	5.9
POL	Carbon Sequester	MT	0	0	0	0	0	0	0.2	0.4	0	0	0	0	0	0.2
POL	Ann. Cost	B.USD	14.7	14.2	19.2	21.3	20.8	15.6	14.6	15.3	17.2	18.7	19.3	19.2	18.3	16.7
POL	Ann. Demand	TWh	145.1	150.6	154.7	162.4	172.8	154.7	162.4	172.8	154.7	162.4	172.8	154.7	162.4	172.8
POL	Ann. Supply	TWh	82	149.8	305	299.1	237.1	170.6	155.7	159.8	248.4	240.1	222.1	303.3	235.2	165.1
POL	Ann. Import	TWh	65.8	13.1	0	4.4	27.7	17.5	53.2	61.8	0.3	6.7	24.3	0	10	62.1
POL	Ann. Export	TWh	1.8	12.2	150.1	140.6	91.6	33.2	44.9	47.3	93.7	83.9	72.5	148.4	82.7	52.6
POL	Gen. Coal	TWh	52.7	29	3.4	0	0	3.4	0	0	3.9	0	0	3.4	0	0
POL	Gen. Gas	TWh	5.8	94	277.4	284.7	167.8	98.1	26.2	20.1	195	161.1	128	275.7	186.7	16.1
POL	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POL	Gen. CCS	TWh	0	0	0	0	0	0	0.4	1	0	0	0	0	0	0.5
POL	Gen. Hydro	TWh	3.7	3.7	1.2	2.5	6.1	6.6	6.6	6.1	1.2	1.4	6.1	1.2	6.6	6.1
POL	Gen. Wind	TWh	13.6	16.4	16.4	5.3	46.6	56	116.4	124.1	33	52.4	62.8	16.4	35.5	136.2
POL	Gen. PV	TWh	0.1	0.6	0.6	0.5	10.6	0.6	0.5	2.8	9.2	19.2	19.2	0.6	0.5	0
PRI	Carbon Emission	MT	15.2	10.2	6.8	4.8	4.8	5.6	0.2	-0.3	5.6	2.5	2.5	6.8	4.8	0.7
PRI	Carbon Sequester	MT	0	0	0	0	0	0	0	0.5	0	0	0	0	0	0
PRI	Ann. Cost	B.USD	2.2	1.6	1.8	1.9	2	2	2.1	2.1	2.4	2.9	2.9	1.8	1.9	2.3
PRI	Ann. Demand	TWh	18.9	20.1	21.3	22.8	24.7	21.3	22.8	24.7	21.3	22.8	24.7	21.3	22.8	24.7
PRI	Ann. Supply	TWh	18.9	20.1	21.8	23.3	25.6	21.9	23.1	24.9	21.7	23.6	25.6	21.8	23.3	25
PRI	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRI	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRI	Gen. Coal	TWh	3.3	3.3	2.7	0	0	1.3	0	0	2.8	0	0	2.7	0	0
PRI	Gen. Gas	TWh	3.8	14.9	10.3	13.1	13.3	10.5	0.6	0.4	7.1	6.7	6.8	10.3	13.1	2
PRI	Gen. Nuclear	TWh	0	0	0	0	0	0.6	8.8	9.7	0	0	0	0	0	8.5
PRI	Gen. CCS	TWh	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0
PRI	Gen. Hydro	TWh	0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PRI	Gen. Wind	TWh	0.3	0.3	0	0.3	0.3	0.3	0.3	0.8	4.9	9.3	9.3	0	0.3	0.9
PRI	Gen. PV	TWh	0.2	0.3	8.5	9.7	11.8	8.8	13.4	13.4	5.9	5.7	7.6	8.5	9.7	13.4
PRK	Carbon Emission	MT	2.8	2.8	1.9	1.1	0.4	0.7	0.1	0.4	1.5	0.8	0.4	1.9	1.1	0.4
PRK	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRK	Ann. Cost	B.USD	1.7	1.6	1.1	1.1	0.9	1.1	1.1	1	1.1	1.1	0.9	1.1	1.1	0.9
PRK	Ann. Demand	TWh	11.3	14.3	18.6	21.7	23.1	18.6	21.7	23.1	18.6	21.7	23.1	18.6	21.7	23.1
PRK	Ann. Supply	TWh	15.7	19.2	22.1	24	23.8	23.8	26.6	24	22.6	24.8	24	22.1	24	23.7
PRK	Ann. Import	TWh	0	0	0	0	0.2	0	0	0.1	0	0	0	0	0	0.2
PRK	Ann. Export	TWh	0	0	0.8	0.8	0.5	2.7	3.5	0.8	1.1	1.1	0.7	0.8	0.8	0.5
PRK	Gen. Coal	TWh	2.4	2.9	1.7	1.1	0	0.6	0.1	0	1.4	0.8	0	1.7	1.1	0
PRK	Gen. Gas	TWh	0	0	0.1	0.1	0.8	0	0.1	0.8	0.1	0.1	0.8	0.1	0.1	0.8
PRK	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRK	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRK	Gen. Hydro	TWh	12.7	15.9	14.7	12.3	5.2	14.7	12.3	5.2	14.7	12.3	5.2	14.7	12.3	5.2
PRK	Gen. Wind	TWh	0	0.2	5.4	10.5	17.3	8.4	14.1	17.5	5.6	10.1	16.4	5.4	10.5	17.3
PRK	Gen. PV	TWh	0	0.1	0.1	0.1	0.5	0.1	0.1	0.5	0.8	1.6	1.5	0.1	0.1	0.5
PRT	Carbon Emission	MT	13.5	12.6	4.4	3.1	0.1	2.3	1.3	0.1	3.8	2.5	0.1	4.4	2	0
PRT	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRT	Ann. Cost	B.USD	5.1	4.7	4.3	3.6	3.2	4.7	3.6	3.6	4.3	3.7	3.4	4.3	3.5	3.3
PRT	Ann. Demand	TWh	51.1	53	54.4	57.2	60.8	54.4	57.2	60.8	54.4	57.2	60.8	54.4	57.2	60.8
PRT	Ann. Supply	TWh	53.7	48.5	49.7	47.9	41.4	55.7	45.9	46.5	48.6	49.3	44.9	49.5	46.6	44.3
PRT	Ann. Import	TWh	8.1	5	6.4	11.3	22.3	4.3	18.1	21.4	7.2	9.7	18.2	6.5	14.5	22.8
PRT	Ann. Export	TWh	10.1	0.4	1.6	1.7	2.8	4.6	5.8	6.7	1.3	1.4	2.2	1.6	2.8	5.8
PRT	Gen. Coal	TWh	11.4	11.2	0	0	0	0	0	0	0	0	0	0	0	0
PRT	Gen. Gas	TWh	8	7.1	11.7	8.5	0.1	6.2	3.6	0.1	10.1	6.6	0.3	11.6	5.4	0
PRT	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRT	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRT	Gen. Hydro	TWh	19	13.6	13.6	11	9.6	13.6	11	9.6	13.6	11	9.6	13.6	11	9.6
PRT	Gen. Wind	TWh	11.8	12.7	10	7.7	7.6	14.4	7.7	7.6	11.5	14	13.9	10	7.7	7.6
PRT	Gen. PV	TWh	0.7	1.1	10.1	16.5	20.2	17.3	19.6	25.5	9.1	13.5	17.1	10.1	18.5	23.2
PRY	Carbon Emission	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRY	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRY	Ann. Cost	B.USD	1.5	1.5	1.8	2.3	2.4	1.8	2.3	2.4	1.9	2.4	2.5	1.8	2.3	2.4
PRY	Ann. Demand	TWh	11.3	12.6	16.5	21	25.8	16.5	21	25.8	16.5	21	25.8	16.5	21	25.8
PRY	Ann. Supply	TWh	26.7	26.7	35.5	46.2	47.7	35.5	46.2	47.7	35.6	49.2	49.3	35.5	46.2	48.4
PRY	Ann. Import	TWh	4.7	2.5	13.7	19.7	52.9	14.5	31.6	57.5	12.5	19.1	45.6	13.7	19.7	49.6
PRY	Ann. Export	TWh	20.1	16.5	32.6	44.6	74.2	33.5	56.3	78.7	31.6	46.9	68.6	32.6	44.6	71.4
PRY	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRY	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRY	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRY	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRY	Gen. Hydro	TWh	26.7	26.7	26.7	26.7	26.8	26.7	26.7	26.8	26.7	26.7	26.8	26.7	26.7	27.1
PRY	Gen. Wind	TWh	0	0	0	0	1.4	0	0	1.4	0.7	1.7	1.7	0	0	1.7
PRY	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.6	1.3	1.3	0	0	0
PSE	Carbon Emission	MT	0	0	0	0	0.1	0	0	0	0	0	0	0	0	0
PSE	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSE	Ann. Cost	B.USD	0	0	0.3	0.5	0.5	0.4	0.4	0.2	1	1.8	1.7	0.3	0.5	0.5
PSE	Ann. Demand	TWh	5.8	6.7	9.1	12.3	14.5	9.1	12.3	14.5	9.1	12.3	14.5	9.1	12.3	14.5
PSE	Ann. Supply	TWh	0	0.1	4.2	6.5	5.9	4.7	4.6	2.1	5.3	8.5	9.2	4.2	6.5	5.9
PSE	Ann. Import	TWh	5.8	13	12.6	47.2	79.1	12.8	48.1	79.3	9.7	27	74.9	12.6	47.1	82
PSE	Ann. Export	TWh	0	6.5	7.7	40.6	69.4	8.3	40.4	66.7	5.8	22.1	65.2	7.7	40.4	72.1
PSE	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSE	Gen. Gas	TWh	0	0	0	0	0.1	0	0	0	0	0	0	0	0	0.1
PSE	Gen. Nuclear	TWh	0	0	3.7	2.9	2.3	0.6	0.5	0.4	2.2	1.5	1	3.7	2.9	2.2
PSE	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSE	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PSE	Gen. Wind	TWh	0	0	0	0	0	0	0	0	2.5	5.5	6.5	0	0	0
PSE	Gen. PV	TWh	0	0.1	0.5	3.6	3.5	4.1	4.1	1.8	0.3	0.5	0.7	0.5	3.6	3.5
QAT	Carbon Emission	MT	15.1	17	13.9	9.4	10.1	0	0.1	0.1	8.7	6.2	6.4	13.9	9.4	4.2
QAT	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
QAT	Ann. Cost	B.USD	3.3	3.7	3.9	4.9	5.4	3.8	4.6	4.5	3.8	5.6	6	3.9	4.9	5

