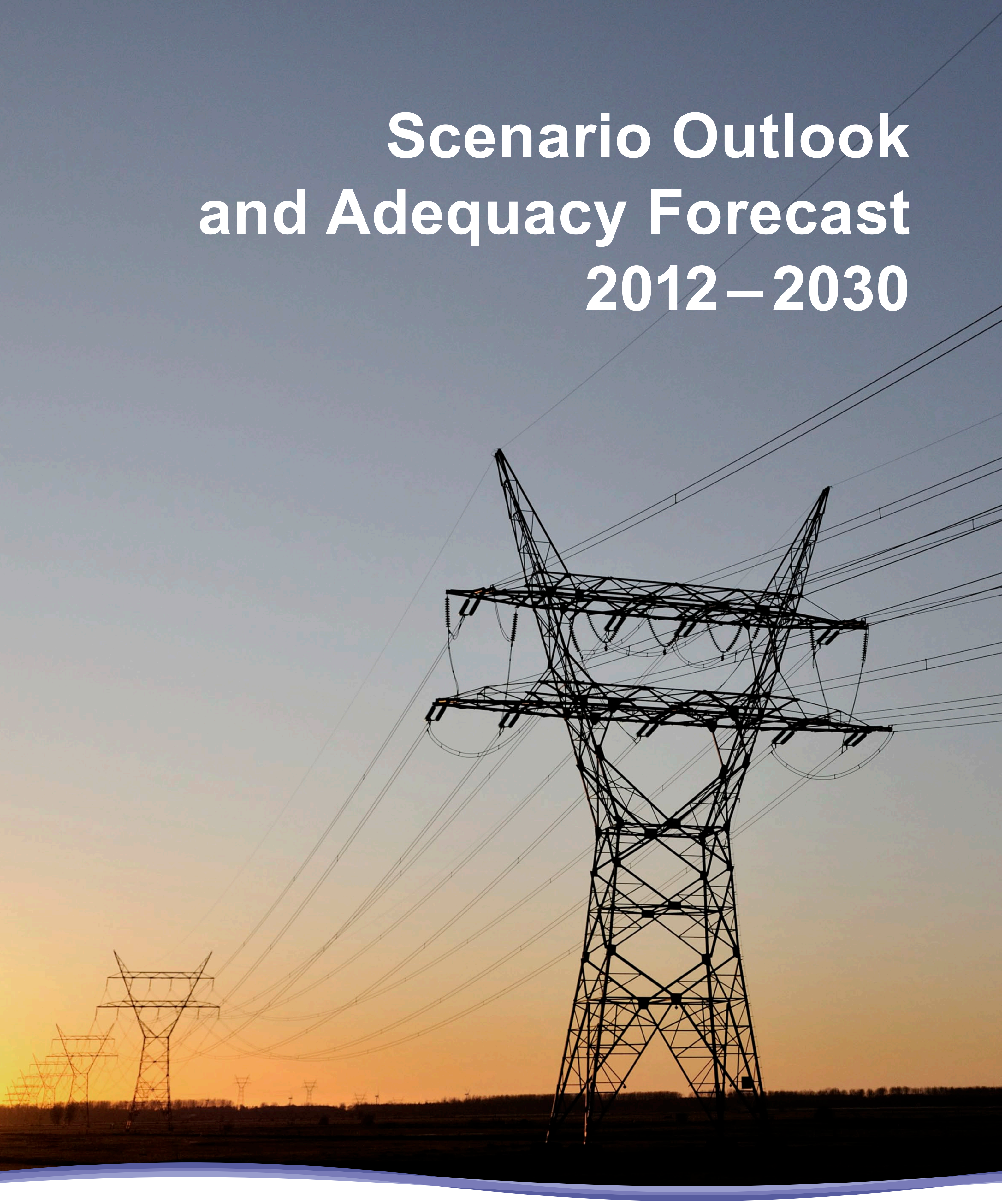
Scenario Outlook and Adequacy Forecast 2012 – 2030



European Network of
Transmission System Operators
for Electricity

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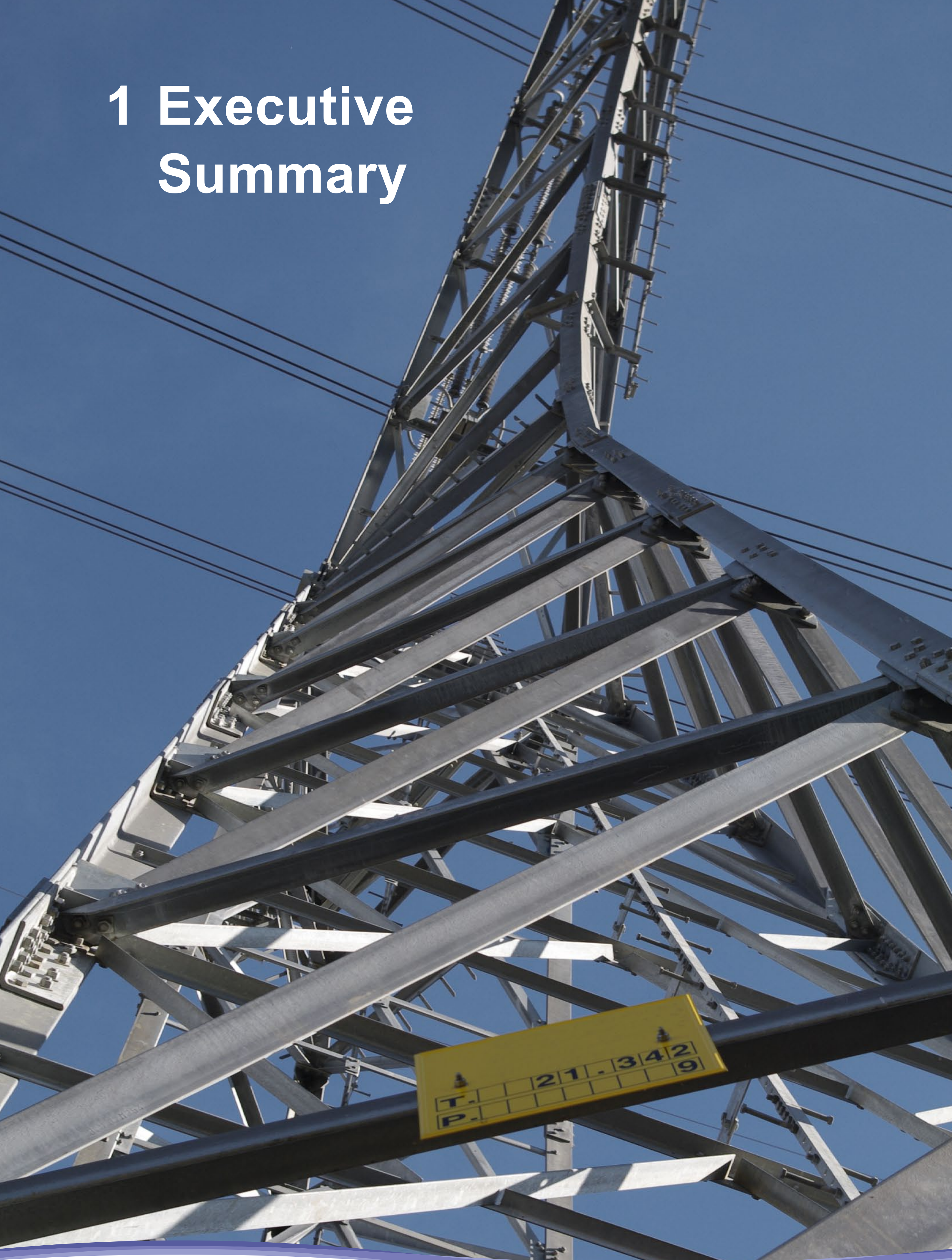
Content

1 Executive Summary



The Scenario Outlook & Adequacy Forecast (SO&AF) is the ENTSO-E annual publication, which presents the scenarios included in the Ten-Year Network Development Plan (TYNDP)[1] in compliance with Regulation (EC) n. 714/2009 and the assessment of the adequacy between generation and demand in the ENTSO-E interconnected power system on mid- and long-term time horizons.

This SO&AF 2012 report is part of the TYNDP 2012 package, comprising six regional investment plans and the community-wide Ten-Year Network Development Plan of ENTSO-E. It sets 3 scenarios for generation and demand[2]: the Scenario EU 2020 derives from the National Renewable Action Plans (NREAPs)[3] in compliance with the European 3 × 20 objectives; Scenario B ("Best Estimate") is based on the expectations of TSOs and Scenario A ("Conservative") derives from Scenario B, with the secure generating capacity only.

In addition, the SO&AF 2012 describes the "Visions" for year 2030, which are presented from an illustrative perspective in order to examine the challenges and opportunities for TSOs' development of longer-term scenarios and in accordance with the EU Energy Roadmap in 2050. The visions presented in SO&AF 2012 will in fact provide a bridge between the EU energy targets in 2020 and the 2050.

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1) www.entsoe.eu/system-development/tyndp/tyndp-2012/

2) More about Scenarios in Chapter 2.

3) NREAPs cover renewable energy and pumped storage plants only.
The development of other generation plants is estimated by TSOs.

1.1 Main Results for Scenario EU 2020

Load power increases continuously in Scenario EU 2020, at both winter and summer reference points[1)] (Figure 1.1). This increase is expected to affect most countries, with a growing number of exceptions: Germany, Italy (where a decrease in load is reported after 2015), and Luxembourg and Poland (where a decrease in load is reported before 2015). The highest growth rates are expected in eastern Europe: Cyprus and the Former Yugoslav Republic of Macedonia (FYROM) in particular.

Also, the energy consumption at the ENTSO-E level in Scenario EU 2020 (Table 1.1) is growing at a fairly constant and smooth rate, and would exceed 3,500 TWh right after 2016.

Net Generating Capacity (NGC) for the ENTSO-E as a whole is also increasing. The most rapidly developing energy sources – as expected – are renewable energy sources (thereinafter only "RES"), including renewable hydro power plants. The NGC of nuclear and non-renewable hydro power plants (pure pumped storage power plants) increases slightly over the whole forecasted period as well, whereas the NGC of fossil fuel power plants is expected to decrease (Figure 1.2).

Within the total RES capacity mix, wind, solar and biomass power plants are expected to increase, while the share of renewable hydro power plants is expected to decrease in some of the monitored years as a consequence of a lower development pace. Onshore wind farms play a major role in the wind power plants category; in each time horizon, their share in total wind capacity reaches about 80 % at least. Yet, offshore wind generation is foreseen to become more and more significant in the future. Furthermore, an important increase of solar capacity is expected for the future in consideration of the current policies adopted at EU and national level in the renewable and energy efficiency field. The fossil fuels capacity is expected to grow contin-

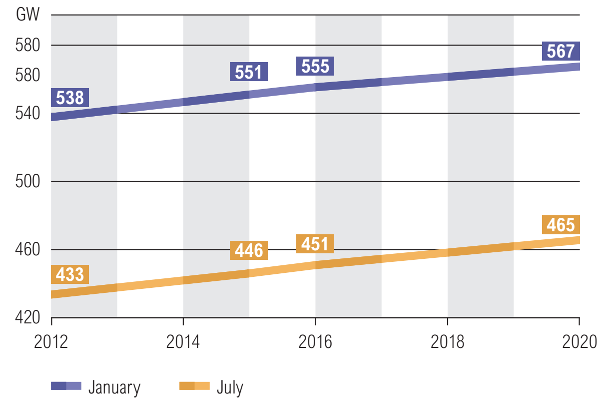

Figure 1.1:
ENTSO-E load for Scenario EU 2020,
January 7 p.m. and July 11 a.m.

2012	2015	2016	2020
3,400 TWh	3,470 TWh	3,497 TWh	3,615 TWh

Table 1.1:
ENTSO-E consumption for Scenario EU 2020

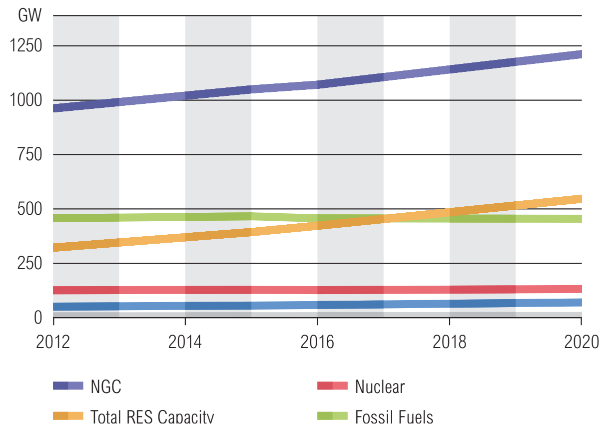

Figure 1.2:
ENTSO-E NGC breakdown for Scenario EU 2020,
January 7 p.m.

1) Reference points are specific hours the power analyses in this report are performed at. More about methodology in Chapter 2.2.

uously up to 2015, but starts to decrease after that year. This seems to be a logical consequence of the increasing share of RES in the Scenario EU 2020, where renewable energy units are taking a market share to the fossil fuel units. In addition, the effects of the Large Combustion Plants Directive (LCP Directive)[1], which forces individual countries to shut down their oldest fossil fuel power plants, must be considered too. At the ENTSO-E level, the capacity share of fossil fuels amounts to 44 % of the total NGC in 2015 and 38 % in 2020. Within the fossil fuel capacity, gas power plants have the highest share (from 40 % in 2012 to 47 % in 2020). On the other hand, the share belonging to hard coal power plants should decrease from 26 % to 22 %.

Reliable Available Capacity (RAC)[2] in January and July is expected to increase during the entire forecasted period. The RAC in January is higher than in July, as is required to cover load. The available capacity is expected to grow at a slower pace than the generation capacity, due to an increase share of intermittent energy sources in the generation mix. The final average share of RAC in the total ENTSO-E NGC is expected to be about 63 % at the reference point in January (and about 60 % in July). Among the countries, Austria, Croatia, Iceland, Luxembourg, the FYROM and Serbia have the highest share of RAC in NGC in 2015 (more than 80 %) and also in 2020 (except from Croatia; FYROM and Serbia show the percentage as very close to 80 %).

The **Remaining Capacity (RC = RAC - load)**[3] increases continuously over the period between 2012 and 2020, once again with the exception of January between 2015 and 2016. Generation adequacy in Scenario EU 2020 is ensured within the whole ENTSO-E system in most situations and for each reference point of the forecast period (not considering capacity limitations between countries and/or regions).

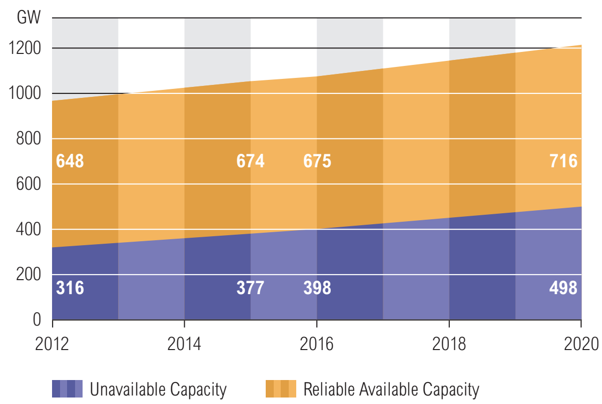

Figure 1.3:
ENTSO-E NGC breakdown to RAC and Unavailable Capacity for Scenario EU 2020; reference point January 7 p.m.

[1] Directive 2001/80/EC of the European parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.

[2] RAC is an estimation of the generating capacity that is statistically available to the market. More about methodology in Chapter 2.

[3] RC is the generating capacity that is statistically left once load has been covered and might be available for cross-border balancing. More about methodology in Chapter 2.2.

1.2 Main Results for Scenario B ("Best Estimate")

Load in Scenario B ("Best Estimate") increases continuously in both reference points - January and July (Figure 1.4). Scenario A used in this report shows the firm generating capacity to be built and known to TSOs, and in this respect it could be understood as a "pessimistic" variant of Scenario B. The Load and decommissioning for both scenarios is recommended to be assessed using the same initial criteria.

The highest load increase between 2012 and 2020 is expected in Cyprus (6% a year), Romania and FYROM (about 3% a year each).

The average annual energy consumption growth rate between 2012 and 2020 is expected to be about 1%. After 2020, an increase by about 0.8% a year is foreseen. Energy consumption in Scenario B is predicted to rise to 3,524 TWh by 2016, instead of 3,497 TWh in Scenario EU 2020. Energy consumption values for Scenario B are in Table 1.2.

Regarding NGC, the most rapidly developing energy sources are RES (Figure 1.5). In Scenario B, their capacity share almost doubles in the next 15 years (312 GW in 2012 and 602 GW in 2025). Each other type of capacity is increasing during the whole forecasted period as well, but with a lower rate. The main difference to Scenario EU 2020 is in RES capacity. Although there is not much difference to Scenario EU 2020 in other categories at the ENTSO-E level, national figures might differ.

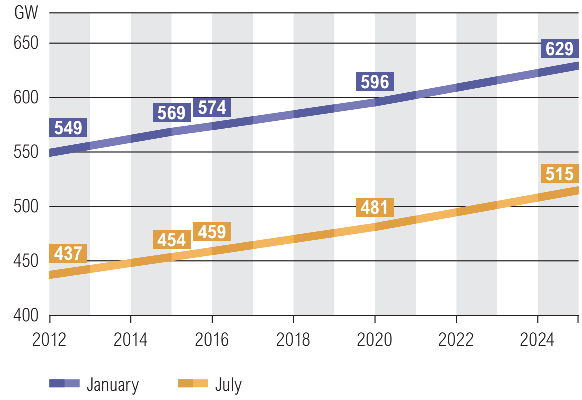

Figure 1.4:
ENTSO-E load for Scenario B, January 7 p.m. and July 11 a.m.

2012	2015	2016	2020	2025
3,389 TWh	3,493 TWh	3,524 TWh	3,663 TWh	3,851 TWh

Table 1.2:
ENTSO-E consumption for Scenario B

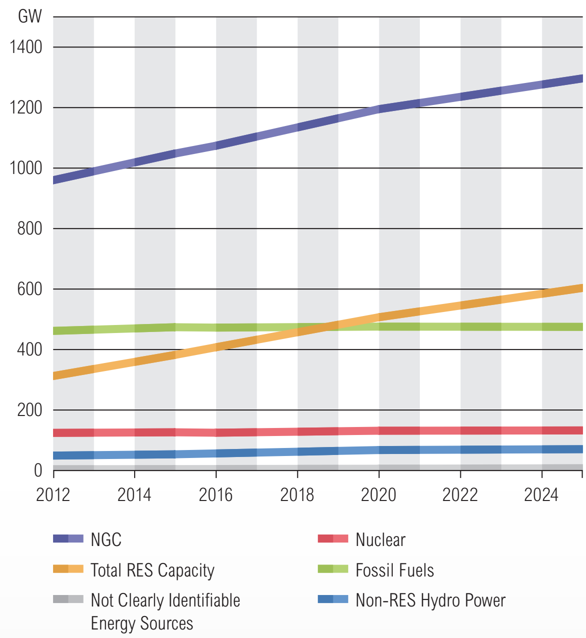

Figure 1.5:
ENTSO-E total NGC breakdown for Scenario B, January 7 p.m.

In Scenario B, wind power plants and other RES hydro power plants have the largest share of the total RES installed capacity in 2015 and 2020. Switzerland, Germany, Spain, Norway, Sweden, Latvia, Iceland and Portugal can be named here as countries with the highest share of RES in their generating capacity mix (more than 50 %), followed by Spain (49 %) or Italy (38 %), for example. Such strong RES development is mainly influenced by the legislation within each country, which encourages the development of RES power plants (excluding or including hydro power plants) by the implementation of policies such as feed-in tariffs and/or the implementation of regulatory provisions put forward in the EU RES directive from 2009 on conditions for RES generators for access and connection to the grid.

The NGC of the fossil fuels category in Scenario B is expected to increase until 2015 at a rate of about 3 %. After that, it decreases to 474 GW in 2016 as a consequence of the LCP Directive and then starts to increase again up to 477 GW in 2020 and 476 GW in 2025. Gas-fired power plants have the largest share within the fossil fuels category (as in Scenario EU 202). This share increases from 39 % in 2012 to 52 % in 2025. Other fossil fuel categories show either more or less visible decreases, or remain fairly stable.

Considering the only firm capacity projects in Scenario A, the total NGC is still increasing. Again, the biggest share has Fossil Fuels and RES, but the share of RES is increasing (from 32 % in 2012 to 41 % in 2020), whereas the share of Fossil Fuels is decreasing (from 48 % in 2012 to 42 % in 2020). Among the Fossil Fuels, the Gas power plants show the highest and increasing share (the rest of the categories are either decreasing or stable). Comparing Scenario B and going far into the future, the amount of Fossil Fuels and RES capacity is lower in NGC in Scenario A.

Reliable Available Capacity in Scenario B increases continuously at both reference points. The **Remaining Capacity (RC)** is higher than the Adequacy Reference Margin (ARM) during the whole forecast period and both time horizons, and generation adequacy is thus met in most of the situations within the whole ENTSO-E system. The adequacy level (measured by the difference between the RC and the ARM) is higher in 2020, compared to 2012 at the reference point in January. However, in 2025 it is lower, compared to the same point in 2012. In order to reach the minimum of today's level of adequacy, an amount of about 12 GW in RAC will be needed, which means approximately 19 GW of the NGC with the equivalent capacity mix in 2025.

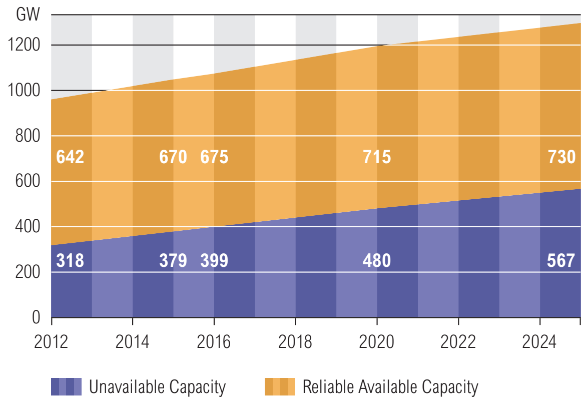

Figure 1.6:
ENTSO-E NGC breakdown to RAC and Unavailable Capacity for Scenario B, January 7 p.m.

The average share of RAC in the total ENTSO-E NGC is expected to be about 62 % in January (59 % in July). Unavailable capacity occupies an increasingly larger share of NGC, most probably as a consequence of the increasing share of RES in the generating capacity mix. Austria, Iceland, Luxembourg, the FYROM, Norway, the Netherlands, Croatia and Serbia have the highest share of RAC in their NGC, in both 2015 and 2020 (more than 80 %; the Netherlands and Croatia only in 2015).

RAC in Scenario A between 2012 and 2015 increases from 642 GW by 11 GW; after that it decreases back to 643 GW in 2016 and then it starts to increase again till 2020 (for January 7 p.m.). Generation adequacy is expected to be met until January 2016. After this year, additional generation units seem to be necessary in Europe. In 2020, 46 GW of additional RAC is required to reach today's level of adequacy, which makes about 72 GW of additional generation capacity, considering the capacity mix is secure for 2020. The situation is illustrated in Paragraph 5.1.1.

The adequacy levels seem adequate enough, even when considering the shutdown of the nuclear power plants in Germany after the Fukushima disaster in 2011, the nuclear phase out, as foreseen in the law in Belgium, and the additional nuclear phase out plans adopted in Switzerland. When comparing these results to the previous Scenario Outlook and Adequacy Forecast (published in 2011), the situation is not foreseen to be worsened.

2 Introduction

2.1 Objectives, Background and Scenarios

The ENTSO-E Scenario Outlook & Adequacy Forecast (SO&AF) assesses the mid- and long-term time horizon. It is focused on adequacy analyses of the ENTSO-E interconnected transmission system throughout an overview of generation adequacy. The SO&AF 2012 report is part of the Ten-Year Network Development Plan Package for year 2012[1)] (thereinafter only "TYNDP"). It outlines, inter alia, the scenarios description used for the TYNDP and Regional Investment Plans (thereinafter only "RgIP").

The SO&AF 2012 report provides an update of the scenarios in respect to the ones presented in SO&AF 2011 (SO&AF for the years 2011 – 2025). The scenarios are in fact used as background assumptions for carrying out market and network studies within the TYNDP framework, which also covers the economic view in the future.

The underlying scenarios adopted for the TYNDP and used for the RgIPs are updated in order to capture the main evolution in respect to the scenarios presented in the previous SO&AF 2011. It helps in getting the correct picture of the ENTSO-E power system when reading the TYNDP after its publication.

Apart from the above-mentioned, the SO&AF 2012 report aims at:

– assessing the generation adequacy of the countries served by ENTSO-E's TSO members for the period 2012 – 2025, by providing an overview of the generation adequacy analysis for ENTSO-E as a whole and for each of the six regional groups defined under the ENTSO-E System Development Committee in order to pursue the regional cooperation set forth in art.12 of EC Regulation n. 714/2009,
– describing the generation adequacy assessment for each individual country, based on national data and comments received from member TSOs,
– presenting the visions of ENTSO-E in 2030 ("2030 Visions"), which aim to make a "bridge" between the European energy targets for 2020 and 2050 (such as, for instance, to check whether the pathway realized for the future falls with a high level of certainty in the range described by the "2030 Visions").

– The adequacy analysis was carried out over three contrasting scenarios, covering different evolutions for generating capacity and load, using the same criteria for the assessment. It is based on the comparison between the reliably available generation and load at two given reference points in time in the year (the third Wednesday in January at 7 p.m. and the third Wednesday in July at 11 a.m.) over the monitored time period under standard conditions.

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1) www.entsoe.eu/system-development/tyndp/tyndp-2012

The three mentioned scenarios in a shortcut are the following[1]:

- Scenario A (or "Conservative Scenario") – this bottom-up scenario shows the necessary additional investments in generation to be confirmed in the future to maintain security of supply, if it is not maintained. It takes into account the commissioning of new power plants considered as sure. Load forecast in this scenario is the best national estimate available to the TSOs, under normal climatic conditions. It is not used to further specify grid development as part of the TYNDP.

- Scenario B (or "Best Estimate Scenario") – this bottom-up scenario gives an estimation of potential future developments, provided that market signals give adequate incentives for investments. It takes into account the generation capacity evolution described in Scenario A as well as future power plants, whose commissioning can be considered as reasonably credible according to the information available to the TSOs. Load should be treated the same as in Scenario A.
  It is an important assumption to further specify grid development in the TYNDP.

- Scenario EU 2020 – this top-down scenario gives an estimation of potential future developments, provided that governmental targets set for renewable generating capacities in 2020 are met.
  It derives from the EU policies on climate change and is based on national targets set in the National Renewable Energy Action Plan[2] (thereinafter only "NREAP") or equivalent governmental plans for renewable energy development if no NREAP applies.
  It is an important assumption to further specify grid development in the TYNDP and does not impose any limitation with regard to further possible renewable energy generation development.

Even though the scenarios are based on the different approach (top-down vs. bottom-up), for their assessment the same criteria and methodology (see the reference to the SO&AF methodology) are used. The only difference, however, is in the methodology for data providing. Scenarios A & B are based on the information and estimations from respective TSOs, whereas Scenario EU 2020 is based on the NREAP.

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1) More information can be found in a separate methodology document under the following link: www.entsoe.eu/resources/publications/system-development/adequacy-forecasts

2) According to article 4 of the Directive 2009/28/EC, member states are supposed to submit national renewable energy action plans by 30 June 2010. These plans have to provide detailed roadmaps of how each member state expects to reach its legally binding 2020 target for the share of renewable energy in their final energy consumption.

It is important to underline that the target of final gross electricity consumption, resulted directly from NREAPs, may differ from the assessment based on data used for SO&AF 2012. The potential differences might be caused by using net values of electricity consumption in the SO&AF report, whereas in NREAPs, it is gross values.

Scenarios are also not intended to recommend any direction of grid development, as this is the purpose of TYNDP. However, there is a strong interplay between the chosen scenario and the results in the TYNDP in terms of grid development. Deeper description of the scenarios and the methodology used for the adequacy assessment can be found in the separate methodology document (see the reference to the SO&AF methodology).

In current SO&AF 2012, the generation adequacy is assessed through the separate parameters Reliable Available Capacity (RAC), Remaining Capacity (RC) and Adequacy Reference Margin (ARM)[1]. The abovementioned approach is a power balance-based assessment, and it is intended to be integrated by the development of an energy approach assessment in the future using the market analyses in the SO&AF report. This is done in addition to the market and network analysis and studies carried out in the RgIPs, and the TYNDP 2012. It is also not the goal of SO&AF to assess the role of interconnectors and impacts of the generation adequacy on the grid. These issues are relevant for TYNDP and RgIPs, rather than to SO&AF.

Wind (non-) availability is estimated upon the experience of each respective TSO. Other RES penetration and availability is also based on the data provided by respective data correspondents, and their experience and no common methodology are used for this purpose in the SO&AF report. The same applies also for the other energy sources assessed in the SO&AF report.

1) For more information, refer to the methodology document.

2.2 Methodology for Scenario Outlook and Adequacy Forecast

2.2.1 Introduction

Purpose of this Document

This document aims to describe the data and the methodology for system adequacy analysis used by ENTSO-E in its Scenario Outlook & Adequacy Forecast report (SO&AF).

SO&AF aims to provide stakeholders in the European electricity market with an overview of generation, demand and their adequacy in different scenarios for the future ENTSO-E Power System, with a focus on the power balance, margins, energy indicators and the generation mix and based on the national data as they are being reported by each ENTSO-E member TSO, or a national organization responsible for data collection for different TSOs.

SO&AF is not concerned with the economic feasibility of generation assets per investigated scenario. The economical aspects are further investigated and analyzed within the market studies performed in the framework of the ENTSO-E Ten-Year Network Development Plan (TYNDP), which is issued biannually, each even year. In market analyses the fuel prices of different technologies can also be mirrored, as well as the greenhouse gases' prices, for example. Thus, SO&AF is focused on the technical aspects of the adequacy assessment without considering the economical aspects.

It is also not the goal of the SO&AF report to assess and report on the role of interconnectors and impacts on the grid development, which is rather relevant to Regional Investment Plans (RgIPs) and/or to TYNDP.

System Adequacy

System adequacy of a power system is a measure of the ability of a power system to supply the load in all the steady states in which the power system may exist considering standard conditions. Within the ENTSO-E Scenario Outlook & Adequacy Forecast, system adequacy is assessed by means of Generation Adequacy and Adequacy Assessment based on Market Studies.

Generation adequacy of a power system is an assessment of the ability of the generation on the power system to match the consumption of the power system. The methodology for generation adequacy analysis is introduced in Chapter 4.2.

Adequacy Assessment based on Market Studies is a relatively new chapter within the Scenario Outlook and Adequacy Forecast. The methodology of this approach is still under development and it will be subject to changes within the following editions of the report.

Geographical Perimeter

System adequacy in ENTSO-E is analyzed at 3 levels:

- Individual ENTSO-E member countries,
- regional blocks and
- the whole ENTSO-E.

In terms of the system adequacy assessment, the following regional blocks can be distinguished within the ENTSO-E power system:

- **NORTH SEA (NS)**:
  Belgium (BE), Denmark (DK), France (FR), Germany (DE), Great Britain (GB), Luxembourg (LU), the Netherlands (NL), Northern Ireland (NI), Norway (NO), the Republic of Ireland (IE)
- **BALTIC SEA (BS)**:
  Denmark (DK), Estonia (EE), Finland (FI), Germany (DE), Latvia (LV), Lithuania (LT), Norway (NO), Poland (PL), Sweden (SE)
- **CONTINENTAL SOUTH WEST (CSW)**:
  France (FR), Portugal (PT) and Spain (ES)
- **CONTINENTAL SOUTH EAST (CSE)**:
  Bosnia & Herzegovina (BA), Bulgaria (BG), Croatia (HR), Former Yugoslav Republic of Macedonia (MK), Greece (GR), Hungary (HU), Italy (IT), Montenegro (ME), Republic of Serbia (RS), Romania (RO), Slovenia (SI)
- **CONTINENTAL CENTRAL SOUTH (CCS)**:
  Austria (AT), France (FR), Germany (DE), Italy (IT), Slovenia (SI), Switzerland (CH)
- **CONTINENTAL CENTRAL EAST (CCE)**:
  Austria (AT), Croatia (HR), Czech Republic (CZ), Germany (DE), Hungary (HU), Poland (PL), Romania (RO), Slovak Republic (SK), Slovenia (SI)

In addition to the regions and countries listed above, analyses are reported on other countries / control areas:

- **ISOLATED SYSTEMS**:
  Cyprus (CY), Iceland (IS)
- **ADDITIONAL CONTRIBUTING CONTROL AREAS**:
  Ukraine West (UA-W), Albania (AL)

All of the above mentioned regions are depicted in Figure 2.1.

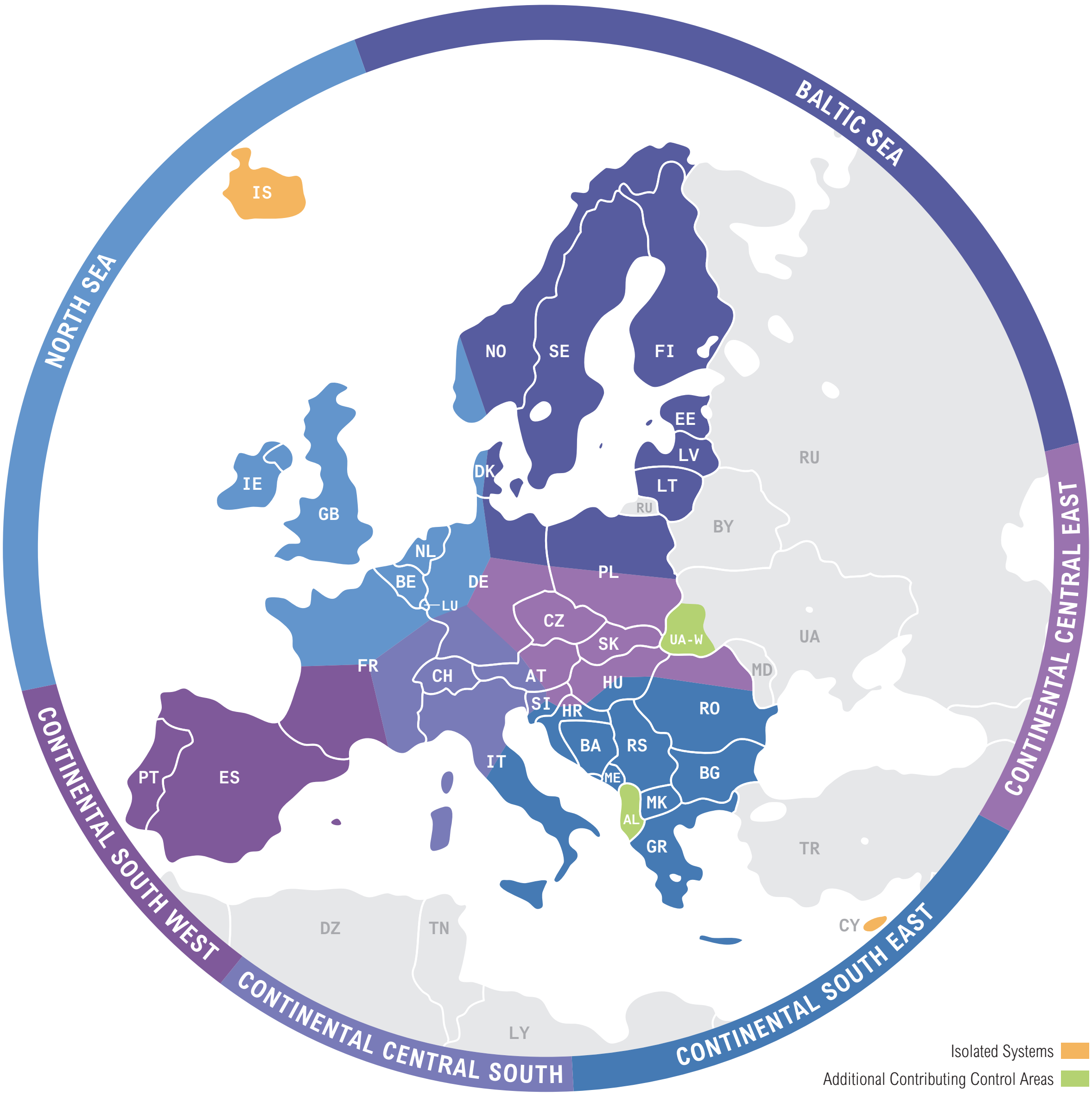

Figure 2.1:
Structure of the ENTSO-E regions, contributing areas and control areas

2.2.2 Data Definition

Time of Reference

Times in the SO&AF report are expressed in:

- Central European Time (CET = UTC[1] + 1) in winter and in
- Central European Summer Time (CEST = UTC + 2) in summer.

All the data and analyses provided are in accordance with this approach.

Time Horizons

Data are collected for different time horizons and for different scenarios. The time horizons per scenario will be mentioned in the data collection letter sent to the data correspondents from each TSO within ENTSO-E. Time horizons should copy the decades and mid-decades of upcoming years at least. Based on the data availability and accurateness, for the most part recommended time horizons for each scenario should not exceed Y + 10 time period (where Y is the starting year of SO&AF report). However, when necessary or useful, the time horizons may go behind this 10 year border.

Aside from these time horizons, other time horizons might also be chosen in order to more thoroughly examine certain political milestones, for example. The total number of time horizons, however, is always chosen to not exceed the reasonable level of seriousness from the data accomplishing point of view.

Reference Points

Reference points are the dates and times data are collected for.

Data collected for the hour H are the average value from the hour H - 1 to the hour H.

2 annual reference points are defined in the SO&AF report:

- The 3rd Wednesday of January on the 19th hour
  (from 18:00 CET to 19:00 CET) and
- the 3rd Wednesday of July on the 11th hour
  (from 10:00 CEST to 11:00 CEST)

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[1] UTC is the international designation for Universal Coordinated Time.

Load

Load on a power system is the net consumption corresponding to the hourly average active power absorbed by all installations connected to the transmission grid or to the distribution grid, excluding the pumps of the pumped-storage stations.

"Net" means that the consumption of power plants' auxiliaries is excluded from the Load, but network losses are included in the Load.

When load on the lowest voltage levels is not assessed, the National Representativeness index is the estimation of the percentage of the national value which the collected data are representative of.

Load Management

Load Management forecast is estimated as the potential load reduction under control of each TSO to be deducted from load in the adequacy assessment.

Forecast Scenarios

As long-term forecast is subject to a high level of uncertainty and considering that it can take several years to build only a new power plant, two bottom-up generation scenarios have been developed to help in assessing the range of uncertainty and evaluating the risk for the security of supply over the coming years.

Besides these scenarios, a Scenario EU 2020 compatible with the 3 × 20 objectives of the European Union (EU) has been developed, the purpose of which is to determine the generation outlook (renewable and conventional generation) which is necessary to reach the EU's 2020 targets. Scenario EU 2020 has therefore been built on the top-down principle using National Renewable Energy Action Plans (NREAP)[1)] as a reference for renewable energy sources and load determination. Fossil fuels' forecast is envisaged to be built on the similar national documents reflecting the EU 2020 targets on the field of energy. For more information refer to paragraph 2.6.3.

Net Generating Capacity and the related primary energy sources breakdown as well as unavailable capacity are built in every country according to these three generation scenarios.

1) ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm

Scenario A or "Conservative Scenario"

This bottom-up scenario shows the necessary additional investments in generation to be confirmed in the future. These are crucial in maintaining security of supply, if it is not already maintained.

This scenario takes into account the commissioning of new power plants considered as sure and whose commissioning decision can no longer be canceled (power plants under construction before the data collection or whose investment decision has been notified as firm to the correspondent company).

As far as decommissioning is concerned, the most likely shutdown of power plants expected during the study period should be considered. Official notifications cannot be the only source for this estimation. Therefore, an assessment of decommissioning based on additional criteria such as technical lifetimes is recommended.

Load forecast in this scenario is the best national estimate available to the TSOs, under normal climatic conditions. It is estimated according to technical, economical and political assumptions, especially on demography, economic growth and energy efficiency policy.

This scenario is not used to further specify grid development as part of the Ten-Year Network Development Plan.

Scenario B or "Best Estimate Scenario"

This bottom-up scenario gives an estimation of potential future developments, provided that market signals give adequate incentives for investments.

This scenario takes into account the generation capacity evolution described in Scenario A as well as future power plants whose commissioning can be considered as reasonably credible according to the information available to the TSOs. Demands for grid connection by a producer cannot be the only source for this estimation. Therefore, an assessment of the likeliness of the projects, based on reasonable regional economic considerations of generation projects for instance, is expected in this scenario. Decommissioning and load should be treated as in Scenario A.

This scenario is an important assumption to further specify grid development in the Ten-Year Network Development Plan.

Scenario EU 2020

This top-down scenario provides an estimation of potential future developments, provided that governmental targets set for renewable generating capacities in 2020 are met.

This scenario is derived from the EU policies on climate change and is based on national targets set in the NREAP[1)] or equivalent governmental plan for renewable energy development if no NREAP applies. It takes into account the renewable generating capacities and electricity consumption mentioned in this plan.

A similar approach in the EU 2020 Scenario is taken as well as in the fossil fuels category meaning that respective national policies/documents dealing with the future of fossil fuels generating units in the views of the EU 2020 goals are taken into account. If no such documents are available, the best TSOs' estimation is requested.

This scenario is an important assumption to further specify grid development in the Ten-Year Network Development Plan and does not impose any limitation with regard to further possible renewable energy generation development.

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1) Values in the SO&AF report might differ slightly from the original ones in NREAP, after their refinement through the communication between the ministries and TSOs to define the data delivered in accordance with general guidelines. The modifications are needed for various reasons: Values in the SO&AF document refer to net generation and net consumption while those within the NREAP refer to gross values, NREAP is based on energy instead of power values, NREAP includes the whole country (including islands) while SO&AF may refer to mainland only, and so on.

Net Generating Capacity

Net Generating Capacity (NGC) of a power station is the maximum electrical net active power it can produce continuously throughout a long period of operation in normal conditions. "Net" means the difference between, on the one hand, the gross generating capacity of the alternator(s) and, on the other hand, the auxiliary equipments' load and the losses in the main transformers of the power station.

If the lowest voltage levels are not considered for load (see 2.4), which is net of generation on these voltage levels, then the generation connected to these lowest voltage levels should not be reported. In this respect, the National Representativeness index (see 2.4) is the estimation of the percentage of the national value which the collected data are representative of. As generation adequacy is based on the comparison of national load and generation, National Representativeness of load data and generation data should be identical in order to make the generation adequacy assessment reliable.

Power plants and projects should be assigned into predefined categories as they appear on the ENTSO-E-extranet.

Unavailable Capacity

Unavailable Capacity is the part of Net Generating Capacity which is not reliably available to power plant operators due to limitations of the output power of power plants. Although a power station can theoretically generate electricity from its total installed power, this is not actually the case in real life for the several causes, some of which are listed below.

It must be mentioned that situations RES is not taken as equivalent to the conventional plants.

Non-Usable Capacity

Aggregates reductions of the net generating capacities due to causes like:

- Limitation due to intentional decision by the power plant operators:
  - Power stations in mothball which may be re-commissioned if necessary
  - Power stations bound by local authorities which are not available for interconnected operation
  - Power stations under construction whose commissioning is scheduled for a certain date, but capacity is not firmly available because of delays or retrofitting
  - Power stations which are converted to other fuels or which are equipped subsequently with desulphurization and de-nitrification plants
  - Power stations in test operation

- Unintentional temporary limitation:
  - Power stations whose output power cannot be fully injected due to transmission constraints
  - Power station in multiple purpose installations where the electrical generating capacity is reduced in favour of other purposes such as heat extraction in combined heat and power plants for instance

- Temporary limitation due to constraints, like power stations in mothball or test operation, heat extraction for CHPs

- Limitation due to fuel constraints management:
  - Nuclear power stations in stretch-out operation
  - Fossil fuel power stations:
    - Power stations with interruptible fuel supply
    - Power stations with poor quality fuel, like unfit coal

- Limitation reflecting the average availability of the primary energy source:
  - Hydro power stations:
    - Run-of-river power stations with usual seasonal low upstream water flow
    - Tidal power stations
    - Storage power stations subject to usual limitation such as limited reservoir capacity, power losses due to high water, loss of head height or limitation of the downstream water flow
  - Wind power stations
  - Photovoltaic power stations
  - Geothermal power stations

- Power stations with output power limitation due to environmental and ambient constraints

- Limitation due to other external constraints:
  - Hydro power stations with water flow regulation for irrigation, navigation, tourism
  - Power stations with output power limitation due to environmental constraints
  - Power stations with output power limitation due to external thermal conditions

- Etc.

Maintenance and Overhauls

This category aggregates scheduled unavailability of generating capacity for regular inspection and maintenance.

Outages

This category aggregates forced – that is, not scheduled - unavailability of generating capacity.

System Services Reserve

This capacity is required to maintain the security of supply according to the operating rules of each TSO, excluding longer-term reserves set up to face potential outages which are counted in the Outages Category.

Peak Load

To extend the results from a unique reference point to a whole analyzed period, ENTSO-E considers the Peak Load: one for summer and one for winter, both under normal conditions.

Peak load is the forecast maximum instantaneous value under normal conditions.

Margin against Peak Load

Margin against Peak Load (MaPL) is the difference between Load at the reference point and the Peak Load over the season (summer or winter) the reference point is representative of. It serves to extend the results from the single reference point to the whole investigated period.

Considering that Load at each reference point is normally lower than the corresponding seasonal Peak Load, the values of MaPL are expected to be non-zero.

Spare Capacity

The spare capacity reflects the additional capacity (in MW) which should be available on a power system to cope with any unforeseen extreme conditions. It comes in addition to system services reserves and Margin against Peak Load.

Spare Capacity should be sufficient to cover a 1% risk of shortfall on a power system, that is, to guarantee the operation on 99% of the situations considering random fluctuations of Load and the availability of generation units. By default, a value ranging from 5 to 10% of net generating capacity could be used at a country-level. Since load/supply severe conditions of individual countries are not likely to occur at the same day and time, Spare Capacity for a set of countries (regional blocks or whole ENTSO-E) will be expressed in the SO&AF report as 5% of Net Generating Capacity.

Simultaneous Interconnection Transmission Capacities

Simultaneous Interconnection Transmission Capacity (SITC) of a power system is the overall transmission capacity through its peripheral interconnection lines within ENTSO-E. SITC are calculated according to the ENTSO-E Regional Investment Plans.

The SITC export value is called Export Capacity and may differ from the SITC import value, called Import Capacity.

Due to potential correlation between the transmission capacities on the adjoining borders of a country, it is not always possible to calculate the SITC of a country by simply adding the Net Transfer Capacity (NTC) on all the borders of the country.

SITC values are potentially different at every reference points on all time horizons.

2.2.3 Scenario Outlook Methodology

Further to an extensive presentation of the generating capacities, consumption and load in the 3 scenarios with emphasis on the most significant figures, comparisons could be made between these scenarios.

When comparing Scenario B with Scenario EU 2020, the difference is shown between the amount of investments considered as likely by the TSO based on known projects, with the investments needed to meet political targets for development of renewable energy according to the National Renewable Energy Action Plan or equivalent governmental plan.

When comparing Scenario EU 2020 with Scenario A, the idea is to show the additional amount of investments needed to meet political targets for the development of renewable energy according to the National Renewable Energy Action Plan, compared to investments which have already been decided.

When comparing Scenario B with Scenario A, the idea is to show the difference in generation investments which have already been decided, with the amount of investments that is considered as likely by the TSO.

2.2.4 Adequacy Forecast Methodology

Power Balance

Power balance calculations concern specific time points and various perimeters, and aim to assess adequacy referring to the following indicators:

- Reliably Available Capacity (RAC)
- Remaining Capacity (RC)
- Adequacy Reference Margin (ARM)

The relation between these three parameters is illustrated in Figure 2.2.

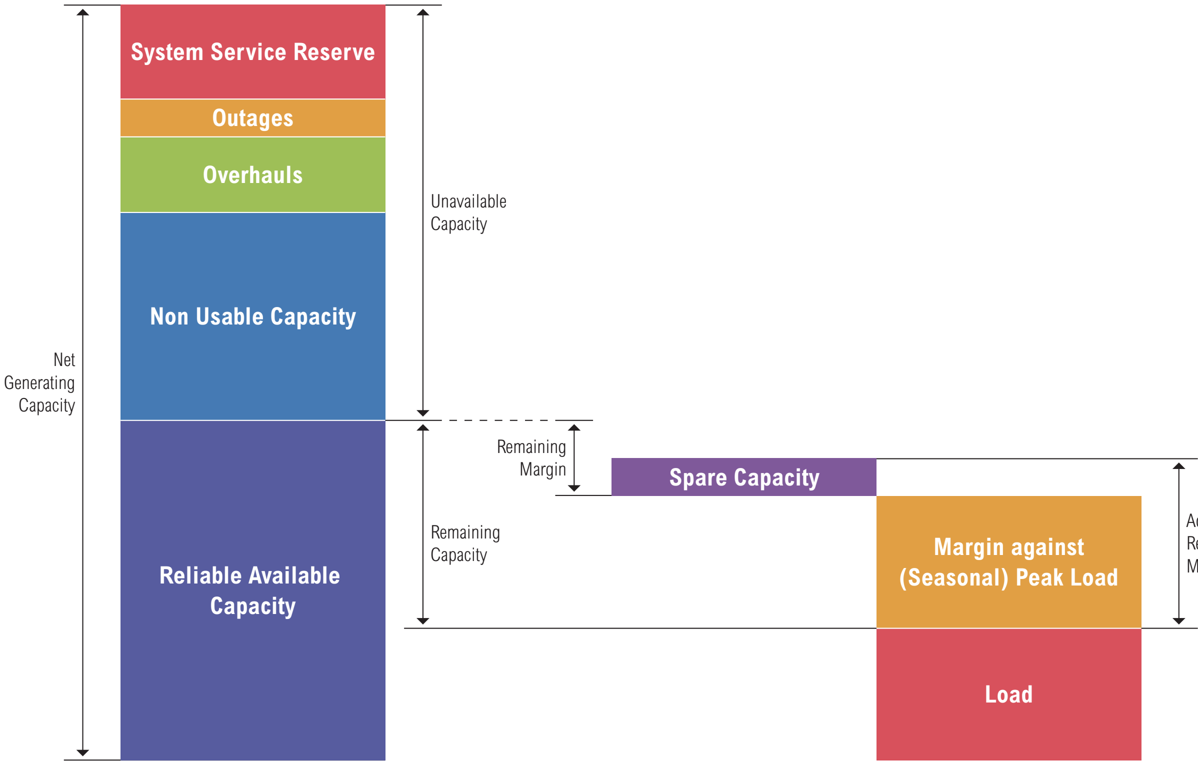

Figure 2.2:
Generation Adequacy Analysis

Reliably Available Capacity

Reliably Available Capacity on a power system is the difference between Net Generating Capacity and Unavailable Capacity.