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
QAT	Ann. Demand	TWh	38.5	43.9	60.2	81	95.6	60.2	81	95.6	60.2	81	95.6	60.2	81	95.6
QAT	Ann. Supply	TWh	38.6	43.5	49.5	64.8	72.7	47.6	60.7	60.4	43.1	65.1	70.6	49.5	64.8	66.2
QAT	Ann. Import	TWh	0	0.4	12	18	25.1	12.7	20.7	36	17.3	18.6	29.7	12	18	31.8
QAT	Ann. Export	TWh	0.1	0.1	1.3	1.8	2.2	0.1	0.3	0.7	0.1	1.6	2.2	1.3	1.8	2.4
QAT	Gen. Coal	TWh	0	0	16.6	11.3	10.4	0	0	0	10.4	7.4	5.6	16.6	11.3	3.8
QAT	Gen. Gas	TWh	38.6	43.4	0.5	0.2	3.6	0	0.2	0.2	0.3	0.3	4.5	0.5	0.2	3.1
QAT	Gen. Nuclear	TWh	0	0	0	0	0	15.1	13	11.2	0	0	0	0	0	0
QAT	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
QAT	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
QAT	Gen. Wind	TWh	0	0	32.4	44.2	44.2	32.4	37.1	37.6	29.2	46.3	39.9	32.4	44.2	44.2
QAT	Gen. PV	TWh	0	0.1	0.1	9.1	14.5	0.1	10.5	11.3	0.1	2.6	12.1	0.1	9.1	14.6
ROU	Carbon Emission	MT	12.5	9.3	0.9	0.5	0.1	1	0.4	0.1	0.9	0.5	0.1	0.9	0.3	-5.8
ROU	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	5.8
ROU	Ann. Cost	B.USD	6.4	5.4	3.2	2.2	1.8	4.1	4.2	3.9	3.4	2.9	2.3	3.2	2.5	4.3
ROU	Ann. Demand	TWh	50	54.7	63.8	74	84.7	63.8	74	84.7	63.8	74	84.7	63.8	74	84.7
ROU	Ann. Supply	TWh	53.1	55.8	44.7	32.4	29.2	56.6	56.5	51.8	48.3	41.7	35.3	44.7	36.9	42.3
ROU	Ann. Import	TWh	3.2	1.5	22.4	48.3	63.3	10.1	21	34.3	18.1	37.1	54.6	22.4	42.8	49.1
ROU	Ann. Export	TWh	5.6	1.9	2.5	5.7	6.4	2.2	3	0.9	1.9	3.9	4	2.6	4.8	5.9
ROU	Gen. Coal	TWh	10.7	7.8	0	0	0	0	0	0	0	0	0	0	0	0
ROU	Gen. Gas	TWh	7.1	6.3	2.4	1.3	0.2	2.7	1	0.1	2.4	1.3	0.2	2.4	0.8	0
ROU	Gen. Nuclear	TWh	9.6	9.6	9.6	9.6	0	11	25.4	20.2	9.6	9.6	0	9.6	9	3.3
ROU	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	7.1
ROU	Gen. Hydro	TWh	15.7	22.1	19.6	13.1	12.8	19.9	13.4	13.1	19.6	13.1	12.8	19.6	13.1	12.8
ROU	Gen. Wind	TWh	8	8	11.2	7.9	15.9	21.1	16.3	18.2	13.1	13.6	18.2	11.2	13.6	18.7
ROU	Gen. PV	TWh	1.6	1.7	1.7	0.1	0	1.7	0.1	0	3.4	3.8	3.8	1.7	0.1	0
RUS	Carbon Emission	MT	256.5	297.3	370.1	350.5	291.2	280.3	98.1	9	296.3	235.7	220.1	276.4	144.4	42.8
RUS	Carbon Sequester	MT	0	0	0	0	0	0	15.2	70.5	0	0	0	0	7.5	19.6
RUS	Ann. Cost	B.USD	59.1	54.8	68.2	83.7	96.3	76.1	91.2	98	68.8	82.3	91.8	65.4	84.6	104.2
RUS	Ann. Demand	TWh	906.9	953.7	1048.5	1137.9	1198.4	1048.5	1137.9	1198.4	1048.5	1137.9	1198.4	1048.5	1137.9	1198.4
RUS	Ann. Supply	TWh	904.4	982.1	1203.6	1297.2	1346.8	1117.4	1175.2	1243.8	1156.8	1219.3	1282.1	1118.4	1166.1	1234.2
RUS	Ann. Import	TWh	33.1	6.5	2.6	4.7	7.8	4.9	14.9	17.9	3.9	5.7	5.8	3.9	17	16.3
RUS	Ann. Export	TWh	18.9	27.5	155.5	163.2	155.1	71.7	48.7	56.2	107.9	84.9	86.6	71	43.2	47.4
RUS	Gen. Coal	TWh	91.3	94.8	38.9	13.2	2.8	11.5	0	0	33.5	6.2	3.9	19.5	0	0
RUS	Gen. Gas	TWh	441.6	512.8	882.6	900.9	768.5	704.8	257.6	142.5	701.9	611.8	575.6	680.5	381.9	144.4
RUS	Gen. Nuclear	TWh	206.8	207	128.7	129	103.7	123	174.9	163.8	125	125.4	102.2	123.6	125.2	98.1
RUS	Gen. CCS	TWh	0	0	0	0	0	0	36.8	115.5	0	0	0	0	18.3	32.6
RUS	Gen. Hydro	TWh	161.3	163	130.7	146.6	174.6	203.9	204.3	198.3	127.8	130.2	154.6	200.5	196.7	203.9
RUS	Gen. Wind	TWh	0	0.5	8.2	93.7	279.5	59.8	485.2	586.5	124.6	267	367.2	79.4	399.5	629.4
RUS	Gen. PV	TWh	0	0.8	0.8	0.8	4.6	0.8	3.4	24	30.2	65.6	65.6	0.8	1.4	17.3
RWA	Carbon Emission	MT	0.1	0.2	0.2	0.2	0.3	0.2	0.1	0.1	0.2	0.2	0.5	0.2	0.2	-1
RWA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1.1
RWA	Ann. Cost	B.USD	0	0.1	0.1	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.3	0.1	0.2	0.4
RWA	Ann. Demand	TWh	0.6	0.9	1.9	3.7	6.3	1.9	3.7	6.3	1.9	3.7	6.3	1.9	3.7	6.3
RWA	Ann. Supply	TWh	0.5	1.1	2.1	2.9	3	2.2	2.5	2.4	2.3	2.6	3.4	2.1	2.8	3.8
RWA	Ann. Import	TWh	0.3	0.2	0.2	0.9	3.5	0.3	1.3	4.2	0.3	1.1	3.1	0.3	1	2.7
RWA	Ann. Export	TWh	0.2	0.4	0.4	0.1	0.1	0.6	0.1	0.3	0.7	0	0.3	0.5	0.1	0.2
RWA	Gen. Coal	TWh	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0
RWA	Gen. Gas	TWh	0	0.4	0.4	0.5	0.7	0.4	0.3	0.4	0.5	0.4	1.3	0.5	0.5	0.3
RWA	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RWA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.2
RWA	Gen. Hydro	TWh	0.3	0.5	1.6	1.7	1.7	1.7	1.7	1.7	1.4	1.4	1.4	1.4	1.7	1.7
RWA	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.3	0.3	0	0	0
RWA	Gen. PV	TWh	0	0.1	0.1	0.6	0.5	0.1	0.4	0.3	0.3	0.4	0.4	0.1	0.5	0.5
SAU	Carbon Emission	MT	194.9	246	174	58.3	39	90.5	9.4	2.3	178.3	62.3	29.4	174	58.3	3.8
SAU	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	5
SAU	Ann. Cost	B.USD	33.8	42	47	48.2	49.5	52.4	50.9	55.7	48.4	49.2	49.4	47	48.2	51.3
SAU	Ann. Demand	TWh	326.1	371.3	509.7	685.4	808.8	509.7	685.4	808.8	509.7	685.4	808.8	509.7	685.4	808.8
SAU	Ann. Supply	TWh	334.9	377.9	552.3	817.2	914.8	533.3	775.6	950.8	555.4	793.3	911.9	552.3	817.2	954
SAU	Ann. Import	TWh	0.8	0.2	5.4	17.5	102.4	1.5	24.7	63.2	4.3	16.4	108.5	5.4	17.5	94.2
SAU	Ann. Export	TWh	0	2	45.3	125.4	169	23	102.5	182.6	46.7	106	162.6	45.3	125.4	184.1
SAU	Gen. Coal	TWh	0	105.2	97.6	53.1	41.9	16.8	1.4	1.2	101.2	57.8	32.9	97.6	53.1	5.4
SAU	Gen. Gas	TWh	222.1	177.5	131.6	36	9.5	91.1	21.5	3.3	135.7	36.8	5	131.6	36	9.6
SAU	Gen. Nuclear	TWh	0	0	4.5	3.2	2.9	106.8	86.3	73.1	0	0	0	4.5	3.2	2.4
SAU	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	5.8
SAU	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SAU	Gen. Wind	TWh	0	0	228.5	635	715.7	228.5	547.9	711.8	197	567.7	696.1	228.5	635	776.5
SAU	Gen. PV	TWh	0.1	0.3	0.3	43.9	98.9	0.3	72.5	116.3	21.2	56.7	103.6	0.3	43.9	108
SDN	Carbon Emission	MT	7.4	7.8	7.2	3	2.8	5	1.1	1.4	6.8	2.2	2.7	7.2	3	2
SDN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SDN	Ann. Cost	B.USD	1.4	2	2.8	3.5	6.2	2.8	3.7	6.4	2.7	3.5	6	2.8	3.6	6.1
SDN	Ann. Demand	TWh	11.6	16.5	34.5	66.1	114	34.5	66.1	114	34.5	66.1	114	34.5	66.1	114
SDN	Ann. Supply	TWh	13	16.9	34.5	68.8	125.6	34.5	69.4	123.2	33.7	67.3	121.4	34.5	68.7	123.9
SDN	Ann. Import	TWh	0.3	0.1	0.6	1.7	2.7	0.4	2.4	2.9	1.3	3.4	4.3	0.6	1.8	3.1
SDN	Ann. Export	TWh	0.8	0.4	0.3	2.7	10.7	0.2	4	8.9	0.2	3.2	8.1	0.3	2.8	9.5
SDN	Gen. Coal	TWh	0.8	0.8	0.5	0.1	0	0.4	0	0	0.6	0.1	0	0.5	0.1	0
SDN	Gen. Gas	TWh	2.6	5.4	9.9	7.9	7.3	5.6	2.9	3.4	9	5.6	6.9	9.8	8	5.5
SDN	Gen. Nuclear	TWh	0	0	0	1.3	1.3	5	5.9	5.3	0	1.2	1.2	0	1	1
SDN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SDN	Gen. Hydro	TWh	4	5	5	5	6.9	5	5	8.5	5	5	7.1	5	5	8.5
SDN	Gen. Wind	TWh	0	0	1.5	27.9	69.3	1	30.1	67.6	3.5	25.2	66.7	1.7	27.7	68.6
SDN	Gen. PV	TWh	0	0.1	0.1	6.8	21.1	0.1	5.3	18.3	2.7	10.2	19.5	0.1	7	20.3
SEN	Carbon Emission	MT	3	3.1	3.3	2.8	4.2	1.3	1	-3.6	2.2	1.9	3.5	3.3	2.8	-2.5
SEN	Carbon Sequester	MT	0	0	0	0	0	0	0	4.4	0	0	0	0	0	4.5
SEN	Ann. Cost	B.USD	0.4	0.7	0.9	1.5	3	1	1.7	3.3	1	1.8	3.2	0.9	1.5	3.6
SEN	Ann. Demand	TWh	3.7	5.2	11	21.1	36.3	11	21.1	36.3	11	21.1	36.3	11	21.1	36.3
SEN	Ann. Supply	TWh	3.1	5.3	9.6	18.8	36.7	10.2	19.1	39	9.5	18	36	9.6	18.8	39.7
SEN	Ann. Import	TWh	0.6	0.1	1.5	2.8	3.3	1.4	2.6	1.8	1.7	3.4	3.8	1.5	2.8	1.2
SEN	Ann. Export	TWh	0	0.2	0.1	0.4	3.6	0.5	0.6	4.3	0.2	0.2	3	0.1	0.4	4.5
SEN	Gen. Coal	TWh	0.3	0.2	0.1	0	0	0.1	0	0	0.1	0	0	0.1	0	0
SEN	Gen. Gas	TWh	0.2	2.7	7	7.6	11.5	1.8	2.7	2.1	4.1	5.1	9.4	7	7.6	5.2
SEN	Gen. Nuclear	TWh	0	0	0	4.3	3.9	4.5	6.6	6.6	0	0.8	0.8	0	4.3	4.7
SEN	Gen. CCS	TWh	0	0	0	0	0	0	0	5	0	0	0	0	0	5.1
SEN	Gen. Hydro	TWh	0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
SEN	Gen. Wind	TWh	0	0	0.3	0.3	1.9	0.3	3.6	10.1	3.7	8.1	8.1	0.3	0.3	5.5
SEN	Gen. PV	TWh	0	0.3	1.3	6.2	19.3	2.5	6	15.1	0.7	3.7	17.5	1.3	6.2	18.4

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
SGP	Carbon Emission	MT	18.1	22.7	7.8	1.5	1.9	12.2	5.6	1.9	7.9	1.4	0.7	7.8	1.5	0
SGP	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SGP	Ann. Cost	B.USD	4	4.9	2.8	1.7	1.1	4.1	3	1.4	2.8	1.7	0.8	2.8	1.7	0.7
SGP	Ann. Demand	TWh	48.3	61.1	90	123	160.5	90	123	160.5	90	123	160.5	90	123	160.5
SGP	Ann. Supply	TWh	48.3	61.1	22.1	5.1	6.2	34	16.3	6.2	22.1	4.8	3	22.1	5.1	1
SGP	Ann. Import	TWh	0	0	67.9	117.9	154.3	56	106.6	154.3	67.8	118.1	157.5	67.9	117.9	159.5
SGP	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SGP	Gen. Coal	TWh	0.7	0.7	0.3	0	0	0.3	0	0	0.3	0	0	0.3	0	0
SGP	Gen. Gas	TWh	46.5	59.1	20.6	4	5.3	32.6	15.2	5.3	20.6	3.7	2.1	20.6	4	0
SGP	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SGP	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SGP	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SGP	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SGP	Gen. PV	TWh	0.1	0.3	0.3	0.2	0	0.3	0.2	0	0.3	0.2	0	0.3	0.2	0
SLE	Carbon Emission	MT	0.1	0.1	0.2	0.2	0.3	0.1	0.1	-0.5	0.1	0.1	0.3	0.2	0.2	0.1
SLE	Carbon Sequester	MT	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0
SLE	Ann. Cost	B.USD	0	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2
SLE	Ann. Demand	TWh	0.2	0.2	0.5	0.9	1.6	0.5	0.9	1.6	0.5	0.9	1.6	0.5	0.9	1.6
SLE	Ann. Supply	TWh	0.2	0.4	0.9	1.4	1.8	0.8	0.9	1.7	0.9	1.4	2.3	0.9	1.4	2.4
SLE	Ann. Import	TWh	0	0	0	0.1	0.5	0	0.4	0.6	0	0.3	0.5	0	0.1	0.3
SLE	Ann. Export	TWh	0	0	0.5	0.6	0.7	0.3	0.4	0.7	0.4	0.7	1.2	0.5	0.6	1.1
SLE	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SLE	Gen. Gas	TWh	0	0	0.4	0.5	0.7	0.2	0.2	0.2	0.2	0.3	0.8	0.4	0.5	0.3
SLE	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SLE	Gen. CCS	TWh	0	0	0	0	0	0	0	0.7	0	0	0	0	0	0
SLE	Gen. Hydro	TWh	0.2	0.3	0.5	0.8	1.1	0.5	0.6	0.8	0.5	0.5	1.1	0.5	0.8	1.7
SLE	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.3	0.3	0	0	0
SLE	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0.1	0.2	0.3	0.3	0.1	0.1	0
SLV	Carbon Emission	MT	1.7	1.5	0.4	1.1	1.1	0.6	0.6	0.6	0.5	0.6	0.6	0.4	1.1	0.7
SLV	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
SLV	Ann. Cost	B.USD	0.5	0.7	0.4	0.5	0.6	0.5	0.5	0.7	0.5	0.6	0.6	0.4	0.5	0.8
SLV	Ann. Demand	TWh	6.3	7.1	9.2	11.8	14.5	9.2	11.8	14.5	9.2	11.8	14.5	9.2	11.8	14.5
SLV	Ann. Supply	TWh	5.3	5.6	4.4	6.1	7.2	4.9	5	8.7	6.1	8	6.6	4.4	6.1	8.9
SLV	Ann. Import	TWh	1.1	1.9	7.4	9	10.2	8.3	11.8	10.4	6.3	7.6	11.6	7.4	9	8.7
SLV	Ann. Export	TWh	0.1	0.4	2.6	3.3	3	4	5	4.7	3.1	3.8	3.7	2.6	3.3	3.1
SLV	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SLV	Gen. Gas	TWh	0	0	0	3	3	0.5	1.6	1.6	0.3	1.7	1.6	0	3	2.9
SLV	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SLV	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.4
SLV	Gen. Hydro	TWh	1.6	1.8	1.8	1.2	0.2	1.8	1.2	3.6	1.8	1.2	0.2	1.8	1.2	1.4
SLV	Gen. Wind	TWh	0	0	0	0	0.5	0	0	0.5	0.8	1.8	1.9	0	0	0.5
SLV	Gen. PV	TWh	0	0.3	0.3	0.5	2.1	0.3	0.8	1.5	0.9	1.8	1.5	0.3	0.5	2.1
SOM	Carbon Emission	MT	0.3	0.2	0.2	0.1	0.1	0.1	0	0.1	0.1	0	0.1	0.2	0.1	0
SOM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOM	Ann. Cost	B.USD	0	0.1	0.1	0.2	0.2	0.1	0.2	0.3	0.1	0.2	0.3	0.1	0.2	0.2
SOM	Ann. Demand	TWh	0.3	0.5	0.9	1.8	3.1	0.9	1.8	3.1	0.9	1.8	3.1	0.9	1.8	3.1
SOM	Ann. Supply	TWh	0.3	0.5	1.6	3.2	5.3	1.5	3	4.9	2.4	3.8	5.9	1.6	3.2	5
SOM	Ann. Import	TWh	0	0	0	0.2	0	0	0.2	0.4	0	0.1	0.2	0	0.2	0.3
SOM	Ann. Export	TWh	0	0	0.6	1.6	2.1	0.6	1.4	2.1	1.4	2	2.9	0.7	1.5	2.1
SOM	Gen. Coal	TWh	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0
SOM	Gen. Gas	TWh	0	0.2	0.4	0.2	0.2	0.4	0.1	0.2	0.4	0.1	0.2	0.5	0.2	0
SOM	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOM	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOM	Gen. Wind	TWh	0	0	0	0.2	1.5	0	1.4	3.4	0.6	1.3	1.9	0	0.2	1.5
SOM	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.3	0.3	0.3	0.1	0.1	0
SRB	Carbon Emission	MT	11.4	9.4	0.2	0	0	0.2	0	-6.8	0.2	0	0	0.2	0	-6.2
SRB	Carbon Sequester	MT	0	0	0	0	0	0	0	6.8	0	0	0	0	0	6.2
SRB	Ann. Cost	B.USD	2.4	2.3	1	0.9	1.2	1.5	1.3	2.1	1.3	1.5	1.5	1	0.9	2.4
SRB	Ann. Demand	TWh	30.9	33.8	39.4	45.7	52.2	39.4	45.7	52.2	39.4	45.7	52.2	39.4	45.7	52.2
SRB	Ann. Supply	TWh	21.2	20.5	15.4	14.8	18.9	22.8	19.9	27.4	19.1	22	22.6	15.4	14.9	26.8
SRB	Ann. Import	TWh	11.1	16.1	27.1	43.6	52.6	21.9	35.2	38.9	24.6	37.6	49.1	27.4	40.9	44.4
SRB	Ann. Export	TWh	1.4	2.8	3.1	12.6	19	4.4	9.3	14	4.3	13.7	19.3	3.3	10	18.7
SRB	Gen. Coal	TWh	12.9	10.7	0.1	0	0	0	0	0	0.1	0	0	0.1	0	0
SRB	Gen. Gas	TWh	0.2	0.1	0.3	0	0.1	0.3	0	0	0.3	0	0.1	0.3	0	0
SRB	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SRB	Gen. CCS	TWh	0	0	0	0	0	0	0	8.3	0	0	0	0	0	7.5
SRB	Gen. Hydro	TWh	8	8.2	10.9	8.5	7.8	10.9	8.5	7.8	10.9	8.5	7.8	10.9	8.5	7.8
SRB	Gen. Wind	TWh	0	1.3	1.3	3.6	8.4	8.8	8.8	8.8	3.6	7.2	8.6	1.3	3.7	8.8
SRB	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	1.6	3.7	3.6	0.1	0.1	0
SSD	Carbon Emission	MT	0.5	0.7	0.4	0.4	0.3	0.3	0.1	0.1	0.4	0.3	0.3	0.4	0.4	0.2