Unavailable Capacity is the part of Net Generating Capacity that is not reliably available to power plant operators due to limitations of the output power of power plants. It is calculated by adding Non-Usable Capacity, Maintenance and Overhauls, Outages and System Services Reserves.

Reliably Available Capacity =
Net Generating Capacity – Unavailable Capacity

Reliably Available Capacity is the part of Net Generating Capacity which is actually available in the power system to cover the load at a respective Reference Point in normal (average) conditions.

Remaining Capacity

Remaining Capacity on a power system is the difference between Reliably Available Capacity and Load at reference point.

Remaining Capacity =
Reliably Available Capacity – (Load – Load Management)

Remaining Capacity is the part of Net Generating Capacity left on the power system to cover any unexpected load variation and unplanned outages at a Reference Point and in normal (average) conditions.

Remaining Capacity is calculated in the SO&AF report including Load Management, which increases the amount of Remaining Capacity.

Adequacy Reference Margin

Adequacy Reference Margin is the part of Net Generating Capacity that should be kept available at all times to ensure the security of supply on the whole period each reference point is representative of. It serves to assess generation adequacy in most of the situations.

Adequacy Reference Margin in an individual country is equal to the sum of the Spare Capacity and the Margin against Peak Load.

Adequacy Reference Margin =
Spare Capacity + Margin against Peak Load

Adequacy Reference Margin in a set of countries (i.e. regional blocks or the whole ENTSO-E) is estimated as the sum of the two following terms:

– Sum of all individual Margin against Peak Load values ($\sum_{k=1}^{n} MaSPL_{ICk}$). As peak loads are not synchronous in all countries, this sum is overestimating the actual Margin against Peak Load of the set of countries.

– Spare Capacity of the set of countries ($0.05 \times \sum_{k=1}^{n} NGC_{ICk}$). This is estimated as 5 % of Net Generating Capacity of the set of countries. For this reason, Spare Capacity of the set of countries may be different from the sum of all individual Spare Capacity values.

Adequacy Reference margin for a set of countries is then given by following formula:

$$ARM_{SC} = \sum_{k=1}^{n} MaSPL_{ICk} + 0.05 \times \sum_{k=1}^{n} NGC_{ICk}$$

– **n** is the total number of countries within the block of countries for which ARM is calculated,

– **SC** is the abbreviation for "Set of Countries" and

– **IC** is the abbreviation for "Individual Country".

Generation Adequacy

Generation adequacy is assessed for each of the individual countries, for each of the regional blocks identified within the ENTSO-E system and for the whole ENTSO-E.

Messages deriving from the assessment of generation adequacy may differ depending on the scenario that is under analysis.

For Scenario A ("Conservative"), the actual need for additional investments in generation power is identified (or just the need for confirmation of projects that are not yet firmly engaged).

Regarding Scenario B ("Best-Estimate"), it is indicated how adequate investments are expected to be from an ENTSO-E point of view.

A similar assessment for Scenario EU 2020 is conducted to establish whether the European 20-20-20 objectives and generation adequacy are compatible.

Generation Adequacy Forecast at Reference Points under Normal Conditions

Generation adequacy forecast on power systems is assessed at the reference points through the Remaining Capacity value (see definition in Chapter 4.1.2) which is calculated under normal conditions.

When Remaining Capacity is positive, it means that some over generating capacity is available on the power system under normal conditions.

When Remaining Capacity is negative, it means that the power system is short of generating capacity under normal conditions. Generally, this shall be interpreted as a potential deficit of generating capacity on power systems if no investments in additional generating units are decided from now on to the analyzed time horizon.

If the absolute value of Remaining Capacity is lower than Import Capacity, it is likely that all the necessary imports to meet load can be imported. However, on the contrary (absolute value of) Remaining Capacity being higher than Import Capacity does not necessarily call for additional transmission capacities, as many uncertainties are to size the adequate import capacity. These are not considered within this report, but within Regional Investment Plans and the Ten-Year Network Development Plan.

These assessments are applicable to individual countries, regional blocks and the whole ENTSO-E.

Seasonal Generation Adequacy Forecast in Most of the Situations

Generation adequacy forecast on power systems is then extended to comprehend seasonal peak load as well as the occurrence of severe conditions. This is achieved through the comparison of Remaining Capacity and Adequacy Reference Margin.

When Remaining Capacity is equal or higher than Adequacy Reference Margin, security of supply of power systems is likely to be guaranteed in most of the situations. Some over generation capacity is likely to be exportable to other systems, even when severe conditions on both demand and supply sides occur.

When Remaining Capacity is lower than Adequacy Reference Margin, it means that the power system is likely to have to rely on imports when facing seasonal peak load and/or severe conditions. Generally, this shall be interpreted as a potential deficit of generating capacity on power systems if no investments in additional generating units are decided from now until the analyzed time horizon.

The (absolute value of) Remaining Capacity minus Adequacy Reference Margin being higher than Import Capacity does not necessarily call for additional transmission capacities, as many uncertainties are to size the adequate import capacity. These are not considered within this report, but within Regional Investment Plans and the Ten-Year Network Development Plan.

When assessing the generation adequacy of regional blocks or whole ENTSO-E, a comparison made between Remaining Capacity and Adequacy Reference Margin still provides indications about potential surplus/deficits of regional blocks and whole ENTSO-E, as well as further eventual needs to additional investments in generating assets.

Adequacy Assessment based on Market Studies

ENTSO-E is constantly trying to find ways to improve the assessment of the adequacy of the European power system. With the introduction of market modeling for the Ten-Year Network Development Plan 2012 (TYNDP 2012), new promising methods for adequacy assessment are within reach. Market modeling could potentially allow for many improvements of the adequacy assessment. For instance improvements with respect to the assessment of the adequacy value of (increased) transmission capacities.

As a first step to investigate the possibilities of Market Modeling Based Adequacy Assessment methods, a few adequacy indicators (LOLE, EENS etc.) extracted from the market studies carried out within the TYNDP 2012 process are used.

Note however that ENTSO-E is still working on more detailed approaches to these questions, using historical data and (probabilistic) market studies to assess the adequacy of a system in a more detailed and complex way. This part of the methodology will thus be updated accordingly in the future.

2.3 Other Important Facts/Information

All input data for this report have been provided by the TSOs (and their respective correspondent), on a national basis, for the years 2012, 2015, 2016, 2020 and 2025 (depending on the scenario). Any other years depicted in graphs or shown in figures are calculated as linear extrapolation and are only estimations. The Data collection process was officially finished in the middle of October 2011. However, after that date, substantial corrections and amendments of the database have been made till the middle of December 2011 (corrections of mistaken data or complete providing missing data for some countries after deadline).

Furthermore, data provided for the time period after the year 2020 should be considered as having quite a high level of uncertainty. It is caused by data availability/unavailability to the respective TSO, along with the fact that a lot of different national policies do not cover such a long-term period, etc. Therefore, the data used and shown after 2020 should be considered, respecting this fact. When available, the data are supplemented by national comments.

Data have been provided for the three scenarios of generating capacity evolution (for more information see methodology document) and for two reference points: 3rd Wednesday of January 7 p.m. (for winter) and 3rd Wednesday of July 11 a.m. (for summer).

Data downloaded from the ENTSO-E Extranet and used for the SO&AF 2012 preparation are values rounded either to one decimal place (for main categories) or to two decimal places (for subcategories).

Calculations and comparisons used in the SO&AF 2012 to characterize the reliability of a power system are calculated mainly for the third Wednesday in January at 7 p.m. for Scenario B and Scenario EU 2020, unless otherwise indicated.

3 2030 Visions

3.1 Introduction

Until the preparation of the TYNDP 2010, the classic way of constructing generation and load scenarios for the identification of grid investment needs used in ENTSO-E was mainly based on a bottom-up approach, extrapolating from market players' present investment perspectives, with no guarantee that a common framework was used (e.g. Scenario B).

A top-down approach

A new methodology was introduced by ENTSO-E to add Scenario EU 2020 in the TYNDP 2012. This scenario was constructed using a top-down approach. The load and generation evolution was constructed for all countries in a way that was compliant and coherent with the same macro-economic and political view of the future. For Scenario EU 2020, this meant that the forecasted load and generation for the future had to be coherent with the EU 3 × 20 targets. Therefore, the load and RES generation in Scenario EU 2020 was derived from the NREAPs for EU countries. The other "conventional" generation was forecasted based on other national documents that focus on the EU 3 × 20 targets.

Multiple visions to deal with uncertainties

As it can take more than 10 years to build new grid connections, the objective is to construct visions that look beyond 2020. However, when looking so far ahead, it becomes more difficult to predict the future. Therefore, the objective of the visions for 2030 is to construct contrasting visions that differ enough from each other to capture a realistic range of possible future pathways as well resulting in different future challenges for the grid. In order to keep the number of long-term visions limited, the decision was made to work around two main axes, which are described later in this text, and as a consequence, limit the number of visions to four.

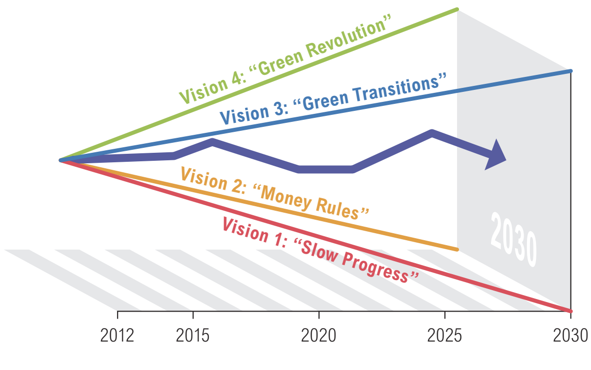

Figure 3.1:
Principle of four possible pathways until 2030

The year 2030 is used as a bridge between the European energy targets for 2020 and 2050. The aim of the "2030 visions approach" should be that the pathway realized in the future falls with a high level of certainty in the range described by the four visions (Figure 3.1).

The visions are not forecasts and there is no probability attached to the visions. These visions are based on previous ENTSO-E and regional market studies, public economic analyses and existing European documents (see Appendix 1).

A European framework

The use of these visions for long-term grid development will lead to the identification of new flexible infrastructure development needs that are able to cope with a range of possible future energy challenges outlined in the visions.

The construction of these visions needs to be compliant with the guidelines in the trans-European energy infrastructure package (EIP)[1)] that states the methodology that needs to be applied for a harmonized energy system-wide cost-benefit analysis for projects of common interest. The construction of visions will allow – in a later phase when these high level story lines are quantified and turned into scenarios – the establishment of common input data sets for the specific horizon of 2030. This horizon lies close to the long-term horizon mentioned in the EIP of n + 20 years.

The visions – further to the above mentioned – are described for 2030 because this is the time horizon that is commonly used in public documents as the intermediate phase toward 2050.

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1) COM (2011) 658 final, Proposal for a Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC: ec.europa.eu/governance/impact/ia_carried_out/docs/ia_2011/com_2011_0658_en.pdf

3.2 Main Axes of the Visions

The identification of the grid development needs related to a particular vision that will be translated in a scenario is a complex resource and time-consuming process. Market analysis needs to be conducted at the whole ENTSO-E level and repeated in more detail at a regional level. The output of this analysis is then used as an input for load flow analysis. Furthermore, this is not a unidirectional process but a process with several feedback loops that could change assumptions, like reserve, flexibility and sustainability of generation. Hence, it is important to keep the number of visions, which will be fully calculated and need to be quantified (or turned into scenarios), limited and to assess the impact of possible different pathways through sensitivity analysis.

It has therefore been decided to work around the two following axes:

- The first axis (Y-axis) is related to the EU commitment to reducing greenhouse gas emissions to 80 – 95 % below 1990 levels by 2050, according to the **Energy Roadmap 2050**. The objective is not to question this commitment but to check the impact of a delay in the realization of this commitment on grid development needs by 2030. The two selected outcomes are viewed to be extreme enough to result in very different flow patterns on the grid. The first selected outcome is a state where Europe is on track to realize the set objective of energy decarbonization by 2050. The second selected outcome is a state where Europe faces a **serious delay** in the realization of the energy 2020 goals and likely delays on the route to decarbonization by 2050.
- The second axis (X-axis) relates to the degree of **European integration** and particularly to how to set objectives of decarbonization for the energy system as well as how these objectives will be generally reached. This can be done in a **strong European framework or a context of a high degree of European integration** in which national policies will be more effective, but not preventing Member States developing the options which are most appropriate to their circumstances, or in a **loose European framework or a context of a low degree of European integration** that lack a common European vision for the future energy system that results in parallel national schemes. The strong European framework should also include a well-functioning and integrated electricity market, where competition ensures efficient dispatch at the lowest possible costs on a European level. On the other hand, a loose European framework results in less market integration and poor cross-border competition.

Figures 3.2 and 3.3 give an overview of the position of the four visions regarding the two axes (see also Appendix 2).

On track for Energy Roadmap 2050

Low degree of integration of the internal electricitiy market ← → **High degree of integration of the internal electricitiy market**

Delay of Energy Roadmap 2050

Vision 3: "Green Transition"

- Favourable economic and financial conditions
- Reinforced national energy politics
- Parallel national R&D research schemes
- High CO_2 prices and low primary energy prices (IEA – WEO 2010 450 scenario)

Vision 4: "Green Revolution"

- Favourable economic and financial conditions
- European energy policy
- European R&D research scheme
- High CO_2 prices and low primary energy prices (IEA – WEO 2010 450 scenario)

Vision 1: "Slow Progress"

- Less favourable economic and financial conditions
- Reinforced national energy politics
- Parallel national R&D research schemes
- Low CO_2 prices and high primary energy prices (IEA – WEO 2010 current policies scenario)

Vision 2: "Money Rules"

- Less favourable economic and financial conditions
- European energy policy
- European R&D research scheme
- Low CO_2 prices and high primary energy prices (IEA – WEO 2010 current policies scenario)

Figure 3.2.:
Overview of the political and economic frameworks of the four visions

On track for Energy Roadmap 2050

Low degree of integration of the internal electricitiy market ← → **High degree of integration of the internal electricitiy market**

Delay of Energy Roadmap 2050

Vision 3: "Green Transition"

- Electricity demand higher than Vision 2
- Demand response potential is partially used
- Electric plug-in vehicles (with flexible charging)
- Smart grid partially implemented
- CCS is not commercially deployed

Vision 4: "Green Revolution"

- Electricity demand higher than Vision 3
- Demand response potential is fully used
- Electric plug-in vehicles (with flexible charging & generation)
- Smart grid implemented
- CCS is commercially deployed

Vision 1: "Slow Progress"

- Electricity demand lowest level (could be negative)
- No demand response
- No electric plug-in vehicles
- Smart grid partially implemented
- CCS is not commercially deployed

Vision 2: "Money Rules"

- Electricity demand slightly higher than Vision 1
- Demand response potential is partially used
- Electric plug-in vehicles (with flexible charging)
- Smart grid implemented
- CCS commercial deployment is faciliated

Figure 3.3.:
Overview of the generation and load frameworks of the four visions

3.3 General Framework

A general assumption common to all 4 visions is that there are no limits to the access of primary energies, including the necessary gas infrastructure.

In addition, CO_2 and fuel prices need to be set. For this, for instance, World Energy Outlook (WEO) 2011 scenarios of the IEA (International Energy Agency)[1)] could be used as well as other references. While not necessary for the high-level vision descriptions and the specification of grid requirements, these assumptions will influence the later cost-benefit assessment of grid development projects. Price data will be used for the most appropriate national market in forecasting future prices for fuels where no international market exists.

In all visions the 2020 targets are met, but in some visions with a delay. R&D progress is taken into account to some extent in all visions.

None of the visions necessarily map directly to Scenario B (bottom-up scenario). In fact, the vision that is most closely aligned to Scenario B may differ between TSOs. For example, for some TSOs, Scenario B achieves the EU (national) 3 × 20 targets, while for others it does not.

3.4 Vision 1: "Slow Progress"

Economic and Market

The general framework of this Vision 1 "Slow progress" is that the economic and financial conditions are less favorable than in Visions 3 and 4 and, as a consequence, national governments have less money to reinforce existing energy policies. Furthermore, the absence of a strong European framework is a barrier to the introduction of fundamental new market designs that fully benefit from R&D developments. Moreover, the opting for parallel national schemes regarding R&D expenses also result in a situation where major technological breakthroughs are less likely due to suboptimal and repeated R&D spending.

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1) If a more recent international reference regarding CO_2 and primary fuel prices becomes available before the starting of the market analysis and this international reference can easily be linked with the storylines, then this reference will be used (for instance WEO 2012).

Since no reinforcing of existing policies occurs, carbon pricing (e.g. the EU Emissions Trading System, carbon taxes or carbon price floors) remains at such a level that base load electricity production based on hard coal is preferred to gas. Carbon and primary energy prices could be based on the current policies scenario of the IEA in their WEO 2011. This means that countries with a lot of hard coal in their energy generation portfolio are likely to be net exporters.

Demand

There are no major breakthroughs in energy efficiency developments (e.g. large-scale deployment of micro-cogeneration or heat pumps as well as minimum requirements for new appliances and new buildings) due to a lack of regulatory push. There are also no major developments of the usage of electricity for transport (e.g. large-scale introduction of electric plug-in vehicles) and heating/cooling. As a consequence, electricity demand is expected to grow at a slower rate than in the other visions (e.g. the growth rate of electricity demand could be negative here). Furthermore, no effort is made, through an adaptation of the market design, to use the demand response potential that would allow partially shifting the daily load in response to the available supply.

Generation

The future generation mix is determined by national policy schemes that are established without coordination at a European level. Due to a lack of financial resources and construction delays due to permitting issues, the generation mix in 2030 fails to be on track for the realization of the Energy Roadmap 2050. If the energy objectives 2020 were only realized in 2030, the need for additional back-up capacity[1)] in 2030 would then remain at the same order of magnitude as that currently estimated for 2020. This back-up capacity is likely to come from gas units, since demand response potential and additional hydro storage are not significantly developed in this vision. However, due to the limited size of the back-up capacity, the need for flexible base load capacity remains reasonable and it is not likely that gas will push out hard coal for base load electricity generation.

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1) Besides the need for back-up capacity, other criteria also need to be taken into consideration when assessing how much dispatchable thermal generation should be assumed in a particular visions, e.g. the yield of return based on a combination of running hours at full load and price mark ups allowing capital recovery.

This vision also takes into account a growing public opposition to nuclear, despite it being a low-carbon technology, in the aftermath of the Fukushima Daiichi nuclear disaster. Nevertheless, the vision permits deviations if this is in line with the current national view. In general, it is assumed that the financial community maintains its refusal to invest in this technology on a merchant basis and that technology-specific support schemes are not likely. The less favorable economic and financial conditions also result in the assumption that commercial deployments of Carbon Capture and Storage (CCS) infrastructure beyond the planned demonstration plants are not realistic.

Grid

Distribution grid and transmission systems connected as today. There is a certain amount of price-elastic demand and smart communication enabling distributed resources to balance the RES fluctuation. However, it is assumed that this does not fundamentally change the load pattern. The impact of electric vehicles is also assumed to be negligible in this Vision (no commercial breakthrough of vehicles to grid connections).

3.5 Vision 2: “Money Rules”

Economic and market

The general framework of this Vision 2 “Money rules” is that the economic and financial conditions are less favorable than in Visions 3 and 4 and, as a consequence, national governments have less money to reinforce existing energy policies. However, there is a strong European framework but, due to the economic and financial outlook, the introduction of fundamental new market designs and R&D expenses focuses on cost cutting and not the goals of the Energy Roadmap 2050.

Since no reinforcing of existing policies occurs, carbon pricing (e.g. the EU Emissions Trading System, carbon taxes or carbon price floors) remains at such a level that base load electricity production based on hard coal is preferred to gas. Carbon and primary energy prices could be based on the current policies scenario of the IEA in their WEO 2011. This means that countries with a lot of hard coal in their energy generation portfolio are likely to be net exporters.

Demand

The breakthrough in energy efficiency developments (e.g. large-scale deployment of micro-cogeneration or heat pumps as well as minimum requirements for new appliances and new buildings) and the development of the usage of electricity for transport (e.g. large-scale introduction of electric plug-in vehicles) and heating/cooling focus on possible economic benefits. As a consequence, the electricity demand is expected to grow at a higher pace than in vision 1 "Slow progress", due to the fact that the introduction of these new uses of electricity more than compensates for the realized energy efficiency improvements. Furthermore, the demand response potential is partially used to shift the daily load in response to the available supply, because it allows a saving on back-up capacity and it is cheaper than storage.

Generation

The future generation mix is determined by a strong European vision that faces a lack of financial resources and construction delays due to permitting issues that result in a delay in the pathway to realization of the Energy Roadmap 2050. If the energy objectives 2020 were only realized in 2030, the need for additional back-up capacity in 2030 would then remain at the same order of magnitude as that currently estimated for 2020. Since there is a European common energy framework, the need for back-up capacity will be lower than in vision 1 "Slow progress", and this back-up capacity is likely to come from demand response as much as possible, since it is cheaper than building additional gas units or storage. In this vision, we can assume that 50 % of the maximum demand response capacity of 10 % is used. This vision takes into account that no technology is preferred and that they compete with each other on a market basis with no specific support measure. Furthermore, carbon pricing is a key driver for decarbonization (no additional policies are assumed if carbon prices are too low to ensure a lower usage of coal-fired units) as well as an assumption of public acceptance of nuclear. The European subsidies for CCS are intensified.

Grid

Distribution grids and transmission systems connected by an advanced monitoring, control and communication link. Distribution grids become active (bidirectional electricity flows). The option of a potential bidirectional energy exchange with the grid ("vehicle-to-grid" or V2G approach) for electric vehicles is partially developed. Electric vehicles are assumed to be flexible on the charging side. Load is partially adapting to generation possibilities.

3.6 Vision 3: "Green Transition"

Economic and market

The general framework of this Vision 3 "Green transition" is that the economic and financial conditions are more favorable than in Visions 1 and 2 and, as a consequence, national governments have money to reinforce existing energy policies. However, the absence of a strong European framework is a barrier to the introduction of fundamental new market designs that fully benefit from R&D developments. Furthermore, the opting for parallel national schemes regarding R&D expenses also result in a situation where major technological breakthroughs are less likely due to suboptimal and repeated R&D spending.

Since there is a reinforcing of existing energy policies, carbon pricing (e.g. the EU Emissions Trading System, carbon taxes or carbon price floors) reaches such levels that base load electricity production based on gas is preferred to hard coal. Carbon and primary energy prices could be based on the 450 scenario of the IEA in their WEO 2011. Gas is likely to push out hard coal for base load electricity generation. This means that countries with a lot of gas in their energy portfolio are likely to be net exporters.

Demand

Efforts in energy efficiency developments (e.g. large-scale deployment of micro-cogeneration or heat pumps as well as minimum requirements for new appliances and new buildings) and the development of the usage of electricity for transport (e.g. large-scale introduction of electric plug-in vehicles) and heating/cooling are intensified to minimize the ecological footprint. However, these are developed in the current market frameworks. As a consequence, electricity demand is expected to grow at a higher pace than in Vision 1 "Slow progress" and Vision 2 "Money rules", due to the fact that the introduction of these new uses of electricity more than compensates for the realized energy efficiency improvements and is intensified through additional subsidies. Furthermore, the demand response potential is partially used to shift the daily load in response to the available supply, because it allows a saving on back-up capacity and it is cheaper than storage.

Generation

The future generation mix is determined by parallel national policy schemes that are on track to realize the decarbonization objectives for 2050. However, it will be at a higher cost than it would be in the case of a strong European framework, since more back-up capacity is needed. The need for back-up capacity for intermitted renewable energy sources in Europe could be substantially more than the back-up capacity[1)] needed for the realization of 3 × 20 objectives. This means that although demand response potential is used (50 % due to no fundamental change in market design), the majority of the additional back-up capacity in 2030 would come from gas units, since additional ways of central hydro storage are not developed due to a lack of a strong European framework. This vision also takes into account the growing public opposition to nuclear power, although it is a low-carbon technology, influenced by the aftermath of the Fukushima Daiichi nuclear disaster. Although the vision permits deviations if this is in line with the current national view, it is assumed that the financial community generally maintains its refusal to invest in nuclear technology on a merchant basis and that technology-specific support schemes are not likely. The absence of a strong European framework results in the assumption that commercial deployment of CCS infrastructure beyond the planned demonstration plants is not realistic.

Grid

Distribution grid and transmission system connected as today. There is a certain amount of price-elastic demand and smart communication, enabling distributed resources to balance the RES fluctuation. However, it is assumed that this does not fundamentally change the height of the daily peak. The impact of electric vehicles is an augmentation of the load during off-peak hours.

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1) "Power Perspectives 2030: on the road to a decarbonised power sector", European Climate Foundation (2011) mentions 5 times more back-up capacity (www.roadmap2050.eu/attachments/files/PowerPerspectives2030_FullReport.pdf).

3.7 Vision 4: "Green Revolution"

Economic and market

The general framework of this Vision 4 "Green revolution" is that the economic and financial conditions are more favorable than in Visions 1 and 2 and, as a consequence, national governments have money to reinforce existing energy policies. Major investments in sustainable energy generation are undertaken. Furthermore, a strong European framework makes the introduction of fundamental new market designs that fully benefit from R&D developments more likely. This also allows R&D expenses to be optimized so that major technological breakthroughs are more likely.

Since there is a reinforcing of existing energy policies, carbon pricing (e.g. the EU Emissions Trading System, carbon taxes or carbon price floors) reaches such levels that base load electricity production based on gas is preferred to hard coal. Carbon and primary energy prices could be based on the 450 scenario of the IEA in their WEO 2011. Gas is likely to push out hard coal for base load electricity generation. This means that countries with a lot of gas in their energy portfolio are likely to be net exporters.

Demand

Efforts in energy efficiency developments (e.g. large-scale deployment of micro-cogeneration or heat pumps as well as minimum requirements for new appliances and new buildings) and the developments of the usage of electricity for transport (e.g. large-scale introduction of electric plug-in vehicles) and heating/cooling are intensified. Furthermore, market designs are adapted in such a way that the highest energy savings are combined with the highest substitution to electricity. As a consequence, electricity demand is expected to grow at a higher pace than in Vision 3 "Green transition", due to the fact that the introduction of these new uses of electricity more than compensates for the realized energy efficiency improvements. These new usages are intensified through additional subsidies. Furthermore, the demand response potential is fully used to shift the daily load in response to the available supply, because it allows a saving on back-up capacity and it is cheaper than storage.

Generation

The future generation mix is determined by a strong European vision that is on track to reach the decarbonization objectives for 2050 at least cost. The need for back-up capacity for intermitted renewable energy sources in Europe could be substantially more than the back-up capacity needed for the realization of 3 × 20 objectives. However, since there is a European common energy framework, the need for back-up capacity will be lower than in Vision 3 "Green transition". This means that besides the demand response potential that is fully used, central additional hydro storage is built in Scandinavia, the Alps and the Pyrenees, and the remaining additional back-up capacity in 2030 will come from gas units. This vision takes into account that the European subsidies for CCS to develop beyond demonstration are intensified in order to speed up to successful commercial deployment, but other technologies compete with each other on a market basis with no specific support measure (no additional policies on top of carbon pricing are assumed) and by assuming the public acceptance of nuclear. The European subsidies for CCS are intensified.

Grid

Distribution grids and transmission systems connected by an advanced monitoring, control and communication link. Distribution grids become active [bidirectional electricity flows]. That configuration allows increased reliability, and efficient management of peak demand. Furthermore, the configuration reduces required back-up generation capacity, increases environmental sustainability and reduces CO_2 emissions, fully accomplishing requirements of the Roadmap 2050 milestones. The option of a potential bidirectional energy exchange with the grid ("vehicle-to-grid" or V2G approach) for electric vehicles is fully developed. Electric vehicles are assumed to be flexible on the charging and generation side. Load is adapting to generation possibilities.

4 Scenario Outlook

All the necessary definitions and methodology for the Scenario Outlook are described in Chapter 2.2.

4.1 Load Forecast

Scenario EU 2020

In this scenario, load is increasing during the whole forecast period. The load trend for both reference points – January (at 7 p.m.) and July (at 11 a.m.) is shown in Figure 4.1.

The difference in expected load between both investigated reference points is almost constant and is equal, approximately 117 GW in average in each monitored year. The annual increase rates are shown in Table 4.1.

The highest annual increase of load up to 2015 in Scenario EU 2020 is expected in Cyprus (about 8.6 %), FYROM (4.3 %), Czech Republic (2.6 %), and Slovenia (2.5 %). In the period between 2015 and 2020, Cyprus (almost 5 %), Romania (2.4 %), Spain (2.3 %), FYROM (2.3 %), and Poland (2.2 %) expect the highest load surplus.

The only country with an expected decrease of load in both forecasted periods is Germany (0.2 % fall between 2012 and 2015 and 0.5 % fall between 2015 and 2020). A decrease of about 3.7 % and 0.5 % are also expected between 2012 and 2015 in Luxembourg and Poland, respectively (Polish Scenario EU 2020 assumes a significant increase in additional energy efficiency very soon, which will allow for achieving the national target of an RES generation share in the final energy consumption). The situation is illustrated in Figure 4.2 and Figure 4.3.

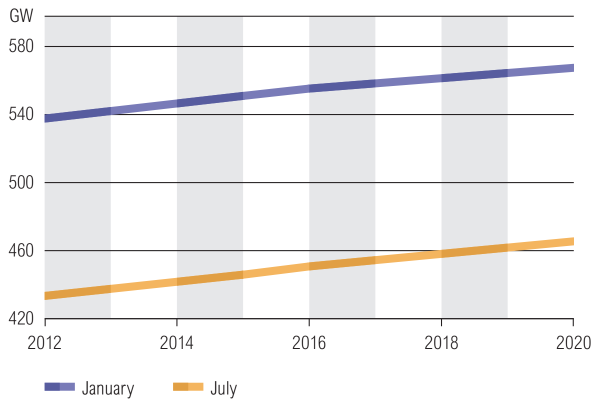
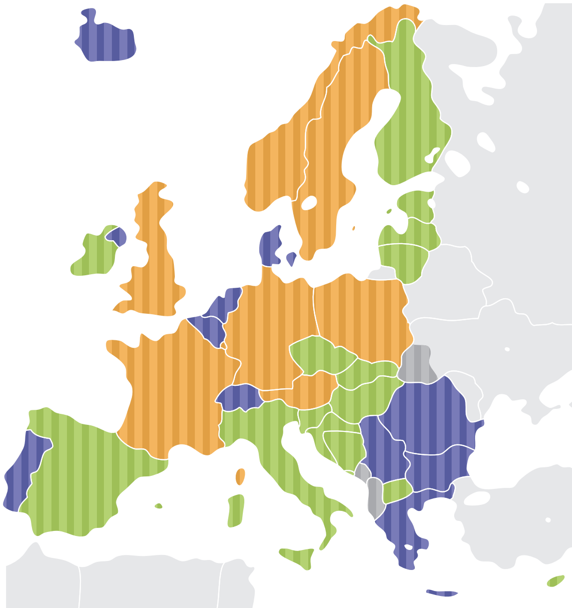


Figure 4.1:
ENTSO-E load forecast for Scenario EU 2020

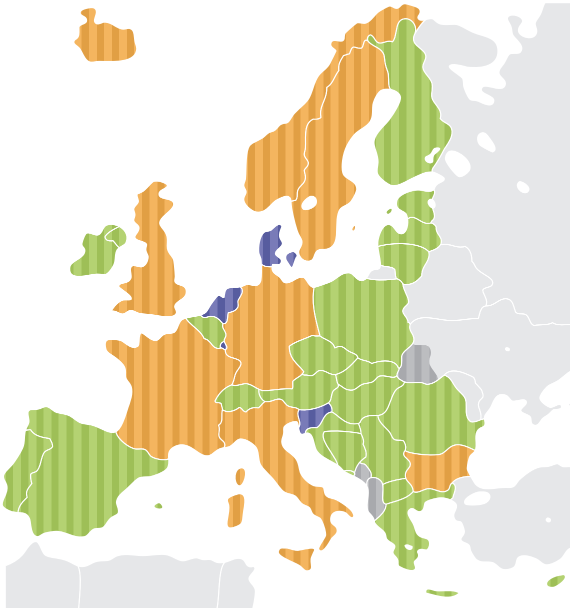
[%]	2012 to 2015	2015 to 2020
January	0.8	0.6
July	1.0	0.9

Table 4.1:
ENTSO-E average annual load increase rate for Scenario EU 2020



> 1.6 % | ≥ 0.8 % (Entso-E average) & ≤ 1.6 % | < 0.8 %
No data provided

Figure 4.2:
Average annual load growth per country between 2012 and 2015, Scenario EU 2020, January 7 p.m.



> 1.2 % | ≥ 0.6 % (Entso-E average) & ≤ 1.2 % | < 0.6 %
No data provided

Figure 4.3:
Average annual load growth per country between 2015 and 2020, Scenario EU 2020, January 7 p.m.

The load forecast for Scenario EU 2020 is established on the basis of the "Additional energy efficiency scenario" of the NREAPs. It takes into account the national plans for a complete mix of energy consumed in the national economy in order to meet national target value, according to the goals of renewable energy sources utilization in total energy consumption, which is defined in the third energy legislation package of the European Union. For some countries, the values mentioned in the NREAP are adapted to take into account the reduced synchronous perimeter reported to ENTSO-E.

NREAPs, however, are not available for each ENTSO-E country, as not each ENTSO-E country is an EU member. For ENTSO-E countries not belonging to the EU and without an NREAP, the latest official document describing the long-term vision of the country or the TSO's best estimate was used.

Scenario B

Load values in Scenario B[1] rise continuously in both reference points, January and July. Figure 4.4 shows only values for Scenario B for both reference points. The difference in load between reference points in absolute values is between 125 GW and 128 GW. A similar behavior of load (shape and increase rate of the curve) was reported last year in SO&AF 2011, where the difference between January and July was approximately 109 GW on average.

The annual increase rate of load in respective periods is shown in Table 4.2. The figures correspond with Figure 4.4, i.e. the most rapid increase is expected between 2015 and 2020.

The biggest annual load increase between 2012 and 2015 is expected in Cyprus (8.6 %), FYROM (4.3 %), and Romania (3.5 %), together with Slovenia, Poland, Luxembourg and Estonia (between 2 % and 3 %).

During the period between 2015 and 2020, the biggest increase of load is expected in Cyprus (5 %), Estonia and Romania (2.6 %). It is shown also in Figures 4.5 and 4.6. Remarkable is the fact that between 2012 and 2015, the load is expected to decrease in Germany (-0.2 %).

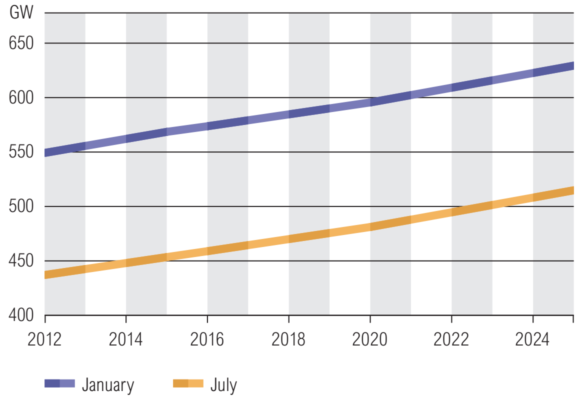


Figure 4.2:
ENTSO-E load forecast for Scenario B, January 7 p.m. and July 11 a.m.

[%]	2012 to 2015	2015 to 2020	2020 to 2025
January	1.6	0.9	1.1
July	1.3	1.2	1.4

Table 4.2:
ENTSO-E average increase rate for load for Scenario B

As a main factor influencing the load (in Scenario A and B), most of the TSOs reported the influence of energy efficiency measures to be taken at the national level in future. The influence of expected weather conditions (based on the experiences from the past), political goals and/or GDP growth were also reported.

1) According to the SO&AF methodology, load values are supposed to be the same for both Scenarios A and B. However, some TSOs have reported different figures for Scenario A and for Scenario B (e.g. Cyprus, Estonia, Great Britain) because of the agreement between TSOs, some stakeholders and national ministries. Although load values in Scenarios A and B differ, further in this document, only values and assessment for Scenario B are made.

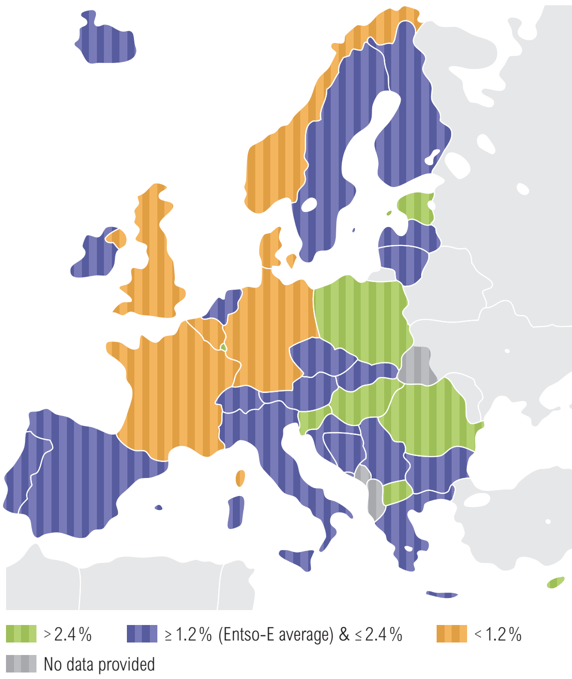


Figure 4.5:
Average annual load growth per country between 2012 and 2015, Scenario B

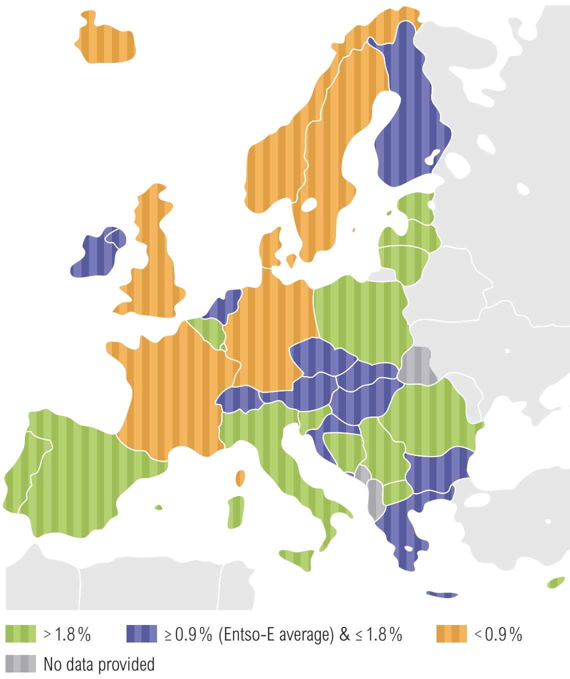


Figure 4.6:
Average annual load growth per country between 2015 and 2020, Scenario B

Comparison of Scenario EU 2020 and Scenario B

A comparison of load between Scenario EU 2020 and Scenario B (reference point is January 7 p.m.) is shown in Figure 4.7. The differences could be caused by the fact that Scenario EU 2020 is based on NREAPs and therefore tends to reflect the political targets of each respective national government, regarding the fulfilment of European goals in climate protection, whereas Scenario B is the best estimation of each respective TSO within ENTSO-E and reflects rather the view and expectations of TSOs (not for each TSO, of course). These two approaches do not have to be necessarily coherent and lead to the same results. Scenario B doesn't eventually take into account future additional measures envisaged by the national authorities to comply with the 2020 objectives; therefore, the scenarios lead to different results shown in Figure 4.7.

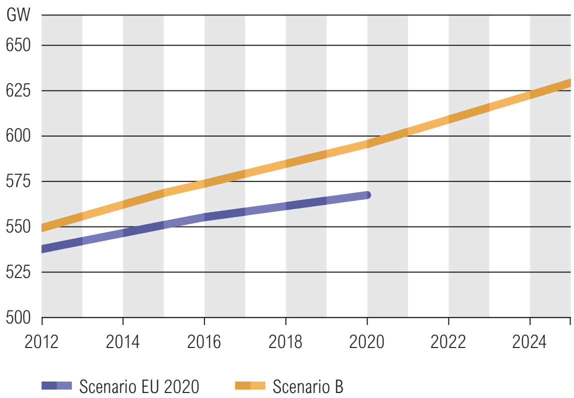


Figure 4.7:
ENTSO-E load forecast,
comparison of Scenario EU 2020 and Scenario B, January 7 p.m.

[%]	2012 to 2015	2015 to 2020	2020 to 2025
Scenario B	1.2	0.9	1.1
Scenario EU 2020	0.8	0.6	—

Table 4.3:
ENTSO-E average annual increase rate for load,
Scenario EU 2020 and Scenario B

The load in Scenario B is not only higher but also its increase is sharper (Table 4.3). In addition to these assumptions, these differences could be caused by different assumptions regarding usage of new electric cars or heat pumps' electricity consumption. That could easily result in higher growth rates.

4.2 Demand Forecast

The energy consumption forecast for Scenario EU 2020 and Scenario B is shown in Figure 4.8. It is clearly visible that the growth of consumption is quite constant and smooth for both scenarios. However, comparing to the previous SO&AF report, there is a visible difference for the period up to 2015, caused mainly by the higher expectations for consumption growth in 2012 in Germany (+35 TWh comparing to the 2011 forecast in SO&AF 2011), and FYROM (+88 TWh).

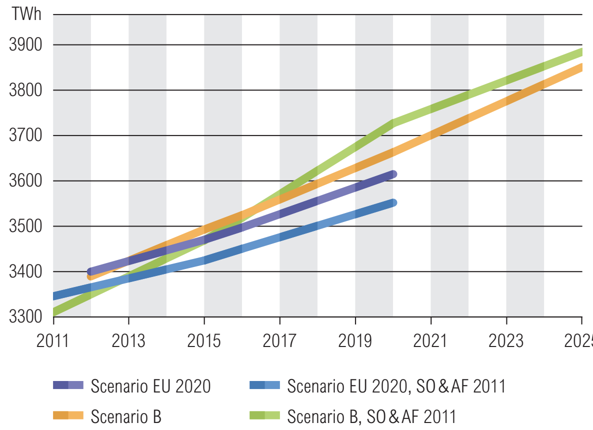


Figure 4.8:
ENTSO-E consumption forecast for Scenario B and Scenario EU 2020

Scenario EU 2020

The average annual consumption growth rate between 2012 and 2020 for Scenario EU 2020 for the whole ENTSO-E is expected to be about 0.8 % (Table 4.4).

[%]	2012 to 2015	2015 to 2020
Annual rate	0.7	0.8

Table 4.4:
ENTSO-E annual consumption increase rate, Scenario EU 2020

The highest annual increase rate between 2012 and 2020 is expected in FYROM (3.2 %), Bosnia & Herzegovina and Lithuania (2.7 %), and Cyprus (2.5 %), followed by Romania and Sweden (about 2 % each). The only country expecting a 0.1 % decrease of consumption in this period is Bulgaria. Annual consumption growth between 2012 and 2020 per country is shown in Figure 4.9.

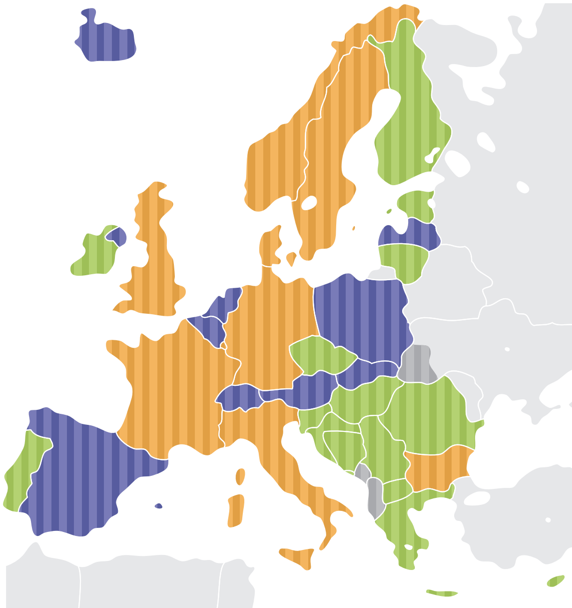


Figure 4.9:
Average annual consumption growth per country between 2012 and 2020, Scenario EU 2020

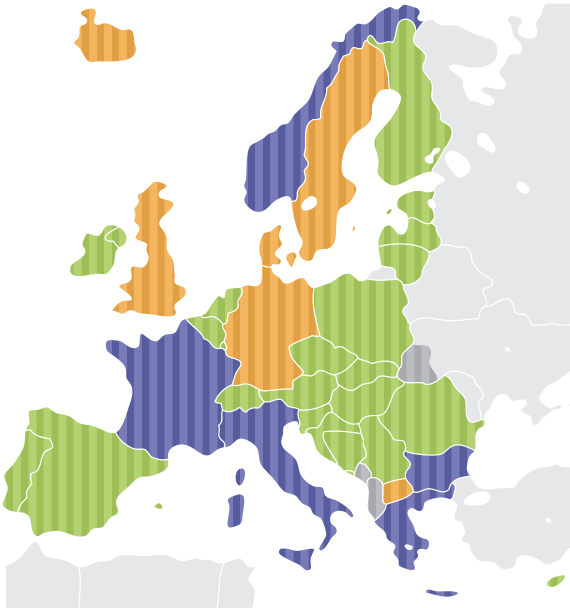


Figure 4.10:
Average annual consumption growth per country between 2012 and 2020, Scenario B

Scenario B

The average annual consumption growth rate between 2012 and 2020 for Scenario B for the whole ENTSO-E is expected to be about 1 % (Figure 4.10). Between 2020 and 2025, an annual increase of about 1 % is forecasted (Table 4.5) as well.

Estonia, FYROM, Slovenia, Bosnia & Herzegovina, Cyprus, and Romania expect the highest annual increases between 2012 and 2020 (between 2.5 % and 3.2 %).

[%]	2012 to 2015	2015 to 2020	2020 to 2025
Annual rate	1.0	1.0	1.0

Table 4.5:
ENTSO-E annual consumption increase rate, Scenario B

4.3 Generating Capacity Forecast

4.3.1 Total ENTSO-E Net Generating Capacity (NGC)

This chapter contains the main description and assessment for each generation category for both scenarios. More details are available within each subparagraph, dealing with particular kinds of fuel and scenarios.

Scenario EU 2020

The evolution of total NGC for whole ENTSO-E is shown in Figures 4.11 and 4.12. The fastest growth registered on energy sources is reported in renewable power plants[1], whose amount expressed in total NGC almost doubles (from 322 GW in 2012 to 548 GW in 2020). Non-renewable hydro power plants are also increasing during the whole forecasted period as well, but their rise is not as fast as in the case of renewable power plants. Only fossil fuels are expected to diminish.

Nuclear power plants are expected to marginally increase the installed capacity. This is despite the German decision to close the German nuclear power plants by year 2022. The main reason for this increase is that some countries are expecting new nuclear power plants, while others expect reinvestments in the existing plants.

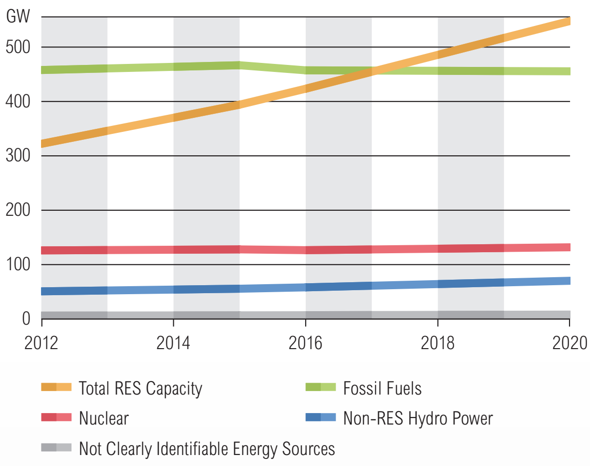


Figure 4.11:
ENTSO-E total NGC breakdown; Scenario EU 2020, January 7 p.m.