SSD	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSD	Ann. Cost	B.USD	0.1	0.1	0.2	0.2	0.3	0.2	0.2	0.4	0.2	0.2	0.4	0.2	0.2	0.3
SSD	Ann. Demand	TWh	0.7	1	2.2	4.2	7.2	2.2	4.2	7.2	2.2	4.2	7.2	2.2	4.2	7.2
SSD	Ann. Supply	TWh	0.5	1.1	2	2.7	6.2	2.5	2.9	7	2.4	3.6	7.2	2	2.7	6
SSD	Ann. Import	TWh	0.6	0.1	0.4	2.6	8.8	0.3	3.6	7.4	0.4	3	7.1	0.4	2.7	8
SSD	Ann. Export	TWh	0.3	0.2	0.3	1.1	7.8	0.6	2.3	7.2	0.6	2.4	7.1	0.3	1.1	6.8
SSD	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSD	Gen. Gas	TWh	0	0.7	0.7	1	0.7	0.5	0.3	0.2	0.7	0.8	0.7	0.7	0.9	0.4
SSD	Gen. Nuclear	TWh	0	0	0	0	0	0.7	0.6	0.6	0	0	0	0	0	0
SSD	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSD	Gen. Hydro	TWh	0	0	1.1	1.5	5.2	1.1	1.5	5.6	1	1.6	5.3	1.1	1.4	5.3
SSD	Gen. Wind	TWh	0	0	0	0.3	0.3	0	0.6	0.6	0.3	0.8	0.8	0	0.3	0.3
SSD	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.2	0.5	0.5	0	0	0
SUR	Carbon Emission	MT	1.5	1.1	0.4	0.1	0.2	0.4	0.2	0.1	0.4	0.1	0.2	0.4	0.1	0.1
SUR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUR	Ann. Cost	B.USD	0.2	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.2
SUR	Ann. Demand	TWh	2.2	2.4	3.2	4.1	5	3.2	4.1	5	3.2	4.1	5	3.2	4.1	5
SUR	Ann. Supply	TWh	2.2	2.4	2.3	1.8	1.9	2.2	2	2.1	2.4	2.6	2.9	2.3	1.8	2
SUR	Ann. Import	TWh	0	0	1	3.4	4.4	1.6	3.3	4.9	1.2	2.4	3.3	1	3.4	7.4
SUR	Ann. Export	TWh	0	0	0.1	1.1	1.3	0.6	1.3	2	0.3	0.8	1.1	0.1	1.2	4.4
SUR	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUR	Gen. Gas	TWh	0	1	0.5	0.3	0.5	0.4	0.5	0.4	0.4	0.4	0.6	0.5	0.3	0.3
SUR	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUR	Gen. Hydro	TWh	0.6	0.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
SUR	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.1	0.3	0.3	0	0	0
SUR	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0	0.3	0.6	0.6	0.1	0.1	0
SVK	Carbon Emission	MT	6.1	1	0.2	0	0	0.2	0	0	0.2	0	0	0.2	0	0
SVK	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SVK	Ann. Cost	B.USD	3.1	3.3	3.1	2	2.3	3.5	2.5	2.2	3.4	2.4	2.1	3.1	2.1	2.4
SVK	Ann. Demand	TWh	26.5	27.5	28.3	29.7	31.6	28.3	29.7	31.6	28.3	29.7	31.6	28.3	29.7	31.6
SVK	Ann. Supply	TWh	30.4	30.3	29.6	18.9	27.2	35.7	26.6	22.6	34.3	25.5	22	29.6	21.6	25.6
SVK	Ann. Import	TWh	3.3	3.1	24.3	49.5	56.4	9.4	26.9	41.5	16.3	34.8	44.8	24.7	36	48.4
SVK	Ann. Export	TWh	7.1	5.9	25.6	38.7	52	16.8	23.7	32.4	22.3	30.5	35.2	26	27.9	42.4
SVK	Gen. Coal	TWh	6.5	0.6	0	0	0	0	0	0	0	0	0	0	0	0
SVK	Gen. Gas	TWh	1.2	1.1	0.4	0	0	0.4	0	0	0.4	0	0	0.4	0	0
SVK	Gen. Nuclear	TWh	13	19	19	5.9	5.8	19	4.8	4.2	19	5.9	5.8	19	5.9	4.6
SVK	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SVK	Gen. Hydro	TWh	8	8	8	8.4	5.1	8.4	8.4	5.1	8	8.4	5.1	8	8.4	5.1
SVK	Gen. Wind	TWh	0	0	0.6	3.6	3.6	3.6	10	10	3.9	7.3	7.4	0.6	3.6	10
SVK	Gen. PV	TWh	0.6	0.6	0.6	0	11.9	3.4	2.7	2.7	2	2.9	3.1	0.6	2.7	5.3
SVN	Carbon Emission	MT	0.1	0.1	0	0	0	0	0	0	0	0	0	0	0	0
SVN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SVN	Ann. Cost	B.USD	1.3	1.2	0.5	0.5	0.8	0.8	0.9	0.8	0.5	0.6	0.7	0.5	0.7	0.9
SVN	Ann. Demand	TWh	13.6	14.1	14.5	15.2	16.2	14.5	15.2	16.2	14.5	15.2	16.2	14.5	15.2	16.2
SVN	Ann. Supply	TWh	10.3	10.5	6	8.3	13.7	12.5	13.5	13.4	6.7	9.8	10.9	6	11	15.1
SVN	Ann. Import	TWh	12	22.8	41.6	31.1	34.6	17.7	14.3	27	34.8	25	29.5	41.9	28.2	31.6
SVN	Ann. Export	TWh	8.7	19.2	33.1	24.2	32.1	15.7	12.5	24.1	26.9	19.5	24.2	33.4	23.9	30.5
SVN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SVN	Gen. Gas	TWh	0.3	0.3	0	0	0	0	0	0	0	0	0	0	0	0
SVN	Gen. Nuclear	TWh	5.2	5.2	0	0	0	0	0	0	0	0	0	0	0	0
SVN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SVN	Gen. Hydro	TWh	4.4	4.6	4.6	6.5	6.5	6.5	6.5	6.5	4.6	6.5	6.5	4.6	6.5	6.5
SVN	Gen. Wind	TWh	0	0	0.9	1.6	2.7	2.7	2.7	2.7	0.9	1.6	2.7	0.9	2.7	2.7
SVN	Gen. PV	TWh	0.3	0.4	0.4	0.1	4.3	3.1	4.1	4.1	1	1.5	1.5	0.4	1.6	5.8
SWE	Carbon Emission	MT	1.3	0.5	0	0	0	0	0	0	0	0	0	0	0	0
SWE	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SWE	Ann. Cost	B.USD	14.7	12.2	7.4	7.2	7.6	9.8	9.5	9.8	7.6	7.5	7.4	7.5	7.7	9.8
SWE	Ann. Demand	TWh	132	137	140.7	147.7	157.2	140.7	147.7	157.2	140.7	147.7	157.2	140.7	147.7	157.2
SWE	Ann. Supply	TWh	164.3	143.3	93.2	92.6	100.9	134.5	131.3	139.5	97.4	97.2	96.3	95.3	100.3	136.1
SWE	Ann. Import	TWh	31.1	48.6	91.7	117.2	130.4	68.6	98.2	106.8	85.3	105.5	138.5	90	111.5	115.1
SWE	Ann. Export	TWh	61.2	53	42.4	60.5	71.6	60.6	79.1	85.8	40.3	53.3	74.7	42.8	62.6	90.6
SWE	Gen. Coal	TWh	0.8	0.4	0	0	0	0	0	0	0	0	0	0	0	0
SWE	Gen. Gas	TWh	1	0.1	0	0	0	0	0	0	0	0	0	0	0	0
SWE	Gen. Nuclear	TWh	67.7	41.9	0	0	0	0	0	0	0	0	0	0	0	0
SWE	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SWE	Gen. Hydro	TWh	68.2	68.1	57.5	48	41.3	59.7	53.8	52.8	57.5	45.4	42.2	57.5	49.3	51.2
SWE	Gen. Wind	TWh	19.3	25.1	28	37	52.3	67.2	69.9	79.6	31.7	42.7	44.9	30.1	43.4	76.3
SWE	Gen. PV	TWh	0.1	0.5	0.5	0.4	0	0.5	0.4	0	1	1.9	1.9	0.5	0.4	0
SWZ	Carbon Emission	MT	0	0	0.3	0.1	0.3	0	0	-0.3	0.4	0.2	0.3	0.3	0.1	0.2
SWZ	Carbon Sequester	MT	0	0	0	0	0	0	0	0.3	0	0	0	0	0	0
SWZ	Ann. Cost	B.USD	0	0	0.3	0.4	0.5	0.2	0.3	0.5	0.3	0.4	0.6	0.3	0.4	0.5
SWZ	Ann. Demand	TWh	1.5	2.1	4.4	8.4	14.5	4.4	8.4	14.5	4.4	8.4	14.5	4.4	8.4	14.5
SWZ	Ann. Supply	TWh	0.2	0.2	3.8	5.4	6.4	2.9	3.5	6.4	3.9	6.1	7.6	3.8	5.4	6.3
SWZ	Ann. Import	TWh	1.3	1.9	1	9.7	16.6	2	10.1	24.6	0.8	4.7	13.4	1	9.6	21.3
SWZ	Ann. Export	TWh	0	0	0.4	6.7	8.5	0.5	5.2	16.5	0.4	2.4	6.5	0.4	6.6	13
SWZ	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SWZ	Gen. Gas	TWh	0	0	0.9	0.4	0.7	0	0	0	1.1	0.5	0.7	0.9	0.4	0.6
SWZ	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SWZ	Gen. CCS	TWh	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0
SWZ	Gen. Hydro	TWh	0.2	0.2	2.3	2.3	2.3	2.3	2.3	2.3	2	2.3	2.3	2.3	2.3	2.3
SWZ	Gen. Wind	TWh	0	0	0.6	2.8	3.4	0.6	1.2	3.7	0.5	2.1	3.4	0.6	2.8	3.4
SWZ	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.3	1.2	1.2	0	0	0
SYR	Carbon Emission	MT	8	4.7	0.3	0	0.4	0.9	0.3	0.8	0.2	0	1.4	0.3	0	1.8
SYR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SYR	Ann. Cost	B.USD	2	1.6	1.1	1.9	2.8	1.3	2.1	3.1	1.2	1.9	3.1	1.1	1.9	3.3
SYR	Ann. Demand	TWh	14.3	16.2	22.3	30	35.4	22.3	30	35.4	22.3	30	35.4	22.3	30	35.4
SYR	Ann. Supply	TWh	17.9	14.4	16.7	37.8	57.3	18.9	39	60.1	17.2	38.5	67	16.7	37.8	61.8
SYR	Ann. Import	TWh	35.7	35.7	41.5	49.5	60.3	35.7	40.2	50.2	37.7	48.1	66.3	41.5	49.5	49.9