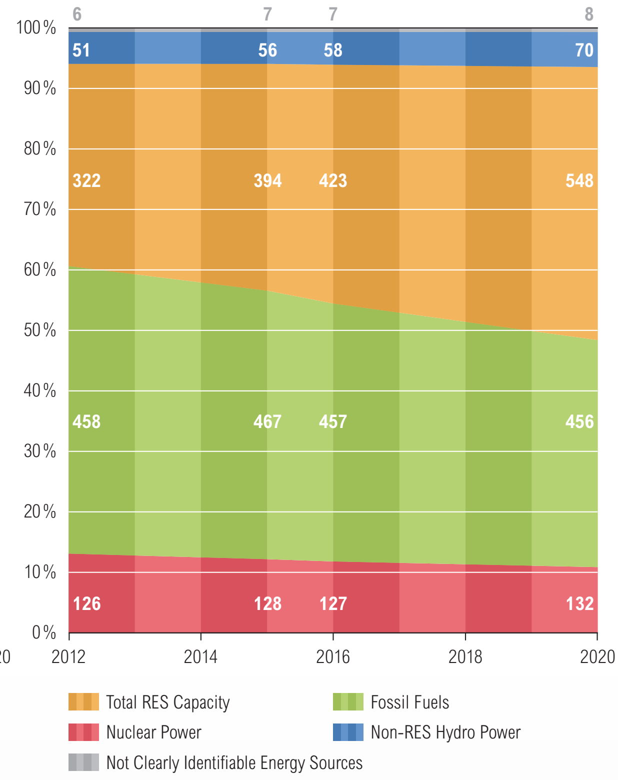


Figure 4.12:
ENTSO-E total NGC mix, Scenario EU 2020, January 7 p.m., values in GW

[1] For the purposes of this report, wind, solar, biomass and renewable hydro power plants are considered as renewable.

The total NGC situation in each respective ENTSO-E member country is depicted in Figures 4.13 and 4.14. The clear "leader" is Germany with about 220 GW of NGC, followed by Italy (147 GW), France (144 GW) and Spain (124 GW). In most countries, the Fossil Fuels and/or RES lead the fictive chart of the most popular technologies in the majority of the ENTSO-E members.

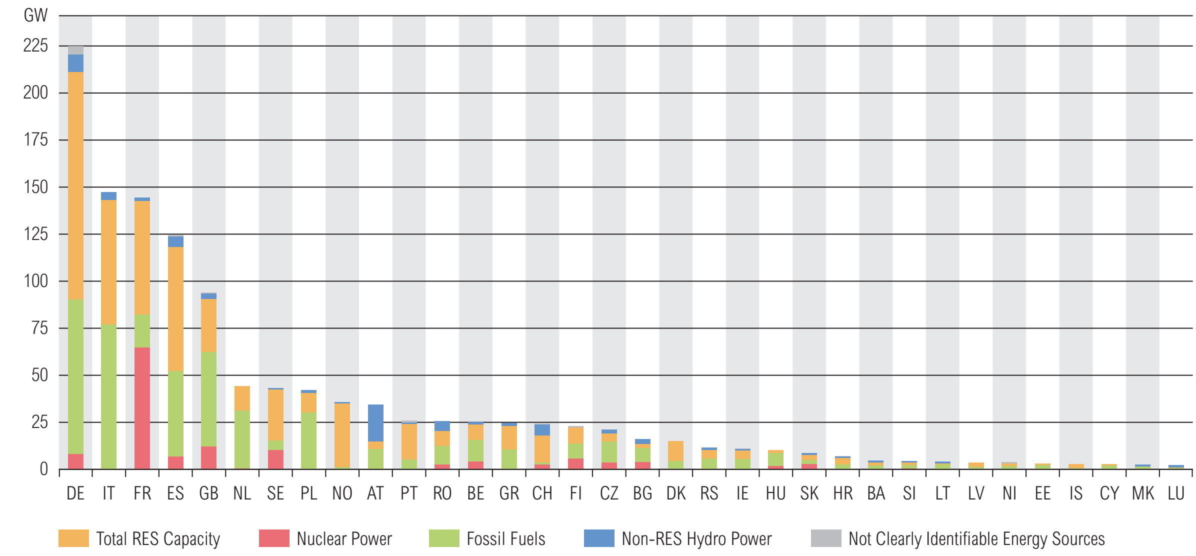


Figure 4.13:
Total NGC breakdown per country in 2020, Scenario EU 2020, January 7 p.m.

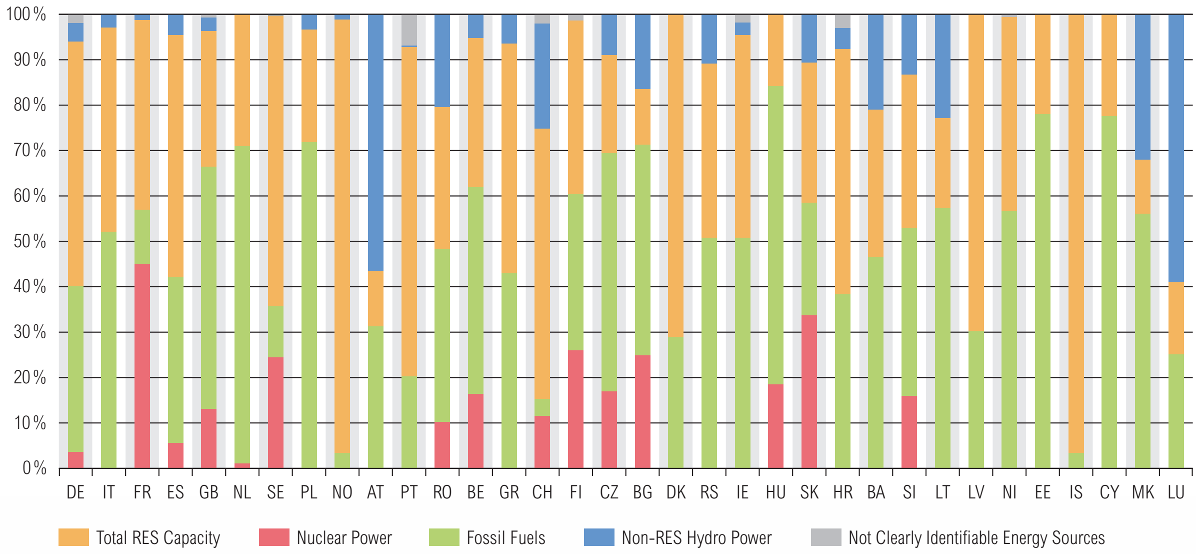


Figure 4.14:
Total generation capacity mix per country in 2020, Scenario EU 2020, January 7 p.m.

Scenario B

The evolution of respective NGC categories is similar to Scenario EU 2020. Each of them is increasing; the most rapid increase, however, is expected for RES (from 312 GW in 2012 to 602 GW in 2025). The total increase of RES between 2012 and 2020 is 62 % (70 % in Scenario EU 2020). Also, Fossil Fuels are slightly increasing during the whole monitored period (463 GW to 476 GW), whereas in Scenario EU 2020 a decrease is expected. The trends are shown in the Figures 4.15 and 4.16.

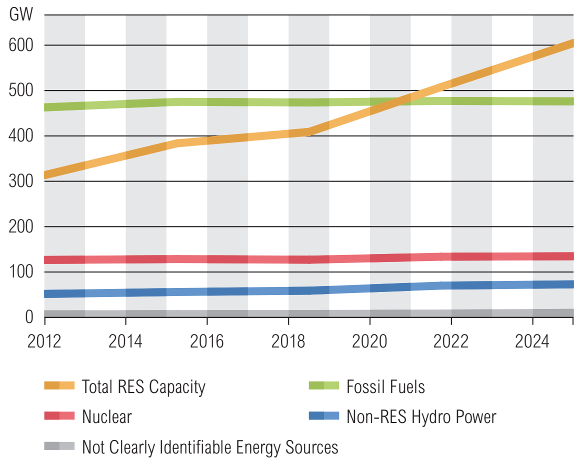


Figure 4.15:
ENTSO-E total NGC breakdown; Scenario B, January 7 p.m.

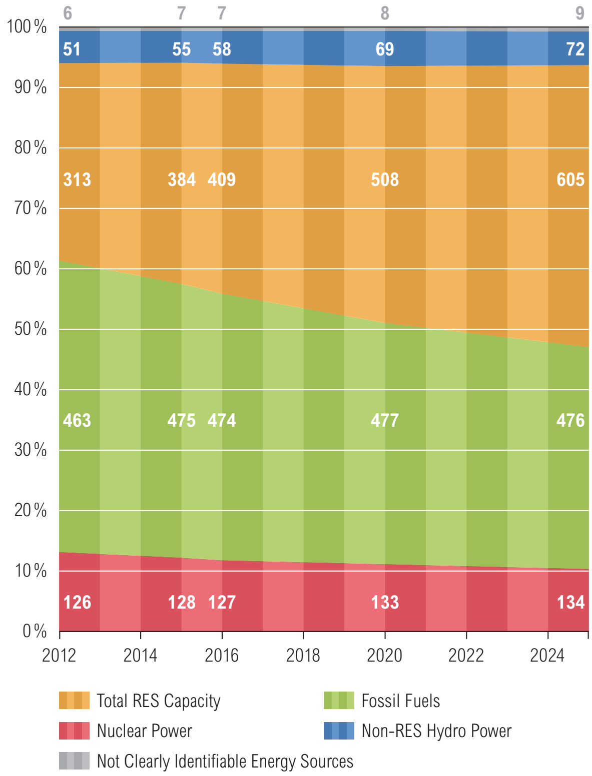


Figure 4.16:
ENTSO-E total NGC mix, Scenario B, January 7 p.m., values in GW

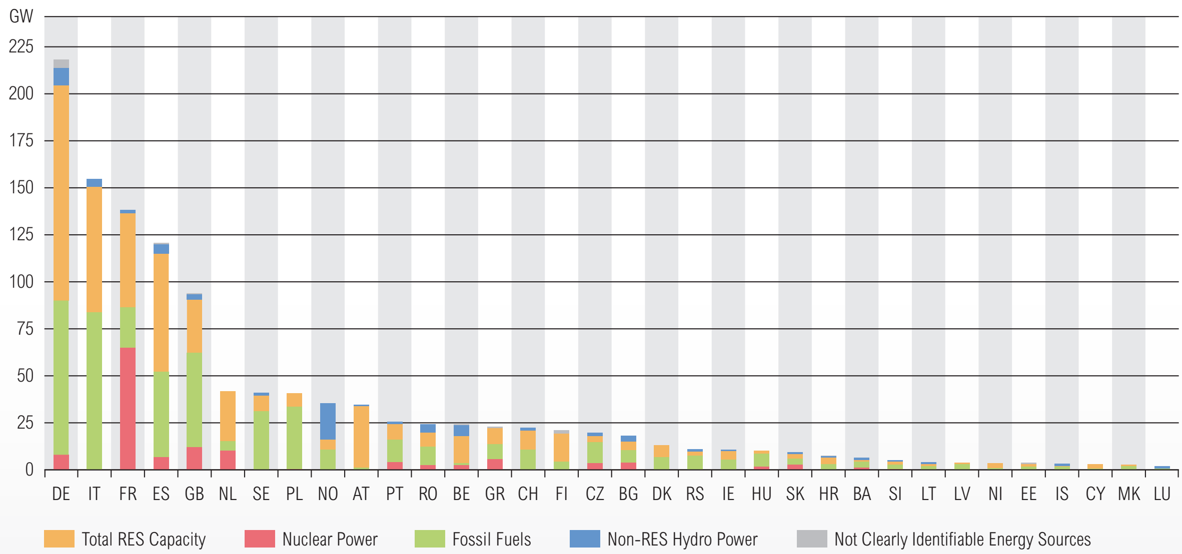


Figure 4.17:
Total NGC breakdown per country in 2020, Scenario B, January 7 p.m.

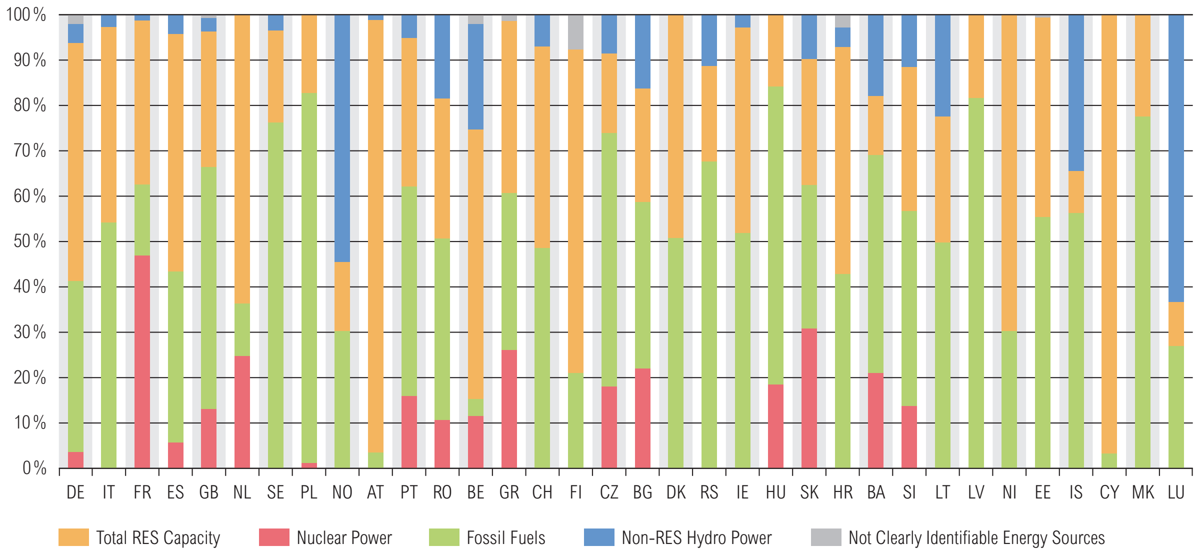


Figure 4.18:
Total generation capacity mix per country in 2020, Scenario B, January 7 p.m.

The situation in NGC per country is shown in Figures 4.17 and 4.18. The leaders are the same as Scenario EU 2020 (Germany, Italy, France and Spain). From another point of view, in this scenario the Fossil Fuels and/or RES are also the leaders among the used technologies in most of the countries.

Comparing the SO&AF 2012 to the SO&AF 2011 (Figure 4.19), we can see the increasing trends in both of the reports for all scenarios. The trends in SO&AF 2012 seem more optimistic, as its lines lie above the curves for SO&AF 2011.

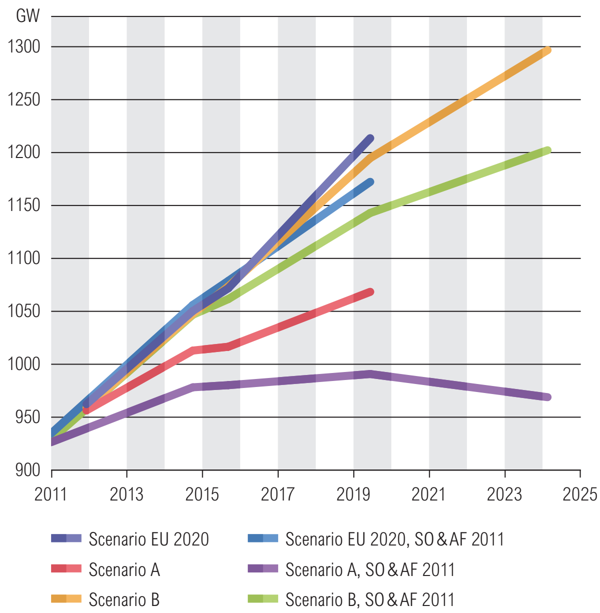


Figure 4.19:
Comparison of NGC per scenario
between SO&AF 2011 and SO&AF 2012, January 7 p.m.

4.3.2 NGC - Fossil Fuel Power Plants

Scenario EU 2020

NGC of the fossil fuel category is expected to increase up to 2015 (increase rate is about 2 % in both monitored reference times; maximum is 467 GW for January, as for July) and falls after that year back to approximately 456 GW by 2020 (decrease rate is about 2 %; see Figure 4.20). The decrease in 2020 is a direct consequence of the higher share of RES expected in each country in this scenario.

On the other hand, the Large Combustion Plants Directive[1], (thereinafter "LCP Directive"), which forces the generators to shut down old fossil fuel power plants (under certain conditions), seems to have a limited influence. This LCP Directive comes into force in 2015, but some countries may have

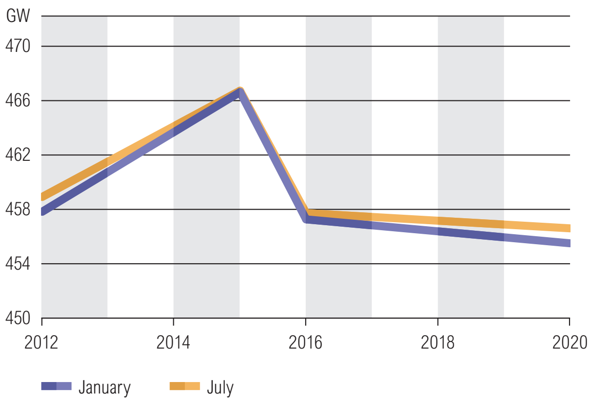


Figure 4.20:
ENTSO-E Fossil fuels generating capacity forecast, Scenario EU 2020

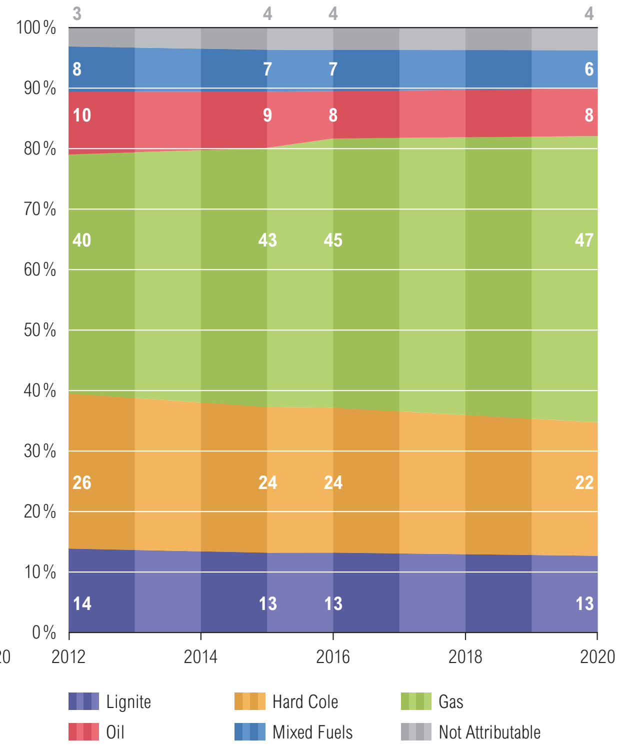


Figure 4.21:
ENTSO-E Fossil fuels generating capacity breakdown, Scenario EU 2020, January 7 p.m.

[1] Directive 2001/80/EC of the European parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.

The Commission adopted on 21 December 2007 a Proposal for a Directive on industrial emissions. The Proposal recasts seven existing Directives (including the IPPC Directive, the Large Combustion Plants Directive, the Waste Incineration Directive, the Solvents Emissions Directive and 3 Directives on Titanium Dioxide the IPPC) into a single clear and coherent legislative instrument.

an exemption period, and effect of this Directive is postponed in their case. However, to assess the fossil fuels category based on the information in NREAPs, it is not trouble-free, as this kind of information is not included in these documents.

In Figure 4.21, the fossil fuels generating mix in Scenario EU 2020 is depicted. The picture shows that the highest share within this category belongs to gas power plants. Their share increases from 40 % in 2012 to 47 % in 2020. On the other hand, other categories are expected to reduce their share; the hard coal power plants' share falls from 26 % to 22 %; with the Oil category, the decrease is from 10 % to 8 % and Lignite decreases from 14 % to 13 %.

On the ENTSO-E level, the share of fossil fuels in total NGC is 44 % in 2015 and 38 % in 2020. More than half of the ENTSO-E countries will exceed the before-mentioned values. The country with the highest levels of fossil fuels in both forecasted years, 2015 and 2020, is Cyprus, followed by Estonia, Poland, the Netherlands and Northern Ireland. Norway, Sweden, Iceland, France and Switzerland are having the lowest share of fossil fuels, compared to each country's total NGC. The overall picture is shown in Figures 4.22 and 4.23.

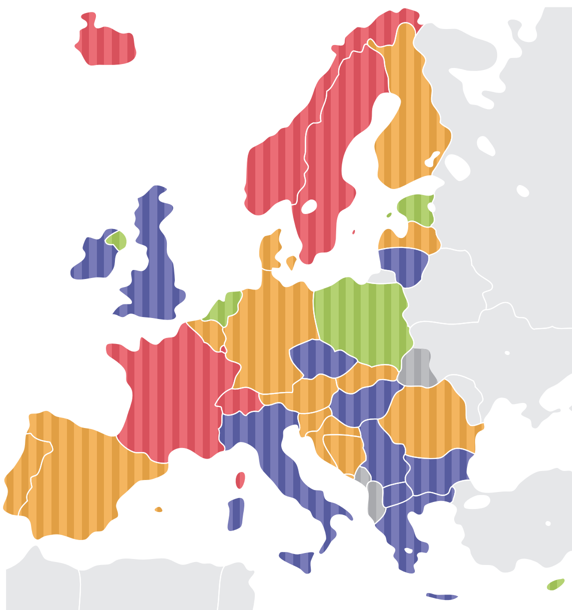


Figure 4.22:
Fossil fuels as a part of NGC per country in 2015, Scenario EU 2020

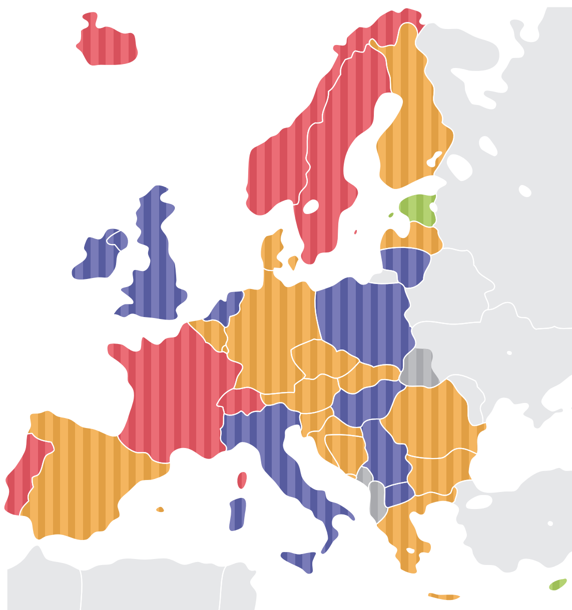


Figure 4.23:
Fossil fuels as a part of NGC per country in 2020, Scenario EU 2020

The LCP Directive applies to combustion plants with a rated thermal output equal to or greater than 50 MW, irrespective of the type of fuel used. The directive sets pollution thresholds for NO_X, SO_X, emissions etc. Existing units in question must abide by these standards by December the 31st, 2015, at the latest, or must be shutdown. Defined limits will be revised again in 2016.

The LCP Directive commits only European Union (EU) member states. Therefore, ENTSO-E member countries outside of the EU perimeter do not have to follow its goals.

Scenario B

NGC of the fossil fuel category for Scenario B is expected to increase throughout the whole monitored period (from 463 GW in 2012 to 476 GW in 2025, see Figure 4.24).

On the other hand, the LCP Directive, which forces the generators to shut down old fossil fuel power plants (under certain conditions) seems to have a deeper influence in Scenario A, where the decrease from 465 GW to 447 GW in 2020 is foreseen after 2015. We can also say that, in Scenario B, the TSOs do not expect such huge Fossil Fuel plants' decommissioning, due to the LCP Directive, and they also expect older Fossil Fuel units in operation (probably after some reconstruction in order to fulfil environmental limits).

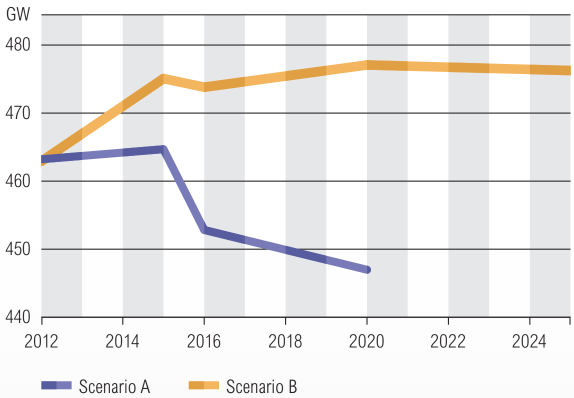


Figure 4.24:
ENTSO-E Fossil fuels generating capacity forecast, Scenario A & B

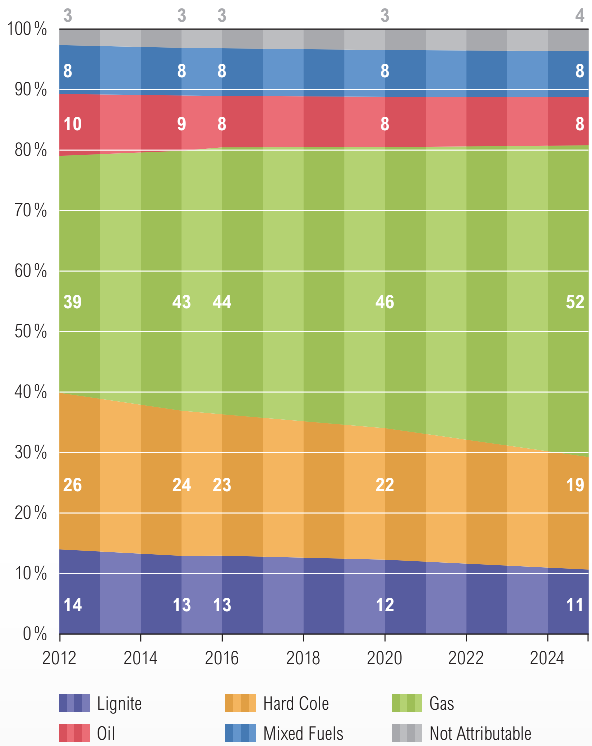


Figure 4.25:
ENTSO-E Fossil fuels generating capacity breakdown, Scenario B, January 7 p.m.

The fossil fuels' generating capacity mix is depicted in Figure 4.25. The picture shows that the highest share within this category belongs also in Scenario B to gas power plants (from 39 % in 2012 to 52 % in 2025). Other categories are expected to reduce their share (Hard coal share falls from 26 % to 19 %, Oil from 10 % to 8 % and Lignite from 14 % to 11 %).

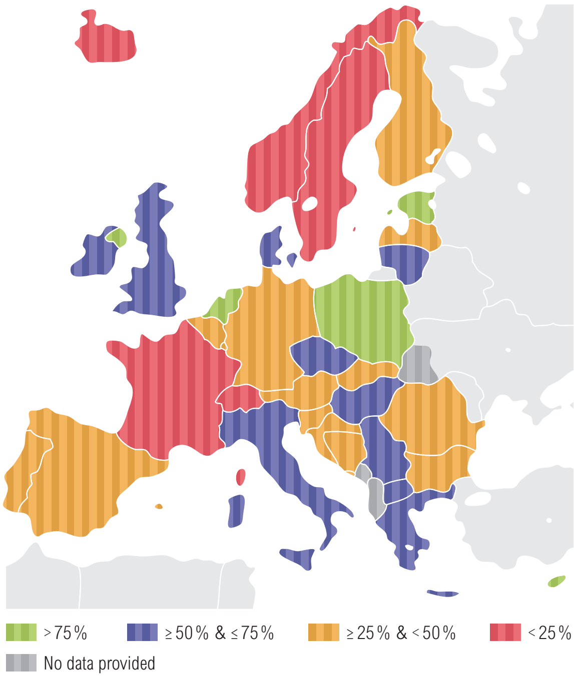


Figure 4.26:
Fossil fuels as a part of NGC per country in 2015, Scenario B

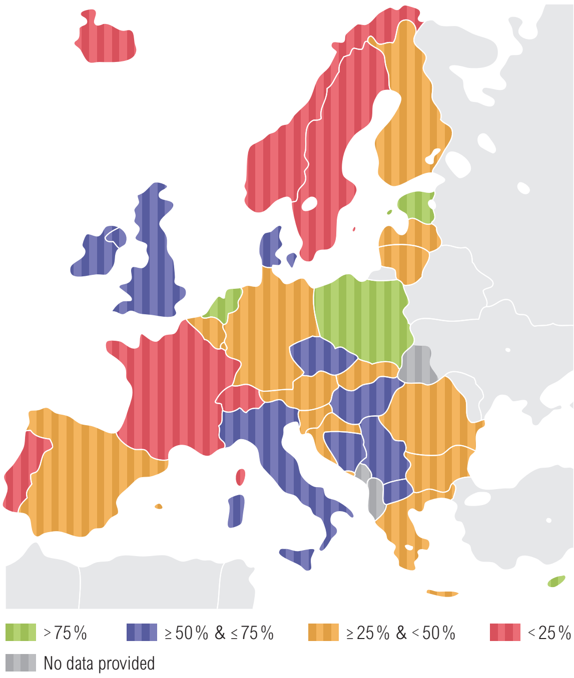


Figure 4.27:
Fossil fuels as a part of NGC per country in 2020, Scenario B

On the ENTSO-E level, the share of fossil fuels in total NGC is 45 % in 2015 and 40 % in 2020. More than half of the ENTSO-E countries that provided the data will exceed the before-mentioned values. The country with the highest levels of fossil fuels in both forecasted years, 2015 and 2020, is Cyprus again, followed by Estonia, Poland, the Netherlands and Northern Ireland. Again, Norway, Sweden, Iceland, France and Switzerland are having the lowest share of fossil fuels in their national NGC mix (see Figures 4.26 and 4.27).

A comparison of SO&AF 2011 and SO&AF 2012 is shown in Figure 4.28.

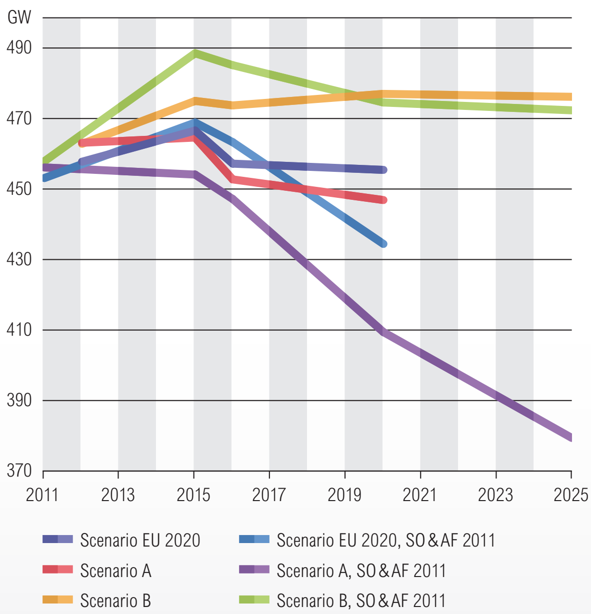


Figure 4.28:
Comparison of NGC per scenario between SO&AF 2011 and SO&AF 2012, January 7 p.m.

4.3.3 NGC – Nuclear Power Plants

Scenario EU 2020

Nuclear power plants are expected to increase the installed capacity in the prognosis. This is despite the German decision to close the German nuclear power plants within year 2022. The main reason for this increase is that some countries are expecting new nuclear power plants, while others expect reinvestments in the existing plants. The nuclear power plants installed capacity in Scenario EU 2020 is expected to be increasing all the time with the exception of the period between years 2015 and 2016 (Figure 4.29).

The share of nuclear power plants in total NGC per country in 2015 and 2020 is depicted in the following maps (Figures 4.30 and 4.31). The countries with the highest share of nuclear power in the national NGC are France (48 % in 2015 and 45 % in 2020) and Slovakia (about 33 % in both years), followed in 2015 by Belgium (28 %) and Sweden (25 %), and in 2020 by Finland (26 %) and Bulgaria (25 %). The average value for the whole of ENTSO-E is about 12 % in both monitored years.

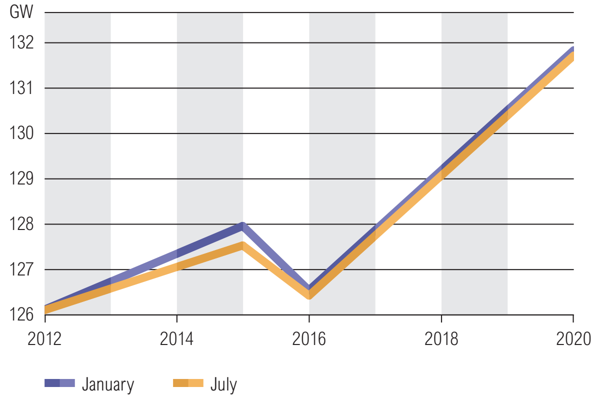


Figure 4.29:
ENTSO-E Nuclear generating capacity forecast, Scenario EU 2020

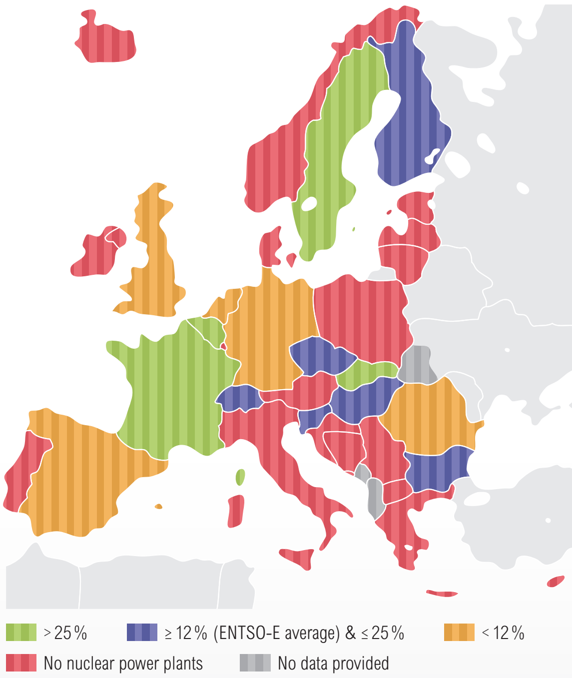


Figure 4.30:
Share of Nuclear power in NGC per country in 2015, Scenario EU 2020

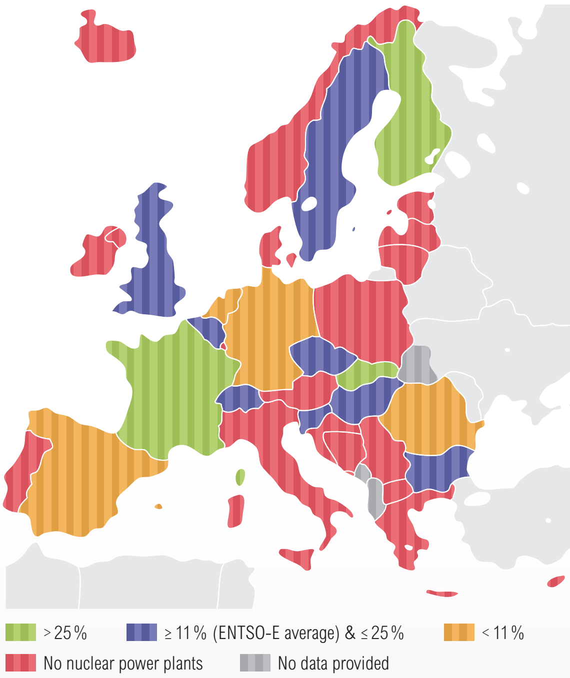


Figure 4.31:
Share of Nuclear plants in NGC per country in 2020, Scenario EU 2020

An increase of nuclear capacity forward till 2020 is expected in Finland (3.2 GW), Bulgaria (2 GW), France (1.9 GW), Great Britain (1.8 GW), Romania (1.3 GW), Slovakia (1.1 GW) and Sweden (1 GW). Germany and Belgium are expecting a reduction, as these countries are planning for a nuclear phase-out.

Scenario B

Nuclear power plants are expected to increase the installed capacity in Scenario B (again despite the German decision to close nuclear power plants; Figure 4.32) by about 6 % in total. The main reason for this increase could be again the fact that some countries are expecting new nuclear power plants, while others expect reinvestments in the existing plants. In Scenario A, this trend is visible only till 2015 (0.95 %) and, after that, the decrease of about 6.6 % is visible.

Comparing also SO&AF 2011 to SO&AF 2012, we can see the big difference of 8 GW, which can be assigned to the decision of the German government to gradually shut down their nuclear power plants (Figure 4.33).

As far as the share of nuclear power plants in total NGC per country in 2015 and 2020 is concerned, the only difference between Scenario B and EU 2020 is Lithuania in 2020, where the new Visaginas nuclear power plant (about 1,358 MW) is considered to be put in operation. This power plant will be built near the closed Ignalina nuclear power plant for optimal use of existing infrastructure.

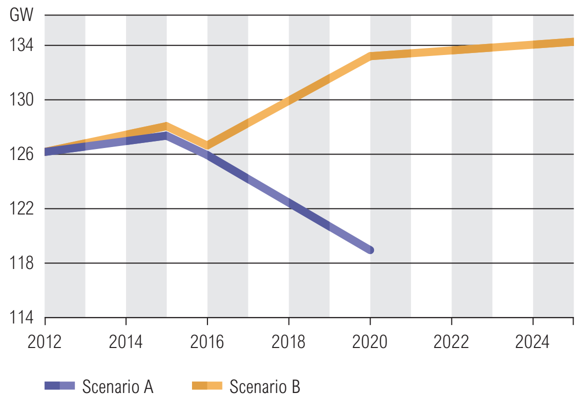


Figure 4.32:
ENTSO-E Nuclear generating capacity forecast, Scenario B

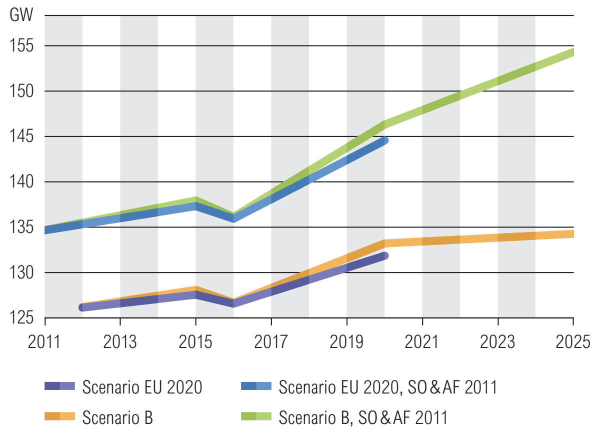


Figure 4.33:
Comparison of Nuclear power plants' installed capacity per scenario between SO&AF 2011 and SO&AF 2012, January 7 p.m.

4.3.4 NGC – Renewable Energy Sources

Scenario EU 2020

As a result of the European energy and climate politics, the RES-production type is expected to be the fastest growing production type. From a level around 300 GW of installed capacity today, it is expected that total RES in year 2020 will be at a level of 550 GW.

In this chapter, renewable energy sources (described "RES"), including renewable hydro power plants (thereinafter as "HPP"), are assessed and are jointly called "total RES". However, evaluations, statements and maps in this paragraph may be slightly biased, as not every TSO was able to divide total hydro power plants' installed capacity into requested sub-categories, which made the proper distinction between individual sub-categories of hydro power plants impossible.

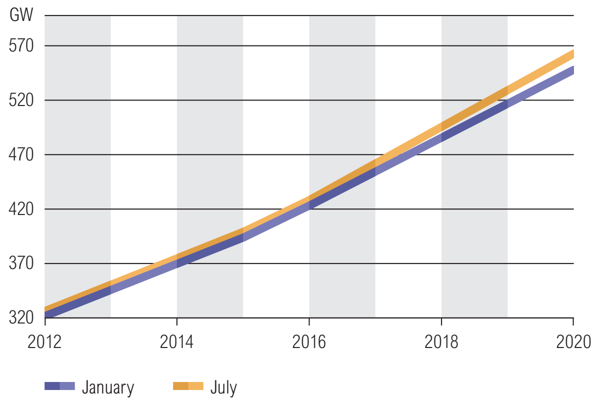


Figure 4.34:
ENTSO-E total RES generating capacity forecast, Scenario EU 2020

The main issue is for TSOs to identify the renewable generating capacity in hydropower units that combine the possibility of pump storage with natural inflow (pure pump storage is not recognized as RES). Hence, TSOs are not always able to identify if the hydro capacity can be classified as a RES capacity, although this is not true for actual generation. When the result or evaluation in the text is influenced by this fact, the reader is early warned.

As RES HPP, the run-of-river and natural inflow storage HPP were considered, this can be applied for most of the ENTSO-E countries. As non-RES HPP, pure pumped storage HPP and the pumping part of mixed natural inflow and pump storage power plants were considered.

Figure 4.34 shows the evolution of total RES installed capacity in Scenario EU 2020 for January and for July. In the period from 2012 to 2020, Europe is in this scenario expected to build around 226 GW of new RES. All European countries are expecting a large investment on RES. The biggest absolute increase is expected in Germany (+61 GW). Also, France (+25 GW), Italy (+24 GW), Spain (+22 GW) and Great Britain (+23 GW) are expecting huge investments in RES.

The biggest increase is expected for wind power with an increase of 140 GW to 245 GW in year 2020. Solar power plants are expected to increase with 50 GW to a level of 100 GW in year 2020. For both these production types, Germany is expected to be the biggest producer.

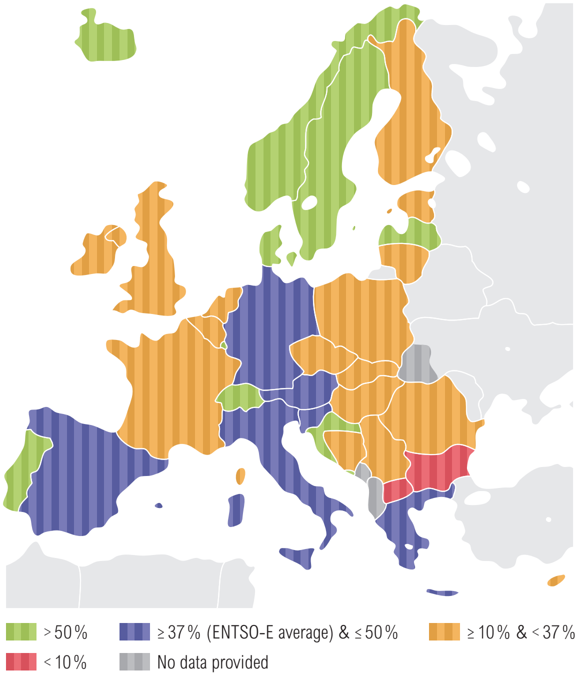


Figure 4.35:
Share of total RES in NGC per country in 2015, Scenario EU 2020

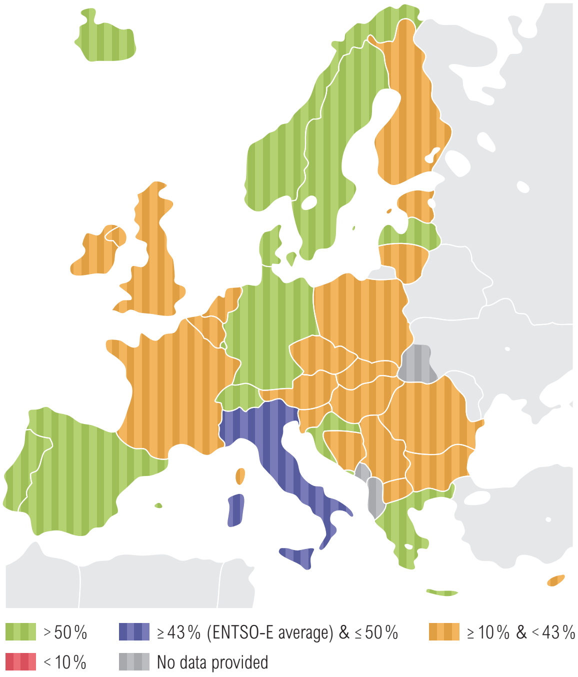


Figure 4.36:
Share of total RES in NGC per country in 2020, Scenario EU 2020

Figures 4.35 and 4.36 show the share of RES in total NGC of each ENTSO-E country in 2015 and 2020. The majority of the countries show a lower share of total RES than the ENTSO-E average in both monitored years. Norway and Iceland are the countries with the highest share of RES in NGC (about 95 % for both). Among other countries with a higher share of total RES in their NGC mix, one can count mainly Sweden, Denmark, Latvia, Germany, Switzerland, Spain, Portugal, Greece and Croatia, which have a significant share, either RES HPP or wind/solar power plants, in their national NGC or which expect more or less rapid development of RES power plants.

The total RES share in NGC in 2020 is higher than in 2015 in almost each country. Wind, solar and biomass are increasing their share in total RES installed capacity, against the share of renewable hydro power plants and not attributable[1)] RES.

1) Within the category "Not attributable RES", the renewable hydro power plants' installed capacity in Austria is also considered.

The share of onshore and offshore wind power plants in total wind installed capacity is shown in Figure 4.37. Onshore wind farms play a major role in the wind power plants category. On the other hand, the offshore wind farms' growth is visible and this subcategory becomes more important by 2020.

And last but not least, it should be mentioned also that solar power plants here, with their share within the RES category, are increasing during the whole monitored period (15 % in 2012 and 18 % in 2020).

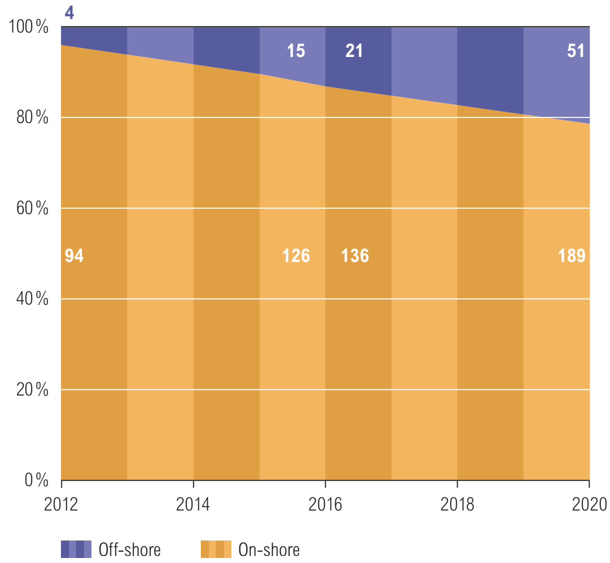


Figure 4.37:
ENTSO-E total wind breakdown, Scenario EU 2020, values in GW

Scenario B

The total RES installed capacity in 2025 is expected to reach the levels of about 605 GW (from a level around 313 GW today, Figure 4.38).

The trend is similar for both Scenarios A and B; in Scenario A, the increase is lower. The biggest absolute increase is expected in Germany (+52 GW). Also, Italy (+25 GW), Spain (+19 GW) and Great Britain (+23 GW) are expecting big investments in RES.

The biggest increase is expected for wind power again with an increase of 117 GW (94 GW to 210 GW in year 2020 and 268 GW in 2025). Solar power plants are expected to increase with 86 GW (137 GW in 2025). Again, Germany is expected to be the biggest producer for both these production types.

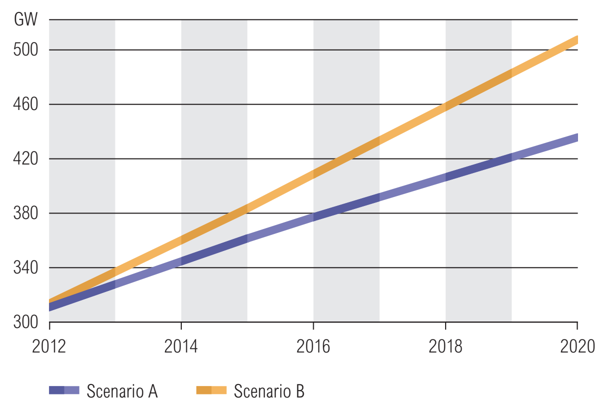


Figure 4.38:
ENTSO-E total RES generating capacity forecast, Scenario B

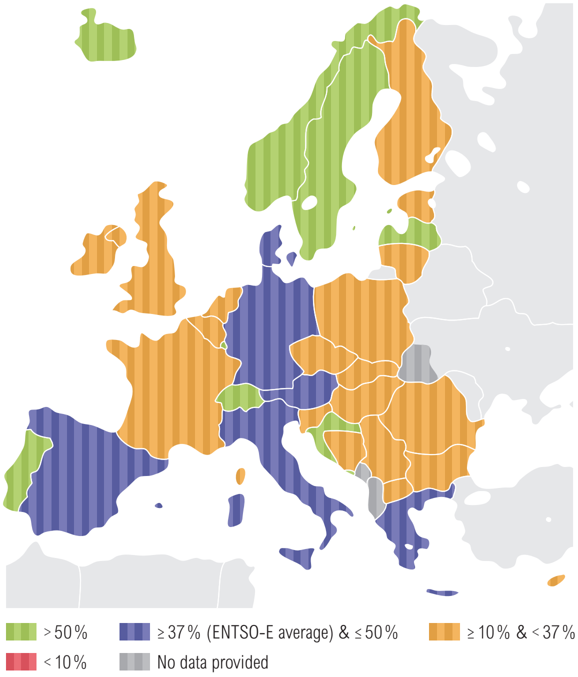


Figure 4.39:
Share of total RES in NGC per country in 2015, Scenario B

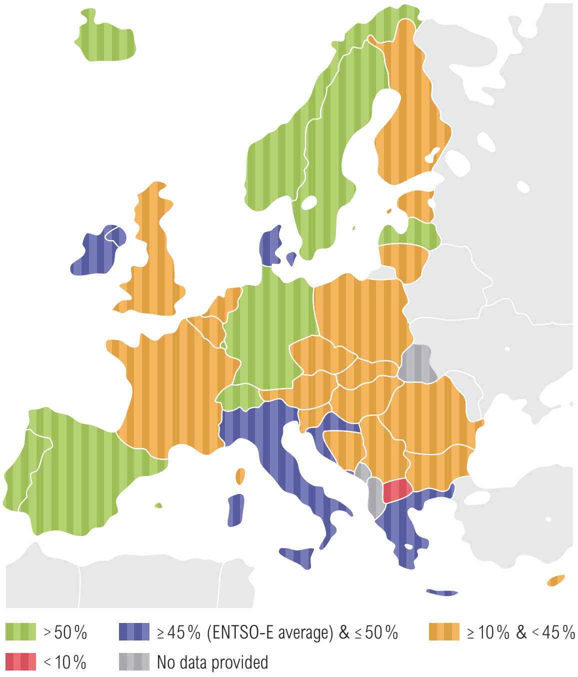


Figure 4.40:
Share of total RES in NGC per country in 2020, Scenario B

Figures 4.39 and 4.40 show the share of RES in total NGC of each ENTSO-E country in 2015 and 2020. The majority of the countries show a lower share of total RES than the ENTSO-E average in both monitored years. Norway (92 % in 2015 and 95 % in 2020) and Iceland (96 % in 2015 and 97 % in 2020) are the countries with the highest share of RES in NGC. Among other countries with a higher share of total RES in their NGC mix, one can count mainly Sweden, Denmark, Latvia, Germany, Switzerland, Spain, Portugal, and Greece.

The share of onshore and offshore wind power plants in total wind installed capacity is shown in Figure 4.41 and is similar to the Scenario EU 2020.

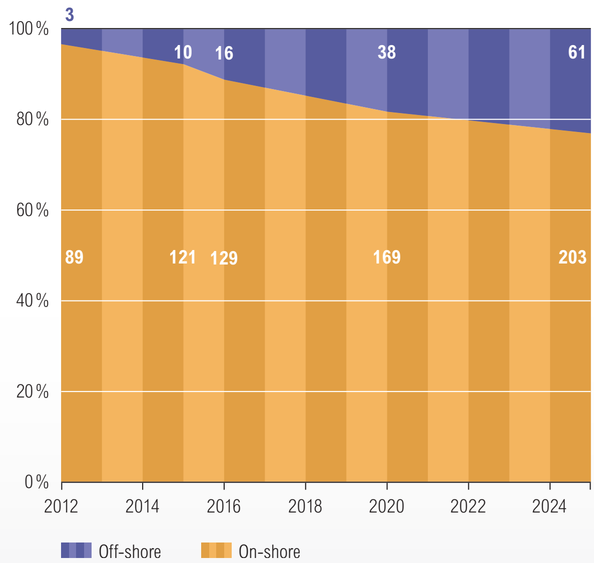


Figure 4.41:
ENTSO-E total wind breakdown, Scenario B, values in GW

Looking at the comparison between Scenario B and Scenario EU 2020 (Figure 4.42), we can see very similar behavior. Thus, we can say that a lot of TSOs consider NREAP as a basis for RES, also in Scenario B.

As regards as the solar power plants, their share within total RES is increasing continuously from 16 % in 2012 to 23 % in 2025 (21 % in 2020). This is higher development than in Scenario EU 2020. In absolute values, the difference is about 7.2 GW in 2015 and 7.5 GW in 2020, which caused mainly the more optimistic situation in Germany for Scenario B.

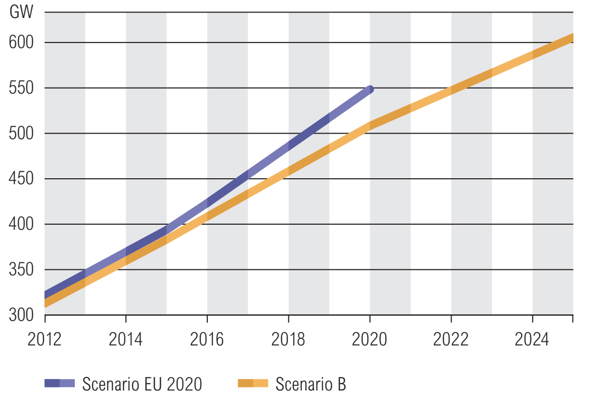


Figure 4.42:
Comparison of Scenario B and EU 2020,
ENTSO-E total RES evolution, January 7 p.m.

4.3.5 NGC – non-RES Hydro Power Plants (HPP)

Scenario EU 2020

As RES HPP, the run-of-river and natural inflow storage HPP were considered. As non-RES HPP, pure pumped storage HPP and the pumping part of mixed natural inflow and pump storage power plants were considered.

In Scenario EU 2020, the installed capacity in the non-renewable hydro power plants (non-RES HPP) category is continuously increasing (Figure 4.43). The increase rate before 2015 is 9.5 % and between 2015 and 2020, it grows to 26 %.

In both 2015 and 2020, the highest amount of non-RES HPP is reported in Austria and Germany.

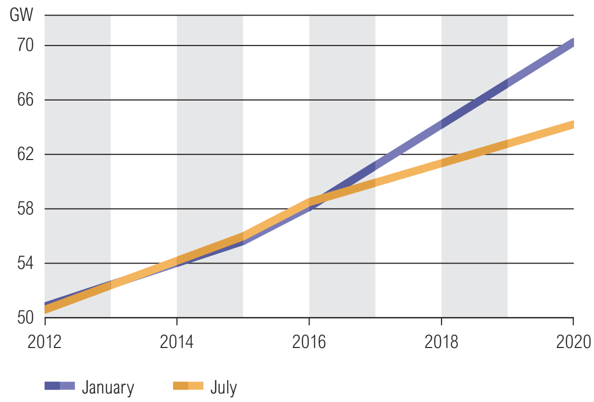


Figure 4.43:
ENTSO-E non-RES HPP generating capacity forecast,
Scenario EU 2020

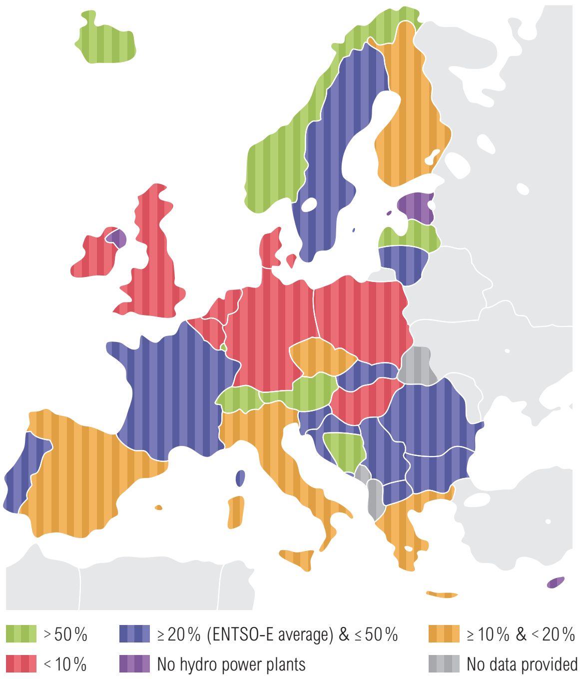


Figure 4.44:
Share of total HPP in NGC per country in 2015, Scenario EU 2020

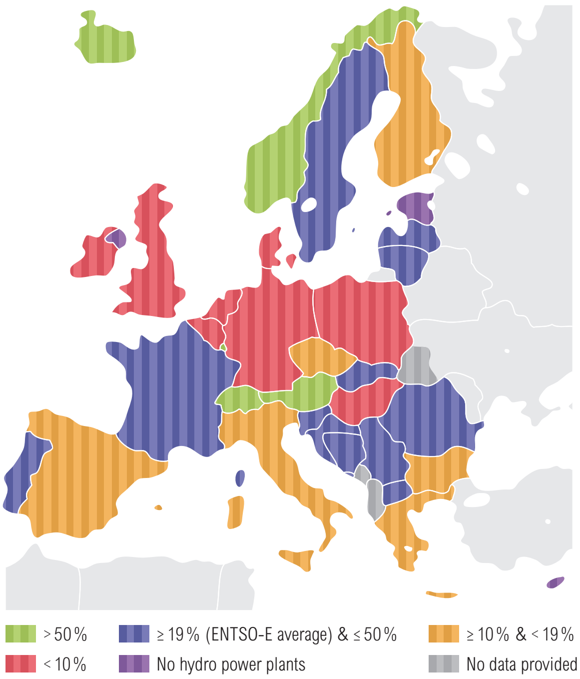


Figure 4.45:
Share of total HPP in NGC per country in 2020, Scenario EU 2020

The share of total HPP (RES HPP + non-RES HPP) installed capacity in NGC per country is shown in the Figures 4.44 and 4.45. The highest share in both 2015 and 2020 shows Norway (92 % and 90 %) and Switzerland (77 % and 79 %), followed by Iceland, Luxembourg and Austria with more than 50 % NGC in HPP.

Scenario B

The share of total HPP for Scenario B per country is shown in the Figures 4.46 and 4.47. The highest share in both 2015 and 2020 shows Norway (92 % and 90 %) and Switzerland (77 % and 79 %), followed by Iceland, Luxembourg, Bosnia & Herzegovina, and Austria with more than 50 % NGC in HPP.

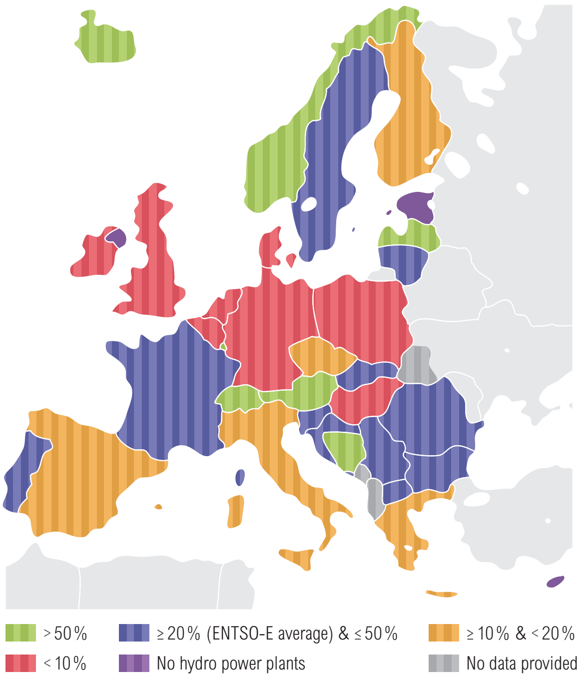


Figure 4.46:
Share of total HPP in NGC per country in 2015, Scenario B

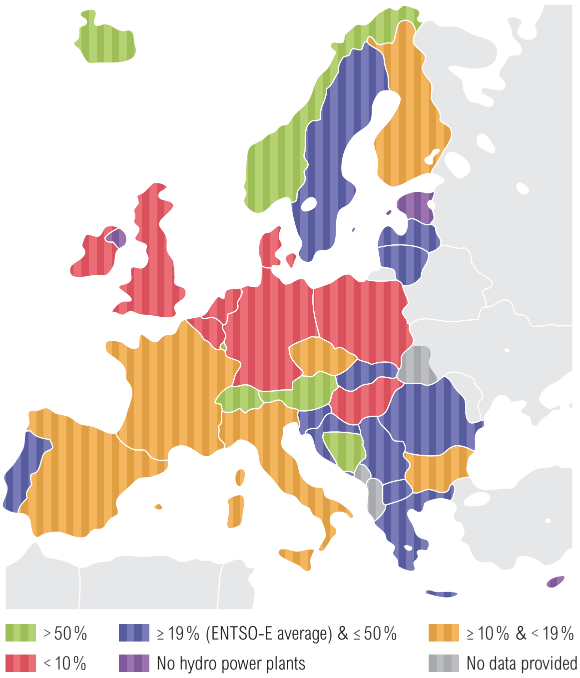


Figure 4.47:
Share of total HPP in NGC per country in 2020, Scenario B

4.3.6 Reliable Available Capacity

Scenario EU 2020

Reliable Available Capacity (RAC) is increasing during the whole forecasted period, both for January and July (Figure 4.48). RAC in January is higher by about 5 % than in July on average. It is most probably caused by the fact that unavailable capacity in July is much higher than in January, due to the higher percentage of RES (wind and solar) in this category.

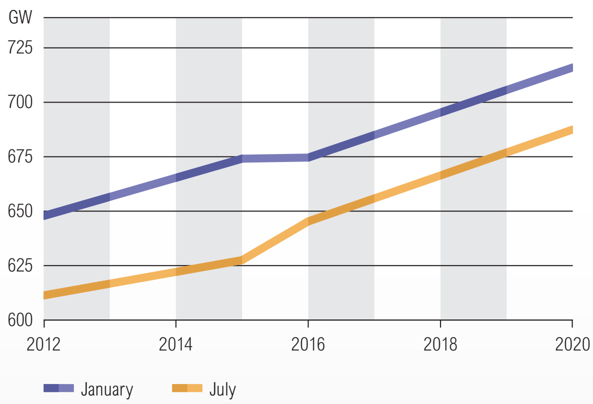


Figure 4.48:
ENTSO-E RAC forecast, Scenario EU 2020

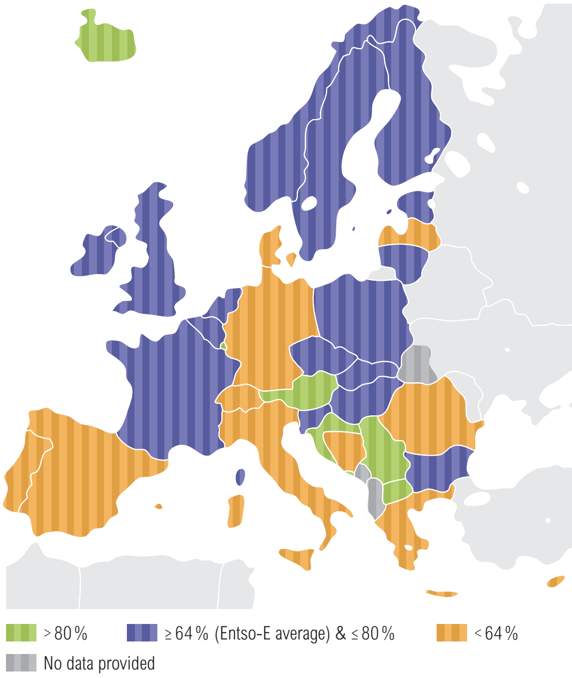


Figure 4.49:
RAC as a part of NGC per country in 2015, Scenario EU 2020

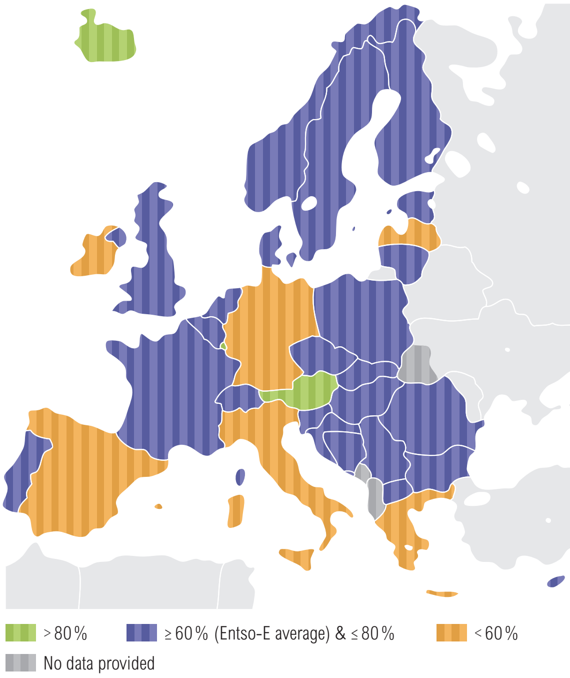


Figure 4.50:
RAC as a part of NGC per country in 2020, Scenario EU 2020

The average share of RAC in total ENTSO-E net generating capacity is expected to be about 64 % in January 2015 and 59 % in January 2020. From ENTSO-E countries, Austria, Iceland, Croatia, Luxembourg, FYROM and Serbia have the highest share of RAC in NGC in 2015 and 2020 (between 80 % and 95 %). As an average for the SO&AF 2012 purposes, the percentage of about 63 % can be considered for the whole ENTSO-E.

In Figures 4.49 and 4.50, there is a classification of the countries by a share of RAC for the whole ENTSO-E in years 2015 and 2020.

RAC will decrease most rapidly in Germany (3.8 GW) between 2015 and 2020, followed by Ireland (1.3 GW), Denmark, Estonia, Lithuania, Northern Ireland, and Slovakia (less than 0.5 GW each). Other countries show an increase of RAC between 2015 and 2020.

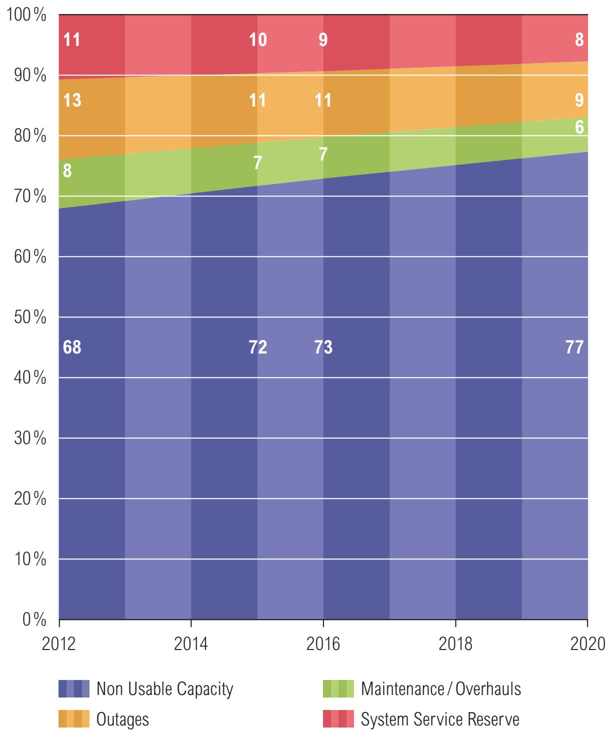


Figure 4.51:
ENTSO-E Unavailable capacity mix,
Scenario EU 2020

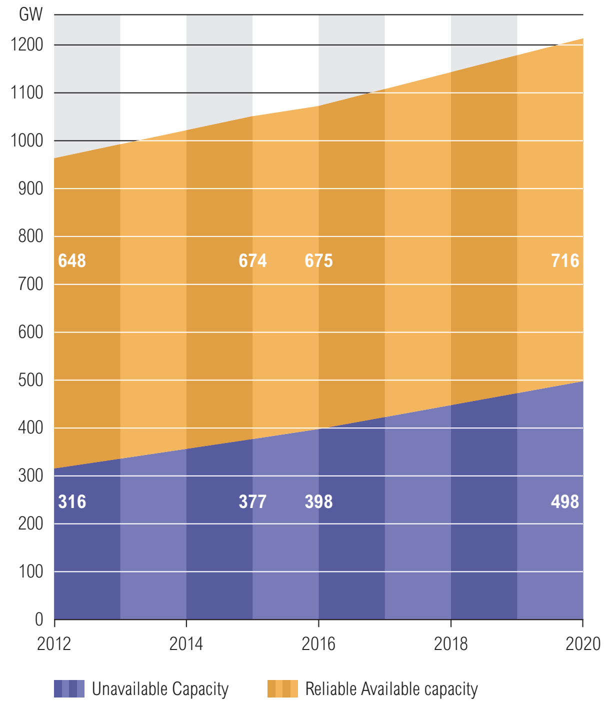


Figure 4.52:
ENTSO-E RAC and unavailable capacity forecast,
Scenario EU 2020

ENTSO-E's unavailable capacity mix is shown in Figure 4.51. The biggest share over the whole forecasted period is for non-usable capacity, followed by system service reserve and outages. Non-usable capacity is the only category that is increasing its share within unavailable capacity from 2015 to 2020. In Figure 4.52, the relation between RAC and unavailable capacity on the level of ENTSO-E is shown. Both categories show an increasing rate, and unavailable capacity always takes a higher part. This effect is probably caused by the increasing share of RES on the total generating capacity mix.

Even if the percentage of all unavailable capacities' subcategories, except for non-usable capacity, are decreasing, in absolute values these subcategories are growing continuously (see Table 4.6). Many TSOs counted RES (wind and solar above all) in the category of non-usable capacity and therefore the major influence is reported on this category.

[GW]	2012	2015	2016	2020
Non-Usable Capacity	214	270	290	385
Maintenance/ Overhauls	26	27	27	29
Outages	42	43	43	46
System Service Reserve	34	36	37	38
Unavailable Capacity	316	377	398	498

Table 4.6:
ENTSO-E unavailable capacity breakdown,
Scenario EU 2020, January 7 p.m.

Comparing Scenarios B and EU 2020, only minor differences are visible (Figure 4.53).

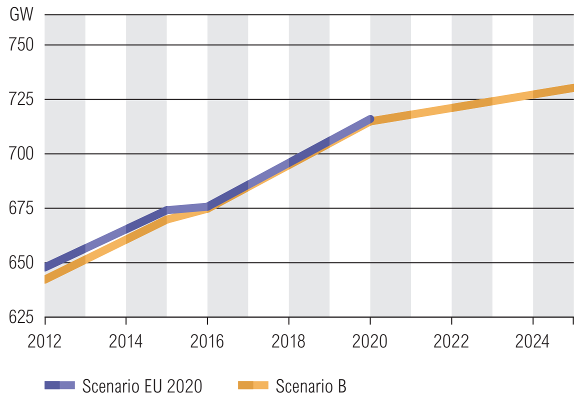


Figure 4.53:
ENTSO-E RAC forecast, Scenario EU 2020 & B

Scenario B

Reliable Available Capacity in January at 7 p.m. in Scenario A and Scenario B is in Figure 4.54. In both scenarios, the RAC is increasing almost all the time. A decrease of about 10 GW between 2015 and 2016 is expected for Scenario A in both reference points.

Likewise in Scenario EU 2020, RAC in January is expected higher than in July for Scenario B. The share of RAC in total ENTSO-E NGC is expected to be about 64 % in January 2015 and 60 % in January 2020 (reference point 7 p.m.). Austria, Iceland, Luxembourg, Croatia, FYROM and Serbia have the highest share of RAC in their NGC in 2015, and without Croatia also in 2020 (more than 80 %). This situation is visible in the Figures 4.55 and 4.56. The average share of RAC in total ENTSO-E NGC is then 62 % for January at 7 p.m.

Germany reported a decrease in RAC of 3.4 GW in 2020, comparing to 2015. More reductions are also expected for Italy (1.9 GW), Ireland, Northern Ireland, the Netherlands, Sweden and Slovakia (less than 0.5 GW). In the rest of the countries, the RAC will increase in this period.

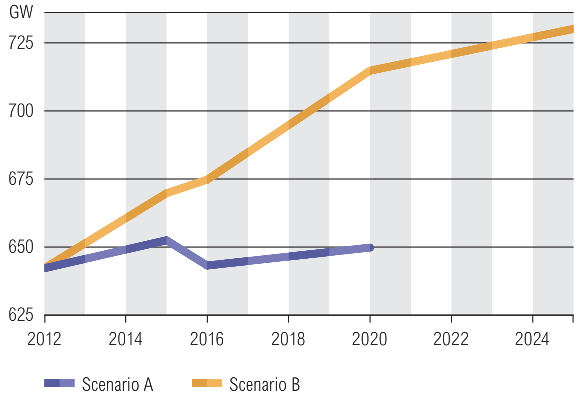


Figure 4.54:
ENTSO-E RAC forecast, Scenario A & B

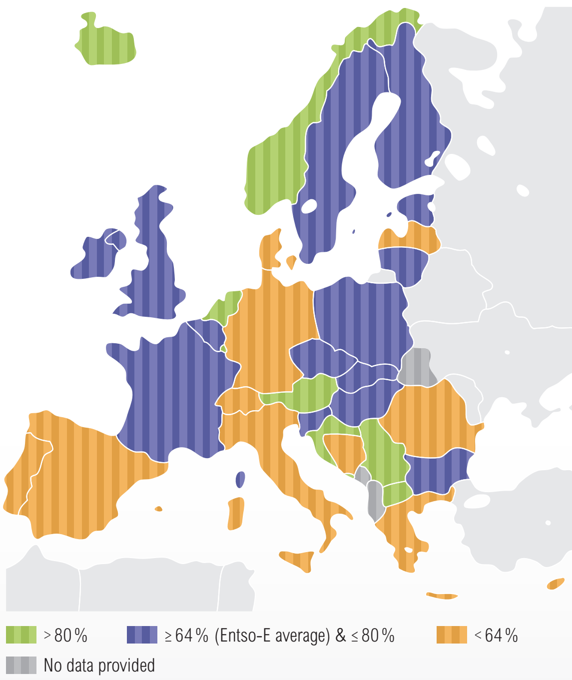


Figure 4.55:
RAC as a part of NGC per country in 2015, Scenario B

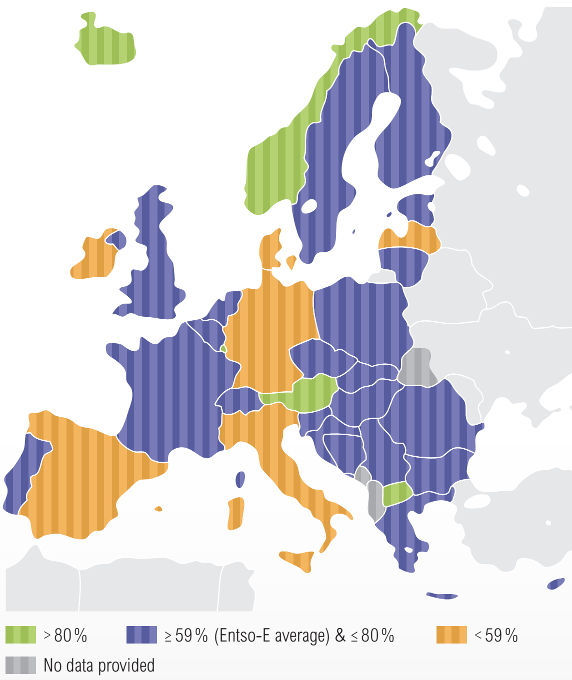


Figure 4.56:
RAC as a part of NGC per country in 2020, Scenario B

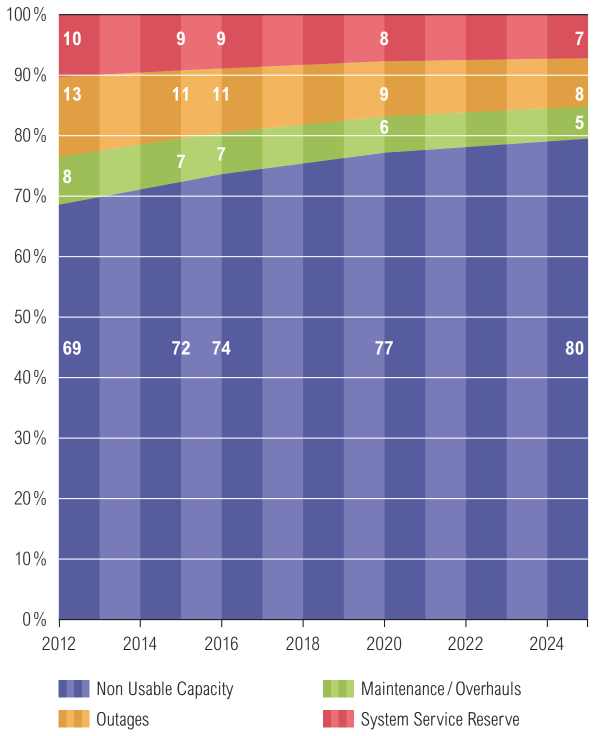


Figure 4.57:
ENTSO-E Unavailable capacity mix, Scenario B

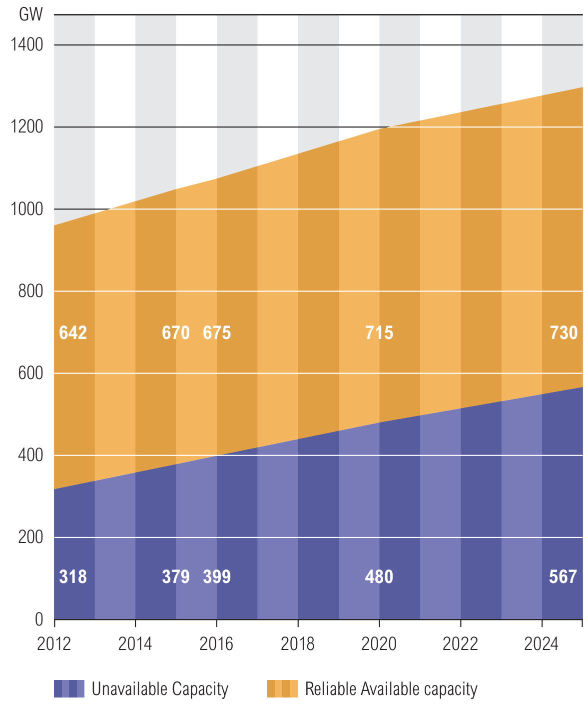


Figure 4.58:
ENTSO-E RAC vs. Unavailable capacity, Scenario B

The biggest share in unavailable capacity over the whole forecasted period is for non-usable capacity, followed by system service reserve and outages (Figure 4.57).

In Figure 4.58, the relation between ENTSO-E reliable available capacity and unavailable capacity is shown. Both categories show an increasing rate; however, unavailable capacity is always growing faster, most probably due to the increasing share of RES in non-usable capacity.

Scenario EU 2020 also being similar to Scenario B, the absolute values of each subcategory within unavailable capacity are increasing (Table 4.7), due to the same reasons as before in Scenario EU 2020.

[GW]	2012	2015	2016	2020	2025
Non-Usable Capacity	218	274	294	371	450
Maintenance/Overhauls	25	27	27	29	30
Outages	42	43	42	44	45
System Service Reserve	33	35	35	37	41
Unavailable Capacity	318	379	399	480	567

Table 4.7:
ENTSO-E unavailable capacity breakdown, Scenario B, January 7 p.m.

4.4 EU 2020 Indicators

Information about these indicators can be found partially in the Regional Investment Plans of each respective region and/or also in the TYNDP report.

5 Adequacy Forecast

All the necessary definitions and methodology for the Adequacy Forecast are described in Chapter 2.2.

5.1 ENTSO-E Adequacy Forecast

The reader should bear in mind that not all TSOs/national data correspondents consider ARM or not all of them have provided this data within the SO&AF data collection process.

Remaining Capacity & Adequacy Reference Margin

Scenario EU 2020

Remaining Capacity (RC) in this scenario is positive and is increasing during the whole forecasted period between 2012 and 2020 for both reference points (see Figure 5.1). Only a slight decrease is visible in January 2016 when the RC value falls from 136 GW to 132 GW (see Table 5.1). Furthermore, RC in July is from 42 % to 56 % higher than in January (50 % in average).

The reason for the differences between RC in January and July is that even if RAC and Load in January is higher than in July, the difference in load in these two reference points is much higher than for RAC. According to the formula used for calculation of RC, the result is rather expected.[1)]

RC, as a part of NGC per country in 2015 and 2020, is shown in Figures 5.2 and 5.3. In most of the countries, the share of RC in total NGC is higher than the average ENTSO-E value (13 % in both 2015 and 2020).

[GW]	2012	2015	2016	2020
January	122	136	132	162
July	189	194	207	235

Table 5.1:
ENTSO-E RC for Scenario EU 2020

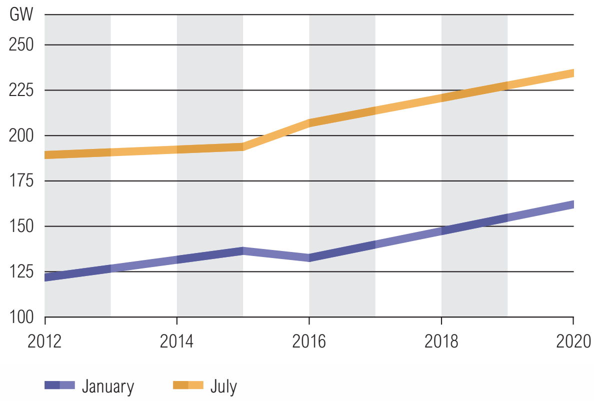


Figure 5.1:
ENTSO-E RC forecast, Scenario EU 2020

1) Remaining Capacity = Reliably Available Capacity - (Load - Load Management)

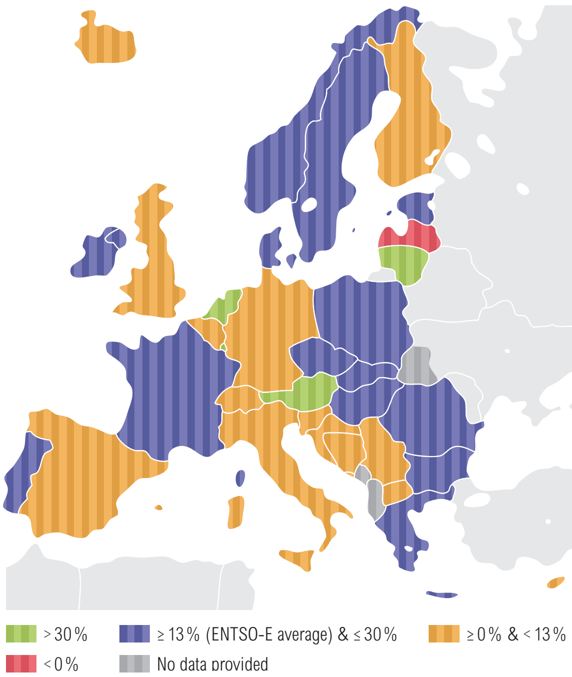


Figure 5.2:
RC as a part of NGC per country in January 2015, Scenario EU 2020

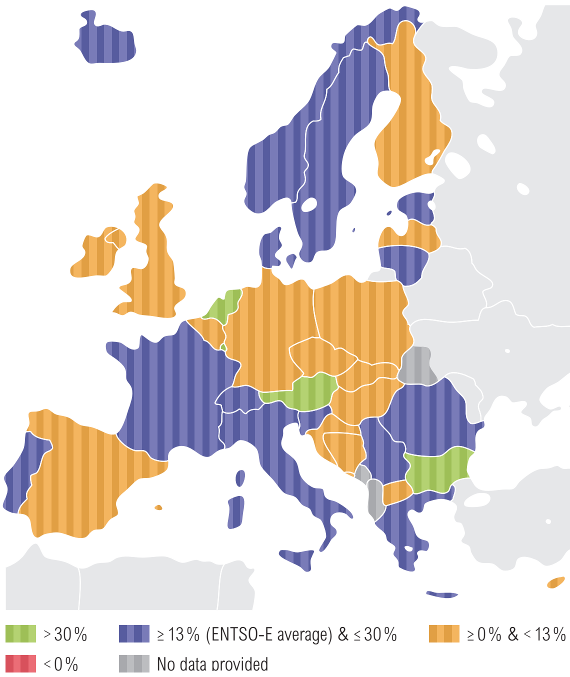


Figure 5.3:
RC as a part of NGC per country in January 2020, Scenario EU 2020

The highest levels of RC as part of NGC in 2015 are foreseen in Luxembourg (52 %), Austria (44 %), the Netherlands (32 %) and Lithuania (30 %); the lowest values are expected in Latvia (-3 %), Finland and Germany (2 % each), Slovenia and Bosnia & Herzegovina (3 % each), and Great Britain (4 %).

In 2020, Luxembourg and Austria show again the highest shares of RC in total NGC (>50 %), followed by the Netherlands and Bulgaria (32 % each). On the other side, Northern Ireland (0 %), Germany (1 %), Bosnia & Herzegovina (2 %), Latvia (3 %), Finland and FYROM (4 % each), have the lowest values.

Comparing the RC to the Adequacy Reference Margin (ARM), one can see that RC is higher during the whole forecasted period in both reference points. Moreover, this difference is increasing between the analyzed years, except for January 2016. In reference point January, the situation is less optimistic than in July, as can be seen in Table 5.2.

	[GW]	2012	2015	2016	2020
January	Margin against Peak Load	30	31	32	33
	Spare Capacity	48	53	54	61
	ARM	**78**	**84**	**86**	**94**
	RC - ARM	**44**	**53**	**47**	**68**
July	Margin against Peak Load	30	32	32	34
	Spare Capacity	48	53	54	61
	ARM	**79**	**85**	**86**	**95**
	RC - ARM	**111**	**109**	**121**	**140**

Table 5.2:
ENTSO-E RC and ARM comparison for Scenario EU 2020

Without considering possible transport capacity limitations between countries and/or regions, the generation adequacy in most of the situations within the whole ENTSO-E system in Scenario EU 2020 is expected to be maintained during the whole forecast period and in each reference point, as can be seen in Figure 5.4.

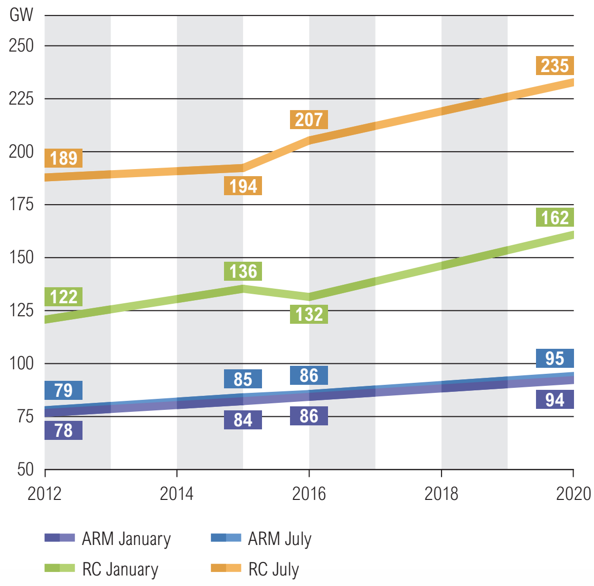


Figure 5.4:
ENTSO-E RC and ARM comparison, Scenario EU 2020

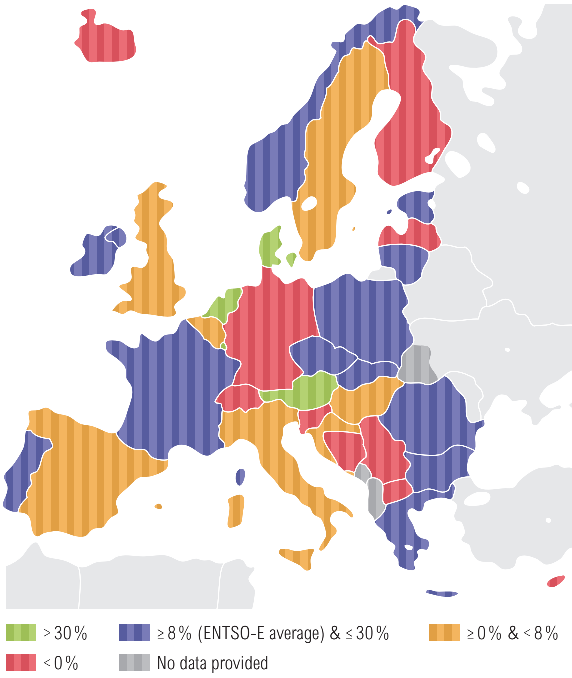


Figure 5.5:
Remaining Capacity minus Adequacy Reference Margin as a part of Reliably Available Capacity per country, Scenario EU 2020, January 2015, 7 p.m.

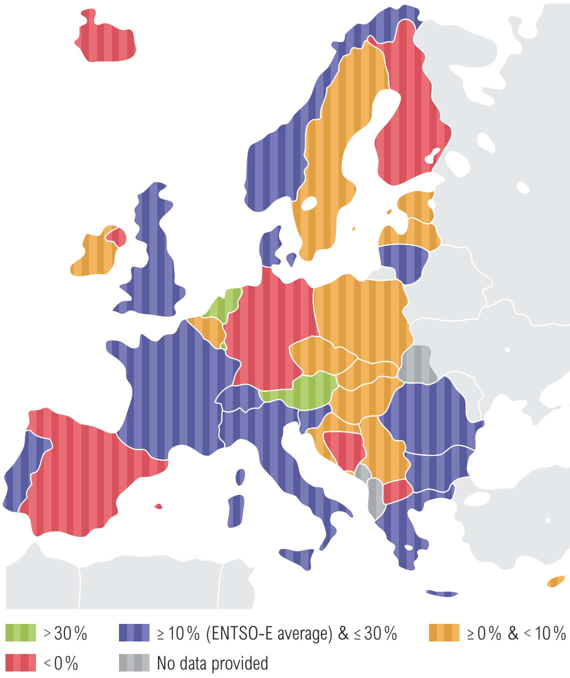


Figure 5.6:
Remaining Capacity minus Adequacy Reference Margin as a part of Reliably Available Capacity per country, Scenario EU 2020, January 2020, 7 p.m.

The situation in each ENTSO-E country is depicted in Figures 5.5 and 5.6. In most of the countries, the difference between RC and ARM is positive.

The countries with the highest share of RC - ARM in RAC are Luxembourg (above 55 %), Austria and the Netherlands (both above 40 %), and Denmark (above 28 %).

The countries with the lowest share of the RC - ARM in RAC are: FYROM (-11 %), Latvia together with Bosnia & Herzegovina and Cyprus (-8 %), Switzerland (-7 %), Serbia (-5 %), Slovenia together with Iceland and Finland (-4 %), Croatia (-6 %), and Germany (-1 %) in 2015.

In 2020, Bosnia & Herzegovina, Germany, Spain, Finland, Northern Ireland, Iceland and FYROM report negative ratios.

Comparison of Scenario EU 2020 and Scenario B

Generation adequacy in most of the situations is better in Scenario EU 2020 than in Scenario B. Nevertheless, in both scenarios, more and more RAC on the whole ENTSO-E power system is left to cope with unexpected load variations or outages etc.

A more exact comparison of these values is given in Table 5.3.

		2012		2015		2020	
	[GW]	Jan	Jul	Jan	Jul	Jan	Jul
Scenario EU 2020	RC	122	189	136	194	162	235
	ARM	78	79	84	85	94	95
	RC - ARM	**44**	**111**	**53**	**109**	**68**	**140**
Scenario B	RC	105	185	115	198	133	217
	ARM	76	80	81	86	91	95
	RC - ARM	**29**	**106**	**34**	**112**	**42**	**122**

Table 5.3:
Comparison of RC and ARM for Scenario EU 2020 and Scenario B

Scenario A and Scenario B

Remaining Capacity shows different trends in Scenario A and Scenario B, according to the different assumptions made for each of them. In Scenario A, the commissioning rate of new units is expected to be much lower (only for guaranteed units), whereas a higher level of decommissioning of older units might be expected. In addition to this, in Scenario B there is a higher development of RES capacity and some kinds of fossil fuels expected, which influences the amount of RC.

In Scenario B, although being generally more optimistic than Scenario A, decreases of RC can be observed between 2015 – 2016 and 2020 – 2025.

The expected values for the whole forecasted period can be seen in Table 5.4. All above-described facts are visible also in Figure 5.7.

	[GW]	2012	2015	2016	2020	2025
Jan	Scenario A	105	98	83	67	
	Scenario B	105	115	115	133	115
Jul	Scenario A	185	181	166	152	
	Scenario B	185	191	197	217	209

Table 5.4:
ENTSO-E RC for Scenarios A & B

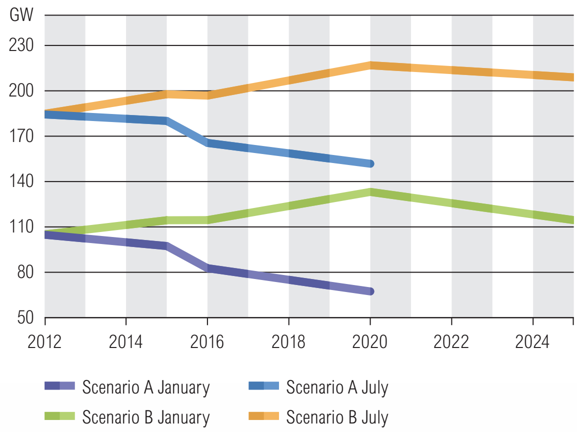


Figure 5.7:
ENTSO-E RC forecast, Scenarios A & B

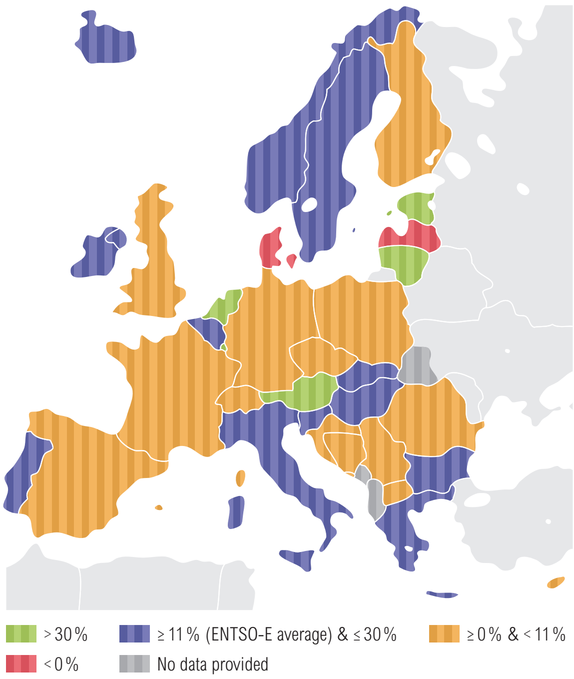


Figure 5.8:
RC as a part of NGC per country in January 2015, Scenario B

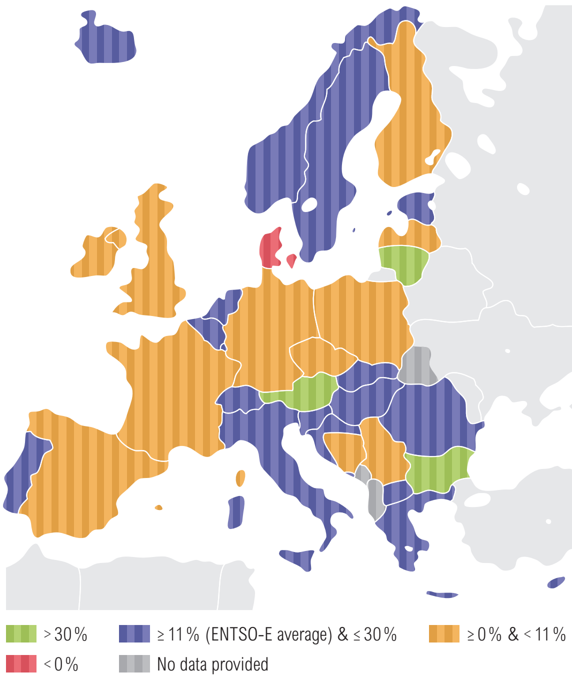


Figure 5.9:
RC as a part of NGC per country in January 2020, Scenario B

Figures 5.8 and 5.9 show RC as a part of NGC per country in 2015 and 2020, in January.

In more than half of the ENTSO-E countries, the share of RC in total NGC is higher than the average ENTSO-E value in both 2015 and in 2020.

The highest levels of RC as part of NGC in 2015 are in Austria (44 %), Luxembourg (37 %), Lithuania (33 %), the Netherlands (32 %) and Estonia (31 %). The lowest values are expected in Denmark (-6 %) and Latvia (-3 %).

In 2020, Austria (51 %), Lithuania (49 %), and Bulgaria (32 %) expect the highest share of RC in NGC. On the contrary, the lowest and only negative RC value (-0.8 GW) shows Denmark (-6 %).

Table 5.5 shows the values of RC - ARM for Scenarios A & B in both reference points. In Scenario A, RC is lower than ARM after 2016 in winter. Scenario B remains with positive values during the whole period.

		[GW]	2012	2015	2016	2020	2025
Jan	Scenario A	Margin against Peak Load	28	28	29	31	
		Spare Capacity	48	51	51	53	
		ARM	**76**	**79**	**80**	**84**	
		RC - ARM	**29**	**18**	**3**	**-17**	
	Scenario B	Margin against Peak Load	28	28	29	31	32
		Spare Capacity	48	52	54	60	65
		ARM	**76**	**81**	**83**	**91**	**97**
		RC - ARM	**29**	**34**	**32**	**42**	**17**
Jul	Scenario A	Margin against Peak Load	31	33	33	35	
		Spare Capacity	48	51	51	54	
		ARM	**79**	**84**	**84**	**89**	
		RC - ARM	**105**	**97**	**82**	**64**	
	Scenario B	Margin against Peak Load	31	33	33	35	37
		Spare Capacity	48	53	54	60	65
		ARM	**80**	**86**	**87**	**95**	**102**
		RC - ARM	**106**	**112**	**110**	**122**	**107**

Table 5.5:
ENTSO-E RC and ARM comparison for Scenario EU 2020

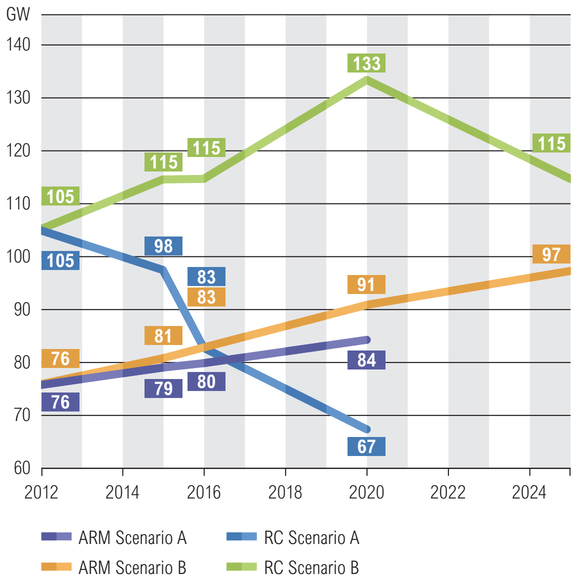


Figure 5.10:
ENTSO-E RC and ARM comparison,
Scenarios A & B, January 7 p.m.