SYR	Ann. Export	TWh	38	32.9	33.9	55.7	81	31.4	48.6	73.8	31.6	55.6	96.8	33.9	55.8	75.3
SYR	Gen. Coal	TWh	0.5	0.1	0.1	0	0	0	0	0	0.1	0	0	0.1	0	0
SYR	Gen. Gas	TWh	9.2	8.8	0.4	0	0.8	2.5	0.9	2.1	0.3	0	3.9	0.4	0	4.8
SYR	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SYR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SYR	Gen. Hydro	TWh	4.2	4.2	4.2	2	2	4.2	2	2	4.2	2	2	4.2	2	2
SYR	Gen. Wind	TWh	0	0	8.2	19.6	20.7	8.4	16.1	17.6	7.3	28.6	51.9	8.2	19.6	19.7
SYR	Gen. PV	TWh	0	0	0	12.4	29.8	0	16.2	34.5	1.5	4.1	5.4	0	12.4	30.9
TCD	Carbon Emission	MT	0.1	0.1	0	0.2	0.3	0	0.2	0.1	0.1	0.2	0.3	0	0.2	0
TCD	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TCD	Ann. Cost	B.USD	0	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.1	0.1
TCD	Ann. Demand	TWh	0.2	0.3	0.6	1.1	2	0.6	1.1	2	0.6	1.1	2	0.6	1.1	2
TCD	Ann. Supply	TWh	0.2	0.3	1.1	2.6	3.8	1.1	2.5	3.7	1.5	2.8	4.2	1.1	2.6	3.4
TCD	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TCD	Ann. Export	TWh	0	0	0.1	1.4	1.8	0.1	1.3	1.8	0.9	1.6	2.2	0.1	1.4	1.5
TCD	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TCD	Gen. Gas	TWh	0.2	0.3	0.1	0.6	0.6	0.1	0.4	0.3	0.2	0.5	0.6	0.1	0.6	0.1
TCD	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TCD	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TCD	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TCD	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.4	0.4	0.4	0	0	0
TCD	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.2	0.2	0.2	0	0	0
TGO	Carbon Emission	MT	0	0.3	1	1.5	1.2	0.4	0.5	-2.1	0.9	0.6	0.8	1	1.5	-1.5
TGO	Carbon Sequester	MT	0	0	0	0	0	0	0	2.5	0	0	0	0	0	2.2
TGO	Ann. Cost	B.USD	0	0.1	0.3	0.5	0.8	0.4	0.5	0.9	0.3	0.5	0.8	0.3	0.5	1
TGO	Ann. Demand	TWh	1.3	1.9	3.9	7.6	13	3.9	7.6	13	3.9	7.6	13	3.9	7.6	13
TGO	Ann. Supply	TWh	0	1	3.5	6.5	10	4.3	5.4	11.2	3.7	4.5	9.6	3.5	6.5	11.9
TGO	Ann. Import	TWh	1.3	2.1	0.7	7	12	0.9	15.1	21.8	0.9	4.1	10.8	0.7	7	9
TGO	Ann. Export	TWh	0	1.3	0.3	5.9	9	1.2	13	19.9	0.6	1.1	7.3	0.3	5.9	7.8
TGO	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TGO	Gen. Gas	TWh	0	0.7	2.6	3.9	3.2	1.1	1.5	1.1	2.4	1.5	2.1	2.6	3.9	1.8
TGO	Gen. Nuclear	TWh	0	0	0	0	0	2.1	2.1	2	0	0	0	0	0	0

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
TGO	Gen. CCS	TWh	0	0	0	0	0	0	0	2.9	0	0	0	0	0	2.5
TGO	Gen. Hydro	TWh	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TGO	Gen. Wind	TWh	0	0	0	0	0	0	0.7	0.7	0.7	2.1	2.1	0	0	0.7
TGO	Gen. PV	TWh	0	0.1	0.7	2.4	6.6	0.9	0.9	4.3	0.3	0.8	5.2	0.7	2.4	6.7
THA	Carbon Emission	MT	81.8	93.6	32.1	20.1	12.3	23.8	11.3	-55.1	29.4	18.7	9.8	32.1	20.1	-5.1
THA	Carbon Sequester	MT	0	0	0	0	0	0	0	57.1	0	0	0	0	0	11.5
THA	Ann. Cost	B.USD	12.2	14.7	20.8	25.2	37.2	25.4	30.4	40.7	22.9	32.1	42	20.8	25.2	40.2
THA	Ann. Demand	TWh	186.5	235.8	347	474.3	619	347	474.3	619	347	474.3	619	347	474.3	619
THA	Ann. Supply	TWh	160.1	182.9	317.2	398.9	593	368.1	454.3	633.6	322.3	424.4	595.8	317.2	398.8	618.5
THA	Ann. Import	TWh	26.7	53.7	43.2	92.7	59.1	23.5	55	42	32.2	74.1	56.8	43.2	92.8	36.8
THA	Ann. Export	TWh	0	0	10.4	13.3	25.2	42.5	31.3	54	5.6	19.6	26.5	10.4	13.3	31.8
THA	Gen. Coal	TWh	44.2	55.6	8.5	4.4	1.5	4.8	0.2	0.1	8.2	4.1	1.5	8.5	4.4	0
THA	Gen. Gas	TWh	95.7	97.3	61.1	40.7	28.8	48.6	28.4	3.9	54.9	38.1	22	61.1	40.7	16.7
THA	Gen. Nuclear	TWh	0	0	29	91.1	174.1	96.3	153	217.6	38.7	58.8	149.8	29	90.9	213.4
THA	Gen. CCS	TWh	0	0	0	0	0	0	0	66.6	0	0	0	0	0	13.4
THA	Gen. Hydro	TWh	11.9	11.9	16.4	16.2	16.1	16.2	16.2	16.3	16.2	16.2	16.1	16.4	16.2	16.1
THA	Gen. Wind	TWh	0.7	6.3	100.4	110.7	170.3	108	113.9	120.6	125.9	215.5	238.7	100.4	110.7	157.6
THA	Gen. PV	TWh	2.1	6.5	76.5	110.9	178.6	68.7	117.5	184.2	53	66.8	143.9	76.5	111	175.1
TJK	Carbon Emission	MT	1.8	1.4	0.1	0	0.1	0.1	0	0	0	0	0.1	0.1	0	-1
TJK	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TJK	Ann. Cost	B.USD	1	1.1	1.3	0.9	1.3	1.4	1.7	1.6	1.2	1	1.1	1.3	0.9	1.4
TJK	Ann. Demand	TWh	13.7	15.8	20.3	25.6	31.7	20.3	25.6	31.7	20.3	25.6	31.7	20.3	25.6	31.7
TJK	Ann. Supply	TWh	16.4	17.8	22.8	16.8	25.1	25.1	29.3	29.4	20.6	17	21.2	22.8	16.8	24.7
TJK	Ann. Import	TWh	6.2	7.6	5.5	14.9	20.4	5.4	11.4	19.3	7.8	12.4	21.3	5.5	14.9	21.4
TJK	Ann. Export	TWh	8.2	9.3	7.7	5.8	13.5	9.4	14.8	16.7	7.8	3.5	10.5	7.7	5.8	14
TJK	Gen. Coal	TWh	2	1.6	0	0	0	0	0	0	0	0	0	0	0	0
TJK	Gen. Gas	TWh	0	0	0.2	0.1	0.1	0.2	0	0	0.1	0.1	0.1	0.2	0.1	0
TJK	Gen. Nuclear	TWh	0	0	0	0	0	0	0.4	0.5	0	0	0	0	0	0
TJK	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	1.2
TJK	Gen. Hydro	TWh	14.4	16.3	16.3	7.7	4.7	18.6	9.9	7	16.3	7.7	4.7	16.3	7.7	4.7
TJK	Gen. Wind	TWh	0	0	5	5	5	5	10	10	2.2	6.1	6.1	5	5	5
TJK	Gen. PV	TWh	0	0	0	2.8	14	0	7.7	10.8	0.8	2	9.1	0	2.8	12.4
TKM	Carbon Emission	MT	8.7	7.9	2.6	0	0	2.6	0	0	2.4	0	0	2.6	0	0
TKM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TKM	Ann. Cost	B.USD	1.5	1.4	1.1	1.6	2.4	1.3	1.5	2.4	1.1	1.5	2.4	1.1	1.6	2.4
TKM	Ann. Demand	TWh	15.1	17.4	22.3	28.1	34.9	22.3	28.1	34.9	22.3	28.1	34.9	22.3	28.1	34.9
TKM	Ann. Supply	TWh	17	15.7	16.7	32.6	51.1	16.9	32.1	50.7	16.4	31.7	50.3	16.7	32.6	51
TKM	Ann. Import	TWh	0	2.4	5.9	3.8	3.2	8.4	8	6.6	6.2	3.3	1.9	5.9	3.8	6.1
TKM	Ann. Export	TWh	1.9	0.6	0.1	6.9	17.2	2.4	9.6	18.7	0.1	5.6	14.9	0.1	6.8	19.3
TKM	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TKM	Gen. Gas	TWh	17	15.5	4.5	0	0.1	4.6	0	0	4.2	0	0.1	4.5	0	0
TKM	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TKM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TKM	Gen. Hydro	TWh	0	0.1	0.1	0.7	0.7	0.1	0.1	0.3	0.1	0.1	0.1	0.1	0.7	0.7
TKM	Gen. Wind	TWh	0	0	12	25.4	41	12.2	32	44.9	10.8	28.5	47.1	12	25.4	43.8
TKM	Gen. PV	TWh	0	0	0	6.5	9.3	0	0	5.5	1.2	3.1	3.1	0	6.5	6.5
TLS	Carbon Emission	MT	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Ann. Cost	B.USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
TLS	Ann. Demand	TWh	0.1	0.2	0.2	0.3	0.4	0.2	0.3	0.4	0.2	0.3	0.4	0.2	0.3	0.4
TLS	Ann. Supply	TWh	0.1	0.2	0.3	0.4	0.6	0.3	0.4	0.7	0.4	0.4	0.5	0.3	0.4	0.5
TLS	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Ann. Export	TWh	0	0	0.1	0	0.1	0.1	0	0.1	0.1	0.1	0.1	0.1	0	0
TLS	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Gen. Gas	TWh	0	0.1	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TLS	Gen. Hydro	TWh	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
TLS	Gen. Wind	TWh	0	0	0.2	0.2	0.4	0.2	0.2	0.4	0.2	0.2	0.2	0.2	0.2	0.2
TLS	Gen. PV	TWh	0	0	0	0	0.1	0	0	0.2	0.1	0.1	0.2	0	0	0.1
TTO	Carbon Emission	MT	3.8	4.2	5.2	1.9	1	1.5	0.4	-0.5	3.5	1.7	1.5	4.4	1.5	-0.1
TTO	Carbon Sequester	MT	0	0	0	0	0	0	0	0.5	0	0	0	0	0	0.4
TTO	Ann. Cost	B.USD	0.7	0.8	1.2	1.5	1.9	1.3	1.6	1.9	1.5	2.1	2.4	1.2	1.5	1.9
TTO	Ann. Demand	TWh	9.9	11.1	14.5	18.5	22.7	14.5	18.5	22.7	14.5	18.5	22.7	14.5	18.5	22.7
TTO	Ann. Supply	TWh	9.9	11.1	14.5	18.5	22.7	14.5	18.5	22.7	14.6	18.6	22.9	14.5	18.5	22.7
TTO	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TTO	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TTO	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TTO	Gen. Gas	TWh	9.9	11	13.7	5	2.7	4	0.9	0	9.1	4.6	4.1	11.7	4	0.9
TTO	Gen. Nuclear	TWh	0	0	0	9.8	16.3	8.1	15.2	19.3	0	2.9	5.8	1.8	11.5	18.5
TTO	Gen. CCS	TWh	0	0	0	0	0	0	0	0.6	0	0	0	0	0	0.5
TTO	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TTO	Gen. Wind	TWh	0	0	0.3	0.3	0.4	0.4	0.4	0.3	4.7	9	9	0.3	0.3	0.3
TTO	Gen. PV	TWh	0	0.1	0.5	3.4	3.3	1.9	1.9	2.6	0.8	2.1	4	0.8	2.7	2.6
TUN	Carbon Emission	MT	5.9	6.8	4.1	0.4	0.9	1.7	0.1	0	4.1	0.1	0.6	4.1	0.4	-0.6
TUN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0.8
TUN	Ann. Cost	B.USD	1.3	1.4	1.6	1.5	2.2	1.8	1.8	2.4	1.7	1.8	2.2	1.6	1.5	2.1
TUN	Ann. Demand	TWh	17.3	19.7	27.1	36.4	43	27.1	36.4	43	27.1	36.4	43	27.1	36.4	43
TUN	Ann. Supply	TWh	15.6	19.2	26.9	34.4	47.9	27.2	35.4	48.3	27.2	41.4	47.5	26.9	34.4	45.5
TUN	Ann. Import	TWh	1.7	0.5	0.2	3.8	3.2	0.2	1.6	1.8	0	3.4	4.1	0.2	3.7	3.7
TUN	Ann. Export	TWh	0	0	0	1	7.4	0.2	0.4	6.6	0.1	8	8.2	0	1	5.5
TUN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TUN	Gen. Gas	TWh	13.7	17.6	10.8	1.1	2.5	4.6	0.3	0.1	10.8	0.3	1.5	10.8	1.1	0.6
TUN	Gen. Nuclear	TWh	0	0	0	0	0	6.5	4.9	3.7	0	0	0	0	0	0
TUN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.9
TUN	Gen. Hydro	TWh	0.2	0.2	0.2	0.2	0.4	0.2	0.2	0	0.2	0.2	0.4	0.2	0.2	0.4
TUN	Gen. Wind	TWh	0.9	1.1	1.1	10.9	21.1	1.1	8.7	22	5.5	15.8	20.4	1.1	10.9	20
TUN	Gen. PV	TWh	0	0.1	0.1	2.2	4	0.1	1.5	2.6	1.9	5.2	5.2	0.1	2.2	3.7
TUR	Carbon Emission	MT	99	100.7	34.9	15.2	10.4	16.7	2.7	2	31	9.7	6.6	34.9	15.2	-19
TUR	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	21.1
TUR	Ann. Cost	B.USD	18	21.4	21.8	23.9	23.6	22.8	22.8	22.6	21.9	24.1	22.9	21.8	23.9	25.4
TUR	Ann. Demand	TWh	238.6	260.9	304.3	352.9	403.9	304.3	352.9	403.9	304.3	352.9	403.9	304.3	352.9	403.9
TUR	Ann. Supply	TWh	259.7	295.6	360.9	424.2	439.3	358.2	391.7	417.8	358	421	438.1	360.9	424.2	432.7
TUR	Ann. Import	TWh	2.2	0.3	0.1	5.4	25.6	0.5	14.7	29.5	0	7.1	40.4	0.1	5.4	25
TUR	Ann. Export	TWh	16.9	29.4	47.5	71	55.5	47.7	47.4	35.4	44.6	69	66.8	47.5	70.9	49.1
TUR	Gen. Coal	TWh	74.7	80.5	32.8	14.2	9.6	13.3	1.1	0.7	29.1	8.9	5.4	32.8	14.2	1.5

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
TUR	Gen. Gas	TWh	74.7	66.4	9.2	5.6	4.1	10.5	4.5	3.5	8.8	4.1	4.5	9.2	5.6	1.5
TUR	Gen. Nuclear	TWh	0	0	11.7	11.8	10.4	19	21.5	17.3	12.8	11.7	7.5	11.7	11.8	11.6
TUR	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	24.6
TUR	Gen. Hydro	TWh	85.3	94.3	140.8	162.2	148	139.8	132.2	124.9	135.9	161	146.9	140.8	162.2	148
TUR	Gen. Wind	TWh	18	28.7	136.4	196.2	227.8	145.6	196.2	231.8	128.9	177.2	208	136.4	196.2	208.7
TUR	Gen. PV	TWh	0.4	10.1	10.1	14.9	21.3	10.1	16.7	17.3	22.6	38.6	39.5	10.1	14.9	18.1
TWN	Carbon Emission	MT	147.2	154.3	197.7	246.1	278.6	143.2	31.5	12.2	139.5	137.6	178.2	159.3	82.7	3
TWN	Carbon Sequester	MT	0	0	0	0	0	0	175.9	214.9	0	0	0	0	76.1	91.1
TWN	Ann. Cost	B.USD	14.6	18.1	23.3	30.2	38.2	30.5	39.8	47	27	36.4	42.1	24.7	35.2	48.2
TWN	Ann. Demand	TWh	241.5	249.2	311.4	377.4	446.8	311.4	377.4	446.8	311.4	377.4	446.8	311.4	377.4	446.8
TWN	Ann. Supply	TWh	241.7	249.3	311.6	377.6	447.2	311.9	379	449.3	313.3	380.9	450.2	311.8	378.7	454.8
TWN	Ann. Import	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TWN	Ann. Export	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TWN	Gen. Coal	TWh	124.5	136	229.5	309	365.5	121	5.8	0	157.1	171.2	239	150.7	38.3	2.3
TWN	Gen. Gas	TWh	57.3	51.3	16.4	0.3	0	108.5	37.6	14.9	16.4	0.5	0	78.6	131.8	1.3
TWN	Gen. Nuclear	TWh	38.6	38.6	0	0	0	0	0	0	0	0	0	0	0	0
TWN	Gen. CCS	TWh	0	0	0	0	0	0	200.2	260.1	0	0	0	0	82.6	130.4
TWN	Gen. Hydro	TWh	7.4	7.4	14.6	14.6	14.6	14.6	14.6	14.7	14.6	14.6	14.7	14.7	14.7	14.7
TWN	Gen. Wind	TWh	1.7	2.1	8.8	8.2	21.5	22.1	76	114.5	81.8	149.1	151.1	22.1	64.7	261.1
TWN	Gen. PV	TWh	1.1	3.9	38.6	41.9	41.9	41.9	41.9	41.9	39.5	41.9	41.9	41.9	41.9	41.9
TZA	Carbon Emission	MT	2	2.9	2.4	1.2	1.6	1.5	0.4	0.5	2.1	0.9	1.7	2.5	1.3	-1.4
TZA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	2
TZA	Ann. Cost	B.USD	0.5	0.7	1.1	1.6	3.1	1.2	1.7	3.2	1.1	1.5	3	1.1	1.6	3.3
TZA	Ann. Demand	TWh	5.8	8.2	17.2	32.9	56.8	17.2	32.9	56.8	17.2	32.9	56.8	17.2	32.9	56.8
TZA	Ann. Supply	TWh	5.1	7.8	17.6	32	61	18.2	32.5	61.6	17.4	29.1	59.1	18	32.2	61.5
TZA	Ann. Import	TWh	1	0.7	0.8	2.5	2.8	0.9	2.9	3.5	1.1	5.2	3.4	0.7	2.4	2.4
TZA	Ann. Export	TWh	0.2	0.3	1	1.3	6.2	1.8	2.2	7.3	1.1	1.1	5.2	1.3	1.3	6.3
TZA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TZA	Gen. Gas	TWh	2.2	5	4.7	3.1	4.1	2.5	1	1.3	3.7	2.3	4.6	5	3.3	1.5
TZA	Gen. Nuclear	TWh	0	0	0	0.7	0.7	2.9	2.2	2.4	0	0	0	0	0.7	0.7
TZA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	2.2
TZA	Gen. Hydro	TWh	1.8	1.8	1.7	6.9	15.9	1.7	9.6	18.1	1.7	6.2	16.9	1.7	6.9	17.9
TZA	Gen. Wind	TWh	0	0	10.6	19.3	30	10.6	17.1	28.5	10.6	17.7	30.3	10.6	19.3	29
TZA	Gen. PV	TWh	0	0.1	0.1	2	10.2	0.1	2.5	11.2	1	2.9	7.3	0.1	1.9	10
UGA	Carbon Emission	MT	0	0.2	0.7	0.6	0.7	0.3	0.2	0.3	0.4	0.2	0.4	0.4	0.4	0.3
UGA	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGA	Ann. Cost	B.USD	0.2	0.3	0.5	0.6	0.7	0.5	0.6	0.8	0.5	0.7	0.7	0.5	0.6	0.7
UGA	Ann. Demand	TWh	2.9	4.2	8.7	16.7	28.8	8.7	16.7	28.8	8.7	16.7	28.8	8.7	16.7	28.8
UGA	Ann. Supply	TWh	2.8	3.8	8.4	11.3	13.1	8.4	11	13.7	8.1	12	13.2	7.7	10.9	12.5
UGA	Ann. Import	TWh	1.9	1.2	1.3	7.5	18.3	1.5	8.5	17.7	1.7	7.6	17.6	1.8	8	18.3
UGA	Ann. Export	TWh	1.7	0.8	1	2	2.3	1.1	2.6	2.4	1.1	2.7	1.7	0.8	2.1	1.8
UGA	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGA	Gen. Gas	TWh	0	0.5	1.9	1.5	1.9	0.8	0.4	0.7	1.1	0.5	0.9	1	1.1	0.8