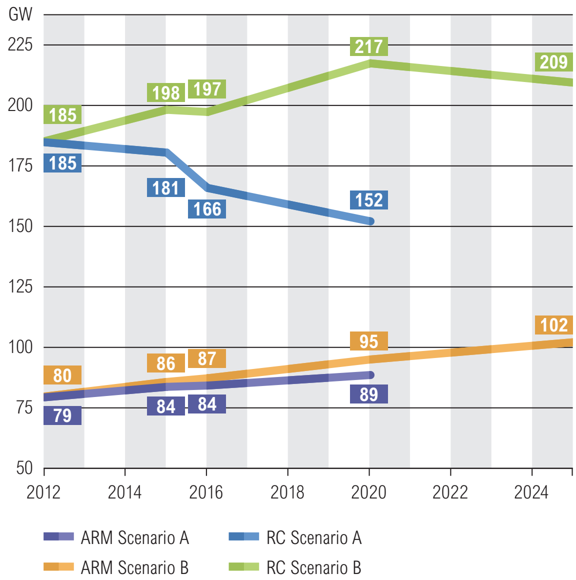


Figure 5.11:
ENTSO-E RC and ARM comparison,
Scenarios A & B, July 11 a.m.

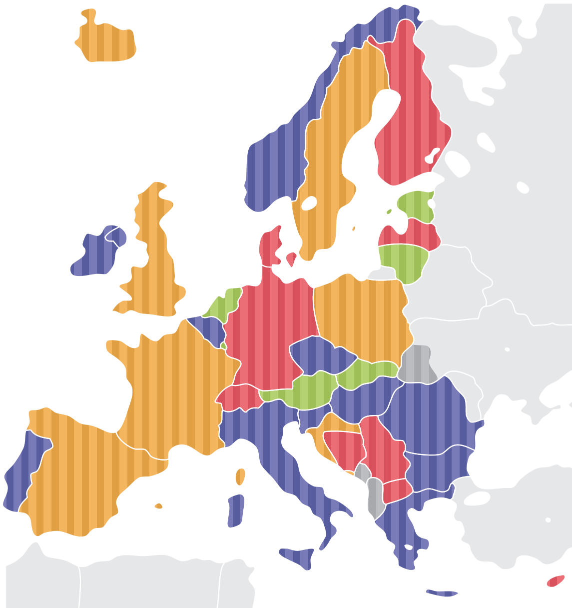
The generation adequacy in most of the situations within the whole ENTSO-E system in Scenario B is expected to be maintained during the whole forecasted period between 2012 and 2025 in both reference points (Figures 5.10 and 5.11). In Scenario A, the generation adequacy is expected to be kept till 2016 in January. After this year, some new generation units seem to be necessary to deal with unexpected load variations within the ENTSO-E power system. No previous statements consider possible transport capacity limitations between countries and/or regions.

As stated before, approximately 62 % of NGC can be considered as RAC for the reference point January 7 p.m.[1] for Scenario B, and 64 % for Scenario A.

Based on this fact, in the 2020 Scenario A reference point January, about 46 GW of RAC is necessary to reach at least today's level of adequacy, which makes about 72 GW in NGC. In July, the RC is sufficient. Nevertheless, in 2020, about 42 GW in RAC seems to be needed to reach today's level of adequacy (69 GW in NGC if 60 % of NGC is to be left as RAC).

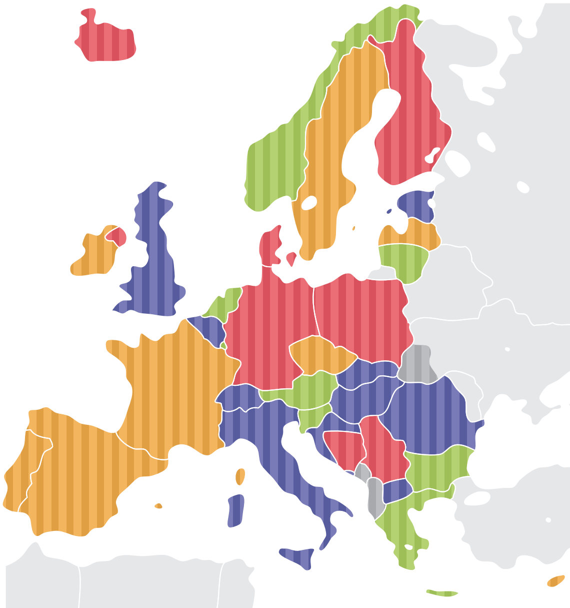
In Scenario B, the RC is higher than ARM during the whole forecasted period. Adequacy should be maintained in each monitored year. The adequacy level in 2020 is expected to be higher than in 2012 by about 13 GW in RAC. In 2025, the adequacy level is lower than today's; therefore, in order to reach today's level of adequacy, the amount of about 12 GW RAC will be needed, which means approximately 19 GW of NGC when considering 62 % of NGC considered as RAC in this case.

[1] For July 11 a.m., it is 60 %.



> 20 % | ≥ 5 % (ENTSO-E average) & ≤ 20 % | ≥ 0 % & < 5 %
< 0 % | No data provided

Figure 5.12:
Remaining Capacity minus Adequacy Reference Margin as a part of Reliably Available Capacity per country, Scenario B, January 2015, 7 p.m.



> 20 % | ≥ 6 % (ENTSO-E average) & ≤ 20 % | ≥ 0 % & < 6 %
< 0 % | No data provided

Figure 5.13:
Remaining Capacity minus Adequacy Reference Margin as a part of Reliably Available Capacity per country, Scenario B, January 2020, 7 p.m.

The situation in each ENTSO-E country is depicted in Figures 5.12 and 5.13. In most of the countries, the difference between RC and ARM is positive.

In 2015, the countries with the highest share of the RC - ARM in their national RAC are Austria (43 %), Luxembourg (39 %) and the Netherlands (30 %). In 2020, Austria (50 %), Lithuania (33 %), Luxembourg (32 %) and Bulgaria (30 %), have the highest values.

The countries with the lowest share in 2015 are Cyprus (-30 %), Denmark (-14 %), Bosnia & Herzegovina (-13 %), Serbia (-11 %) and Latvia (-8 %), followed by Switzerland, FYROM, Finland, Germany, Croatia and Iceland, with ratios between -7 % and 0 %. Bosnia & Herzegovina, Denmark, Northern Ireland, Poland, Serbia, Iceland, Finland, Germany, Cyprus and Spain show a share between zero and -19 %, each in 2020.

5.2 Regional Adequacy Forecast

In Table 5.6 (next page), the regional assessment of generation adequacy is reported for Scenario B and EU 2020 (only the years 2015 and 2020). It is assessed through the comparison of the Remaining Capacity and Adequacy Reference Margin for the whole respective region.

The regional Remaining Capacity was calculated as the sum of the RCs of individual countries within the respective region. The regional Adequacy Reference Margin was calculated as the sum of individual MaPL values and Spare Capacity for a set of countries, where Spare Capacity was set as 5 % of the NGC of the region (i.e. sum of NGCs for individual countries within the respective region).

It is visible that for illustrated years, the RC - ARM is positive for almost all regions and both of the scenarios. This, however, does not prejudice that the RC - ARM at the level of individual countries is positive as well. The exception among all the regions is only RG BS, where in January 2015 and 2020 in Scenario B and in January 2020 in Scenario EU 2020, negative values of RC - ARM are foreseen. However, looking deeper into the importing possibilities of the RG BS, one can see that the region could easily transmit missing electricity from neighboring areas, as its importing capacity seems adequate.

More detailed information about each respective region can be found in Appendix 3. Information about national adequacy of each respective ENTSO-E member can be found in Appendix 4.

		Scenario B				Scenario EU 2020			
		2015		2020		2015		2020	
	[GW]	Jan	Jul	Jan	Jul	Jan	Jul	Jan	Jul
NS Region	RC	42.20	86.40	43.00	87.90	60.10	93.90	63.90	98.40
	Spare Capacity	21.16	21.32	23.70	23.83	21.25	21.33	24.47	24.23
	Margin against Peak Load	3.81	6.86	4.11	7.23	4.91	6.73	5.13	6.89
	ARM	24,97	28.18	27.81	31.06	26.16	27.70	29.60	31.12
	RC - ARM	**17.24**	**58.23**	**15.19**	**56.84**	**33.95**	**66.21**	**34.31**	**67.29**
BS Region	RC	22.20	54.90	21.90	52.80	29.80	60.20	26.40	57.70
	Spare Capacity	20.25	20.48	22.84	23.04	20.22	20.42	23.70	23.53
	Margin against Peak Load	8.74	9.04	9.14	9.34	9.12	9.36	9.41	9.67
	ARM	28.99	29.52	31.98	32.38	29.34	29.78	33.11	33.20
	RC - ARM	**-6.79**	**25.39**	**-10.08**	**20.43**	**0.46**	**30.42**	**-6.71**	**24.51**
CSW Region	RC	24.40	36.80	23.80	40.20	38.30	43.00	42.10	49.30
	Spare Capacity	3.04	3.04	3.37	3.37	3.09	3.09	3.39	3.39
	Margin against Peak Load	6.88	9.74	7.73	10.87	7.38	9.14	8.23	10.47
	ARM	9.92	12.78	11.10	14.24	10.47	12.23	11.62	13.86
	RC - ARM	**14.49**	**24.03**	**12.70**	**24.96**	**27.84**	**30.78**	**30.48**	**35.44**
CSE Region	RC	29.30	45.90	39.90	53.90	27.70	29.20	43.00	60.90
	Spare Capacity	10.29	10.29	12.21	12.22	10.42	10.47	12.54	12.58
	Margin against Peak Load	8.92	9.49	9.91	9.76	10.27	8.89	10.73	9.19
	ARM	19.21	19.78	22.12	21.98	20.69	19.36	23.27	21.77
	RC - ARM	**10.10**	**26.13**	**17.79**	**31.93**	**7.02**	**9.85**	**19.74**	**39.14**
CCS Region	RC	48.10	86.60	57.90	96.00	57.40	72.60	73.50	104.80
	Spare Capacity	3.29	3.30	3.75	3.76	3.26	3.26	3.73	3.23
	Margin against Peak Load	8.35	8.82	8.66	9.05	8.65	8.11	8.75	8.34
	ARM	11.64	12.12	12.41	12.81	11.91	11.37	12.48	11.57
	RC - ARM	**36.47**	**74.49**	**45.50**	**83.20**	**45.50**	**61.24**	**61.02**	**93.23**
CCE Region	RC	28.40	47.20	33.40	51.50	33.50	47.80	36.70	43.00
	Spare Capacity	7.23	7.24	8.01	8.02	7.41	7.46	8.51	8.05
	Margin against Peak Load	3.49	3.26	4.14	3.53	4.95	2.73	5.19	3.03
	ARM	10.72	10.50	12.15	11.55	12.36	10.19	13.70	11.08
	RC - ARM	**17.68**	**36.70**	**21.26**	**39.96**	**21.15**	**37.61**	**23.00**	**31.92**

Table 5.6:
Adequacy Forecast for the ENTSO-E Regions,
Scenarios B & EU 2020, January 7 p.m. and July 11 a.m.

6 General Conclusion

The SO&AF 2012 was prepared based on input data provided by TSOs (national data correspondents) from ENTSO-E member countries at the end of September 2011, with modification till the middle of December 2011 and covers the time period from 2012 to 2025 (depending on the scenario). Assessment and evaluations were done for three scenarios:
- Scenario EU 2020 (based on NREAPs),
- Scenario A ("Conservative Scenario") and
- Scenario B ("Best Estimate Scenario").

More details about scenarios can be found in a separate methodology document.[1)]

Load is expected to increase throughout the whole forecasted period in each scenario. The same expectation applies to consumption as well. The biggest annual average energy consumption growth between 2012 and 2020 in Scenario B is expected in Estonia and FYROM and in Scenario EU 2020, for example, it is Bosnia & Herzegovina or FYROM again. The total energy consumption growth from 2012 to 2020 for the whole ENTSO-E in Scenario EU 2020 is expected to be about 215 TWh (462 TWh in Scenario B between 2012 and 2025). At the same time, for the whole ENTSO-E area, the expected total load growth in Scenario EU 2020 is about 30 GW from 2012 to 2020 (about 80 GW in Scenario B).

The total ENTSO-E Net Generating Capacity (NGC) is increasing in each scenario as well. Of all primary energy sources, the biggest development is reported for renewable energy sources (including renewable hydro generation). The increase in RES capacity (regardless of the scenario) was expected and it is a confirmation of continuous great "popularity" of these kinds of power plants among investors, promoted by different support schemes on national or European level. The development of RES capacity (excluding hydro) still corresponds mainly with the wind farms, solar and biomass power plants' development and is increasing in each scenario and in all reference points (offshore wind farms are becoming more important within the total wind installed capacity mix as well). The total increase of RES from 2012 to 2020 in Scenario EU 2020 is 216 GW (of which 142 GW is wind, 51 GW solar and 16 GW biomass), whereas in Scenario B, within time period 2012 – 2020, it is 194 GW (117 GW is wind, 55 GW solar and 11 GW biomass).

The main developing capacities within fossil fuels are gas power units in each scenario. This increase is continuous from 2012 to 2015, regardless of the scenario. The Netherlands and Cyprus are leaders in the installed capacity of gas power units as a part of NGC in both scenarios, followed, for example, by Hungary and Ireland. Lignite, hard coal and oil power plants are on the decrease in each scenario.

1) More information can be found in a separate methodology document under the following link:www.entsoe.eu/resources/publications/system-development/adequacy-forecasts

The report also notes that the generation adequacy is expected to be maintained during the whole forecasted period in each scenario and in each reference point, even after the expected shut down of German (but also Swiss and Belgian) nuclear power plants after the Fukushima disaster. The only exception is Scenario A, the reference point January, where the generation adequacy is expected not to be kept during the whole period between 2012 and 2020. More precisely, till 2016, no problems are expected in January. But after 2016, about 46 GW of RAC is necessary in January 2020, which will require about 72 GW in NGC to get today's level. When comparing these results to the previous SO & AF 2011, no worsened situation is foreseen.

7 Appendices

7.1 Appendix 1: Reference Documents for Chapter 3 – "2030 Visions"

1. Draft communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee of the Regions – Energy Roadmap 2050 (2011)
   www.endseurope.com/docs/111018a.pdf

2. COM (2011) 658 final, Proposal for a Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC
   ec.europa.eu/governance/impact/ia_carried_out/docs/ia_2011/com_2011_0658_en.pdf

3. Roadmap 2050, European Climate Foundation (2011)
   roadmap2050.eu/downloads

4. "Power Perspectives 2030: on the road to a decarbonised power sector", European Climate Foundation (2011)
   www.roadmap2050.eu/attachments/files/PowerPerspectives2030_FullReport.pdf

5. "Strategic Research Agenda for Europe's electricity networks of the future", European Technology Platform SmartGrids 2035 (draft version 12 September 2011)

6. "World Energy Outlook 2011", International Energy Agency (2011)

7. "ENTSO-E Report Novel and Unconventional Transmission Technologies", ENTSO-E, 19 October 2011 (Draft version for the SDC Approval 27 October 2011)

8. "Research and Development Plan – European Grid towards 2020 Challenges and Beyond", ENTSO-E, 28 October 2011 (First Edition – Update 2011, Draft 1.10)

9. "D1.1 Setup of SUSPLAN Scenarios ", project "Development of regional and Pan-European guidelines for more efficient integration of renewable energy into future infrastructure 'SUSPLAN'", 2009
   www.susplan.eu/fileadmin/susplan/documents/downloads/WP_1/D1.1_main_report.pdf

7.2 Appendix 2: Overview of hypotheses from Chapter 3 – "2030 Visions"

	Vision 1: Slow Progress	Vision 2: Money Rules	Vision 3: Green Transition	Vision 4: Green Revolution
Economic and financial conditions	Less favorable	Less favorable	Favorable	Favorable
Focus of energy politics	National	European	National	European
Focus of R&D research schemes	National	European	National	European
CO_2 prices and primary energy prices	Low CO_2 prices and high primary energy prices	Low CO_2 prices and high primary energy prices	High CO_2 prices and low primary energy prices	High CO_2 prices and low primary energy prices
Electricity demand	Lowest level	Higher than in Vision 1	Higher than in Vision 2	Higher than in Vision 3
Demand response potential	Used as today	Partially used	Partially used	Fully used
Electric vehicles	No commercial break through of electric plug-in vehicles	Electric plug-in vehicles (with flexible charging)	Electric plug-in vehicles (with flexible charging)	Electric plug-in vehicles (with flexible charging and generation)
Heat pumps	Implemented (although not evenly spread around Europe)	Implemented (although not evenly spread around Europe)	Implemented (although not evenly spread around Europe)	Much more heat pumps implemented (although not evenly spread around Europe)
Back-up generation	Level of back-up generation higher than in Vision 2 but lower than in Vision 4	Lowest level of back-up generation	Highest level of back-up generation	Level of back-up generation higher than in Vision 2 but lower than in Vision 3
Nuclear	National view	Public acceptance	National view	Public acceptance
CCS	Not commercially implemented	Partially implemented	Not commercially implemented	Fully implemented
Storage	As planned today	As planned today	Decentralized storage (limited amount but higher than in Vision 4)	Mainly additional centralized hydro storage + some decentralized storage
Smart grid solutions	Partially implemented	Fully implemented	Partially implemented	Fully implemented

Table 7.1:
Overview of hypotheses from Chapter 4 – "2030 Visions"

7.3 Appendix 3: Regional Adequacy Forecast

This Appendix contains the adequacy assessment of the individual regional groups of ENTSO-E. Each of the following paragraphs consists of the results of two different assessment methods, i.e. the existing method and a new method based on market modelling.

The existing method uses the comparison of Remaining Capacity and the Adequacy Remaining Margin parameters. This is the way the adequacy has been assessed in SO&AF reports for a long period and, in this report, it has been maintained because the SO&AF 2012 aims at updating the assessment of SO&AF 2011.

The colors displayed in the maps illustrate the worst situation for the comparison of RC and the ARM parameters (RC - ARM) for each country in each region of ENTSO-E in 2020 for both Scenarios B & EU 2020 at the reference points January 7 p.m. and July 11 a.m.:

Red color means that RC - ARM is negative at both reference points,

yellow color means that RC - ARM is zero or negative at one of reference points and

green color means that RC - ARM is positive at both reference points.

grey color means that no data was provided.

With the introduction of market modelling in the Ten-Year Network Development Plan 2012, new promising methods for adequacy assessment became within reach. In potential, market modelling allows for many improvements of the adequacy assessment. For instance, improvements with respect to the assessment of the adequacy value of transmission capacities and the option to introduce probabilistic assessment methods. As a first step to investigating the possibilities of "Market Modelling-Based Adequacy Assessment methods", the following adequacy indicators, extracted from the regional market studies, carried out within the TYNDP 2012 process, are presented in this appendix:

- **LOLE** – Loss of Load Expectation
  represents the expected number of hours per year, where available supply is smaller than the load (in hours per year)
- **LOEE** – Loss of Energy Expectation
  (or EENS – Expected Energy not Served) represents the expected amount of energy per year that cannot be served because of insufficient supply (in GWh)
- **DUMP** – Dumped Energy
  indicates excess production situations where production resources cannot be reduced far enough to meet the load (in GWh)

The results in each region for both the existing and the new method are reported on a country level. It should be noted that the outcomes of the existing and new methods cannot directly be compared, due to the different definition and meaning of the existing and new indicators. From a general point of view, low levels of the (RC - ARM) indicators in the existing method should be accompanied by high levels of LOLE and LOEE/EENS in the market modelling-based methods. It should also be noted that conclusions drawn from both methods might not completely be in line, due to the fact that the existing method is based on more updated datasets available. Finally, for countries belonging to more than one RG, the application of the market modelling-based method may bring different results. Notwithstanding that and in order to make the assessment sounder for those countries, the results have been checked to be in line with the national standards, when applicable.

If the country in the map is colored by the grey color, it means that this country has not provided any data during the data collection process.

Final conclusions from the new method can, therefore, not be drawn.

7.3.1 Regional Group North Sea (RG NS)

Remaining Capacity & Adequacy Reference Margin

In Scenario B, the Remaining Capacity is forecasted to be higher than the Adequacy Reference Margin for the Regional Group North Sea (Belgium, Denmark, Germany, Great Britain, France, Ireland, Luxembourg, the Netherlands, Northern Ireland and Norway) from now until 2020 at all reference points. In 2020, the prognosis is expected to be negative for Denmark, both for the summer and the winter reference. For Northern Ireland and Germany, the winter reference is slightly negative. For all the other countries, both the summer and the winter prognosis are expected to be positive.

In Scenario EU 2020, the Remaining Capacity is forecasted to be higher than the Adequacy Reference Margin for the whole RG NS from now until 2020 at all reference points. In 2020, the prognosis is expected to be negative for Northern Ireland (winter) and Germany (winter). For all the other countries, both the summer and the winter prognosis are expected to be positive.

The regional assessment for the Regional Group North Sea in both scenarios indicates that if no constraints occur on the transmission network, some generating capacity should be available for exports out of the Regional Group North Sea, in all time horizons and at all reference times.

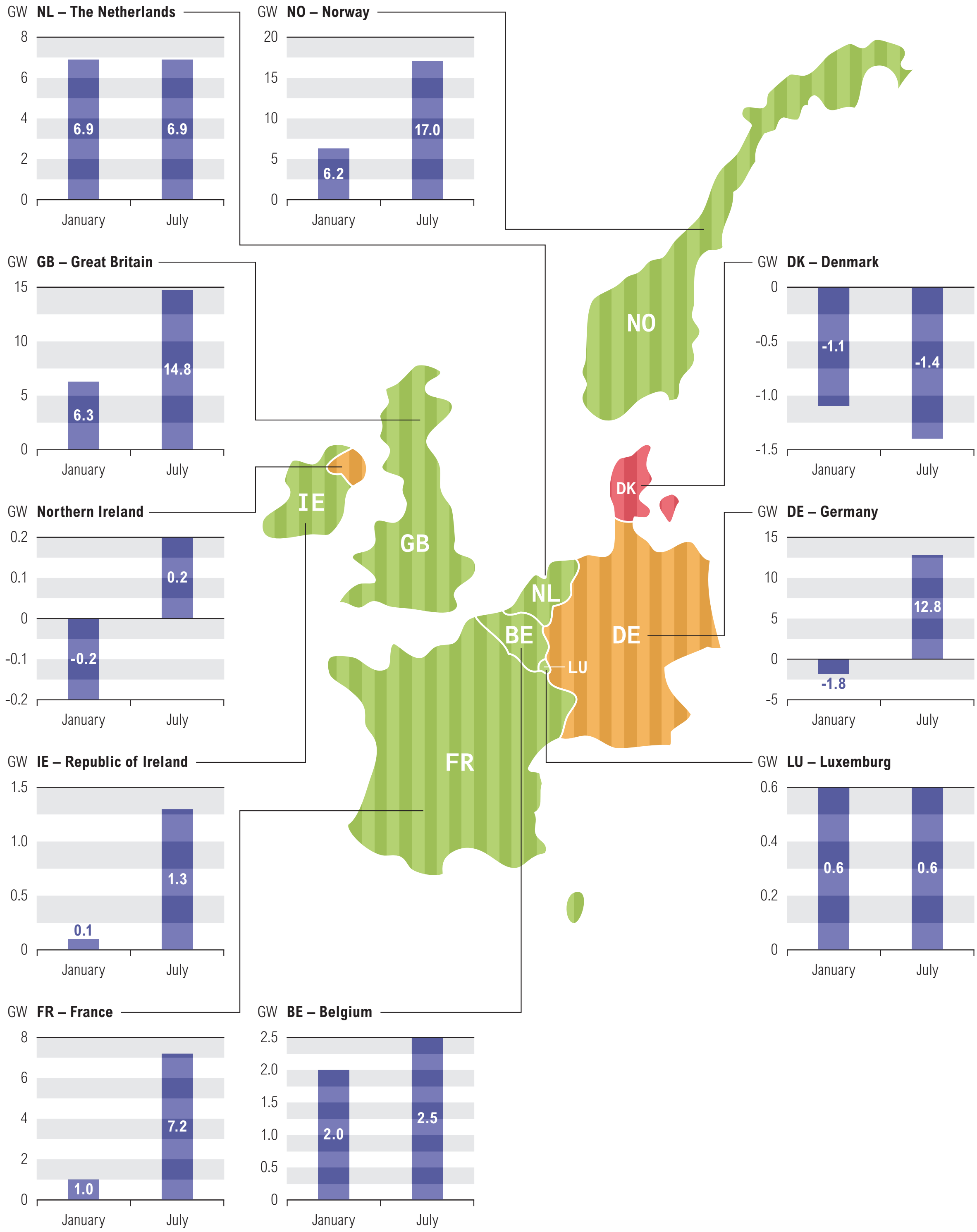


Figure 7.1:
RC - ARM for each country within RG NS for January (7 p.m.) and July (11 a.m.) 2020, Scenario B

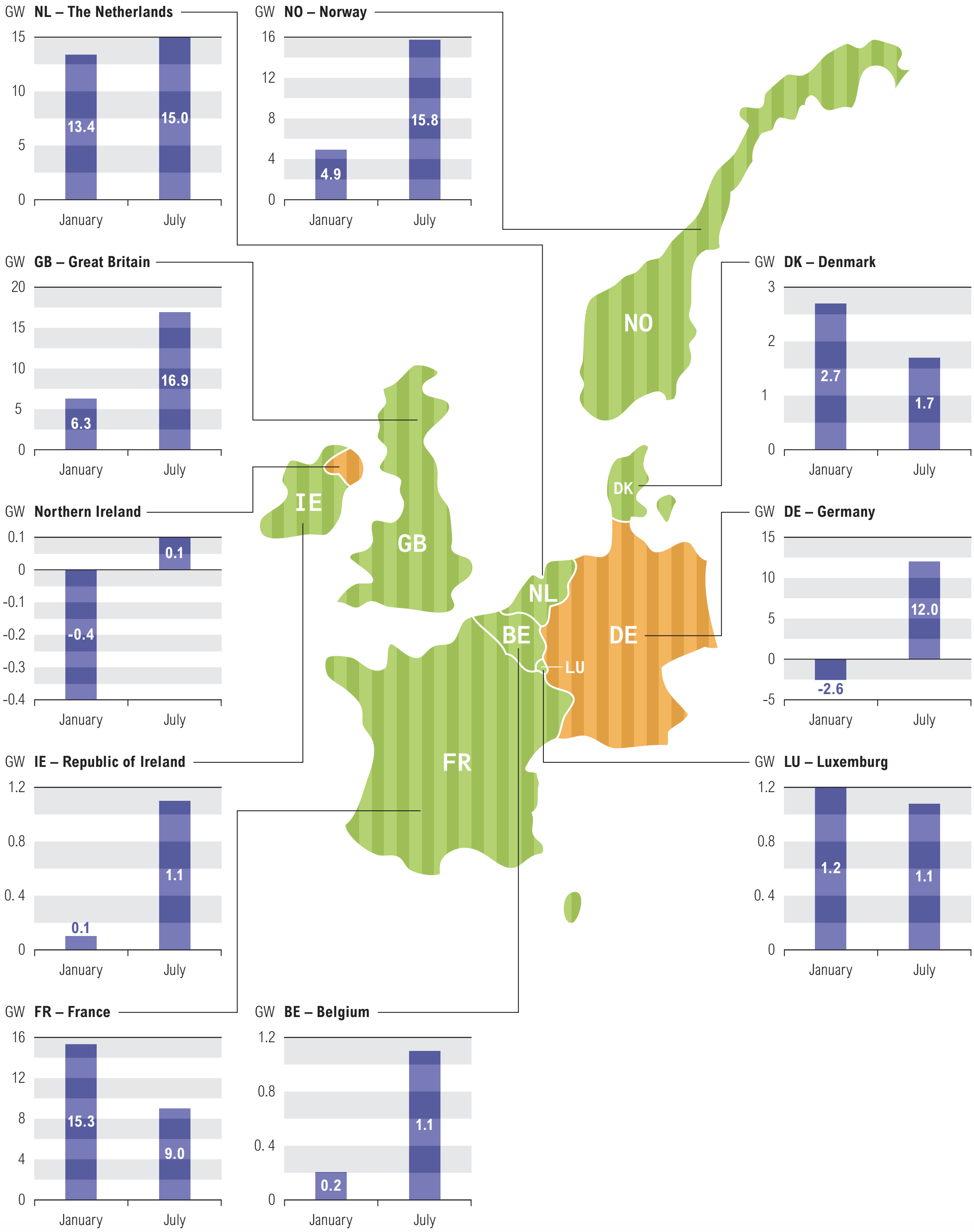


Figure 7.2:
RC - ARM for each country within RG NS for January (7 p.m.) and July (11 a.m.) 2020, Scenario EU 2020

Market Modelling-Based Assessment of Adequacy Indicators

Models used for the adequacy assessment were ANTARES and PowrSym4. Both models use a Monte Carlo method to take into account several uncertainties.

Uncertainties taken into account:
- load uncertainties
- availability of thermal generating resources
- hydro uncertainties
- wind uncertainties

Uncertainty correlations were assumed regarding severe load conditions in northwest Europe.

Main conclusions for the grid configuration in 2015 and grid configuration in 2020 variants are as follows:
- High level of adequacy in all countries, both in terms of LOLE and ENS.
- Only a small reduction of dump power between grid variants.

Conclusions from the isolated cases (i.e. grid configuration as today, theoretical case):
- Results show dependency for many countries on connections to neighboring countries to guarantee generation adequacy .
- Comparison of the results from RG NS and RG BS show that LOLE and EENS in DK, NO, and SE are much higher in the RG NS results; further investigation is needed to find the cause of these deviations.
- In addition to comparison with RG BS, results should also be compared to other RGs for those countries represented in more than one ENTSO-E region.

Feedback from the TSOs with respect to the level of adequacy, compared to the national standards:
- Not all countries have their own national standards.
- The adequacy levels are compliant with the national standards for grid 2015 and 2020 (for all countries that are reported to have national standards).
- No compliancy for theoretical case grid configuration as today for many countries, but this variant is not a realistic case.

The results of the analyses and aforementioned facts are summarized in the following tables (Tables 7.2 and 7.3).

	Grid capacities (isolated system)			Grid capacities as expected in 2015			Grid capacities as expected in 2020			Comment on the level of adequacy
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	compared to the national standards in each scenario
BE	1.8	0.6	919.5	0.0	0.0	0.5	0.0	0.0	0.1	The Ministry of Energy that is responsible for the long term assessment of the electricity supply-demand balance in Belgium does not have a specific probabilistic criteria. However, the probabilistic adequacy criterion for an autonomous electricity supply-demand balance in Belgium used by the regulator (Commission for Electricity and Gas Regulation – CREG) is a LOLE level set at maximum 16 hours / year. This criterion is respected in the simulations with grid considered as an isolated system.
DE	0.2	0.1	1,362.2	0.0	0.0	1.9	0.0	0.0	0.1	These analyses indicate that there are no serious problems with the german System Adequacy. There is some LOLE for the BTC0 scenarios, but these are only a theoretical cases.
DK	552.4	205.2	1,393.9	0.0	0.0	14.2	0.0	0.0	0.0	BTC0: We have not made the exact same calculations. From other studies, we estimates the results to be wrong with a factor of 10.
FR	57.6	322.6	0.2	0.2	0.5	0.0	0.1	0.1	0.0	The adequacy indicators are in line with national standards, except for BTC0
GB	0.1	0.1	968.8	0.0	0.0	53.8	0.0	0.0	0.4	In the fully liberalized GB market there are no national adequacy standards that correspond directly with these being calculated here. There are planning standards to plan the long-term development of the system and ensure adequate Transmission capacity is available. There is no mechanism in the GB market to fund generation over and above the reserve capacity that the System Operator contracts for. In essence it is for the market to provide adequate generation and respond to the relevant market signals. Our long-term plans assume the market responds to the relevant signals, therefore it is to be expected that any LOLE and EENS calculations are zero or close to zero.
IE	104.6	30.2	1,091.6	1.0	0.2	454.3	1.0	0.2	427.4	Ireland's adequacy standard is 8 hours Loss of Load Expectation (LOLE). The LOLE result of 1 hour for grid capacities expected in 2015 and 2020 comply with this standard. With regards to the case of grid considered as an isolated system results, the methodology to calculate capacity adequacy used in Ireland takes interconnection in account so the case of grid considered as an isolated system result is not seen as relevant.
LU	8,734.7	3,856.0	0.5	0.1	0.0	0.0	0.1	0.0	0.0	
NI [1)]	20.3	1.8	2,436.4	0.3	0.1	418.7	0.3	0.1	392.9	Northern Ireland's standard is 4.9 hours Loss of Load Expectation (LOLE). Following the completion of the additional 2nd north – south tie-line in 2017 between Northern Ireland and Ireland, generation adequacy analysis is consolidated into an all-island analysis where a standard of 8 hours LOLE is applied. The LOLE result of 0.3 hours for grid capacities considered in 2015 and 2020 comply with both the Northern Ireland and all-island standards. With regards to the case of grid considered as an isolated system results, the methodology to calculate capacity adequacy used in Northern Ireland takes interconnection into account so the case of grid considered as an isolated system result is not seen as relevant.
NL	0.0	0.0	606.5	0.0	0.0	0.1	0.0	0.0	0.1	The criterion used for the Dutch adequacy assessment is a maximum Loss of Load Expectation (LOLE) of 4 hours. Results for all scenarios and grid variants comply with this criterion.
NO	336.1	604.7	17,068.1	0.0	0.0	200.9	0.0	0.0	0.0	
SE	50.7	17.6	901.5	0.0	0.0	39.6	0.0	0.0	0.0	LOLE and ENS results for grid considered as an isolated system deviate a lot from the results for Sweden in the RGBS; in the case of grid in 2015 and 2020 everything is OK.

Table 7.2:
Adequacy indicators for Scenario B

1) GB Northern Ireland

	Grid capacities (isolated system)			Grid capacities as expected in 2015			Grid capacities as expected in 2020			Comment on the level of adequacy
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	compared to the national standards in each scenario
BE	1.8	0.6	919.5	0.0	0.0	0.2	0.0	0.0	0.0	See "Results Scenario B"
DE	50.6	88.9	790.9	0.0	0.0	0.1	0.0	0.0	0.0	
DK	552.4	205.2	1,393.9	0.0	0.0	7.0	0.0	0.0	0.0	
FR	57.6	322.6	0.2	0.2	0.5	0.0	0.1	0.1	0.0	
GB	0.1	0.1	968.8	0.0	0.0	55.5	0.0	0.0	0.4	
IE	104.6	30.2	1,091.6	1.0	0.2	456.8	1.0	0.2	430.7	
LU	8,734.7	3,856.0	0.5	0.1	0.0	0.0	0.1	0.0	0.0	
NI[1)]	20.3	1.8	2,436.4	0.3	0.1	413.0	0.3	0.1	386.0	
NL	0.0	0.0	606.5	0.0	0.0	0.0	0.0	0.0	0.0	
NO	336.1	604.7	17,068.1	0.0	0.0	170.4	0.0	0.0	0.0	
SE	50.3	15.8	834.9	0.0	0.0	22.0	0.0	0.0	0.0	

Table 7.2:
Adequacy indicators for Scenario B, nuclear variant

7.3.2 Regional Group Baltic Sea (RG BS)

Remaining Capacity & Adequacy Reference Margin

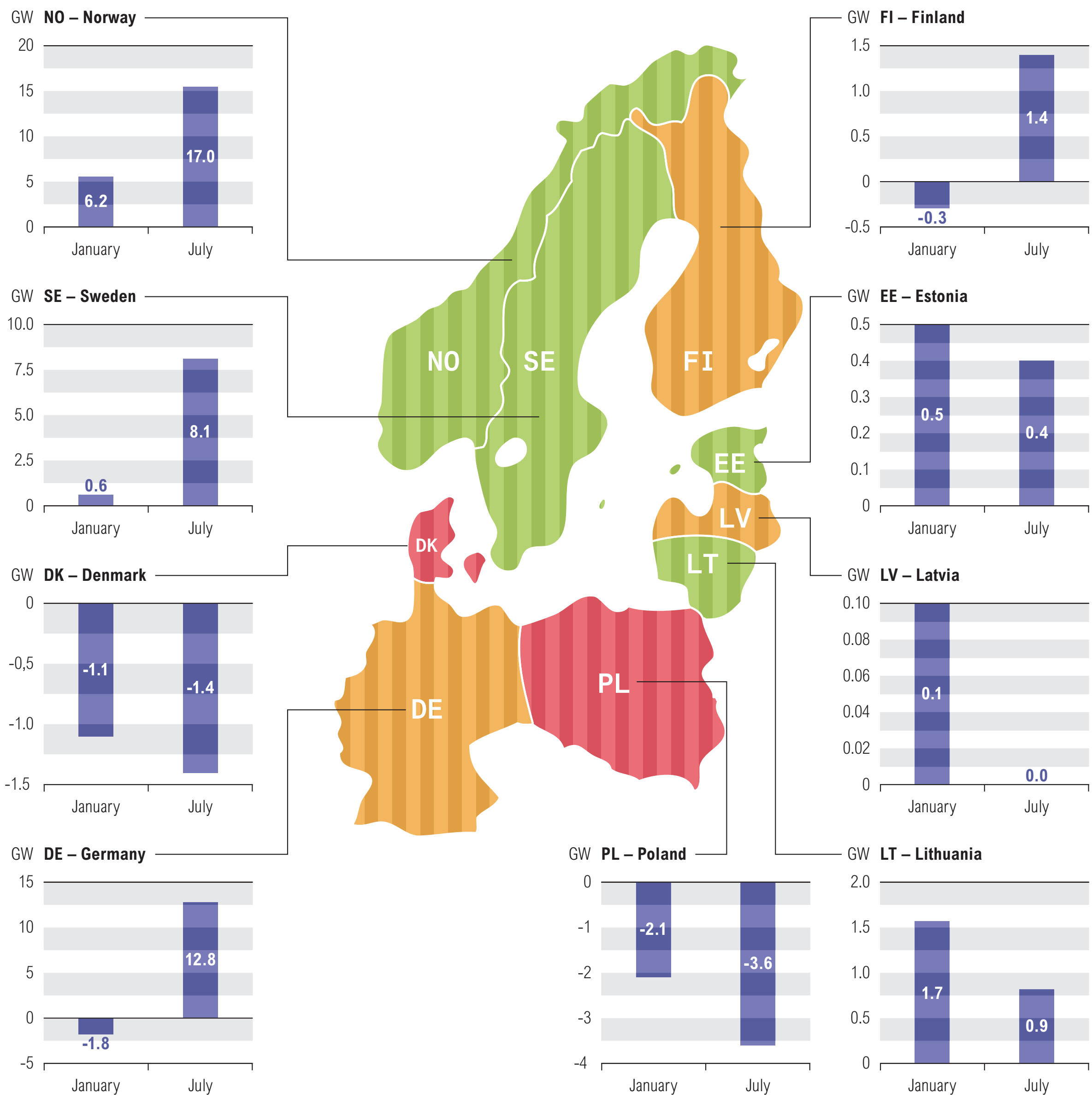


Figure 7.3:
RC - ARM for each country within RG BS for January (7 p.m.) and July (11 a.m.) 2020, Scenario B

Figure 7.3 shows that 4 of 9 countries report positive RC - ARM values and 2 countries (Denmark and Poland) show negative RC - ARM values for both reference points in 2020. Germany and Finland show negative RC - ARM values just for January 2020 and Latvia reports a zero RC - ARM value for July 2020.

The situation in 2015 is slightly different compared to the year 2020: Norway, Sweden, Estonia and Lithuania report positive values, and Denmark and

Latvia report negative RC - ARM values for both reference points. Finland and Germany show negative RC - ARM values just for January, and Poland only for the July reference point.

For Scenario EU 2020, 4 of 9 countries report positive RC - ARM values for both January and July reference points. Germany and Finland show negative RC - ARM values just for January, and Poland only for July; Lithuania and Latvia report zero RC - ARM values for the July reference point.

When we compare the situation in 2015, Denmark, Norway, Sweden, and Estonia report positive RC - ARM values for both reference points. Finland and Germany, on the other hand, report negative RC - ARM values just for January, and Poland only for the July reference point.

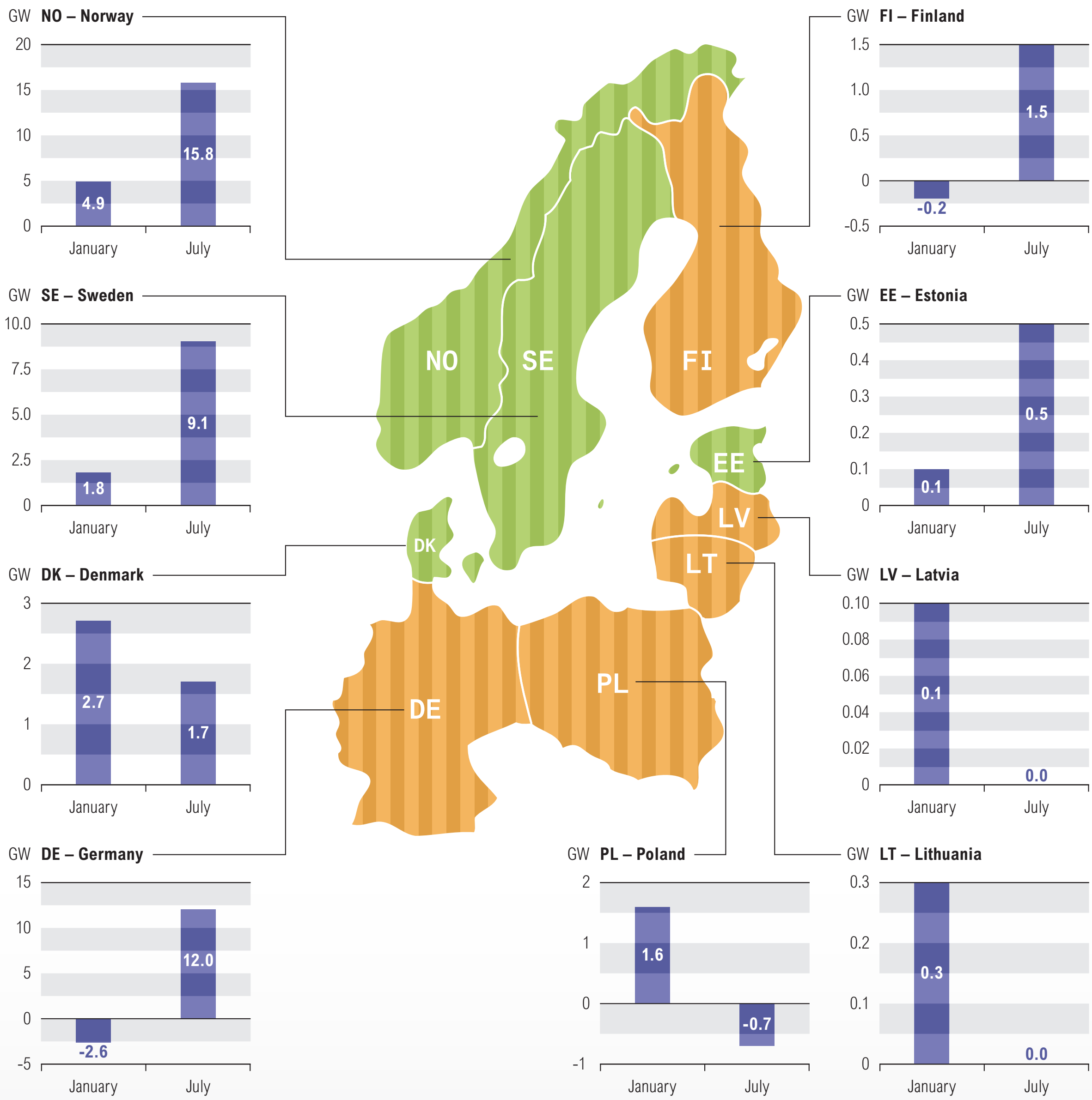


Figure 7.4:
RC - ARM for each country within RG BS for January (7 p.m.) and July (11 a.m.) 2020, Scenario EU 2020

Market Modelling-Based Assessment of Adequacy Indicators

The model used for the Adequacy Indicators' calculation is called MAPS (Multi Area security analysis of large-scale electric Power Systems). It was developed by Vattenfall Company at the beginning of the 90s.

The model is belonging to the class of models applying non-sequential Monte Carlo simulation. Demand and generation is modelled in each area with limited transmission capacity between areas, where the maximum number of allowed areas to model is 100. Cables outside the modelled area are treated as generation nodes with half of the cable capacity. Demand is modelled as a curve of 1,080 hours of peak period load, together with forecast uncertainties, due to cold and mild winters, with 10 levels of corresponding probabilities. Generation is described in a power plant unit level, which is generation capacity together with its forced outage rate. Between areas, limited transmission capacity is modelled together with probability of the transmission capacity to be in operation. Since no reserves are included, the results are valid for a market failure.

The following countries were modelled in the study:
- Norway: 7 areas
- Sweden: 4 areas
- Denmark: 2 areas
- Finland: 2 areas
- Estonia, Latvia and Lithuania: 1 area each

Since the task was to provide one figure for LOLE and one figure for EENS per country, and since several countries in the region are divided into several subareas, the highest LOLE for the respective subarea and the sum of EENS for all subareas was used for each respective country of RG BS.

The severe load situation was the main assumption for all countries, and availability for wind power was set to 6% for all Baltic and also Nordic countries. Since neither Germany nor Poland have delivered their data for Scenario B, year 2020 with nuclear phase out, that scenario has been performed with the following simplifications:
- All connections outside the modelled areas, except to the United Kingdom and Russia, have been put to zero.
- For areas with connections to Germany, the same amount of production as the size of the connections to Germany has been removed. This has not been done for the connection between Germany and Jylland (Denmark); that connection has just been put to zero.

The results of the analyses are summarized in the following tables (Tables 7.4 and 7.5).

	Grid capacities (isolated system)			**Grid capacities as expected in 2015**			**Grid capacities as expected in 2020**			**Comment on the level of adequacy**
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	compared to the national standards in each scenario
DK	0.88	7.093	—	0	0.001	—	0	0	—	The adequacy compared are in line compared to national standards, except for the grid considered as an isolated system.
EE	28.91	2.483	—	0	0.000	—	0	0	—	The adequacy compared are in line compared to national standards, except for the grid considered as an isolated system.
FI	89.35	57.324	—	0	0.036	—	0	0	—	The adequacy compared are in line compared to national standards, except for the grid considered as an isolated system.
LT	0.00	0.000	—	0	0.000	—	0	0	—	The adequacy compared are in line compared to national standards
LV	0.00	0.000	—	0	0.000	—	0	0	—	The adequacy compared are in line compared to national standards
NO	0.88	0.335	—	0	0.000	—	0	0	—	The adequacy compared are in line compared to national standards, except for the grid considered as an isolated system.
SE	0.88	0.245	—	0	0.006	—	0	0	—	The adequacy compared are in line compared to national standards, except for the grid considered as an isolated system.

Table 7.4:
Adequacy indicators for Scenario B

	Grid capacities (isolated system)			**Grid capacities as expected in 2015**			**Grid capacities as expected in 2020**			**Comment on the level of adequacy**
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	compared to the national standards in each scenario
DK	0.88	7.093	—	0	0.042	—	0	0.013	—	The adequacy compared are in line compared to national standards. Except for the grid considered as an isolated system.
EE	28.91	2.483	—	0	0.000	—	0	0.000	—	The adequacy compared are in line compared to national standards. Except for the grid considered as an isolated system.
FI	89.35	57.324	—	0	0.081	—	0	0.000	—	The adequacy compared are in line compared to national standards. Except for the grid considered as an isolated system.
LT	0.00	0.000	—	0	0.000	—	0	0.000	—	The adequacy compared are in line compared to national standards
LV	0.00	0.000	—	0	0.000	—	0	0.000	—	The adequacy compared are in line compared to national standards
NO	0.88	0.335	—	0	0.000	—	0	0.000	—	The adequacy compared are in line compared to national standards. Except for the grid considered as an isolated system.
SE	0.88	0.245	—	0	0.049	—	0	0.005	—	The adequacy compared are in line compared to national standards. Except for the grid considered as an isolated system.

Table 7.5:
Adequacy indicators for Scenario B, nuclear variant

The Baltic Sea region does not notice any dumped energy for Scenario B, year 2020, and also for Scenario B, year 2020 with nuclear shutdown.

This may be due to the fact that the results from the market model were used (the EMPS model), and are printed out in ten blocks per week where each block represents an average number of hours, making the hours in which the possibility of dumped energy exist not captured.

7.3.3 Regional Group Continental South West (RG CSW)

Remaining Capacity & Adequacy Reference Margin

In Scenario B, lower levels (than in Scenario EU 2020) of adequacy are observed, but on the contrary, no deficits are foreseen, meaning that Remaining Capacity is expected to be higher than the Adequacy Remaining Margin between 2012 and 2025.

In January 2020 and onwards, however, the extra capacity in the Regional Group South West is no higher than 2.3 GW. This is the consequence of the French and Portuguese perspectives on the Remaining Capacity not being as optimistic as in Scenario EU 2020.

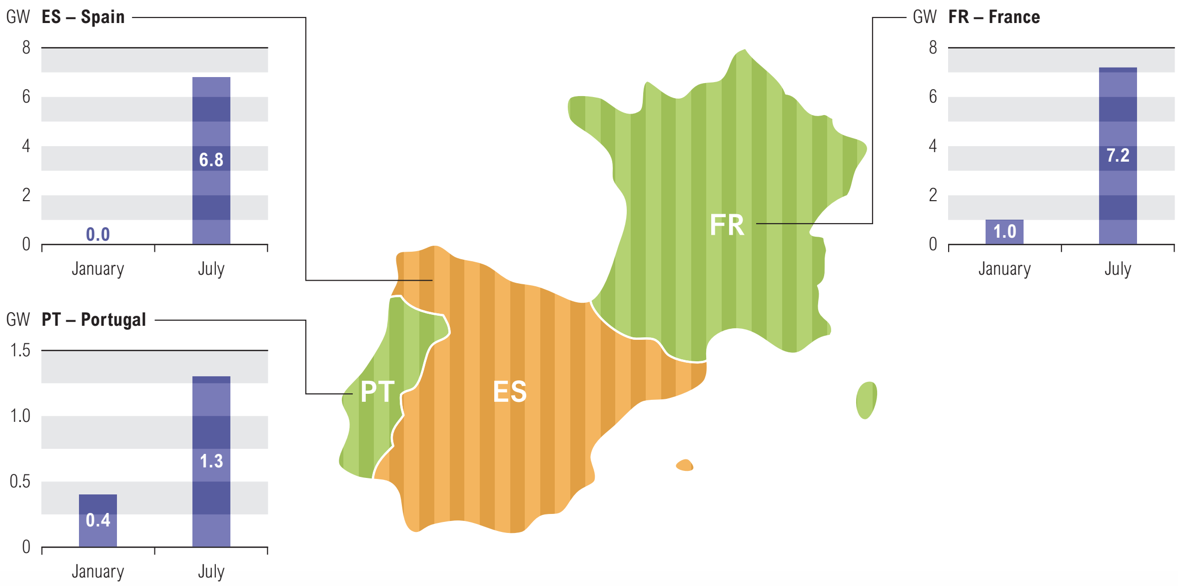


Figure 7.5:
RC - ARM for each country in RG CSW for January (7 p.m.) and July (11 a.m.) 2020, Scenario B

In the Regional Group South West (France, Portugal and Spain), under Scenario EU 2020, Remaining Capacity is expected to be higher than the Adequacy Remaining Margin during the analyzed period, except for Spain in January 2020.

In spite of the deficit (of 0.8 GW) foreseen for Spain in January 2020, there is extra capacity of about 19 GW in the region under this situation.

Should no constraints occur in the transmission network, the overall capacity that can be potentially exported to other regions (i.e. which result from subtracting ARM from RC) is expected to remain always above 16 GW during the period from 2012 to 2020. Since annual peak load is observed during the winter period for the three countries, exportable capacity is particularly high (> 21 GW) during the summer reference point.

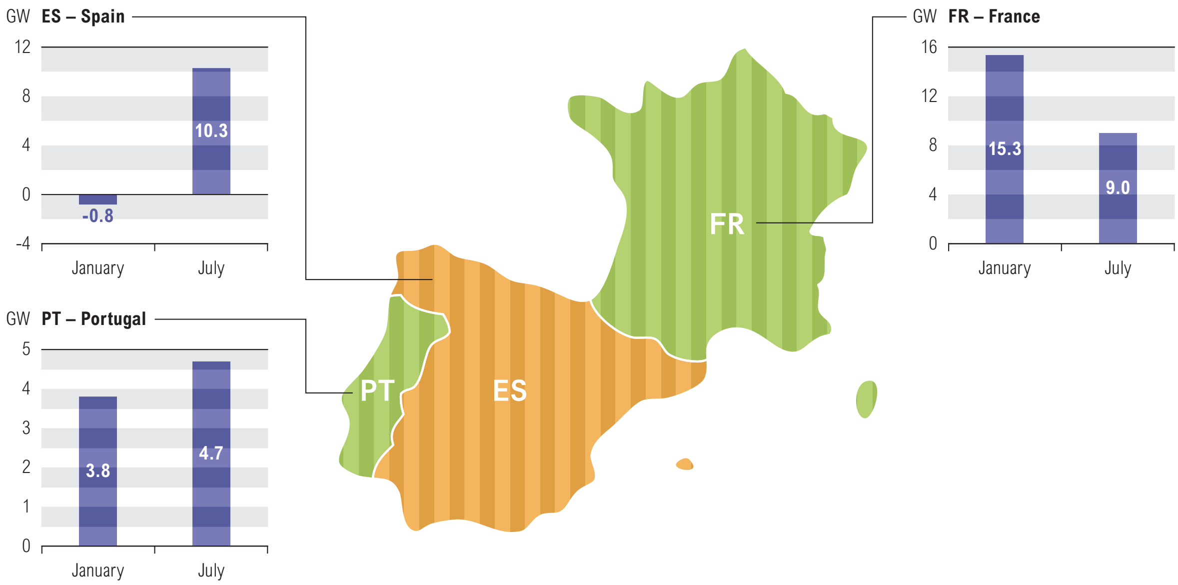


Figure 7.6:
RC - ARM for each country in RG CSW for January (7 p.m.) and July (11 a.m.) 2020, Scenario EU 2020

Market Modelling-Based Assessment of Adequacy Indicators

For the Adequacy Indicator assessment, the ANTARES software (developed by RTE) and RESERVAS software (developed by REE & REN) have been used. Both are adequacy Monte Carlo simulators.

The following uncertainties were taken into account:
- Load, including sensitivity to temperature,
- wind condition,
- hydro conditions (i.e. dry or average or wet in ANTARES, and a series of monthly reservoir volumes in RESERVAS) and
- availability of generating units (i.e. forced outages and scheduled maintenances).

The following correlations regarding uncertainties were taken into account:
– wind – spatial correlation between countries (ANTARES)
– load – spatial correlation,
  i.e. cold in France = cold everywhere (ANTARES)
– hourly load, wind time series and hydro generation (RESERVAS)

The results of the analyses are summarized in the following tables (Tables 7.6 and 7.7).

	Grid capacities (isolated system)			**Grid capacities as expected in 2015**			**Grid capacities as expected in 2020**			**Comment on the level of adequacy**
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	compared to the national standards in each scenario
ES	0.45	0.7	2160	0.01	0.01	590	0.01	0.01	332	National standard respected in all situations
FR	45.17	252.07	0	1.05	2.98	0	0.55	1.60	0	National standard respected with the case of grid capacities as expected in 2015 (LOLE < 3 h)
PT	0.00	0.00	1129	0.00	0.00	491	0.00	0.00	388	National standard respected in all situations

Table 7.6:
Adequacy indicators for Scenario B

	Grid capacities (isolated system)			**Grid capacities as expected in 2015**			**Grid capacities as expected in 2020**			**Comment on the level of adequacy**
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	compared to the national standards in each scenario
ES	0.45	0.70	2160	0.01	0.01	606	0.01	0.01	343	National standard respected in all situations
FR	45.17	252.07	0	1.07	3.03	0	0.57	1.61	0	National standard respected with grid capacities as expected in 2015 (LOLE < 3h)
PT	0.00	0.00	1129	0.00	0.00	497	0.00	0.00	394	National standard respected in all situations

Table 7.7:
Adequacy indicators for Scenario B, nuclear variant

Probabilistic methodologies and indexes use very different methodologies, compared to the deterministic indexes of system adequacy. The new context of very high RES penetration, especially in the case of the Spanish System, suggests that reference criteria for probabilistic methodologies should be further tested for a clear interpretation of results, before raising conclusions about system adequacy. This said, results of LOLE for the Spanish System seem to generally show the adequacy margin slightly higher than deterministic methods.

7.3.4 Regional Group Continental South East (RG CSE)

Remaining Capacity & Adequacy Reference Margin

The RC in Scenario B is forecasted to be higher than the ARM for the overall RG CSE (Bosnia & Herzegovina, Bulgaria, Croatia, FYROM, Greece, Hungary, Italy, Montenegro, Romania, Serbia and Slovenia) from now until 2020 at all reference points.

In all studied years till 2020, this regional extra capacity is expected to be lower at the winter reference point, with the absolute lowest additional capacity appearing in 2016. If no constraints occur in the transmission

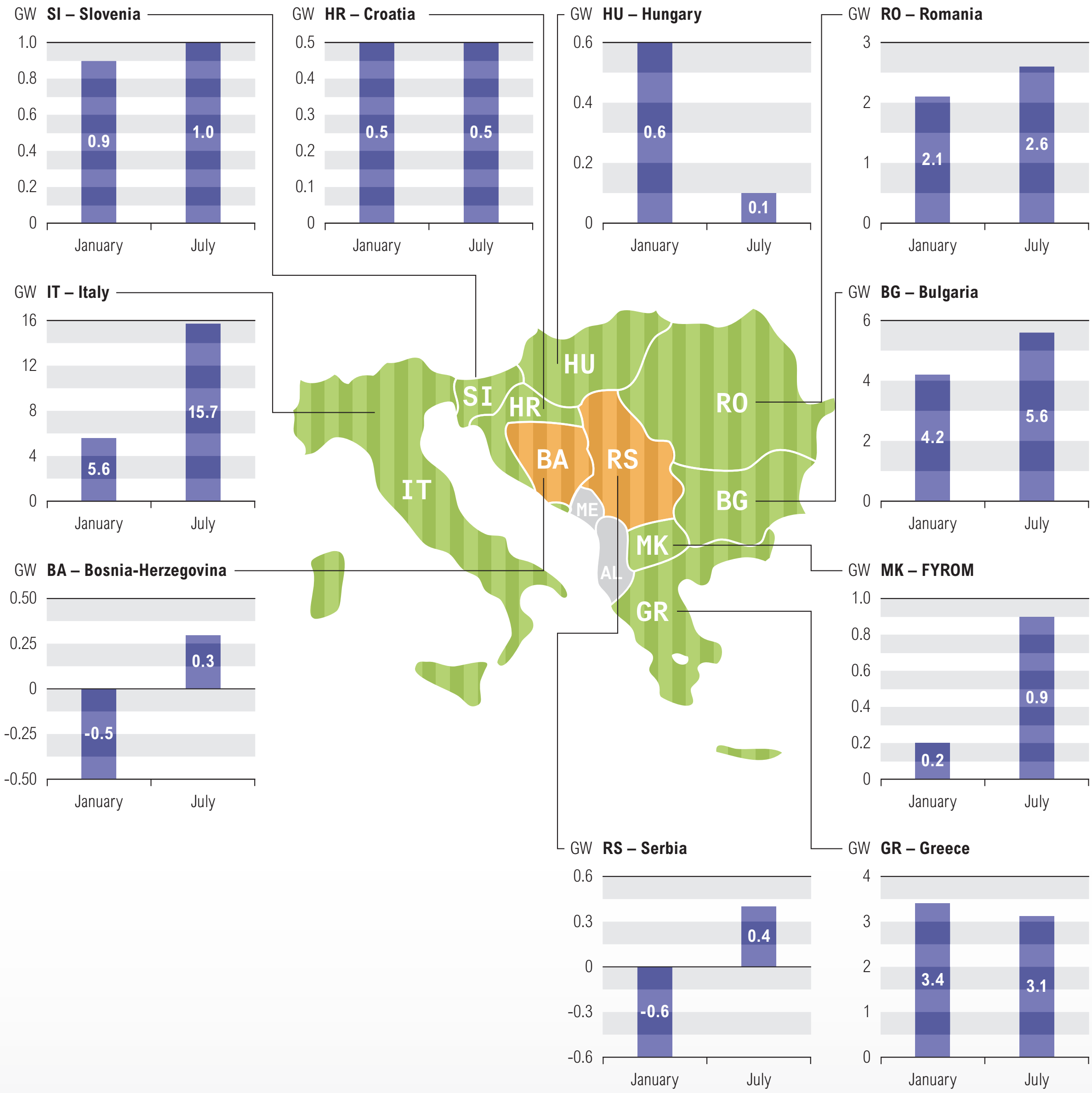


Figure 7.7:
RC - ARM for each country within RG CSE for January (7 p.m.) and July (11 a.m.) 2020, Scenario B

network, the overall capacity that can be potentially exported to other regions is expected to remain always at no less than 4 GW during the period 2012 – 2020.

The regional remaining capacity is expected to be higher than the ARM at both the reference points in each time horizon. It should be noted that the most important characteristic of the CSE region comprises the significant role of Italy, which represents more than 50 % of the total Net Generating Capacity and Load of the region, thus affecting to a great extent the assessment of the various regional adequacy indicators.

Regarding the summer reference point, the highest regional extra capacity is expected to happen in 2020, exceeding 30 GW.

Four countries of the RG CSE (Bulgaria, Greece, Romania and Slovenia) have a positive assessment for the RC - ARM criterion at all reference points from 2015 onward. The same is also valid for Bosnia & Herzegovina and Italy, except for the winter of years 2020 and 2025. FYROM has a positive assessment for the RC - ARM criterion at all reference points from 2016 onward. Serbia has a negative assessment of the RC - ARM criterion for all winter reference points and a positive assessment for all summer reference points. Croatia develops equal values for RC and ARM at all reference points up to year 2016 and has a positive assessment for the RC - ARM criterion at all reference points from 2020 onward. On the contrary to all other reference points, ARM exceeds RC in Hungary only in summer 2016. In all cases where RC - ARM is negative, the respective countries can safely rely on imports, since their import capacity exceeds the (negative) RC and ARM difference.

Between 2012 and 2025, a quite high increase, of over 60 GW, is expected in RES capacity (other than hydro), more than 40 GW of which is located in Italy (Greece follows with 8 GW additional capacity). Fossil fuel, hydro and nuclear capacity should have a more moderate increase of almost 18, 8 and 6 GW, respectively. Focusing on load, an increase of more than 30 GW is expected during this period (but only 18 GW till 2020). It is worth mentioning that although in 2012 there is a difference between the total load in winter and summer (4 GW more in winter), this difference is gradually reduced until its total elimination in 2025 (Italy's contribution is again the explanation).

In Scenario EU 2020, the RC is forecasted to be higher than the ARM for the overall RG CSE from now until 2020 at all reference points.

In all studied years except 2015, this regional extra capacity is projected to be lower at winter reference points, with the absolute lowest additional capacity appearing in 2016. In 2015, the regional extra capacity is projected to be lower at the summer reference point, mainly due to the expected great reduction of RC in Italy at that point. Should no constraints occur in the transmission network, the overall capacity that can be potentially exported to other regions is expected to remain always above 6 GW during the period from 2012 to 2020.

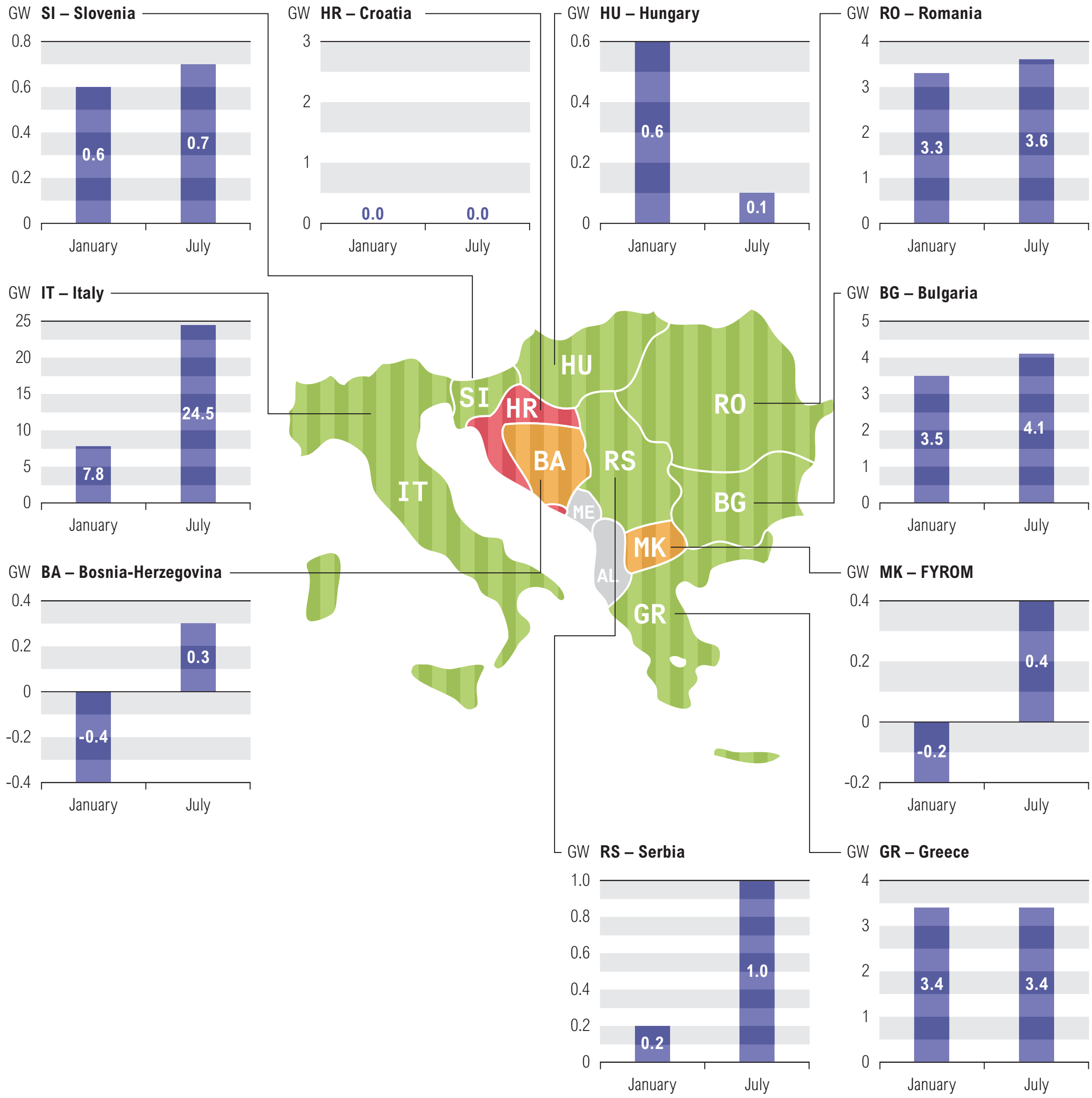


Figure 7.8:
RC - ARM for each country within RG CSE for January (7 p.m.) and July (11 a.m.) 2020, Scenario EU 2020

As can be observed, in 2020 there is extra capacity under the most extreme situation, which is expected to happen at the summer reference point. At that moment, overall extra capacity should exceed 38 GW.

Four countries of the RG CSE (Bulgaria, Greece, Italy and Romania) have a positive assessment for the RC - ARM criterion at all reference points. Hungary and Slovenia have a positive assessment for the RC - ARM criterion for all reference points, with one exception: summer 2016 for Hungary and winter 2015 for Slovenia. RC - ARM becomes negative for Bosnia & Herzegovina and FYROM only at every winter reference point. Serbia has a negative assessment for the RC - ARM criterion at all winter reference points, except of the year 2020, while it is positive for every summer reference point. Croatia develops equal values for RC and ARM at all reference points throughout the whole studied period. As in Scenario B, in all negative RC - ARM cases, the respective countries can safely rely on imports.

The most important difference with Scenario B appears to the load, the increase of which between 2012 and 2020 is limited to 7.5 and 13 GW, for winter and summer, respectively. The equalization between winter and summer is achieved earlier, namely in 2020. Regarding generating capacity, compared to Scenario B ("Best Estimate"), there is a higher RES (other than hydro) development (3 GW more in 2020), and a moderate fossil fuel development (up to 10 GW less in 2020), while the situation is kept at the same levels for hydro and nuclear capacity.

Market Modelling-Based Assessment of Adequacy Indicators

Uncertainties regarding the availability of generation units as well as interconnections were taken into account. Load data and all RES generation data was obtained from the PEMD (average hydraulic conditions were assumed). No correlations regarding uncertainties were taken into account.

	Grid capacities (isolated system)		Grid capacities as expected in 2015		Grid capacities as expected in 2020	
	LOLE [h/yr]	EENS [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]	LOLE [h/yr]	EENS [GWh/yr]
AL	432.64	30.74	28.12	1.70	28.12	1.70
BA	288.09	39.19	11.60	1.47	10.47	1.35
BG	64.20	20.71	7.51	2.21	7.51	2.21
GR	1.06	0.31	0.07	0.02	0.07	0.02
HR	938.82	190.97	16.06	2.83	5.13	0.96
HU	724.93	208.90	2.88	0.78	2.21	0.56
ME	4,490.99	649.28	169.03	22.88	138.19	19.68
MK	554.46	80.25	8.95	1.15	8.95	1.15
RO	0.02	0.00	0.00	0.00	0.00	0.00
RS	7,419.57	5,486.81	131.88	49.88	106.8	40.25
SI	1,494.04	352.18	122.05	27.68	36.64	7.38

Table 7.8:
Adequacy indicators for Scenario B, nuclear variant

7.3.5 Regional Group Continental Central South (RG CCS)

Remaining Capacity & Adequacy Reference Margin

In their Scenario B ("Best Estimate Scenario"), TSOs expect a massive RES capacity development (excluding hydro) in the region in the next 15 years, foreseen from about 95 GW in 2012 to 195 GW in 2020 and 247 GW ultimately. 15 GW more capacity is expected, both for hydro and fossil fuel generation. Nuclear capacity should be reduced, due to the gradual withdrawal of the nuclear plants in Germany, which will have been completed until 2025. Meanwhile, load is expected to increase by 25 and 30 GW at winter and summer reference points, respectively.

As a consequence, Remaining Capacity minus the Adequacy Reference Margin of the overall Regional Group is expected to remain positive until 2025 in Scenario B. There will be a steep reduction in the value of this indicator at the winter reference point of 2025, mainly due to the great reduction of RC in Italy at that time, accompanied by the on-going nuclear withdrawal in Germany. Thus, there should be enough available generating capacity in the region to cover load in most of the situations until 2020.

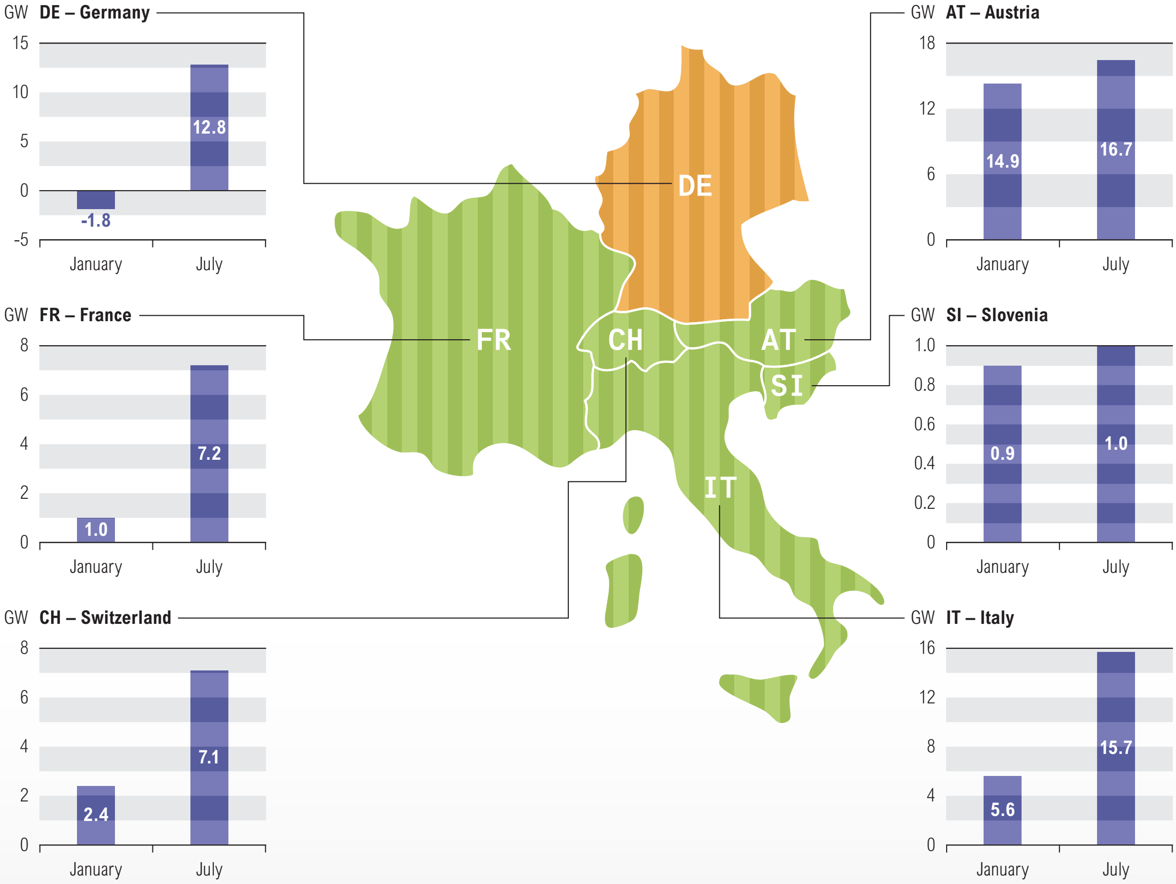


Figure 7.9:
RC - ARM for each country within RG CCS for January (7 p.m.) and July (11 a.m.) 2020, Scenario B

Regarding the national level, Germany and Italy are expected to see Remaining Capacity lower than the Adequacy Reference Margin at every winter reference point, making these countries more likely to rely on imports to balance their load. The same assessment is partially foreseen for Italy (2020 and 2025) and Switzerland (until 2016). Yet, as mentioned before, the necessary installed capacity should be available in the region to secure power supply. More details on the national drivers of this assessment are to be found in the related national sections.

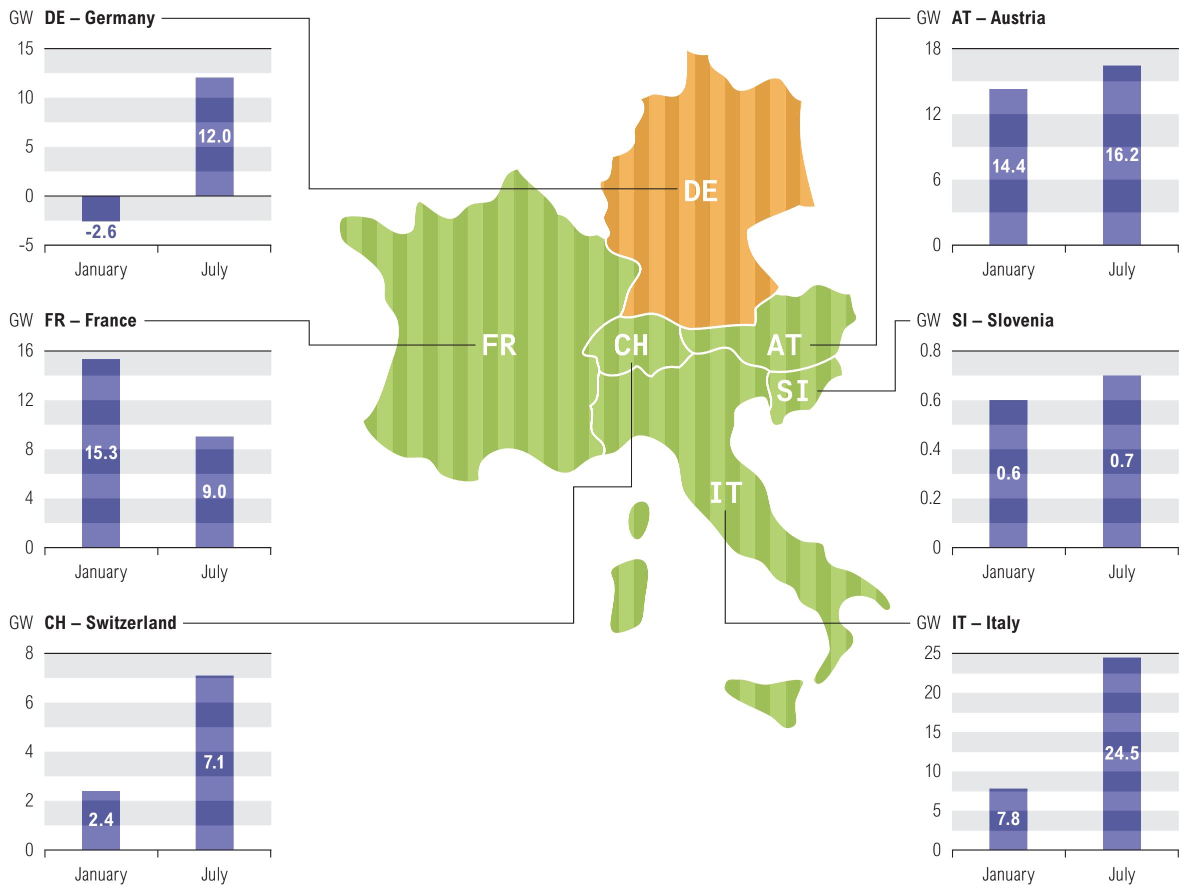


Figure 7.10:
RC-ARM for each country within RG CCS for January (7 p.m.) and July (11 a.m.) 2020, Scenario EU 2020

Scenario EU 2020 has been built according to the National Renewable Energy Action Plans, driven by EU policies on CO_2 emission reduction, energy efficiency and RES development. The most striking deviation to Scenario B is the much smaller increase of load. Indeed, load at the winter reference point should then increase no more than 1% (2.5 GW more) up to 2020 and less than 11 GW at the summer reference point. In this scenario, load will be almost stable in France and reduced in Germany, while about 11% more load will come in Italy (in summer). This remarkable regional trend comes together with almost 40 GW more solar capacity (20 GW in Germany only) and a 50% increasing capacity fuelled by biomass.

As a general conclusion, although having a similar evolution to the Scenario B in summer, Remaining Capacity excess to the Adequacy Reference Margin will end at an over-double level in winter 2020.

Market Modelling-Based Assessment of Adequacy Indicators

For the Adequacy Indicator assessment, the Antares software has been used (adequacy and market Monte Carlo simulator), which simulated 200 Monte Carlo years. The software has been developed by RTE.

The following uncertainties were taken into account:
- Sensitivity of load to temperature,
- sensitivity to wind conditions,
- sensitivity to Hydraulic conditions (dry or average or wet) and
- availability of generation units (planned or unplanned outages).

For load, the spatial correlation (cold in France = cold everywhere) has been taken into account.

The results of the analyses are summarized in the following tables (Tables 7.9 and 7.10).

	Grid capacities (isolated system)				Grid capacities as expected in 2015				Grid capacities as expected in 2020				Comment on the level of adequacy
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLP [%]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLP [%]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLP [%]	compared to the national standards in each scenario
AT	0.0	0.0	35	0	0.0	0.0	0	0.00	0.0	0.0	0	0.00	The adequacy compared are in line compared to national standards
CH	0.0	0.0	0	0	0.0	0.0	0	0.00	0.0	0.0	0	0.00	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system in which the modelling is not applicable
DE	0.2	0.1	1,633	10	0.0	0.0	52	0.00	0.0	0.0	8	0.00	The adequacy compared are in line compared to national standards
FR	45.0	257.0	2	92	0.4	0.5	0	0.12	0.2	0.2	0	0.07	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system
IT	0.3	0.2	0	6	0.0	0.0	0	0.00	0.0	0.0	0	0.00	The adequacy compared are in line compared to national standards
SI	39.0	9.0	302	100	0.0	0.0	0	0.00	0.0	0.0	0	0.00	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system

Table 7.9:
Adequacy indicators for Scenario B

	Grid capacities (isolated system)				Grid capacities as expected in 2015				Grid capacities as expected in 2020				**Comment on the level of adequacy**
	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLP [%]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLP [%]	LOLE [h/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	LOLP [%]	compared to the national standards in each scenario
AT	0.0	0.0	35	0	0.0	0.0	0	0	0.0	0.0	0	0	The adequacy compared are in line compared to national standards
CH	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system in which the modelling is not applicable
DE	85.0	156.0	1,199	100	0.0	0.0	34	0	0.0	0.0	2	0	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system
FR	45.0	257.0	2	92	0.7	1.5	0	15	0.4	0.7	0	11	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system
IT	0.3	0.2	0	6	0.0	0.0	0	0	0.0	0.0	0	0	The adequacy compared are in line compared to national standards
SI	39.0	9.0	302	100	0.0	0.0	0	0	0.0	0.0	0	0	The adequacy compared are in line compared to national standards, except for grid assessed in the case of isolated system

Table 7.10:
Adequacy indicators for Scenario B, nuclear variant

7.3.6 Regional Group Continental Central East (RG CCE)

Remaining Capacity & Adequacy Reference Margin

Figure 7.11 shows that for Scenario B in 2020, 7 of 9 countries report positive values of RC-ARM for both January and July reference points. Germany shows negative values in January only, and Poland in both January and July.

For the year 2015, 6 of 9 countries report positive values of RC-ARM; negative values take place in Germany (January) and in Poland (July). RC-ARM for Croatia equals zero for both reference points.

Figure 7.11:
RC-ARM for each country within RG CCE for January (7 p.m.) and July (11 a.m.) 2020, Scenario B

Figure 7.12:
RC - ARM for each country within RG CCE for January (7 p.m.) and July (11 a.m.) 2020, Scenario Eu 2020

Figure 7.12 shows that for Scenario EU 2020 – the scenario is based on government data (mainly National Renewable Action Plan) – in 2020, 5 of 9 countries report positive values of RC - ARM for both January and July reference points. Germany shows negative values in January, and Poland in July. RC - ARM for Croatia equals zero for both reference points.

For the year 2015, 6 of 9 countries report positive values of RC - ARM in both reference points; negative values in January occur in Germany and in Slovenia. Croatia reports that RC - ARM equals zero for both reference points.

Market Modelling-Based Assessment of Adequacy Indicators

Results are based on a market simulation calculation, when maintenance and outages are taken into account. Maintenance is planned based on supply and outages on the stochastic model. The results of the analyses are summarized in the following tables (Tables 7.11 and 7.12):

	Grid capacities (isolated system)		Grid capacities as expected in 2015		Grid capacities as expected in 2020	
	EENS [GWh/yr]	DUMP [GWh/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	EENS [GWh/yr]	DUMP [GWh/yr]
AT	0.0	5,967.5	0.0	3.0	0	0
CZ	0.0	0.0	0.0	0.0	0	0
DE	0.0	330.2	0.0	6.4	0	0
HR	493.5	3.9	0.0	0.0	0	0
HU	74.9	0.1	0.0	0.0	0	0
PL	28.0	82.4	1.5	0.0	0	0
RO	0.0	79.1	0.0	0.0	0	0
SI	52.2	61.5	0.0	0.0	0	0
SK	24.4	1,867.6	0.0	0.0	0	0

Table 7.11:
Adequacy indicators for Scenario B

	Grid capacities (isolated system)		Grid capacities as expected in 2015		Grid capacities as expected in 2020	
	EENS [GWh/yr]	DUMP [GWh/yr]	EENS [GWh/yr]	DUMP [GWh/yr]	EENS [GWh/yr]	DUMP [GWh/yr]
AT	0.0	5,974.4	0.0	1.6	0	0
CZ	0.0	0.3	0.0	0.0	0	0
DE	276.2	176.9	0.0	0.0	0	0
HR	435.2	2.2	0.0	0.0	0	0
HU	66.9	0.1	0.0	0.0	0	0
PL	21.6	82.1	0.1	0.0	0	0
RO	0.0	79.1	0.0	0.0	0	0
SI	79.0	62.3	0.0	0.0	0	0
SK	71.8	1,864.8	0.0	0.0	0	0

Table 7.12:
Adequacy indicators for Scenario B, nuclear variant

7.4 Appendix 4: National Adequacy Forecast

This section consists of a graph comparing Import/Export capacity to the difference between Remaining capacity and the Adequacy reference margin in Scenario A, B and EU 2020 for each ENTSO-E member or corresponding member. When Export/Import capacity differed in scenarios, a separate graph for each respective scenario is inserted.

The text part of this chapter consists of comments provided by each data national correspondent during the data collection process. If the country did not provide any data at all, it is not even mentioned in this chapter. As not every ENTSO-E country is obliged to set its national environmental goals according to the EU 3rd package, a lot of countries do not have their own NREAP and also Scenario EU 2020 (or their Scenario EU 2020 is based on a similar document to NREAP). Therefore, if nothing contrary is stated in the national comments, these paragraphs are valid for each scenario (A, B and EU 2020).

Data displayed in the graphs refers to the January, 7 p.m. reference point.

7.4.1 AT – Austria

Generating Capacity

Calculations for Scenario B are based on data collected for the "Masterplan 2009 – 2020" (APG 2009). Pump storage generating capacity data is taken from Scenario B and not from NREAP 2010.

Load

The forecast of load in Scenario A and B is based on the consumption forecast for the reference scenario of the NREAP 2010. Forecast of load in Scenario EU 2020 is based on the efficiency scenario of NREAP 2010.

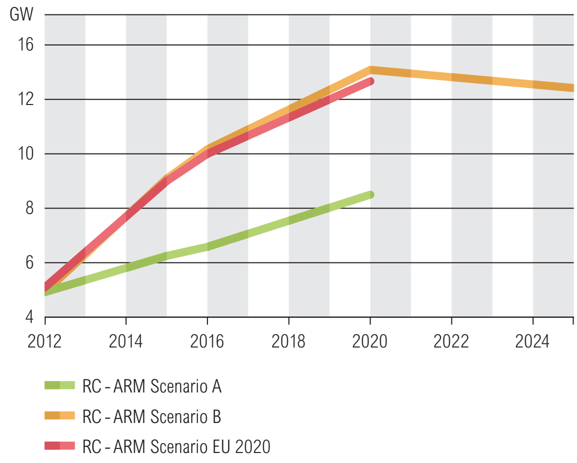


Figure 7.13:
RC - ARM Comparison Austria,
Scenarios A, B and EU 2020, January 7 p.m.

Generation Adequacy

The forecast of seasonal peak load in Scenario A and B is based on the consumption forecast for the reference scenario of the NREAP 2010.

7.4.2 BA – Bosnia & Herzegovina

SO&AF Scenario A is updated according to the last Production Development Indicative Plan 2012 – 2021 year (www.nosbih.ba) and results of the Wind Integration Study. SO&AF Scenario B is the same as SO&AF Scenario A, except for the data about NGC of RES (other than hydro) and System Service Reserve.

The Scenario EU 2020 is based on the same assumptions as Scenario A.

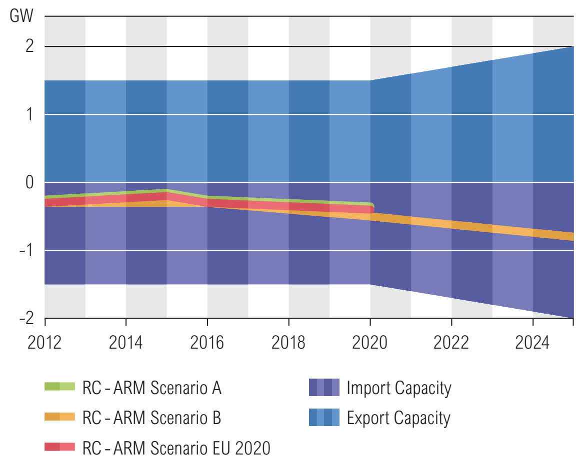


Figure 7.14:
RC - ARM Comparison Bosnia & Herzegovina,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

In Scenario A, a new 150 MW of wind power in 2015 is added, and 300 MW in 2020, according to results from the Wind Integration Study for B&H. According to this, the System Service reserve is increased. In Scenario B, there is no wind power.

It has added a new 150 MW of wind power in 2015, and 300 MW in 2020, according to results from the Wind Integration Study for B&H. According to this, the System Service reserve is increased.

7.4.3 BE – Belgium

The Belgian figures refer to Belgian territory and reflect the Belgian national figures (including all voltage levels in Belgium). Furthermore, the reference point for the load figures is based on real measurements that were supplemented by estimates to ensure 100 % representativeness.

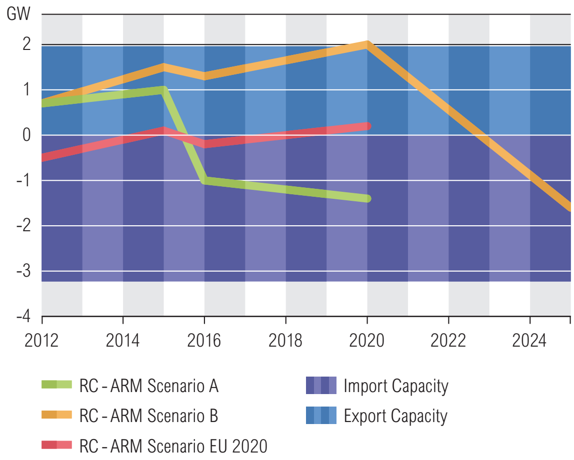


Figure 7.15:
RC - ARM Comparison Belgium,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

The installed generation capacity of centralized power stations in Scenario A (“Conservative”) is obtained by using information from specific confirmed projects (projects whose commissioning decision cannot be cancelled anymore) announced to the TSO as well as information regarding decommissioning that is derived from laws, directives, information given by generation companies or theoretical maximum lifetimes (the applied maximum theoretical lifetime was assumed to be 45 years).

In Scenario B (“Best Estimate Scenario”), the specific confirmed new power units are complemented with a selection of CCGTs that have a grid connection capacity reservation and that are needed to comply with an acceptable level of generation adequacy.

In Scenario EU 2020, the additional thermal capacity needed on top of Scenario A is assessed, taking into account the import level mentioned in the Scenario BASE_HICV of the Prospective Study Electricity of the Ministry of Energy and the Belgian Federal Planning Bureau (October 2009). This scenario assumes that the nuclear phase-out takes place and that a higher carbon value is implemented, namely 54 €/ton CO_2 in 2020.

Since the penetration level of renewable energy sources is assumed to augment significantly by 2020, classic back capacity needs to be flexible enough to cope with the typical volatile generation patterns of wind turbines and solar panels. Therefore, it was assumed that the additional added generation capacity in Scenario B and Scenario EU 2020 are CCGTs. The increase in decentralized generation capacity is based on a similar methodology.

Specific projects announced to the TSO and DSOs are added to the installed generation capacity in all three scenarios. The amount of renewable energy sources is based on the installed generation capacity of renewable energy sources that is given in the Belgian National Renewable Action Plan (NREAP), with the exception of the installed capacity of solar panels in 2012. The installed capacity of solar panels in 2012 reflects the actual installed capacity that is higher than the one mentioned in the Belgian NREAP.

The level of renewable energy sources in 2025 was obtained by adding the following capacities: 217 MW of onshore wind turbines and 666 MW of solar panels. The implementation of the nuclear phase-out is taken into consideration in all three scenarios, although a revision of this law is currently under discussion in Belgium. An adaptation of the existing law concerning the nuclear phase out will result in different scenarios.

Unavailable capacity will increase over the period 2010 – 2025, mainly due to a rise in the number of wind farms, biomass power stations and CHPs included in the net generating capacity for which the average unavailability is considered. This trend will lead to an increase in the volume of non-usable capacity. The higher net generating capacity of windmills in the future will result in a rise in the volume of the system service reserve.

Scenario EU 2020 deviates from last year's forecast SO&AF 2011 – 2025, due to an adaptation of the fossil fuel installed capacities based on recent information concerning decommissioning as well as the delay for realization of not-yet-confirmed CCGTs. The installed capacity of solar panels, as well as onshore and offshore wind capacities, was assessed for 2012, based on the actual installed capacities in 2011. The actual installed capacity of solar panels in 2011 led to a review of the installed capacity in 2015 & 2016 so that a logic evolution for the installed capacity of solar panels could be obtained. See also comments for Scenarios A & B.

The adaptations of the installed generation capacity in Scenario EU 2020 led to an adaptation of the non-usable capacity, the maintenance and overhauls as well as the outages. The system service reserve values in Scenario EU 2020 are based on the values of Scenarios A & B. However, these values were revised, compared to last year's forecast SO&AF 2011 – 2025. See also comments from Scenarios A & B.

Load (all scenarios)

For Scenarios A and B, the average annual energy consumption growth in Belgium is based on the long-run growth prospects forecasted by the PRIMES model (source: Study of the prospects of electricity supply in Belgium 2008 – 2017, conducted by the ministry of energy and the Belgian Federal Planning Bureau). For the medium term (+1 year till +4 years), the growth rates of PRIMES are adapted in order to address the most recent trends of Belgian energy consumption, notably the current global recession. For Scenario EU 2020, the energy consumption is based on the values mentioned in the energy efficiency scenario of the Belgian NREAP. The winter load values for 2012 are the historic normalized values of the 3rd Wednesday of January 2011 at 7 p.m., augmented by the Belgian electricity growth rate of 2011/2012 in order to simulate the future values of 2012 (the same methodology was used for the load values of the years 2015, 2016, 2020 and 2025). The summer load value for 2012 is the historic value of the 3rd Wednesday of July 2010 at 11 a.m., augmented by the Belgian electricity growth rate of 2010/2011 and 2011/2012 in order to simulate the future values of 2012 (the same methodology was used for the load values of the years 2015, 2016, 2020 and 2025).

The load management values in Scenario EU 2020 are based on the values of Scenarios A & B. However, these values were revised, compared to last year's forecast SO & AF 2011 – 2025. There are numerous load-shedding contracts with industrial customers. These contracts are part of the system service reserve and increase from a contracted volume of 412 MW in 2012 to 467 MW in 2025. See also comments from Scenarios A & B.

Generation Adequacy

If the generation development projects, namely 8 new CCGTs, of Scenario B ("Best Estimate Scenario") are realized within the indicated deadlines, the remaining capacity will ensure self-sufficiency till 2020. After 2020, the system will rely on supplementary generation development projects that are as yet unknown to maintain the remaining capacity at a sufficient level. A level is estimated as sufficient when it ensures that Belgium doesn't rely on structural import from neighboring countries. However, in case of the minimum investment scenario (Scenario A), the interconnection transmission capacity will remain crucial after the realization of the first phase of the nuclear phase-out in Belgium. In Scenario EU 2020, the remaining capacity will not ensure self-sufficiency for the years 2012 and 2016. The non-self-sufficiency in 2012 is related to the higher load used for Scenario EU 2020 that is based on the NREAP. The analysis for January 2012 is in line with the results mentioned in the winter outlook 2011 – 2012, namely that under normal circumstances, no structural dependency on import is foreseen. Deviations are due to the fact that actual maintenance is taken into account in the winter outlook 2011 – 2012, while in SAF 2012 – 2025, statistical averages are used. Also, the non-usable value is different due to the fact that, in the winter outlook, the actual maintenance of CHPs connected to the Elia grid is taken into account. The peak loads and loads at specific times in SAF 2012 – 2025 are normalized loads and do not represent extreme conditions. These severe load conditions were taken into account in the winter outlook 2011 – 2012. A more detailed analysis of the situation during the coming winter 2012 at extreme situations (severe peak load conditions) reveals that, at these moments, Belgium structurally depends on imports between weeks 47 and 50 of 2011 and weeks 3, 4 and 11 of 2012, even when assuming that the nuclear phase out is carried out as foreseen in the Belgian Law.

For Scenarios A and B, the winter peak load is obtained by aggregation of the forecasts of the TSO of individual loads at the different nodes of the transmission grid for those years at the peak moment. To obtain the summer peak load, historic maximum values of the summer 2010 (quarter three and four) were combined with the average annual energy consumption growth rate of the forecast of the TSO. This methodology results in a slightly increasing Margin against Peak Load over the period 2010 – 2025. For Scenario EU 2020, the obtained values are based on the ratio between the energy consumption in the energy efficiency scenario of the Belgian NREAP and the energy consumption forecasted by the TSO for the SO&AF 2011 – 2025.

Interconnection Capacity

The simultaneous import and export capacity is the assessed average simultaneous import and export capacity for the winter 2011 – 2012. Future possible interconnection reinforcements that are still under study (such as new interconnections between Belgium and Luxemburg, between Belgium and Germany and between Belgium and the UK) are not considered in the current assessment of the simultaneous import and export capacity.

7.4.4 BG – Bulgaria

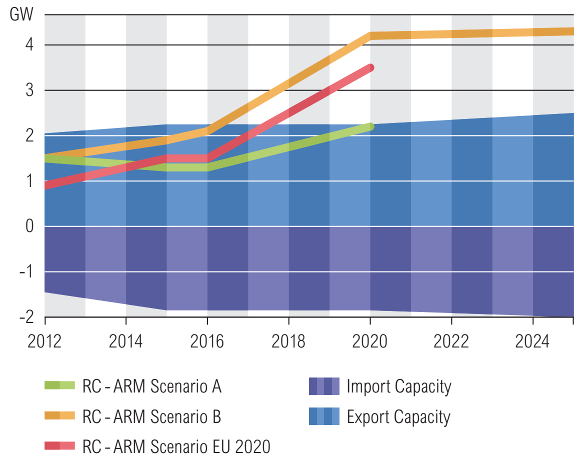


Figure 7.16:
RC - ARM Comparison Bulgaria,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.5 CH – Switzerland

Generating Capacity

Currently it is planned not to replace the current nuclear power plants which leads to a decrease of the nuclear power plant output.