UGA	Gen. Nuclear	TWh	0	0	0	0	0	0.7	0.6	0.6	0	0	0	0	0	0
UGA	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGA	Gen. Hydro	TWh	2.8	3.1	6.3	9.7	9.8	6.7	9.7	9.8	6.1	9	9.8	6.4	9.7	10
UGA	Gen. Wind	TWh	0	0	0	0	0	0	0	0	0.3	0.9	0.9	0	0	0
UGA	Gen. PV	TWh	0	0.1	0.1	0.1	1.3	0.1	0.1	2.4	0.5	1.5	1.5	0.1	0.1	1.6
UKR	Carbon Emission	MT	38.9	30.3	6.9	3.4	0.6	6	0.1	-12.5	6.6	1.5	1.1	5.8	0.1	-26.9
UKR	Carbon Sequester	MT	0	0	0	0	0	0	0	12.7	0	0	0	0	0	27
UKR	Ann. Cost	B.USD	19.6	13	6.1	7.6	10.6	10	13.1	15.4	8.7	11.8	14.3	10	14	18.7
UKR	Ann. Demand	TWh	135.3	147.9	172.5	200.1	229	172.5	200.1	229	172.5	200.1	229	172.5	200.1	229
UKR	Ann. Supply	TWh	169.8	160.5	79.7	101.2	143.4	132.2	176.5	204.6	114.1	153	190.9	135.4	181	207
UKR	Ann. Import	TWh	0.3	1.8	105.9	111.2	105.7	44.2	34.8	40.9	66.8	55.4	49.7	41.1	33	38.5
UKR	Ann. Export	TWh	33.3	13	9.4	8.5	15.5	3.1	10	14.7	6.2	6.6	8.4	3.2	12.9	14.8
UKR	Gen. Coal	TWh	40.8	31.5	7.7	3.9	0.7	6.7	0	0	7.4	1.7	1.2	6.4	0	0
UKR	Gen. Gas	TWh	7.6	6.8	0.2	0.1	0.1	0.2	0	0	0.2	0	0.1	0.1	0	0
UKR	Gen. Nuclear	TWh	100	102.4	51.2	51.2	28.7	66.2	74	75	51.1	51.1	33.1	67.7	75.2	45.6
UKR	Gen. CCS	TWh	0	0	0	0	0	0	0	15.5	0	0	0	0	0	31.6
UKR	Gen. Hydro	TWh	18.4	15.1	12.7	11.7	8.1	12.7	11.7	7.6	12.7	11.7	8	12.7	11.7	7.6
UKR	Gen. Wind	TWh	1.5	2	5.4	32.9	97.8	43.9	85.4	95.9	32.5	69.6	130.8	45.8	88	109.6
UKR	Gen. PV	TWh	1	2.3	2.3	1.3	7.9	2.3	5.4	10.6	9.9	18.8	17.7	2.3	1.3	6
URY	Carbon Emission	MT	1.3	0.9	0.3	0	0	0.3	0	0	0.3	0	0	0.3	0	0
URY	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
URY	Ann. Cost	B.USD	1	1.2	1	0.7	0.8	1	0.7	0.8	1	0.9	1	1	0.7	0.8
URY	Ann. Demand	TWh	11.6	13	17	21.6	26.6	17	21.6	26.6	17	21.6	26.6	17	21.6	26.6
URY	Ann. Supply	TWh	11.4	12.6	11.9	8.9	9.5	11.9	8.9	9.5	12.3	11.5	11.5	11.9	8.9	11.1
URY	Ann. Import	TWh	1.4	1.3	12.1	13.8	18.2	23.2	16.7	21.6	17.1	12.4	16.9	12.1	13.7	16.7
URY	Ann. Export	TWh	1.2	0.9	7	1.1	1.2	18.1	4.1	4.5	12.5	2.3	1.8	7	1.1	1.3
URY	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
URY	Gen. Gas	TWh	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0
URY	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
URY	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
URY	Gen. Hydro	TWh	4.5	4.5	4.5	4.5	3.9	4.5	4.5	3.9	4.5	4.5	3.9	4.5	4.5	4.1
URY	Gen. Wind	TWh	3.8	5.6	5.6	3.1	4.6	5.6	3.1	4.6	5.6	4.1	4.6	5.6	3.1	5.2
URY	Gen. PV	TWh	0.3	0.4	0.4	0.3	0	0.4	0.3	0	0.9	1.9	1.9	0.4	0.3	0.6
USA	Carbon Emission	MT	1604.4	1520.6	1483	1156.2	941.4	1057	163.1	65.1	1202.2	794.1	675.3	1386.9	653	18.6
USA	Carbon Sequester	MT	0	0	0	0	0	0	201.3	202.7	0	0	0	0	0	154
USA	Ann. Cost	B.USD	342.4	276.7	292.7	302.7	348.3	367.2	372.4	387.7	323.6	368	397.3	294.2	331.7	422.7
USA	Ann. Demand	TWh	4110.7	4378.1	4638	4968.5	5384.5	4638	4968.5	5384.5	4638	4968.5	5384.5	4638	4968.5	5384.5
USA	Ann. Supply	TWh	4066.3	4376.1	4667.1	4883.3	5250.5	4728.2	4977.1	5162.9	4690.7	4950.6	5274.9	4678.4	4854.9	5229.7
USA	Ann. Import	TWh	82.8	103.5	109.8	193.4	243.8	121.4	204.4	442.1	119.3	155	263.4	111.6	239.7	351.1
USA	Ann. Export	TWh	34.1	90.5	133.7	73	73.2	182.5	137.7	105.5	161.6	114.8	104.1	144.1	76.7	72.4
USA	Gen. Coal	TWh	1169.9	589.1	126	4.5	0.5	56.1	0	0	119	21.7	6.3	102.7	12.3	0
USA	Gen. Gas	TWh	1361	2523.4	3554.3	3058.4	2496	2619.9	397.5	139.1	2824.9	2049.6	1770	3364.5	1698.7	357.8
USA	Gen. Nuclear	TWh	782.8	455.1	61.8	43.8	24.5	61.4	912.3	1015.2	61.8	43.8	24.6	61.8	347.5	766
USA	Gen. CCS	TWh	0	0	0	0	0	0	487.9	491.2	0	0	0	0	0	229.9
USA	Gen. Hydro	TWh	340.8	287.9	278.6	508	488.7	514.4	506.7	503.5	236.7	377.8	405.2	415.4	499.7	511.5
USA	Gen. Wind	TWh	277.5	329.1	326.8	726.6	1038.8	954.2	1857.6	1952.2	839.4	1468.8	1850.3	409.5	1495.8	2146.3
USA	Gen. PV	TWh	38	104	104	326.7	987.2	305.9	601.8	852.7	393	774.7	1004.5	107.9	586	912.5
UZB	Carbon Emission	MT	26.4	19.6	3.5	0.4	0.2	3.7	0.4	-3.7	3	0.7	0.3	3.5	0.4	-2.5
UZB	Carbon Sequester	MT	0	0	0	0	0	0	0	3.7	0	0	0	0	0	2.5

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
UZB	Ann. Cost	B.USD	3.7	2.7	2.1	2.4	2.3	3.6	3.9	3.9	2.5	3.3	3	2.1	2.4	2.8
UZB	Ann. Demand	TWh	51.9	59.7	76.7	96.7	119.9	76.7	96.7	119.9	76.7	96.7	119.9	76.7	96.7	119.9
UZB	Ann. Supply	TWh	54.2	39.6	32	40.6	42.9	55.7	62.3	63	38.1	51.4	50.9	32	40.6	45.8
UZB	Ann. Import	TWh	8.6	32.2	57.2	75.3	96.3	37.5	61.3	84.8	52.4	61.6	88.4	57.2	75.3	99.4
UZB	Ann. Export	TWh	10.5	10.9	11.2	17.7	18.1	15.3	25.1	27	12.7	15.6	18.5	11.2	17.6	22.6
UZB	Gen. Coal	TWh	15.2	13.3	0	0	0	0	0	0	0	0	0	0	0	0
UZB	Gen. Gas	TWh	33.5	20.6	9	1	0.4	9.6	1.1	0.1	8	1.8	0.7	9	1	0
UZB	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UZB	Gen. CCS	TWh	0	0	0	0	0	0	0	4.6	0	0	0	0	0	3.1
UZB	Gen. Hydro	TWh	5.4	5.6	4.1	11.2	11.2	14.7	13	14.6	5.5	10	10	4.1	11.2	12.1
UZB	Gen. Wind	TWh	0	0	18.2	21.6	24.5	29.4	40.5	34.1	19.2	25.8	26.4	18.2	21.6	23.3
UZB	Gen. PV	TWh	0	0.1	0.6	6.8	6.8	2	7.8	9.8	5.5	13.8	13.8	0.6	6.8	7.3
VEN	Carbon Emission	MT	21.6	20.7	5.9	2.9	5	5.2	1	2.5	5.3	0.9	3.3	5.9	2.8	1.7
VEN	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VEN	Ann. Cost	B.USD	7.6	7.8	7.2	7.9	10.3	7.3	7.8	10.4	7.3	7.9	9.8	7.2	7.9	9.9
VEN	Ann. Demand	TWh	80	89.7	117	149.2	183.4	117	149.2	183.4	117	149.2	183.4	117	149.2	183.4
VEN	Ann. Supply	TWh	107.5	114	139.6	177.6	231.2	138.3	177.5	231	138.3	175.5	219.2	139.6	177.8	233
VEN	Ann. Import	TWh	3.3	1.9	12.1	13.7	9.7	17.6	17.4	10.8	14.7	15.1	11.6	12.1	13.9	12.7
VEN	Ann. Export	TWh	27.3	22.7	29.4	37.6	50.7	32.9	38.9	49.9	30.8	37	43	29.4	37.9	52.6
VEN	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VEN	Gen. Gas	TWh	21.3	34	5.1	7.6	13.2	3.2	2.6	5	3.6	2.3	8	5.1	7.5	4.7
VEN	Gen. Nuclear	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VEN	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VEN	Gen. Hydro	TWh	71	71	71	78	95.1	71	92.1	114.4	71	74.8	83.5	71	78.5	116.7
VEN	Gen. Wind	TWh	0.2	0.2	53.9	69.1	100	53.3	59.9	88	54.7	63.6	93	53.9	68.8	88.8
VEN	Gen. PV	TWh	0	0.1	0.1	0.1	0	0.1	0.1	0.7	4.7	12	11.9	0.1	0.2	0.1
VNM	Carbon Emission	MT	73.8	108	21.1	17.4	20.9	17.2	6.2	-35.6	19	14.5	20.7	21.1	17.4	-30.8
VNM	Carbon Sequester	MT	0	0	0	0	0	0	0	40.9	0	0	0	0	0	36.5
VNM	Ann. Cost	B.USD	10	13.5	15.5	22.1	28.4	16.9	22.8	30.3	15.9	22.7	28.9	15.5	22.1	30.1