In the Swiss Alps, new storage and pumped storage power plants are foreseen.

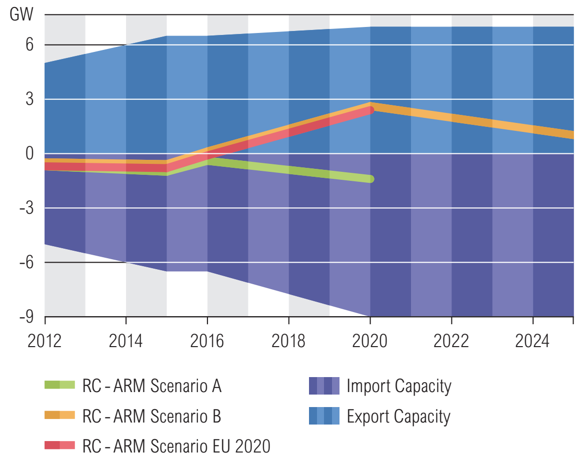


Figure 7.17:
RC - ARM Comparison Switzerland,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.6 CY – Cyprus

The Cyprus System is going through an emergency state. Due to a large explosion within a nearby Naval Base, there was a devastation of the whole “Vasilikos” Power Station, which is the largest Power Station in Cyprus, with a major loss on the generation of a capacity of 868 MW (60 % of the National Generation Capacity). Data for all scenarios for the year 2012 show a forecast, due to the effects of this devastation.

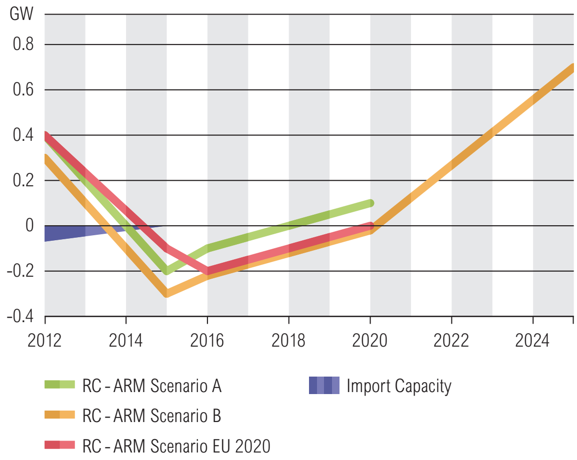


Figure 7.18:
RC - ARM Comparison Cyprus,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

Contracts of renting internal combustion engine generators of a total of 165 MW generation capacity are in effect. Actions started so as to repair the damaged generating units in the “Vasilikos” Power Station. The goal is that the system should be able to meet the summer peak demand of 2012.

Load

For the year 2012, the Load Forecast is re-evaluated with a decrease of 10 %, due to the assumption that the appeals to consumers for energy saving will be effective.

For the year 2012 in the case of severe weather conditions and the winter peak demand above the generation capacity, a Cyclic Interruption Load Schedule Programme will be implemented. This scheme is already prepared and controlled by the SCADA system.

Generation Adequacy

NGC Renewables, of which is wind, in an isolated system, is not considered as a part of the calculations for the Reliable Available Capacity.

7.4.7 CZ – Czech Republic

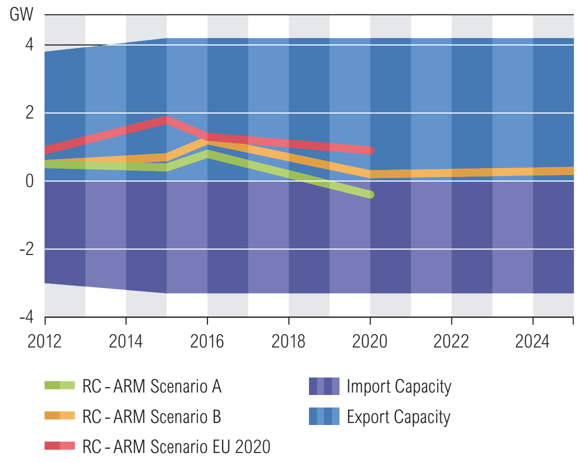


Figure 7.19:
RC - ARM Comparison Czech Republic,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.8 DE – Germany

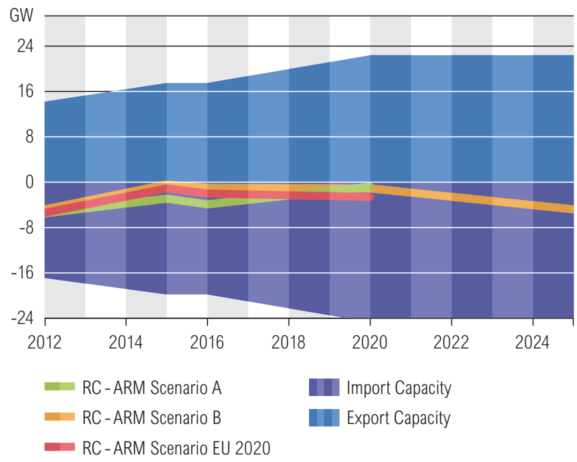


Figure 7.20:
RC - ARM Comparison Germany,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.9 DK – Denmark

Generating Capacity

All wind (100 %) and solar is considered as unusable. Maintenance is set to 0 % for January and to 20 % of the Net Generating Capacity Total for July. The average outage rate is set to 5 % of the Net Generating Capacity Total.

Scenario EU 2020: All wind (100 %) and solar is considered as unusable. Maintenance is set to 0 % for January and to 20 % of the Net Generating Capacity Total for July. The average outage rate is set to 5 % of the Net Generating Capacity Total.

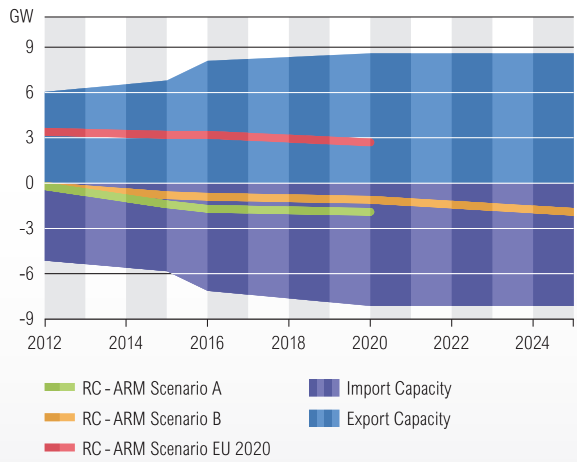


Figure 7.21:
RC - ARM Comparison Denmark,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.10 EE – Estonia

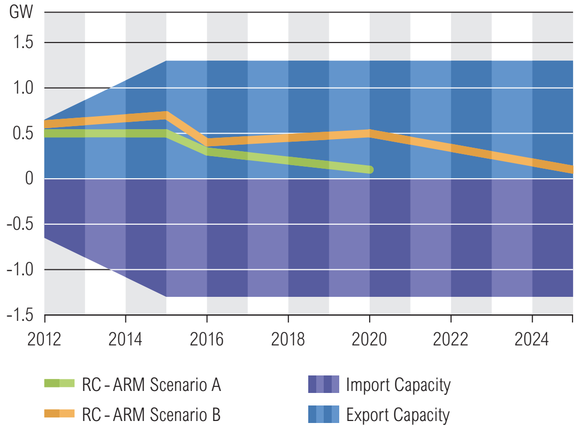


Figure 7.22:
RC - ARM Comparison Estonia,
Scenarios A and B, January 7 p.m.

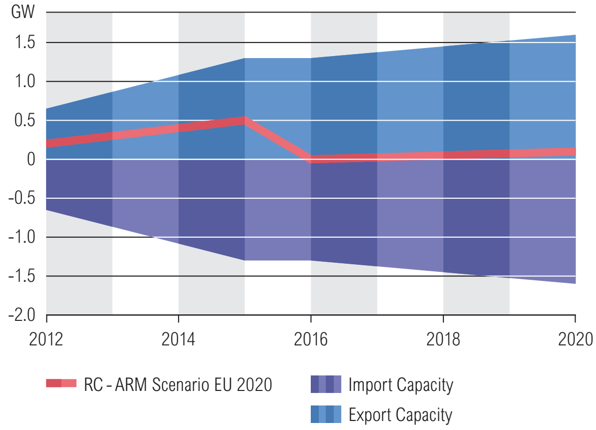


Figure 7.23:
RC - ARM Estonia,
Scenario EU 2020, January 7 p.m.

Generation adequacy of the Estonian system should not be at risk up to 2015. The first problems may arise in 2015, when the emission limitations of existing oil shale units will be in force. The power units, which contribute significant capacity, do not meet the requirements of the EU directive of large combustion plants. However, the Industrial Emissions Directive (IED, adopted by European Parliament) gives the possibility to use additional capacity of 0.64 GW during the period from 1 January 2016 to 31 December 2023, under the conditions in the IED, not to operate for more than 17 500 operating hours during the above-mentioned period. Due to this, the Estonian demand will be covered in both Scenarios A and B by domestic production considering an expected demand increase during wintertime. In case of a faster increase of the demand, the shortage of 0.2 – 0.84 GW can be expected after 2016. The value of shortage will depend on the growth of the demand, the usage of limited operating hours under the IED and on the implementation of investment plans in the construction of the new power plants. However, the probability of this shortage is lowly expected.

Generating Capacity

There is no particular risk of shortage expected until 2015. The power system of Estonia presently has 2.5 GW of generation capacity installed and that capacity will be sufficient to cover peak loads according to both Scenarios A and B. The most important investments from the supply security point of view from the Elering side will be the implementation of a second interconnection between Finland and Estonia with capacity of 0.65 GW and construction of the new power plant of 0.25 GW for disturbance reserve. Those projects will be finished by the end of 2014 and 2015, accordingly.

Scenario A – the conservative point of view.
It includes the following assumptions:
- Only those new developments that Estonia's TSO currently knows to bound construction have been included.
- Decreasing of generating capacity of 0.95 GW, due to fulfillment of the Large Combustion Plant Directive (not taking into account the permitted number of hours).
- Installation of SO_2 filters to four existing oil shale burning units, whose total net capacity is 0.65 GW by 2016.
- A new oil-shale unit with NGC of 0.27 GW in 2015 will be constructed.

Today, 0.16 GW of wind parks have been connected to the Estonian national grid; in addition, there is a number of new wind parks planned and under construction. Elering is informed about new wind parks, the size of which are 0.1 GW and being constructed nowadays. The total amount of wind energy in use and under construction in the A scenario is 0.27 GW. Within the period 2012 – 2020, we do not take into account the wind park projects, the construction of which we are not informed about. Scenario B takes into account the wind energy amount, which is the same as the National REAP. However, all the wind generation was considered as non-usable generation capacity in both A and B scenarios; in addition, wind parks contribute to the increase of system load during the peak consumption period with their auxiliary power. Some of the existing power plants with capacity of 1.3 GW are expected to be decommissioned due to the expected end of their technical lifetime after 2023. In case of faster growth of demand, the shortage can be expected not to exceed 0.2 – 0.8 GW after 2018.

Scenario B is consistent with our "Best View" generation background and includes the following assumptions:
- An additional new oil-shale unit with NGC of 0.27 GW in 2019 will be constructed.
- 0.15 GW of a new CHP plant based on different fuels (peat and biomass) will be constructed during the next ten years. According to Estonian legislation, power plants with efficient technology of heat and power cogeneration are eligible for subsidies. Based on this assumption, an increase of construction of new CHP can be expected.
- Construction of a new nuclear power plant after 2022.

By non-usable capacity, we mean mothballed units, all kinds of limitations and all installed wind power. The power units that have NGC about 0.9 GW will be mothballed due to emission limitations starting from 2016. It was assumed that about 50 % of CHP power would be unavailable due to the maintenance and technological limitations during the summer period. According to hydrological conditions (water inflow), it was assumed that available capacity of hydro power plants would be about 50 % of their net generating capacity.

Load

The worked-out electricity demand forecast is based on the respective forecast in the main branches of economy as well as on the projections of GDP growth rates. The main factors influencing energy demand are changes in GDP. According to the average weather conditions, growth during this period is expected to be around 2.5 % annually.

Generation Adequacy

Considering Scenario A, the situation will worsen from 2016; however, due to the IED directive mitigation, the adequacy would be met within the winter period during 2016 – 2020. Scenario A shows the necessity of the construction of new generation units or import for the period 2016 – 2025. According to Scenario B, the remaining capacity would be met with a surplus during the whole period in case of fast and expected demand growth.

Interconnection Capacity

The possible export will be in the range of 0.65 – 1.3 GW in winter and 0.6 – 1.25 GW in summer during 2010 – 2025. The increase of interconnection transmission capacity will be expected after the construction of new interconnection (Estlink 2) with Finland and reinforcement of a 330 kV network after 2013. Interconnection capacity is forecast to increase with new connection to Latvia, but this project is still under consideration.

7.4.11 ES – Spain

Generating Capacity

The peninsular Spanish electricity system is characterized by a high degree of penetration of renewable generation, which currently amounts to almost 50 % in terms of power and 35 % in terms of energy. In Scenario B ("Best Estimate Scenario"), the installed wind power is expected to reach 34 GW in 2020, including some offshore facilities, and about 40 GW in 2025. Solar energy (both PV and CSP) is expected to keep growing in the medium term, exceeding 10 GW in 2020. In Scenario EU 2020, an even higher deployment of solar energy and offshore wind facilities is foreseen in 2020.

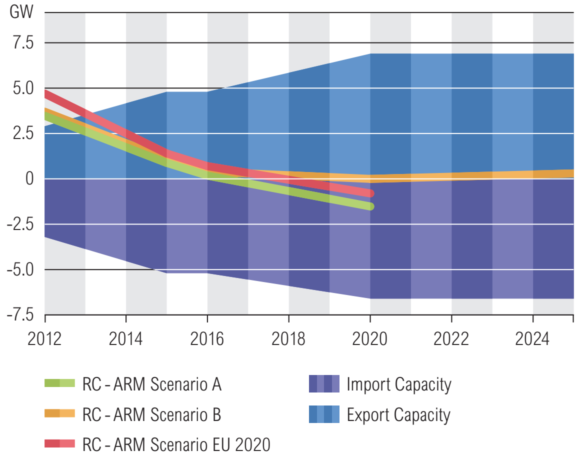


Figure 7.24:
RC - ARM Comparison Spain,
Scenarios A, B and EU 2020, January 7 p.m.

Regarding hydro generation, new pumping units are expected, adding 3 GW of additional installed capacity before 2020, and 3 more GW by 2025. These projects, along with the development of new interconnections, are of utter importance to effectively integrate the expected renewable power in the electrical system, which is a strategic objective for the System Operator. This goal is driven by the Government in the context of fulfilling the objectives set by the European Union for 2020.

Since 2001, generation expansion planning has been based on RES and the commissioning of combined cycle gas turbines (CCGT). However, no new thermal generation is certain until the end of the decade, although the System Operator detects the need for additional firm capacity to fairly ensure security of supply. In the longer term, there are potential projects of coal-fired units with carbon capture and storage (CCS), but apart from the Compostilla demonstration project, they are uncertain at the moment and hence have not been taken into account.

In this report, Scenario B is based on keeping a coverage index (ratio between available power and expected peak demand) equal to 1.1. Scenario EU 2020 is built based on the Spanish NREAP, published in June 2010; non-renewable generation is added, when necessary, in order to achieve an appropriate coverage index. This criterion implies the commissioning of 2 additional GW of dispatchable power plants (typically CCGT, OCGT or pure pumping units) by 2020, and 5.5 GW by 2025. Scenario A, in turn, covers the case in which no additional units were to be built after 2013.

These are the most important assumptions taken into account in every scenario for the calculation of non-usable capacity in terms of a system adequacy forecast:

- Thermal forced outage rate:
  available thermal capacity with an average probability of 95 % has been considered.
- Dry hydro conditions:
  significant non-usable hydro capacity resulting from a lack of water in the reservoirs.
- Wind conditions:
  available wind production exceeded with a probability of 90 % has been considered.

Solar PV power is considered unavailable in the winter peak. Solar CSP is considered partly available, thanks to the contribution of heat storage in tanks of melted salts and the possibility of backup with fuel.

Load

Over the last years, demand growth rate has decreased, from historical values of 5 % (period 1995 – 2005) down to a historical minimum of -4.9 % in the year 2009. As a consequence, at the moment demand is at 2007 levels, both in energy and peak demand.

The demand coverage studies are based in the demand forecast studies carried out by Red Eléctrica. From these studies, values for annual energy and annual peak demand are forecasted, values that will define the evolving needs of the generating equipment to meet this demand and to maintain the security and quality of electricity supply. Energy is expected to keep growing at average values slightly above 2 % (y/y), and peak demand is expected to reach 57 TW in the winter of 2020 under severe conditions, in Scenario B.

Generation Adequacy

In the short term, the situation of the Spanish system is not critical for the next year, and forecasted remaining capacity (RC) is higher than the adequacy reference margin (ARM), even in the case of extreme peak demand.

In Scenario B, RC - ARM is positive for all of the 2011 – 2025 period, but this margin is expected to decrease. Moreover, it will be highly dependent on the effective commissioning of the required additional power and also on weather conditions (mainly wind). In fact, in Scenario A, this margin is no longer positive beyond 2016, and so the system could be at risk of suffering shortages before 2020 if no new conventional power plants were built, under conditions of low wind production and scarce support of neighboring countries. It is worth mentioning that, beyond 2020, political decisions regarding the life extension of 7 GW of nuclear units will be very relevant in terms of adequacy.

More complex probabilistic approaches and regional studies have been performed in order to better assess system adequacy with large-scale penetration of renewable energy sources and higher interconnection capacity. According to the results of the RG CSW adequacy studies, also presented in this report, the probabilistic adequacy standards are met in Spain for Scenario B in the year 2020.

Interconnection Capacity

The Iberian Peninsula has a very low interconnection exchange capacity with France, which is below 3 % with respect to peak demand. Nevertheless, the new interconnection line to France through the eastern Pyrenees, whose commissioning is projected for 2014, will allow doubling the NTC between the two countries (and hence with the rest of the ENTSO-E system). In the longer term, a new interconnection with France through the Bay of Biscay is under study to be commissioned by the 2020 horizon; it will raise the level of interconnection up to more than 4 GW, which would still be below the 10 % minimum recommended by the European Union.

Furthermore, the benefits of the development of the Spain-France interconnections include the improvement of the quality and safety of supply, the growth of energy trade between the Iberian Peninsula and the rest of ENTSO-E, as well as also allowing a greater and more efficient integration of renewable energy into the Iberian Peninsula system.

The increase of the transmission capacity not only to France but also to Portugal, in the framework of the Iberian electricity market, is of great importance and one of the main concerns of Spanish TSOs, regarding system adequacy and operational issues. Two new Spain-Portugal interconnections are expected in this period (years 2012 and 2014, respectively). All these efforts will raise the bilateral NTC between Portugal and Spain to 3 GW.

7.4.12 FI – Finland

Scenario EU 2020 is identical to Scenario B, naturally until year 2020. Hence, comments given there are also valid for Scenario EU 2020.

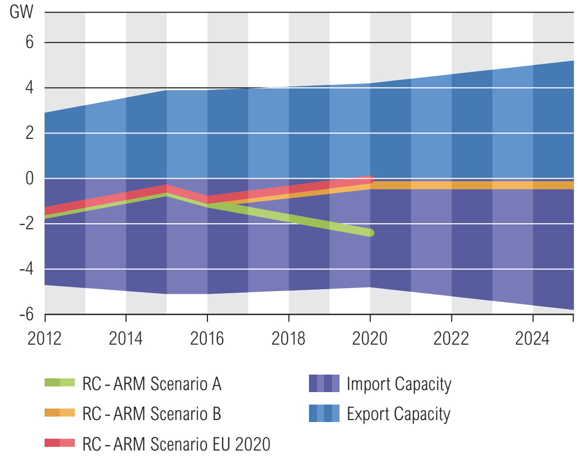


Figure 7.25:
RC - ARM Comparison Finland,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

The renewable generation capacity is based on the National Renewable Energy Action Plan (NREAP) provided to the Commission in June 2010. In May/June 2010, the Finnish Government approved and the Parliament ratified decisions in principle regarding two new nuclear power units. In Scenario B, these plants are included in the capacity, the timing being based on public information of the power unit owners and the TSO's best estimate. The capacity of combined heat and power plants is assumed to remain approx. at the existing level. The Government's aim is that the nation's own capacity should be able to provide for peak consumption and possible import disturbances. The amount of necessary fossil capacity is based on the TSO's estimate, taking into account the above-mentioned aim. Many power plants use several different fuels. Hence, power plants are classified according to their main fuel. A mixed fuel means peat. Biomass in most cases means black liquor or wood in different forms. Waste is included in "non-identifiable" capacity.

The amount of unavailable capacity is based on a TSO's estimate. It is not divided into different categories, except the System Service Reserve. Maintenance and overhauls of major plants are done during the summer; electricity generation in combined heat and power plants is remarkably limited during the summer due to a lack of heat load, etc. These mainly explain the big difference between summer and winter. The availability of wind power is assumed to be small during the reference and peak hours, 6 % of the capacity.

Load

The load forecast is estimated based on the Ministry's latest demand forecast included in the NREAP. Load at reference points corresponds to average temperature conditions.

Some demand response is included in winter peak load, i.e. it is considered in Margin against Peak Load.

Generation Adequacy

In Scenario A, the Remaining Capacity in winter remains negative during the whole period. In Scenario B, the Remaining Capacity is positive during the whole period in normal winter conditions. The consumption in Finland is strongly temperature-dependent, so that in cold conditions the Remaining Capacity is negative.

In winter, the Margin against Peak Load takes into account the impact of cold weather; some demand response is assumed, however. The big Margin against Peak Load in summer is explained by the fact that the load is at the lowest at the time of the reference day, while the load remarkably increases by the end of the season, i.e. the end of September.

Interconnection Capacity

One new interconnection has been taken into operation at the end of 2011. One new interconnection is under construction and is included in all scenarios. Two more are under planning and these are included in Scenarios B and EU 2020.

7.4.13 FR – France

Corse is not part of the control zone operated by RTE and is excluded from this report, as usual.

In light of the new forecasts for consumption and generation, security of supply looks reasonably assured through to the 2015 timeframe. Scenario EU 2020 is built upon the figures mentioned in the French NREAP published in August 2010.

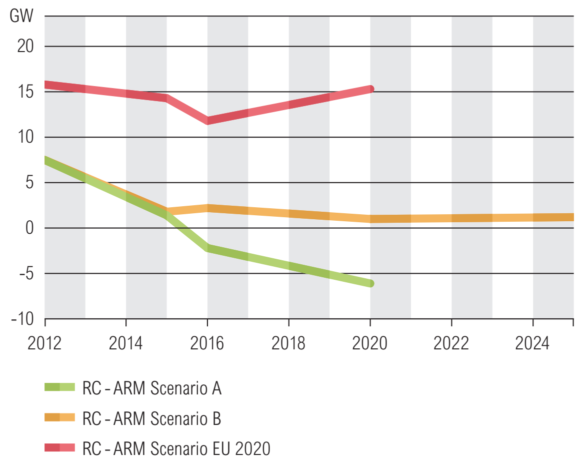


Figure 7.26:
RC - ARM Comparison France,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

The following assumptions have been made to build **Scenario A** ("Conservative"):

- Around half of hard coal capacities will be shut down between 2013 and 2015 due to the end of the derogation to the LCP Directive at the end of 2015.
- A "low nuclear" scenario has been used, in accordance with the RTE's GAR 2011 (i.e. 63.5 GW of nuclear installed capacity in 2020).
- A significant part of the existing oil units (6 over 8) could close at the beginning of 2016, in the light of the Industrial Emission Directive (IED).
- Finally, no more CCGT or RES capacities are yet confirmed after 2014.

Scenario B ("Best Estimate") derives from Scenario A:

- With a higher scenario for nuclear (65 GW in 2020 and 2025), in accordance with the RTE's GAR 2011 (equivalent to two PWR closures or no PWR closures, but an additional EPR unit).
- With no closure of the existing oil units before 2020.
- With the addition of peak units in 2025.
- And finally with a massive development of wind and photovoltaic capacities. 70 % of the installed wind capacity is considered as unavailable on average.

The following assumptions have been made to build **Scenario EU 2020**:

- No thermal park is described in the French NREAP and it had to be adapted from Scenario B to match with the demand and the renewable park in the NREAP.
- The only firm CCGTs have been reported and the existing Oil units are shut down by 2016 for 6 of them and by 2023 for the others.
- It can be noted that solar capacity in 2012 is slightly lower in Scenario EU 2020 than in Scenarios A and B because of the most recent boom in the commissioning of solar capacity in France that ends up in cutting in the subsidies. The offshore wind capacities mentioned for 2012 will not be in service at that date.
- The massive development of wind capacity foreseen in the French NREAP does end up with a higher unavailable capacity.

Load

The demand forecast used in both Scenario A and Scenario B has been reviewed following the recent economic crisis. 2009 has shown a decrease of electricity consumption due to a declining industrial sector. Yet, winter peaks are connected to the widespread use of electric space heating in France, making consumption highly sensitive to outdoor temperatures: currently, a drop of one degrees Celsius induces a 2,300 MW burst of demand. This figure rises over time with the increasing number of housing units using electricity for space heating, through either resistance heaters or heat pumps.

Demand Response shall be understood as mechanisms to manage final consumption of electricity in response to supply conditions, either by delaying the use of electrical appliances, or by substituting an alternative fuel for electricity in dual energy schemes. Demand response has been the subject of increased interest in recent years, as seen in the emergence of new demand-response aggregator players and their increasingly large undertakings. In a report published on 2 April 2010, the "managing peak demand" workgroup, chaired by Senator Sido and Deputy Poignant, recognized their contribution to the supply-demand balance and formulated a number of proposals to encourage their development. In its "Capacity Obligation", the NOME Act addresses some of these proposals and also considers demand response and generation methods on a level playing field. Given all the above, the overall demand-response capacity used in medium- and long-term supply-demand balance studies is conservatively kept constant at 3 GW, which is close to the current level. The implementation of the capacity obligation could eventually allow for greater volumes.

The demand for Scenario EU 2020 is based on the French NREAP. It was built upon the load in 2005. It does not take into account the recent economic crisis and its lowering or delaying impact on the demand forecast. However, it does not take into account the increasing effect, due to the lasting development of electric heating. All together with efficient energy-saving measures make demand much lower than in Scenarios A and B.

For Load management, see comments for Scenarios A and B.

Generation Adequacy

Remaining Capacity minus Adequacy Reference Margin will significantly decrease from now until 2016. It should be connected to the conclusion of the 2011 update of the French generation adequacy report, which states that in light of the new forecasts for consumption and generation, security of supply looks reasonably assured through to the 2015 timeframe, but might be at risk from 2016.

Low values for the winter reference time show that peak demand will still take place around 19:00 in Winter.

More information is available in the 2011 update of the French generation adequacy report:
www.rte-france.com/uploads/Mediatheque_docs/vie_systeme/annuelles/bilan_previsionnel/an/generation_adequacy_report_2011.pdf

7.4.14 GB – Great Britain

Scenario B has been developed to meet the 2020 targets. This scenario, developed by NGET, represents a potential generation and demand background, which meets the environmental targets and the unilateral GHG emissions target. It takes a holistic approach to the meeting of the targets, i.e. assumes that heat and transport will contribute toward the environmental target of 15 % of the UK's energy to come from renewable sources by 2020. It therefore reflects the approach taken by the UK Government's Renewable Energy Strategy, which identified that in order to meet this target, approximately 30 % of the UK's electricity will have to come from renewable sources by 2020, with a corresponding 12 % from heat and 10 % from transport.

Scenario EU 2020 and Scenario B are identical, as Scenario B has been developed to meet the 2020 targets.

For electricity consumption, the figures provided for Scenario EU 2020 are for Transmission demand only. This is consistent with the capacity figures provided for Scenario A and Scenario B.

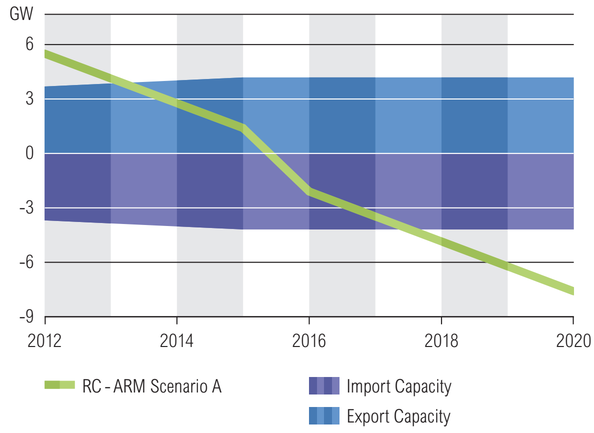


Figure 7.27:
RC - ARM Great Britain, Scenario A, January 7 p.m.

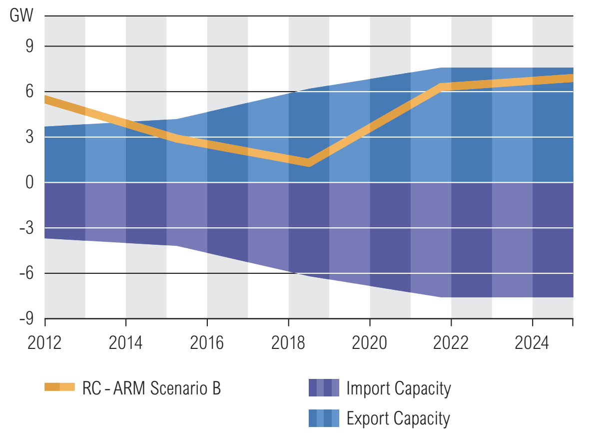


Figure 7.28:
RC - ARM Great Britain, Scenario B, January 7 p.m.

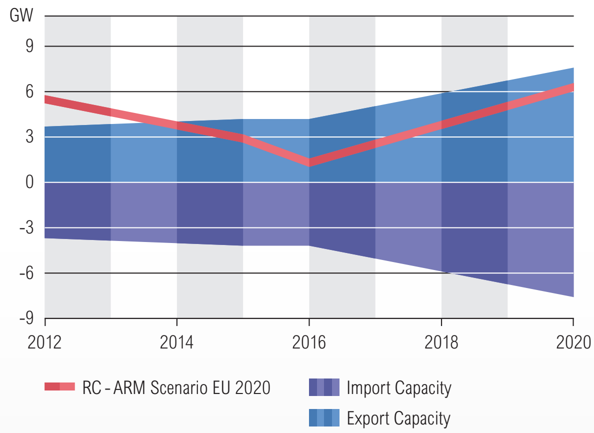


Figure 7.29:
RC - ARM Great Britain, Scenario EU 2020, January 7 p.m.

Generating Capacity

Scenario A includes all new plants that are under construction. Plant closures are consistent with Scenario B. 12 GW of coal and oil plants is forecast to close by 2015 due to LCPD. This scenario includes a strong build up of wind generation, with the supply chain and thus growth in offshore wind, maintained post-2020. Nuclear AGR plants are assumed to receive an additional five-year life extension, maintaining the level of nuclear capacity until the advent of new nuclear plants and assisting in lowering the level of carbon emissions from the generation sector. A CCS plant is envisaged at both coal and gas plants in the future, with thermal plants, developed after 2023, required to have CCS technology. The increased lifespan of the AGR plant results in existing Combined Cycle Gas Turbine (CCGT) plant closing.

Load

The level of demand in this background represents a scenario where the 2020 targets are met with an increase in energy-efficiency measures assumed. The impact of new demand sectors is also considered, namely heat pumps and electric vehicles. The impact of the electrification of heat and transport has been assessed in more detail, with demand increasing toward the end of the period post-2025. This assessment has been based on a view that electric vehicle charging is supported by smart meters and therefore has no material impact on peak demand (within the study period). For heat pumps, it has been assumed that as the penetration rate (for heat pumps) increases, they will start to impact on peak electricity demand. In addition to the transmission-connected generation detailed in Scenario B, embedded generation has an important role to play and grows from 9 GW today to around 14 GW by 2020 and 19 GW by 2030, which limits the growth in Transmission demand.

Generation Adequacy

In the fully liberalized GB market, there are no national adequacy standards that correspond directly with those being calculated in this document. There are planning standards to plan the long-term development of the system and ensure adequate Transmission capacity is available. There is no mechanism in the GB market to fund generation over and above the reserve capacity that the System Operator contracts for. In essence, it is for the market to provide adequate generation and respond to the relevant market signals. Our long-term plans consider the prospective generation projects that could potentially be developed and assumes the market responds to the relevant signals.

The GB market is currently undertaking a review of the generation capacity markets under the guise of Electricity Market Reform. This may result in some changes to the market structure that are detailed above.

The generation capacity required in the long-term scenarios is assessed against a long-term planning margin of ~20 % (wind de-rated to 5 %) and a de-rated margin of between 8 % and 12 %, where all capacity is de-rated against an assessment of expected availability. More detail on the levels of availability that may be expected and the analysis that underpins this assessment can be found in the National Grid's Winter Outlook publication.

Interconnection Capacity

An increase in interconnection capacity is included with further links to France, Belgium, Ireland and Norway included.

7.4.15 GR – Greece

All data provided by HTSO refers solely to the system of the mainland and the islands that are interconnected to it. Data concerning the non-interconnected islands is not available to HTSO.

For the construction of Scenarios A and B, it is considered that by the year 2020, the Cyclades islands will be interconnected to the system of the mainland, while the islands of northern Aegean (Lesvos, Limnos and Chios) and the island of Crete will be interconnected by the year 2025.

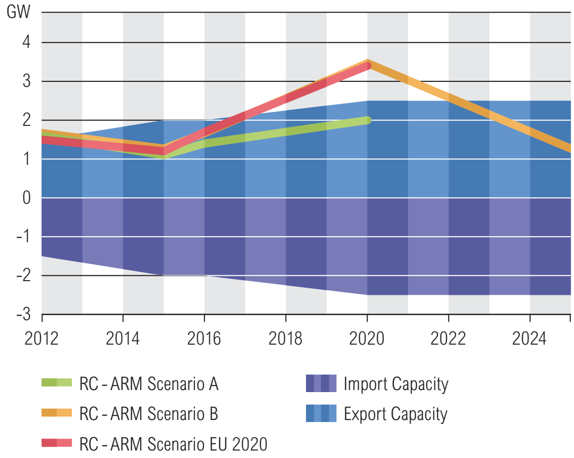


Figure 7.30:
RC - ARM Comparison Greece,
Scenarios A, B and EU 2020, January 7 p.m.

Data for constructing Scenario EU 2020 has mainly been obtained from the Greek NREAP and its accompanying Committee Working Paper that provides detailed background information on the assumptions made. It should be noted that the Greek NREAP refers to the entire country and therefore all values have been appropriately scaled down in order to reflect only the interconnected system of the mainland (and the islands interconnected to it). In Scenario EU 2020, only the interconnection of the Cyclades islands is considered by the year 2020, as in the NREAP (and Scenarios A and B). All other comments provided for the construction of Scenarios A and B are valid for Scenario EU 2020.

Generating Capacity

Currently, there are two mechanisms considering new generation in the Greek system: the market-driven mechanism and through tenders by HTSO to ensure adequacy. The values presented here for years after 2016 are indicative. The generation license granted to PPC (Public Power Corporation) and recent legislation allow PPC to substitute existing old generating units with new capacity, of the same magnitude. PPC has announced a large-scale program, through which it plans to install new generating capacity, while at the same time decommissioning old inefficient units (mainly lignite and oil units). This plan has been taken into account in the construction of both Scenarios (A and B). It should be noted that the oil-fired units that appear in both Scenarios (A and B) in the year 2025 are existing and planned units located in Crete, which is expected to be interconnected with the mainland by 2025. It is not known yet whether the existing units will be mothballed or if their operation will continue. It is assumed that planned units and a portion of the existing ones (about 800 MW) will remain in operation. Considering renewable energy sources, and in view of achieving national set targets for 2020, new legislation has given strong motivation for the installation of RES, as well as simplifying licensing procedures. A large number of RES projects have been announced by investors. Scenario A assumes that a small portion of these will be realized, while in Scenario B it is assumed that a larger portion of these will be realized (including RES projects on islands that will be interconnected by 2025).

The Non-Usable Capacity includes mainly hydro capacity (which is reduced due to limited water reserves) and capacity of wind power plants (an average of 75 % of which are non-usable during the summer peaks). The water management aims at saving the water reserves to use them at the peak demand and only along with irrigation management. Furthermore, it is considered that solar units do not contribute at the first reference point (3rd Wednesday of January on the 19th hour). Additionally, limitation of the availability of thermal units due to temperature (heat) is considered for the second reference point (3rd Wednesday of July on the 11th hour). The overhauls of the thermal power plants are avoided during periods of high demand. In this assessment, a provisional overhaul schedule of the thermal units has been considered. The overhauls of the hydro power plants are implemented during periods of low use, that is low water reserves or low load periods. Therefore, the scheduled outages of the hydro power plants do not affect the remaining generating capacity. System services include primary, secondary and tertiary reserve, according to the UCTE OH Policy 1.

Load

A large increase in loads in the year 2025 is mainly due to the interconnection of Crete and the islands of the northern Aegean.

Types of Load Management measures in Greece are:
- Industrial customers participating in a peak shaving scheme (new legislation since 2006)
- Irrigation management (during high peak hours; if necessary, irrigation is limited, through existing contracts)
- Programs for reducing domestic energy consumption are being implemented by the Ministry of Environment, Energy and Climatic Change, including incentives for the replacement of cooling appliances (air-conditioners and refrigerators) with new energy-efficient (class A) ones, as well as incentives for improving household efficiency (installation of solar water heaters, replacement of old windows with aluminum ones etc.).

7.4.16 HR – Croatia

The index is 99 %, since TSO data does not include production of industrial power plants, which was not delivered to the grid, but was consumed in their industrial facilities.

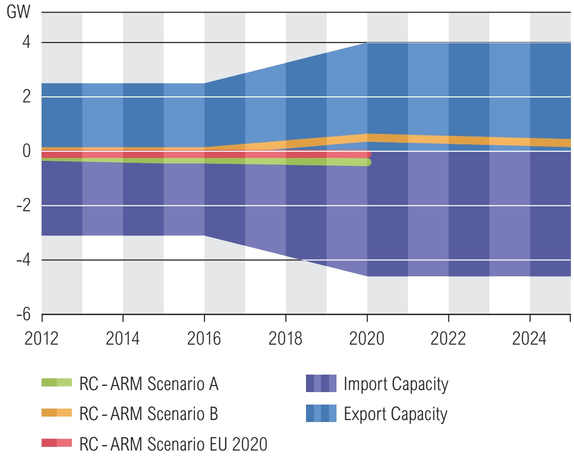


Figure 7.31:
RC - ARM Comparison Croatia,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

Scenario B – Data about the planned installed capacity of hydro power plants and other renewable energy sources are taken from a draft of The National Renewable Energy Action Plan (NREAP):

- Until a 2020 installation of new and revitalization of existing hydropower plants is planned, which would increase the installed capacity of HPP for about 400 MW.
- In the year 2020, the installed capacity of wind power plants is planned to be 1,200 MW.
- In the year 2020, installed capacity of the other RES is planned to be 300 MW (100 MW of biomass + 200 MW of RES, which are mentioned in the row "non-identifiable energy sources").

Data about the planned installed capacity of power plants using fossil fuels are taken from the Croatian Energy Development Strategy, which provides:

- The commissioning of new thermo power plants rated 2,400 MW by the year 2020.
- The decommissioning of the existing thermo power plants rated 1,100 MW by the year 2020.

Scenario A – The installed capacity of hydropower plants and other RES (except wind) is the same as for Scenario B. In the year 2020, the installed capacity of wind power plants is planned to be 800 MW. Compared to Scenario B, it is estimated to lower the installed capacity of coal power plants of 500 MW.

Scenario EU 2020 – Data about the planned installed capacity of hydro power plants and other renewable energy sources are taken from a draft of The National Renewable Energy Action Plan (NREAP):

- Until a 2020 installation of new and revitalization of existing hydropower plants is planned, which would increase the installed capacity of HPP for about 400 MW.
- In the year 2020, the installed capacity of wind power plants is planned to be 1,200 MW.
- In the year 2020, installed capacity of the other RES is planned to be 300 MW (100 MW of biomass + 200 MW of RES, which are mentioned in the row "non-identifiable energy sources"). Installed capacity of RES enables reaching the national target of 35 % of total electricity demand in the year 2020.

Data about the planned installed capacity of power plants using fossil fuels are the same as for Scenario A.

Depending on hydrological circumstances and availability of renewable energy sources (of which the installed capacity in the amount of net generating capacity will increase constantly), the constant increase of unavailable capacity is expected. A contribution to that will also come from the performance of the regular maintenance works of the generation facilities as well as a continuous increase of the necessary amount of System Service Reserve. This trend will be more significant than no usable capacity in old TPP units that will gradually stop operation.

Load

The load forecast has been built, taking into account medium- and long-term projections of economic growth rate. Growth of the load depends directly on the industry development and growth of the household consumption.

Suppliers of electricity use different tariffs to influence consumer behavior.

Generation Adequacy

Scenario B –
Remaining capacity will increase significantly in the year 2020, dominantly due to increased volume of power plants using fossil fuels.

Scenario A –
Remaining capacity will remain at the same level in the period 2012 – 2020.

Scenario EU 2020 –
Remaining capacity will increase slightly in the period 2012 – 2020.

The values of the Margin against Peak Load will remain stable during the observed period of the time for all scenarios.

Interconnection Capacity

The project of the new substation 400/110 kV Lika will facilitate the connection of RES. Substation Lika is a precondition for new interconnection with Banja Luka in Bosnia & Herzegovina. OHL 400 kV Lika – Banja Luka will increase the cross-border capacity, support market integration, improve the security of supply and support conventional generation integration. The project of the new substation 220/110 kV Plat will enable re-establishment of previously existing two overhead lines 220 kV Plat – Trebinje between Croatia and Bosnia & Herzegovina. Two overhead lines 220 kV Plat – Trebinje will increase the cross-border capacity and support better market integration. Eventual installation of phase shift transformers (PST) in some of the border substations is also under consideration. A construction of a 400 kV HVDC submarine cable with a 500 – 1,000 MW capacity between Dalmatia in Croatia and Italy is under consideration on the long-term horizon.

7.4.17 HU – Hungary

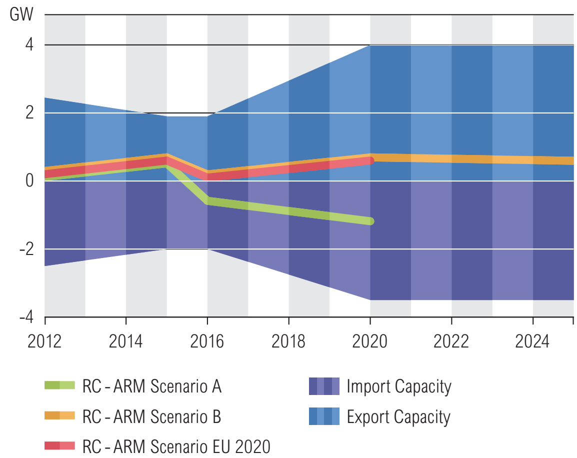


Figure 7.32:
RC - ARM Comparison Hungary,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.18 IE – Ireland

After completion of the additional north-south interconnector in 2017, the transmission systems for both Ireland and Northern Ireland will be essentially consolidated into one. These regions also currently share reserve requirements and operate in a single electricity market. The response for the two regions has therefore been coordinated as much as possible for all scenarios.

In the realistic scenario (Scenario B), the adequacy situation is positive for all years. Scenario EU 2020 also shows a positive adequacy situation for all years.

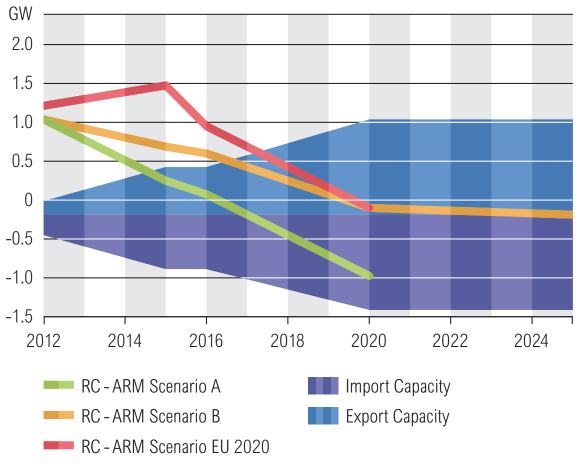


Figure 7.33:
RC - ARM Comparison Ireland,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

In all scenarios, decommissioning dates have been estimated based on the age of generators.

Unusable capacity is due to wind generation and other small-scale generation. The value of installed wind capacity is estimated in terms of a thermal plant always operable at full capacity. It is called the "wind capacity credit". The difference between installed wind capacity and wind capacity credit is entered as unusable capacity. System Service reserve is based on the largest generator on the island of Ireland, and is shared 3:1 with Northern Ireland. The largest generator is expected to be 440 MW, so Ireland provides 330 MW of reserve and Northern Ireland provides 110 MW.

Load

Load figures for Scenarios A & B are based on an economic model, as prepared for Ireland's annual generation capacity statement.

The growth rates used for Scenario EU 2020 follow those presented in Ireland's NREAP report. However, overall figures differ slightly, as we have used a different start point. Our estimate for 2010 consumption differs slightly to those presented in NREAP.

In forecasting annual peak and also calculating the Margin against Peak Load, the models already account for load management. This has therefore been entered as zero to avoid double counting; however, it is typically ~ 150 MW during winter peak hours.

Generation Adequacy

For 2025, it is assumed that the market will ensure enough generation is available for a secure system. The thermal portfolio for all other years is based on actual planned projects. The demand forecast model calculates future peaks. Historical (2007) relationships between demand at the reference points and annual peaks are also used. The values assume average winter temperatures.

Interconnection Capacity

After 2017, the figure includes 1,000 MW in interconnection with Northern Ireland. The Northern Ireland figure is somewhat artificial, since it is planned to consolidate both transmission networks in each jurisdiction into a single transmission region once this interconnector is built. Ireland already operates under a single electricity market with Northern Ireland.

7.4.19 IT – Italy

Generating Capacity

An increase reaching about 9 GW in conventional thermal power plants is expected between 2012 and 2020 within Scenarios A ("Conservative") and Scenario B ("Best Estimate"). For Scenario B, the estimated figure for conventional thermal power plants on 2025 is about 11 GW higher than the corresponding value in 2012. In Scenario EU 2020, the variation between 2012 and 2020 is restrained into about 4 GW.

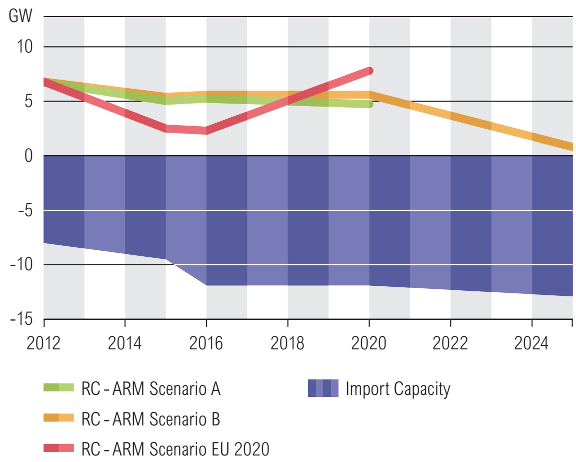


Figure 7.34:
RC - ARM Comparison Italy,
Scenarios A, B and EU 2020, January 7 p.m.

Due to the impressive development of solar generating capacity, we take for all scenarios figures of 23 GW on 2016 and 30 GW for 2020. Also these values could be affected by an uncertainty of about one or two GW, because of the quickness of the solar development in the Italian system.

Another effect of the great spread of renewable source of energy could be a delay, and possibly a decrease, of the estimated deployment of new conventional generation. However, at the moment, it is difficult to evaluate the entity of this possible phenomenon.

In the long-term scenarios, the possible presence of new pumping capacity is under study, in order to allow a full use of unpredictable renewable energy sources. Therefore, in the next years, the pumping capacity could be updated.

For the EU 2020 Scenario in particular, other renewable sources have been treated accordingly to the Italian National Renewable Energy Action Plan, presented by the Italian Ministry of Economic Development on 30 June 2010.

Load

For a better estimation of the power in order to cover future demand, we consider the same evolution for both Scenario A ("Conservative") and Scenario B ("Best Estimate"). A lower level of load has been proposed for the EU 2020 Scenario, according to an expected lower level of electricity energy demand.

Generation Adequacy

In normal conditions, the remaining capacity in most of the contingencies will be sufficient. This value can be higher if the full import capacity should be considered. The spare capacity is assumed to be 5 %.

Interconnection Capacity

The figures have been built considering all planned facilities included within "Piano di Sviluppo" of Terna.

7.4.20 IS – Iceland

The addition of a single, large customer to a small power system, like the Icelandic one, may have a significant impact on the system adequacy if not followed by a new power plant.

Generating Capacity

- 75 % is hydro based and 25 % is based on geothermal energy, thus 100 % RES.
- Approx. 0.14 GW is devoted to system services.

Load

- Annual load growth is approximately 1 %.
- Curtailable load may be used for load management.