VNM	Ann. Demand	TWh	156.7	198.2	291.7	398.7	520.3	291.7	398.7	520.3	291.7	398.7	520.3	291.7	398.7	520.3
VNM	Ann. Supply	TWh	157	198	291	424.8	518.7	293.2	426.1	533.1	292	434.5	525	291	424.8	518
VNM	Ann. Import	TWh	1.1	1.4	24	27.1	54.6	16.9	23.1	34	18.4	21.6	47.5	24	27.2	47.1
VNM	Ann. Export	TWh	0.6	0.1	19.4	47.7	46.4	14.2	43.1	42.3	16.2	50.8	46	19.4	47.7	39.1
VNM	Gen. Coal	TWh	61.2	97.7	18.5	14.1	11	6	0.1	0.3	16.5	12.6	11.5	18.5	14.2	0.9
VNM	Gen. Gas	TWh	38.3	34.2	5.1	7.5	25.1	28.3	15.5	12.5	5	4.1	23	5.1	7.3	12.5
VNM	Gen. Nuclear	TWh	0	0	75.5	74.9	111.3	67	73.9	122.7	78.5	74.4	108.5	75.5	75	97.1
VNM	Gen. CCS	TWh	0	0	0	0	0	0	0	47.8	0	0	0	0	0	42.5
VNM	Gen. Hydro	TWh	55.9	64.3	63.7	83.6	81.2	63.7	83.6	81.2	63.7	83.6	81.2	63.7	83.6	81.2
VNM	Gen. Wind	TWh	0.9	0.9	120.9	219	218.6	121.9	219.1	218.6	105.5	208.6	220.1	120.9	219	218.6
VNM	Gen. PV	TWh	0	0.4	1.3	20.1	66.1	0.4	28.2	44.6	16.9	45.9	75.3	1.3	20.1	59.4
XKX	Carbon Emission	MT	4.1	4.3	0	0	0	0	0	-0.3	0	0	0	0	0	-0.3
XKX	Carbon Sequester	MT	0	0	0	0	0	0	0	0.3	0	0	0	0	0	0.3
XKX	Ann. Cost	B.USD	0.5	0.6	0.1	0.1	0.1	0.2	0.3	0.3	0.1	0.2	0.2	0.1	0.1	0.3
XKX	Ann. Demand	TWh	5.1	5.6	6.5	7.5	8.6	6.5	7.5	8.6	6.5	7.5	8.6	6.5	7.5	8.6
XKX	Ann. Supply	TWh	4.7	5	1.3	2.3	2.3	2.9	3.9	4.2	1.8	3.4	3.4	1.3	2.3	3.8
XKX	Ann. Import	TWh	0.9	1.6	9.2	15.2	20.8	8.9	16.2	17.4	7.5	9.1	18.3	9	12.4	15.2
XKX	Ann. Export	TWh	0.5	1	4	10	14.5	5.3	12.6	13	2.8	5	13	3.9	7.2	10.3
XKX	Gen. Coal	TWh	4.7	4.9	0	0	0	0	0	0	0	0	0	0	0	0
XKX	Gen. Gas	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
XKX	Gen. Nuclear	TWh	0	0	0	0	0	0.6	0.5	0.5	0	0	0	0	0	0
XKX	Gen. CCS	TWh	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0.3
XKX	Gen. Hydro	TWh	0	0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
XKX	Gen. Wind	TWh	0	0	0.8	1.8	1.8	1.8	2.9	2.9	1.1	2.5	2.5	0.8	1.8	3
XKX	Gen. PV	TWh	0	0	0	0	0	0	0	0	0.2	0.4	0.4	0	0	0
YEM	Carbon Emission	MT	3	2.2	1	0.2	0	0.9	0.1	0	0.9	0.2	0	1	0.2	0
YEM	Carbon Sequester	MT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
YEM	Ann. Cost	B.USD	0.6	0.6	0.5	0.4	0.4	0.7	0.5	0.6	0.5	0.5	0.5	0.5	0.4	0.5
YEM	Ann. Demand	TWh	3.4	3.9	5.4	7.2	8.5	5.4	7.2	8.5	5.4	7.2	8.5	5.4	7.2	8.5
YEM	Ann. Supply	TWh	4.2	4	5.3	10.6	15.1	5.5	11.5	19.4	6.9	12.5	28.3	5.3	10.6	15.6
YEM	Ann. Import	TWh	0	0	0.1	0.2	0.3	0.4	0.2	0.2	0	0	0	0.1	0.2	0.4
YEM	Ann. Export	TWh	0	0	0	3.6	6.8	0	4.5	11	0.7	5.1	12.2	0	3.6	7.3
YEM	Gen. Coal	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
YEM	Gen. Gas	TWh	1.7	2.1	1	0.4	0	0.7	0.1	0	0.7	0.4	0	1	0.4	0
YEM	Gen. Nuclear	TWh	0	0	0	0	0	0.2	1.6	0.9	0	0	0	0	0	0
YEM	Gen. CCS	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
YEM	Gen. Hydro	TWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
YEM	Gen. Wind	TWh	0	0	0	0	0	0	0	0	1.8	3.4	8.9	0	0	0
YEM	Gen. PV	TWh	0	0.3	0.3	0.3	0	0.3	0.3	0	0.6	0.7	1.6	0.3	0.3	0
ZAF	Carbon Emission	MT	202.9	219.1	64.8	9.5	13	12.5	2.9	2.5	60.4	12.7	13.6	64.8	9.5	8.4
ZAF	Carbon Sequester	MT	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0.3
ZAF	Ann. Cost	B.USD	20	22	21.1	23.3	28.9	22.2	26.2	33.3	21.3	23.3	29	21.1	23.3	30.1
ZAF	Ann. Demand	TWh	224.4	240.8	290.9	364.9	458.8	290.9	364.9	458.8	290.9	364.9	458.8	290.9	364.9	458.8
ZAF	Ann. Supply	TWh	237.1	260.4	300.7	374.3	459.6	300.4	398.5	509.4	297.7	367.2	459.5	300.7	374.2	476.5
ZAF	Ann. Import	TWh	1.2	0.5	23.6	58.9	73.2	24.8	35	55.4	22.3	48.5	74.9	23.6	57.6	61
ZAF	Ann. Export	TWh	11	16.4	30.8	60.2	65.5	31.9	64.2	100.5	27	42.7	66.1	30.8	58.8	69.4
ZAF	Gen. Coal	TWh	204.8	223.8	30.8	0.3	0.5	10.5	0	0	25.2	0.6	0.5	30.8	0.3	0.2
ZAF	Gen. Gas	TWh	0	0	94.7	24.9	33.7	5.2	7.5	7.4	97.2	32.6	35	94.7	24.9	23
ZAF	Gen. Nuclear	TWh	13.3	13.3	0	0	0	109.7	110	107.7	0	0	0	0	0	0
ZAF	Gen. CCS	TWh	0	0	0	0	0	0	0	0.4	0	0	0	0	0	0.4
ZAF	Gen. Hydro	TWh	5.1	5.1	23.3	23.3	22.8	15.1	23.6	23.1	19.9	23.3	22.8	23.3	23.3	22.8
ZAF	Gen. Wind	TWh	9.2	11.2	145.5	279.7	335.1	148.9	239	322.1	128.5	245.4	327.7	145.5	279.7	368.9
ZAF	Gen. PV	TWh	4	5.2	5.2	45.7	67.4	10	17.8	48.8	25.9	65.2	73.5	5.2	45.7	61
ZMB	Carbon Emission	MT	3.7	5.1	4.1	2.2	7.1	1.5	0.8	-2.9	4.5	3.6	7.9	4.1	2.2	0.5
ZMB	Carbon Sequester	MT	0	0	0	0	0	0	0	3.8	0	0	0	0	0	3.5
ZMB	Ann. Cost	B.USD	0.6	0.9	2.6	4.8	8.3	2.7	4.8	7.6	2.7	4.8	8.4	2.6	4.8	7.9
ZMB	Ann. Demand	TWh	12.5	17.7	37.2	71.2	122.8	37.2	71.2	122.8	37.2	71.2	122.8	37.2	71.2	122.8
ZMB	Ann. Supply	TWh	9.8	13.4	38.7	71.8	119.1	38.7	70.7	108.7	39.9	69.5	120.8	38.7	71.8	109.2
ZMB	Ann. Import	TWh	4.4	5.2	3	9.2	12.2	1.8	9.1	20	2.2	10.1	11.2	3	9.2	20.1
ZMB	Ann. Export	TWh	1.6	0.8	4.5	9.5	8.2	3.3	8.2	5.6	4.9	8.2	8.9	4.5	9.5	6.3
ZMB	Gen. Coal	TWh	3.4	3.9	0.8	0.2	0.4	0.7	0	0	0.8	0.2	0.3	0.8	0.2	0.2
ZMB	Gen. Gas	TWh	0	2.8	8.5	5.4	18.3	1.9	2	2.3	9.7	9.1	20.6	8.5	5.4	10.1
ZMB	Gen. Nuclear	TWh	0	0	0	0	0	6.8	6.6	6.7	0	0	0	0	0	0
ZMB	Gen. CCS	TWh	0	0	0	0	0	0	0	4.3	0	0	0	0	0	4
ZMB	Gen. Hydro	TWh	6.1	6.5	9.9	15.8	27.7	8.9	11.2	18.8	10.1	15.2	28.1	9.9	15.8	23.2
ZMB	Gen. Wind	TWh	0	0	18	38.1	39.7	17.6	40	40	16.6	34.8	39.7	18	38.1	39.7
ZMB	Gen. PV	TWh	0	0.1	1.4	12.3	33.2	2.8	10.8	36.9	2.7	10.3	32.2	1.4	12.3	32.1
ZWE	Carbon Emission	MT	10	9.6	0.6	0.3	0.9	0.2	0.2	-2.9	0.4	0.3	0.5	0.6	0.3	-1

Country /district	Data Item	Unit	REF					HCS			MCP			CNS		
			2015	2020	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
ZWE	Carbon Sequester	MT	0	0	0	0	0	0	0	3.1	0	0	0	0	0	1.4
ZWE	Ann. Cost	B.USD	0.7	1	1.2	2.9	5.8	1.5	2.8	5.6	1.2	2.7	5.5	1.2	2.9	5.9
ZWE	Ann. Demand	TWh	7.6	10.7	22.4	43	74.1	22.4	43	74.1	22.4	43	74.1	22.4	43	74.1
ZWE	Ann. Supply	TWh	11.9	12.6	18.6	45.7	90	22	41.9	81.1	18.2	42.5	86	18.6	45.7	87.5
ZWE	Ann. Import	TWh	4.6	5.7	8.2	12.7	15.3	4.3	9.6	16.3	8.2	14.5	14.1	8.2	12.6	14.4
ZWE	Ann. Export	TWh	8.9	7.5	4.2	15.2	30.3	3.8	8.4	22.7	3.8	13.5	24.8	4.2	15.1	27.1
ZWE	Gen. Coal	TWh	9.7	9.5	0	0	0	0	0	0	0	0	0	0	0	0
ZWE	Gen. Gas	TWh	0	0	1.6	0.8	1.9	0.5	0.4	0.4	1	0.7	1.1	1.6	0.8	0.8
ZWE	Gen. Nuclear	TWh	0	0	0	0	0	4.5	4.4	3.9	0	0	0	0	0	0
ZWE	Gen. CCS	TWh	0	0	0	0	0	0	0	3.5	0	0	0	0	0	1.6
ZWE	Gen. Hydro	TWh	2.1	2.9	3.2	9.3	17	4.1	4.1	4.1	2.6	11.8	13.7	3.2	9.3	11.2
ZWE	Gen. Wind	TWh	0	0	11	24.3	49.9	11	22.6	49.9	11.1	18.6	49.9	11	24.3	49.9
ZWE	Gen. PV	TWh	0	0.1	2.7	11.2	21.1	1.9	10.4	19.4	3.4	11.2	21.3	2.7	11.2	24