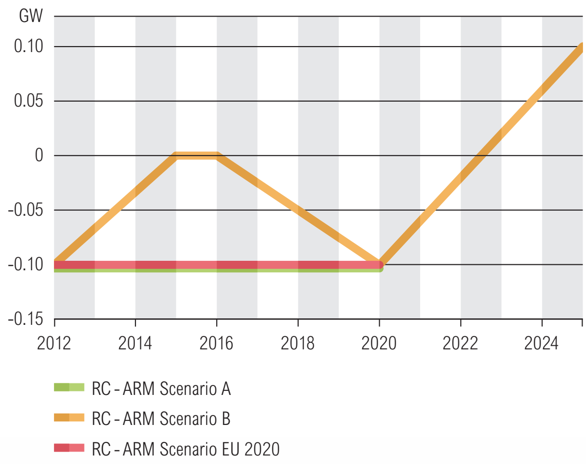


Figure 7.35:
RC - ARM Comparison Iceland,
Scenarios A, B and EU 2020, January 7 p.m.

Generation Adequacy

The seasonal variation curve is fairly flat in Iceland, due to the large share of power-intensive users with a high utilization factor.

Interconnection Capacity

No interconnections with other grids are planned in the analysis period.

7.4.21 LT – Lithuania

In the Lithuanian case, Scenario EU 2020 is the same as Scenario A. RES development in all scenarios (A, B, EU 2020) is modelled in accordance with NREAP.

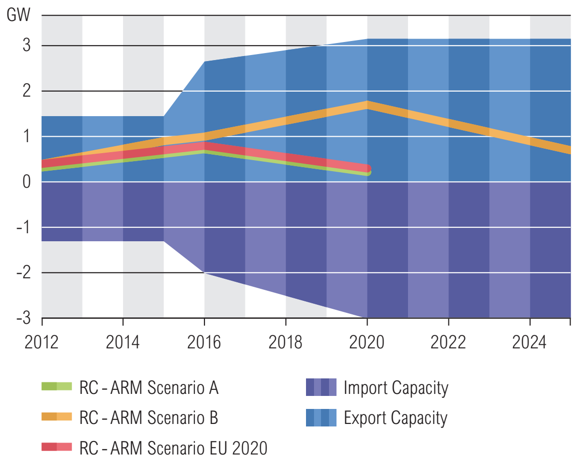


Figure 7.36:
RC - ARM Comparison Lithuania,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

Following the Scenario A definition, only confirmed generation development projects were considered: 450 MW (installed capacity) CCGT unit in Lithuanian PP and 250 MW (installed capacity) in Kruonis HPSPP. Scenario B ("Best Estimate") estimates an increase of gas-fired PP capacity. The data on decommissioning apply to both Scenarios A and B. RES development (wind power will be the major part) in both Scenarios A and B modelled in accordance with NREAP. For Lithuania, Scenario A is the same as EU 2020.

Unavailable capacity is based on the TSO's estimates and includes mainly capacity of HPSPP and Wind PP. Maintenance and overhauls of PP are considered during the summer period. The availability of wind power is assumed to be 6 % of the capacity.

Load

The load forecast is based on the GDP growth forecast. The same load evolution is considered for both Scenarios A and B.

Generation Adequacy

In both Scenarios A and B, remaining capacity remains positive for the whole period. However, even if Lithuania has enough capacity to cover peak demand, local generation costs are not competitive compared to an imported electricity cost (mostly from Russia).

Interconnection Capacity

Currently, Lithuania does not have any connection to the European network, but preparatory works for construction of two interconnections between Lithuania and Poland and Lithuania and Sweden have already started. Commissioning of a 400 kV double circuit LitPol interconnection is expected in 2015 (I stage) and 2020 (II stage). NordBalt interconnection (700 MW capacity) is expected to be in operation in 2016. Construction of these interconnections is very important for ensuring security of supply and integration into the European electricity market for both the Lithuanian and Baltic (Lithuania, Latvia, Estonia) region. Implementation of these projects will secure fuel diversification in Lithuania and reduction of dependence on Russia.

7.4.22 LU – Luxembourg

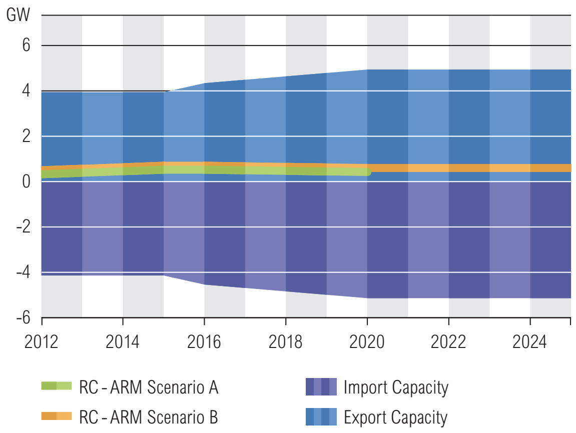


Figure 7.36:
RC - ARM Comparison Luxembourg,
Scenarios A and B, January 7 p.m.

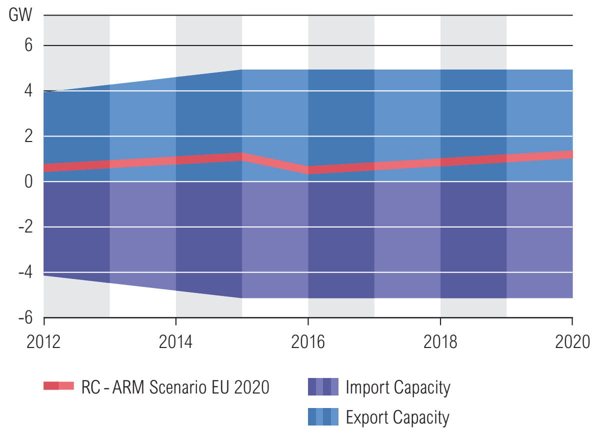


Figure 7.36:
RC - ARM Luxembourg,
Scenario EU 2020, January 7 p.m.

As Creos perform TSO as well as DSO functionalities, data are retrieved from the DSO level and so are assumed to be 100 % representative.

The figures for Luxembourg refer to the Luxembourg territory and include all the loads and power plants located on this territory, despite the fact that some loads are connected in radial to the neighboring grids or that part of the power plants inject energy direct to these grids.

The Scenario EU 2020 is built on the figures mentioned in the NREAP report of Luxembourg to the EU.

Generating Capacity

The values for renewable energy in Scenario EU 2020 are taken from the NREAP report. This has no impact on the other generation plants in Luxembourg. Non-renewable generation capacity is identical to SAF B values. To reach the NREAP renewable figures, very high provisions have to be done by the government in encouraging investments in renewable energy production.

Load

We notice a direct correlation between load growing and national gross domestic product of the country. As important measures are encouraged by the politicians in order to maintain for the future the gross domestic product growth at a similar level to the past, we can assume a further constant growing also for the load. In 2010, the load growth in energy was of > 5 %; in Power it attempts > 4 %.

The NREAP report, however, simulates a reduction of energy consumption due to efficiency measures until 2015 and a very slow increase (< 1 %) of consumption between 2015 and 2020. This is actually not remarked in the grid. Very high efficiency measures have to be put in place to reach the target of NREAP in the future.

Generation Adequacy

When considering the remaining capacity for Luxembourg, it is very important to have in mind the grid configuration in this country. The two large power plants located on the territory of Luxembourg do not inject their energy in the national public grid. As they are located at the borders, they are connected via dedicated lines to the German grid of RWE and to the Belgium grid of ELIA. The public grid of Luxembourg depends highly on reimports of this energy. The given remaining capacity is valid, as contribution of Luxembourg to the interconnected ENTSO-E grid only and cannot be considered as isolated value for the grid of Luxembourg.

Interconnection Capacity

The import and export capacity takes into account the lines for the connection of the power plants located at the border on the Luxembourg territory. The remaining interconnection capacity available for the grid is lower but is sufficient to cover the national load in the grid in normal operation. Transit flows between different countries through Luxembourg are not possible. As Luxembourg is depending highly on imports of energy, the n-2 case is considered for the security of supply and a reinforcement of the interconnection capacity beyond 2015 is needed and studied.

7.4.23 LV – Latvia

Information reported corresponds to the Latvian TSO Annual report.

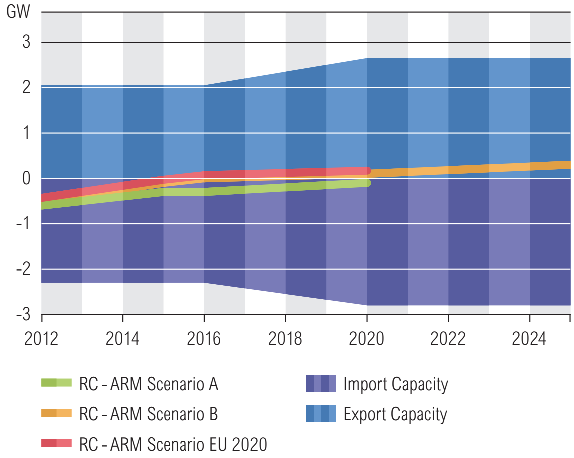


Figure 7.39:
RC - ARM Comparison Latvia,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

Latvian power system base power is generated by CHP plants and, in the nearest future, it is planned to decommission one old block and commission one new block as well. The biggest part of installed generation capacity is run-of-the-river hydro power plants on the Daugava River, and big changes of installed capacity until 2020 are not expected. The Latvian TSO is planning approximately the fourth part of installed capacity of run-of-the-river to cover load at any time. Unavailable Capacity depends on weather conditions and water inflow in HPPs.

Post-2015 will most intensively see an increase in installed power capacity of wind, biomass, biogas and solar power plants.

Load

Due to the current economic situation in Latvia and the expected growth rate of the economy until 2020, the load is expected to increase at a 1.5 – 2 % yearly rate. The load sensitivity is dependent on air temperature.

Interconnection Capacity

In 2020 and 2025:
1) 5 lines between LT – LV
2) 3 lines between EE – LV
3) 1 line between RU – LV

7.4.24 MK – Former Yugoslavian Republic of Macedonia

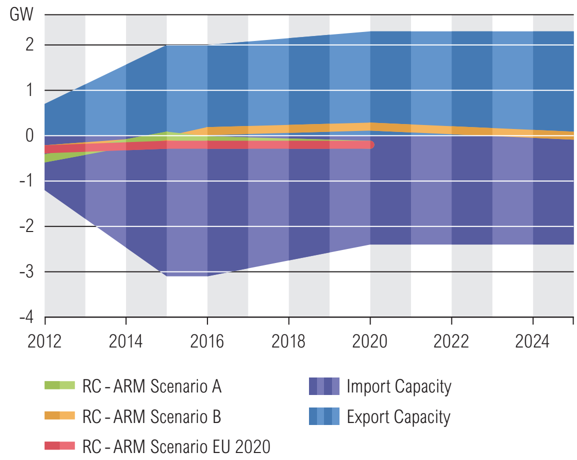


Figure 7.40:
RC - ARM Comparison FYROM,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.25 NI – Northern Ireland

After completion of the additional north-south interconnector in 2017, the transmission systems for both Ireland and Northern Ireland will be essentially consolidated into one. These regions also currently share reserve requirements and operate in a single electricity market. The response for the two regions has therefore been coordinated as much as possible for all scenarios.

Northern Ireland does not have its own specific NREAP. Energy matters in Northern Ireland are devolved to the Northern Ireland Assembly. Within the Northern Ireland Government, the Department of Enterprise, Trade and Investment is responsible for Energy matters in Northern Ireland. They have produced a "Strategic Energy Framework for Northern Ireland", from which the basis of the EU 2020 Scenario has been generated. This can be found at the following link: www.detini.gov.uk

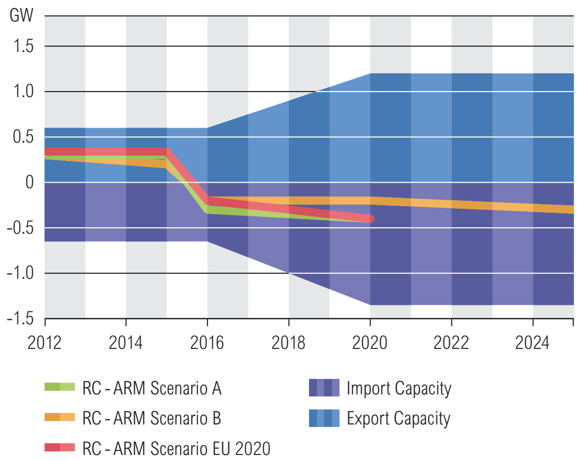


Figure 7.41:
RC - ARM Comparison Northern Ireland,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

In Scenarios A & B, 510 MW of Fossil Fuel generation will be decommissioned by the end of 2015. 333 MW are included as oil; however, it should be noted that this is distillate and not heavy oil. Not Clearly Identifiable consists of small-scale embedded generation.

Unusable capacity is due to wind generation and other small-scale generation. The value of installed wind capacity is estimated in terms of a thermal plant always operable at full capacity. It is called the "wind capacity credit". The difference between installed wind capacity and wind capacity credit is entered as unusable capacity. System Service reserve is based on the largest generator on the island of Ireland, and is shared 3 : 1 with Northern Ireland. The largest generator is expected to be 440 MW, so Ireland provides 330 MW of reserve and Northern Ireland provides 110 MW.

Load

The NI load forecast is temperature-corrected to an average cold spell (ACS), and growth rates applied are in line with forecasted economic growth. In normal economic conditions, there is a normal underlying growth rate of 1.5 %. This forecast is used in our annual generation capacity statement.

In Scenario EU 2020, loads have been reduced by 1 % from the Scenario B loads in line with a target 1 % efficiency target, as set out in the Strategic Energy Framework for Northern Ireland (www.detini.gov.uk).

In forecasting annual peak and also calculating the Margin against Peak Load, our models already account for load management. We have therefore left this as zero to avoid double counting; however, it is typically approx. 90 MW during the winter peak hour.

Generation Adequacy

For 2025, we have assumed that the market will ensure enough generation is available for a secure system. The thermal portfolio for all other years is based on an actual planned project.

The Margin against Peak Load values assume average winter temperatures.

Interconnection Capacity

After 2017, the figure includes 1,000 MW Import and Export interconnection with Ireland as well as the existing 450/410 MW Import and 295/287 MW Export with Great Britain. The Ireland figure is somewhat artificial, since it is planned to consolidate both transmission networks in each jurisdiction into a single transmission region once this interconnector is built. We already operate under a single electricity market with Ireland.

7.4.26 NL – The Netherlands

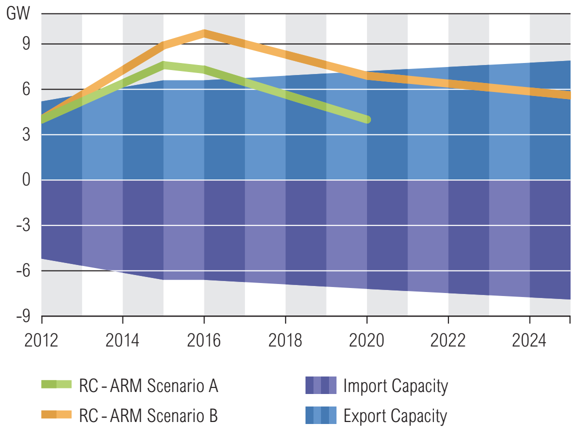


Figure 7.42:
RC - ARM Comparison The Netherlands,
Scenarios A and B, January 7 p.m.

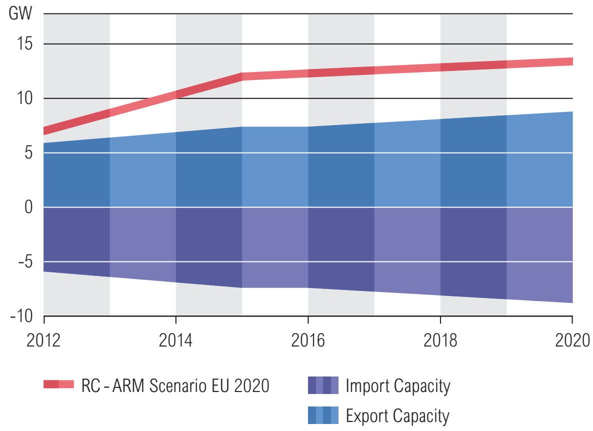


Figure 7.43:
RC - ARM The Netherlands,
Scenario EU 2020, January 7 p.m.

Generating Capacity

The installed thermal generation capacity in the Netherlands in Scenario A ("Conservative") in 2020 is extending more than 30 %, in comparison to year 2011 (nearly 23 GW) toward more than 30 GW. The present 3.2 GW renewable power is to be constant (wind power is 2.2 GW).

Scenario B shows a much higher growth of the thermal generation capacity in 2020, approximately 43 % in comparison to year 2011. The extending generation capacity can be distinguished into 3.3 GW coal and 6.8 GW gas-fired units. This best estimate generation scenario also includes an increasing amount of 3.7 GW of wind power in 2020.

Scenario EU 2020 was based on the Dutch National Renewable Action Plan (NREAP). In this NREAP, the total value of renewable supply (15.0 GW, including 1 GW hydro and solar) was translated into Scenario EU 2020 in two separate parts: 12.7 GW renewable capacity by primary fuel capacity and 2.2 GW renewable by secondary fuel capacity, the latter being biomass in coal-fired units. The total amount of wind power in 2020 was estimated more than 11 GW. Other basic principles taken into account were derived from Scenario B.

So, the NGC in 2020 shows nearly 34.3 GW in Scenario A and 40.7 GW in Scenario B; however, 3 GW will be mothballed according to the latest reports from producers. For Scenario EU 2020, the NGC in 2025 will be 44 GW, assuming the same as in 2020.

Load

The development of load in Scenarios A and B was based on historic growth figures of electricity consumption and realized economic growth rates, including the consumption dip impact because of the economic crisis. For each year, a 1.5 % growth rate was used.

In Scenario EU 2020, the load values for Scenario B were downscaled based on the ratio of the electricity consumption in the energy efficiency scenario of the Dutch NREAP and the electricity consumption forecasted by the TSO, resulting in an average growth rate of 0.9 % in this scenario.

Generation Adequacy

The total amount of unavailable capacity in the reporting period will increase from approximately 5 to 8 GW in Scenario A, respective to 11 GW in Scenario B and to 13 GW in Scenario EU 2020, mainly due to the increasing amount of wind power. However, the development of the NGC in all scenarios will increase much stronger and the remaining capacities (RC) will never show a negative value, even in the conservative scenario. So, it could be foreseen that there will be a certain comfortable space for updating the installed generation capacity by replacing old or insufficient units. This process would be speeded up when the development of load can be reduced by savings according to the Scenario EU 2020.

Interconnection Capacity

Extending interconnection capacities for the Netherlands:

In 2011, the BritNed cable operated commercially: a 1,290 MW HVDC bipolar installation, including 260 km of 450 kV DC subsea cable between the UK (Grain) and the Netherlands (Maasvlakte) with an increase of 1 GW NTC. This is the first electricity connection between the UK and the Netherlands. It is for enhancing diversity and security of supply for both markets, opening access for all market parties by explicit auctions and a market-coupling increase of interconnection capacity and market transparency.

A new 400 kV double circuit interconnection 60 km line between Germany (Niederrhein) and the Netherlands (Doetinchem) is foreseen in 2014 – 2015, according to the TYNDP, with increasing NTC from 1 GW as a result of overloads due to high north-south power flows through the auctioned frontier between the Netherlands and Germany in peak hours of wind in-feed. Progress status of TYNDP: design and permitting.

Further on, there is COBRA under design & permitting 2017 – 2018: a new single circuit HVDC connection between Denmark (Jutland) and the Netherlands via 350 km subsea cable; the DC voltage will be up to 450 kV and the capacity to 700 MW. A need to increase the current transfer capacity for the purpose of allowing the exchange and integration of wind energy and increasing the value of renewable energy into the Dutch and Danish power systems.

Under consideration was NorNed 2: a second HVDC connection between Norway and the Netherlands via 570 km 450 kV DC subsea cable with minimal 700 MW capacity. A need to increase the current transfer capacity between both countries as diversity of supply: connection between a hydro and a thermal power system.

7.4.27 NO – Norway

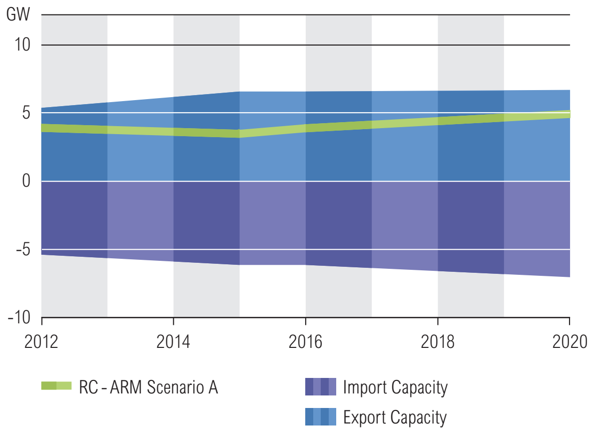


Figure 7.44:
RC - ARM Norway,
Scenario A, January 7 p.m.

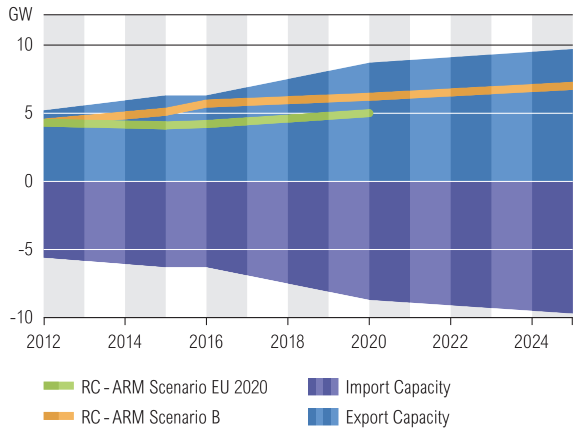


Figure 7.45:
RC - ARM Comparison Norway,
Scenario B and Scenario EU 20, January 7 p.m.

7.4.28 PL – Poland

Input data on generation and consumption for Scenario Outlook & Adequacy Forecast (SO & AF) 2012 – 2025 were collected in September 2011.

Generation data for Scenarios A and B based on information from producers were collected in February 2011. Load and energy consumption data in A and B comes from PSE Operator-own analysis prepared in 2008.

Generation and consumption data for Scenario EU 2020 comes from the official National Renewable Action Plan (NREAP) dated on December 2011 and from the Energy Policy of Poland until 2030 dated on November 2009. The Ministry of Economy prepared both documents. All values coming from these documents have been converted into net values.

National representativeness is 100 %.

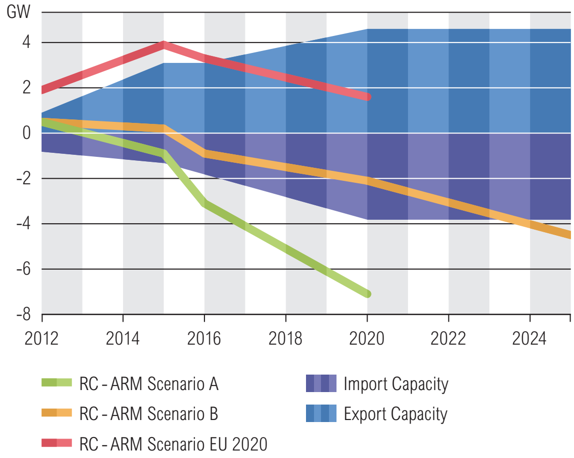


Figure 7.46:
RC - ARM Comparison Poland,
Scenarios A, B and EU 2020, January 7 p.m.

Generating Capacity

1. Information on the subject of the derogation clause from LCP and IE directives in Poland

Poland, during negotiations on its accession to the European Union (joined April 1, 2004), achieved the derogation clause from the LCP Directive (2001/80/EC), which came into effect in 2008 (for SO_2) and 2016 (for NO_X). The derogation clause from the directive means the emission limit values shall not apply until January 1, 2016 for SO_2 and January 1, 2018 for NO_X for selected power stations and combined heat and power plants (CHPs). No derogation for power plants is in force for dust.

The IE Directive (2010/75/EU) amends the LPCD and the IPPCD and introduces new, more restrictive limits concerning SO_2, NO_X and dust emissions for power plants as well as for CHPs. It is coming into effect from 2016, but taking into account the derogation described above, the new limits for NO_X emission will be in force in Poland not earlier than 2018, the same as (LCPD) producers. The IED has not been implemented in Polish law yet.

2. Main results of the implementation of LPCD and IED on generation capacity

The Polish TSO, based on the producers' declaration, assesses that in Poland, as the consequence of entering into effect the results of LCPD and IED as well as exceeding the life span of units, the following capacity decommissioning is to take place:
- 2.4 GW (in previous SO&AF report 5.5 GW) – until the end of 2015,
- 2.3 GW (in previous SO&AF report 4 GW) – between 2016 and 2020 (mainly until the end of 2017),
- 1.3 GW (in previous SO&AF report 3.5 GW) is to be decommissioned between 2020 and 2025. The decommissioning after the year 2020 is mainly caused by exceeding the life span of units.

The total decommissioned capacity in Poland till 2025 amounts 6 GW toward the 13 GW reported in the previous SO&AF. In the opposite side, the PSE Operator noticed a lower (than in previous SO&AF report) level of new commissioning in Poland. Both differences result from the change of producers' strategies.

3. Detailed information concerning NGC in SO&AF scenarios

a) The Scenario A ("Conservative")

Following the ENTSO-E definition, this scenario indicates a potential unbalance owing to a lack of new investments in the future. For thermal and nuclear power plants, the PSE Operator S.A. adopted the following criterion of confirmation of the execution of the investment: concluding an agreement (with subcontractors) by an investor for the construction of a unit. For other generating sources, mainly wind farms, the Polish TSO has utilized the level of the net generation capacity, which is to be reached within a three-year time horizon according to the Yearly Coordination Plans (system balance plans, published on PSE Operator S.A. web page).

Taking into account the criteria mentioned above, there is no new commissioning of thermal units taken into account in this scenario (state as of September 2011). Development of wind generation up to the level of 3.2 GW installed capacity is envisaged.

b) Scenario B ("Best Estimate")

NGC in this scenario is based on information from producers, with regard to the investment projects by generators, and takes into account the achievable level of power capacity assessed by the PSE Operator S.A., which amounts to about 5.5 GW till 2020. Additionally, for the year 2025, the PSE Operator S.A. included the input from the first nuclear unit in Poland that is specified in the "Polish nuclear energy plan" published by the Ministry of the Economy. Observed differences in dynamics of increased NGC and reliable available capacity (RAC) result mainly from the assessed factor of the unavailability level of wind farms – wind NGC growth by 5.5 GW between 2012 and 2025 corresponds with wind RAC growth by 1.4 GW only. Data in Scenario B for starting year 2012 are the same as in Scenario A.

c) Top-down Scenario EU 2020

Net Generating Capacity data in this scenario bases on the following documents:

- NREAP –
  for NGC of renewable energy sources (RES)
  for the analyzed period (2011 – 2020).
- Energy Policy of Poland until 2030 (PE2030) –
  for NGC of conventional thermal PPs.
  The exception is year 2012 (not listed in PE2030), where data from Scenario A and B is used. For 2016 (not listed in PE2030), the value of thermal NGC is derived as the linear interpolation between 2015 and 2020.
- Yearly Coordination Plans –
  for NGC of conventional thermal PPs in 2012
  (there is only year 2010, 2015, 2020, 2025).

Load

In both Scenarios A and B, the PSE Operator S.A. forecasts, as in the previous SAF/SO&AF reports (SAF 2010 – 2025, SO&AF 2011 – 2025), the yearly increase of load by 1.8 % until 2020 and by 2.9 % between 2020 and 2025. Deployment of additional efficiency measures and tools might influence the level of peak loads and electricity consumption, thus optimizing the level of load increase.

Load in Scenario EU 2020 is calculated on the basis of final energy consumption stemming from an additional energy efficiency scenario in the Polish NREAP, according to ENTSO-E Guidelines for Constructing a Top-Down 2020 Scenario. Energy consumption/load data in this scenario are lower (at about 10 – 12 %) than the prognosis prepared by the Polish TSO. Taking into account the observed strong growth of energy consumption by 4.9 % in 2010 and by about 2 % in 2011, the PSE Operator, as in the previous report, raised the prognosis of energy consumption and load power for the first analyzed year for this scenario in the report.

Generation Adequacy

There is the same methodology used in all three scenarios for calculation details of unavailable capacity and the Adequacy Reference Margin. This methodology, based on ENTSO-E requirements, came from Guidelines for SO&AF Data Collection.

1. Unavailable capacity

Elements of unavailable capacity and short description:

a) Non-usable capacity:

- average factor of unavailability of wind generation – 75 %,
- technological limitation of production in combined heat and power plants (summer season),
- restrictions owing to cooling water temperature in some thermal power plants (summer season),
- limitations owing to transmission network capacity constraints caused by high temperature (summer season),
- increase of the heat production in combined heat and power plants (winter season) and
- a part (ca. 40 %) of pump storage total availability is treated as non-usable (usage of hydro power determined by duration of peak load in winter season).

b) Maintenance and overhauls:

For 2012, the level of capacity, concerning maintenance and overhaul schedules and agreed between the PSE Operator S.A. and producers, is given; however, for following years, the level is estimated in relation to the level of thermal net-generating capacity for these years.

c) Outages:

- forced outages,
- outages owing to unexpected faults during the start of the unit within the ongoing maintenance process.

d) System Service Reserve:

The PSE Operator sets the level of primary reserve according to ENTSO-E requirements, and the secondary reserve at the level of the potential outage of the biggest element in the system (bus bar, unit). Both reserves are kept in conventional thermal system power plants.

2. Remaining capacity

In Scenario A, remaining capacity (RC) significantly decreases, especially after the year 2015, as the result of decommissioning caused by the LCP Directive and IE Directive coming into effect as well as the limitation of the units' lifespan (nb: no new big thermal units confirmed after the year 2012). Since year 2015, the value of RC, together with the adequacy reference margin (ARM), is negative; beyond 2016, this value exceeds forecasted NTC in the import direction.

In Scenario B, the level of the remaining capacity slowly decreased – the amount of new investments (according to PSE Operator assessment) in comparison with the load growth and decommissioning – does not permit to save RC (with ARM) at a satisfied level; however, the potential lack of power may be covered using a forecasted level of import capacity.

Scenario EU 2020, because values of load are lower than in the PSE Operator's S.A. scenarios, is characterized by a fairly high level of remaining capacity.

3. Spare Capacity

The Polish TSO assumes 5 % of NGC, minus the sum of maintenance and overhauls.

4. Margin against Peak Load

For Poland, the representative season for winter comprises December, January and February (peak load usually takes place at 17:15).

For summer, it is the period between the second half of June and the first half of August with a daily peak load at 13:15. The time of occurrence of this peak load justifies the choice of the representative months for the summer period because statistically, before and after this summer period, the daily peak loads take place in the afternoon. Calculation of the Margin against Peak Load is based on statistical data and its value is constant for the forecast period.

Interconnection Capacity

The increase of SITC indicated in 2015 for a synchronous profile is the result of phase shifter installation in Krajnik and Mikułowa substations (connected PL and DE systems) and change in the voltage level for the Krajnik-Vierraden line from 220 kV to 400 kV. Another increase of SITC for this profile, in 2020, is the result of building a third 400 kV interconnection between PL and DE. For the asynchronous profile, a 400 kV double circuit line Alytus-Ełk with a back-to-back substation (500 MW in 2015 – import to Poland only – and 1,000 MW in 2020) is being considered. The PSE Operator S.A. follows a single coherent vision of cross-border interconnection development, and therefore the values presented in Scenario A are the same as in Scenario B.

NTC [MW] [1]	2012	2015	2016	2020	2025
PL – DE/CZ/SK [2]	1,000/800 [3]	2,500	2,500	3,000	3,000
DE/CZ/SK [2] – PL	0	500	500	2,000	2,000
PL – UA [4]	0	0	0	0	0
UA – PL	215	215	215	215	215
PL – LT [5]	not applicable	0	0	1,000	1,000
LT – PL [5]	not applicable	500 [6]	500	1,000	1,000
PL – SE	0	600	600	600	600
SE – PL	600	600	600	600	600
PL export	1,000/800	3,100	3,100	4,600	4,600
PL import	815	1,815	1,815	3,815	3,815

Table 4.13:
Cross-border interconnections development

1) Values presented in the table are maximum NTC values forecasted for winter/summer seasons at peak time.
State as of 28 September, 2011 (year 2012 modified in December 2011).
Capacity offered to the market may differ from values shown above.

2) PSE Operator S.A. gives aggregated data for the whole synchronous PL – DE/CZ/SK profile.

3) Winter/summer season

4) Radial connection using 220 kV Zamosc – Dobrotvir line at the moment.

5) Back-to-back connection

6) Realization of the first stage of this investment is planned till June, 2015.
Polish as well as Lithuanian TSOs take into account functioning of this connection since July 2015.

7.4.29 PT – Portugal

Generating Capacity

The Portuguese Electricity system is currently characterized by a high penetration of renewable energy, which currently amounts to 45 % of the energy supplied. The Portuguese strategy for energy has driven to an important growth of RES, mainly from wind generation. In addition, Portuguese NREAP (released on July 2010) has ambitious goals for 2020, mainly in pumped hydro, wind and solar generation development.

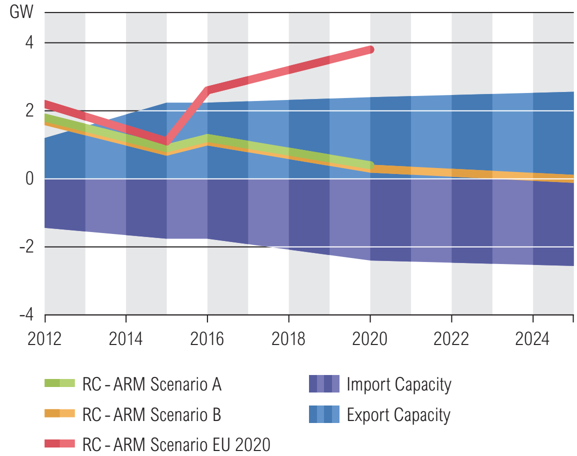


Figure 7.47:
RC - ARM Comparison Portugal,
Scenarios A, B and EU 2020, January 7 p.m.

Scenario EU 2020 was based on Portuguese NREAP, which estimates the evolution of the Portuguese generating system as in the National Strategy for Energy (ENE 2020), defined by the Portuguese government. Main developments include a strong development of renewable energy sources until 2020, particularly wind power that nearly reaches 7,000 MW and the integration of new 4,500 MW of large hydro power plants (3,400 MW with pumping). The relatively high amount of hydro power plants equipped with pumping capacity, along with the development of new interconnections, are of absolute importance to successfully compensate the volatility of wind and solar production. New already-licensed CCGT units sum up a total capacity of 800 MW.

Scenarios A and B correspond to the evolution of the Portuguese generating system necessary to ensure long-term system adequacy[1)], considering some conservative approaches. This means that the same scenario was used in order to fulfil Scenarios A and B required by ENTSO-E. In both scenarios, a slower growth of supply capacity of the various components of generation is estimated when compared to the national strategy for energy, as defined in NREAP. There are no new thermal units considered before 2020, in spite of the decommissioning of some old oil and coal power plants. Between 2020 and 2025, 4 new CCGT units (1,600 MW) are expected. Both scenarios indicate the integration of a new 2,000 MW of large hydro power plants until 2020 (1,850 MW with pumping) and a further 500 MW until 2025 (350 MW with pumping). Strong development of renewable energy sources will happen, particularly wind power that reaches nearly 6,500 MW in 2025.

Non-identifiable energy sources correspond to the non-renewable share of CHP and Urban Solid Wastes.

1) Adequacy studies that support the above-mentioned evolution of the Portuguese system were performed by REN in the beginning of 2011. The significant decrease of demand that has occurred in 2011 and other developments will, eventually, introduce adjustments in future long-term studies that are to be developed during 2012.

Non-Usable Capacity definition used:

- Wind Energy –
  reflects the average lack of wind power (70 %)
- Hydroelectric energy (large power stations) –
  reflects the average lack of primary energy, along with the incorporation of new mixed-pump power plants
- Thermal RES and CHP (small independent producers) –
  reflects the average amount of capacity not being delivered to the grid, based on historical values

Outages: The largest unit installed in the Portuguese system was assumed.

System Service Reserve:

- to face load forecast uncertainties and
- to face interconnection capacity forecast uncertainties.

Load

The energy consumption forecast in Scenarios A, B, and EU 2020 is based on estimations, enabling the compliance of the "National Action Plan for The Energy Efficiency" that defines for the electric sector a total amount of savings of 7 % of consumption in 2015. After 2015, further savings are expected as well as the effects of electric cars. This consumption forecast is the same as the one considered in NREAP.

Generation Adequacy

RC - ARM always remains positive in each scenario.

According to the last 4 years of demand data, the Margin against Peak Load is assumed to be 5 % and 4 % of peak load, on January 3rd Wednesday at 19 h and July 3rd Wednesday at 11 h, respectively.

Interconnection Capacity

The Iberian Electricity Market (MIBEL) requires interconnection capacity capable of enabling the required market energy exchanges, in both directions and with limited grid congestions.

REN and REE have been developing several projects (internal reinforcements and interconnections), which have allowed improving the interconnection capacity between Portugal and Spain from 550 – 850 MW in 2003 to 1,800 – 2,000 MW in 2011.

Despite this great increase, important congestions still exists. To overcome these congestions, several investment projects, including two new 400 kV interconnections, are in progress. REN and REE have a common goal to increase the NTC value to a range around 3,000 MW.[1)]

The Iberian Peninsula has a very low interconnection exchange capacity with the rest of ENTSO-E. The reinforcement of the Spain-France interconnection will allow an improvement of the quality and safety of supply, the growth of energy trade between the Iberian Peninsula and the rest of ENTSO-E and will allow a greater and more efficient integration of renewable energy into the Iberian Peninsula system.

7.4.30 RO – Romania

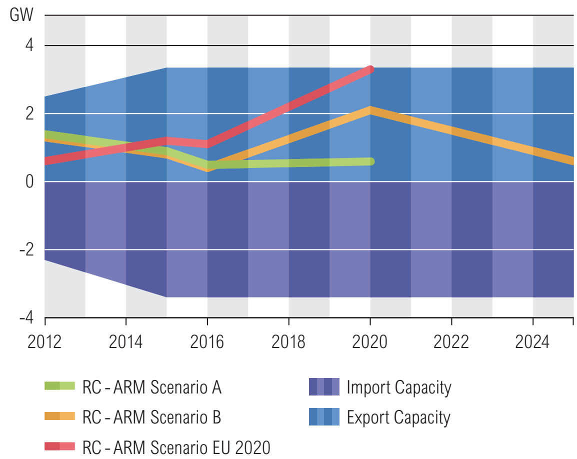


Figure 7.48:
RC - ARM Comparison Romania,
Scenarios A, B and EU 2020, January 7 p.m.

1) Simultaneous Interconnection Transmission Capacity was calculated based on 80 % of expected NTC between Portugal – Spain.

7.4.31 RS – Serbia

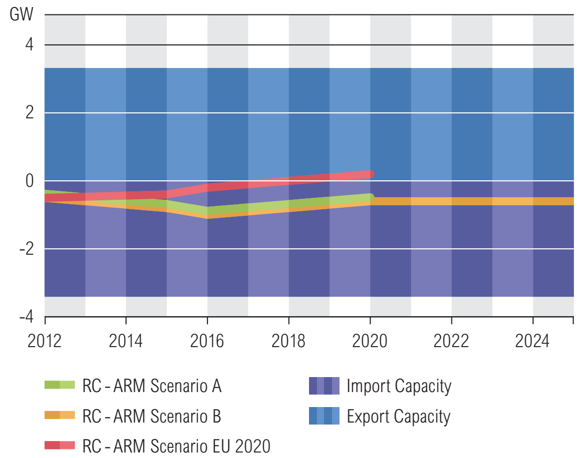


Figure 7.49:
RC - ARM Comparison Serbia,
Scenarios A, B and EU 2020, January 7 p.m.

7.4.32 SE – Sweden

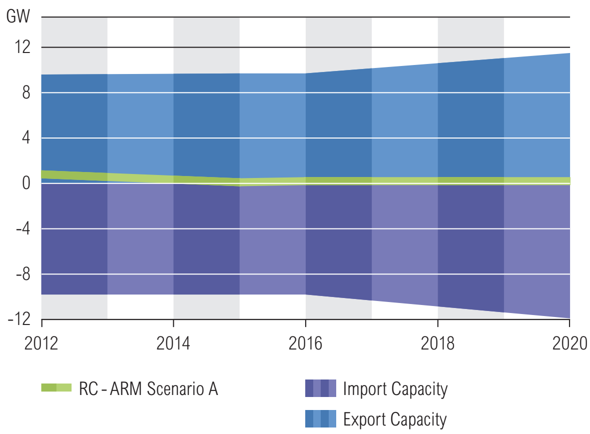


Figure 7.50:
RC - ARM Sweden,
Scenario A, January 7 p.m.

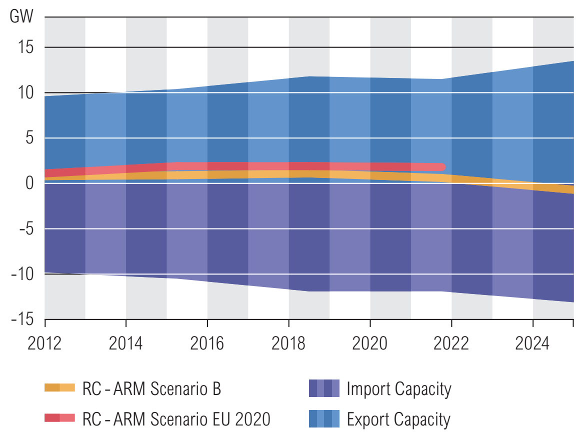


Figure 7.51:
RC - ARM Comparison Sweden,
Scenarios B and EU 2020, January 7 p.m.

Generating Capacity

The NGC of nuclear power is expected to increase due to efficiency upgrades. In addition, a large increase of electricity generation from renewable sources is assumed to be driven by the Swedish-Norwegian green certificates: the electricity certificate system. The increase of the power generation from renewable sources is mainly expected to come from biomass and wind power generation. The trend of refitting existing fossil fuel plants to biomass is expected to continue. Svenska Kraftnät has been notified of wind power projects with a total capacity of about 30 – 40 GW. Even though the main part of the planned wind power will probably not be built, the huge amount of wind power plans is an indication of a large increase of wind power generation. The NGC of fossil fuels is expected to decrease, due to decommissioning of oil and coal power plants.

10 % of the NGC of nuclear power is assumed to be unavailable in both summer and winter. Normally, maintenance is done during summer when the demand is low, but this is not reflected in the SAF balances. 10 % of the NGC for fossil fuels and biomass is assumed to be Non-Usable Capacity. About 10 – 15 % of the NGC for fossil fuels and biomass is assumed to be unavailable due to maintenance during winter. During summer, about 30 % of the NGC for fossil fuels and biomass is assumed to be unavailable due to maintenance. 862 MW of the fossil fuel plants are "mothballed" and are included in the non-usable capacity. 94 % of the wind power is assumed to be non-usable. This assumption is done due to the variable and uncertain characteristics of wind power generation. 2.5 GW of the hydropower is non-usable capacity due to hydrological limitations.

A large increase of electricity generation from renewable sources is expected in Scenario EU 2020, mostly from biomass and wind power generation. In the Swedish NREAP in table 10.a and 10.b, the NGC biomass increases from 2,683 MW in 2010 to 2,914 MW in 2020. During the same time, the energy increases from 10,567 GWh to 16,689 GWh. As a large increase of the energy isn't realistic when the NGC only increases slightly, the Swedish Energy Agency was consulted. New NGC for the biomass and the wind power was calculated from the energies given in NREAP with the help of the Swedish Energy Agency.

Load

The prognosis of the demand is used as a reference value when the load of the reference time has been approximated. The consumption in 2012 is expected to be 147 TWh. The economy is assumed to have improved in 2015 and 2016. Therefore, the demand is assumed to increase to 153 TWh. Thereafter a lower annual average growth rate is chosen and the demand is only slightly increasing between 2016 and 2020. Increased energy efficiency, efforts to reduce environmental impact, higher fuel and electricity prices are assumed. It should be mentioned that a large-scale introduction of electric vehicles could increase the demand more than assumed in these SAF-scenarios. On the other hand, the demand has hovered around 135 – 150 TWh during the last decade and there has been a trend of a non-growing consumption in Sweden, even before the financial crisis in 2008. In 2025, an increase of the demand is assumed due to the use of electric vehicles. In 2025, the demand is assumed to be 158 TWh.

Load management consists of load that can be disconnected. The Load Management data is based on the information found in the Swedish Government's proposal of a new legislation concerning Load Management. The document is called "Proposition 2009/10: 113 Effektreserven i framtiden".

To harmonize the Swedish system with the European, the Swedish Government wishes to increase the share of load that can be disconnected in the Swedish peak load arrangement (load that can be disconnected and generation that can be activated with short notice that Svenska Kraftnät has purchased). In 2025, the peak load arrangement is expected to be handled by the market.

The prognosis of the demand in the Swedish NREAP is used as reference values when the loads have been approximated for Scenario EU 2020.

For Load management in Scenario EU 2020, the same assumptions as Scenario A and B are used.

Generation Adequacy

Scenario A: The Adequacy Reference Margin is met by the Remaining Capacity (RC) in all years.

Scenario B: The remaining capacity is slightly increasing until 2016, due to the increase of NGC in nuclear, wind power and biomass. In 2020 and 2025, the RC is decreasing somewhat, mainly due to decommissioning of oil power plants. The ARM is not met by the RC in winter 2025 because of the mentioned decommissioning of oil power plants, but also due to the fact that the load management in 2025 is assumed to be 0 GW. During summer, the ARM is well met by the RC, but during winter the margin is smaller. This means that there is a larger need for import during winter and that there is room for export during summer.

The Margin against Peak Load is the difference between the load at the reference points and the peak load for winter and summer, respectively. The peak loads and the loads at the reference points were approximated from a load curve from 2007, which was up-scaled to the assumed demand.

The ARM is always met by the RC in Scenario EU 2020. The Margin against Peak Load in this scenario is calculated in the same way Scenarios A and B was.

Interconnection Capacity

The Simultaneous Import and Export Capacities are assumed to be the Maximum Net Trading Capacity at Nord Pool Spot. These capacities might be somewhat higher than the real simultaneous Import and Export Capacities. In the end of 2011, Fenno-Skan 2 was taken into operation. In the end of 2015, Nord Balt is expected to be in operation. In 2019, the Swedish-Norwegian part of the South West Link is assumed to be in operation. In 2025, a third AC-interconnection between Sweden and Finland is expected to be in operation. Finally, the 130 kV-interconnections to Zealand are assumed to be replaced with a 400 kV-interconnection by year 2025.

7.4.33 SI – Slovenia

Generating Capacity

The generating capacity increases due to new hydro units on the middle and lower Sava River, a new pump-storage unit on the Drava River, a new lignite thermal unit in Sostanj and gas units in Brestanica and Trbovlje. Higher wind power and new units in the nuclear power plant Krsko are expected in the Scenario B ("Best Estimate"). Decommissions in both scenarios arrive at the end of the thermal units' lifetime.

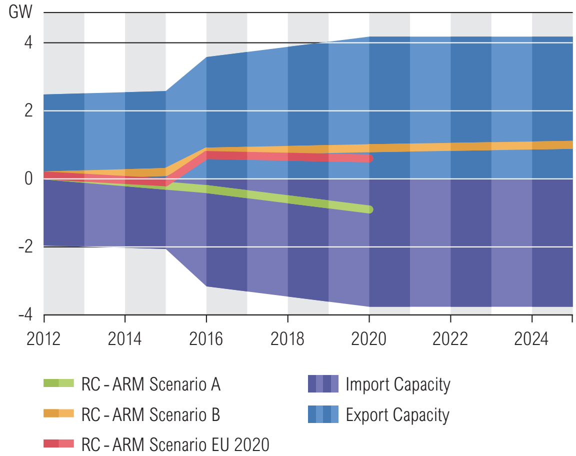


Figure 7.52:
RC - ARM Comparison Slovenia,
Scenarios A, B and EU 2020, January 7 p.m.

Nuclear power plant Krsko: The table considers 100 % of its generation capacity, although ownership of the nuclear power plant Krsko is equally divided between Slovenia and Croatia, thus half of its generation is delivered to Croatia in accordance with the international agreement.

A Non-Usable Capacity arrives mainly from lower availability of the primary energy source in hydro power stations and wind farms. The reserves increase dramatically due to commission of the new lignite unit in Sostanj and the new nuclear unit in Krsko. Their high installed capacities require high tertiary reserves.

Load

The Energy forecast is mainly based on GDP growth and demography development. In the GDP forecast, "U-shaped" economic recession is predicted. The peak load in summer will increase faster than in the winter; however, annual peak load is expected in winter in the whole period.

Generation Adequacy

The cause of the bad conditions in Scenario A is the fact that only two planned projects meet the criteria for this scenario. Bad conditions in Scenario A and a great difference between the scenarios show, on the one hand, the need for realization of the projects in Scenario B and, on the other hand, the obvious delay of these projects.

Interconnection Capacity

SITC increases due to new double OHL 400 kV Bericevo – Krsko and new interconnection lines with

- Hungary/Croatia
  (double OHL 400 kV Cirkovce – Heviz (HU)/Zerjavinec (HR)) and
- with Italy
  (double OHL 400 kV Okroglo – Udine).

7.4.34 SK – Slovakia

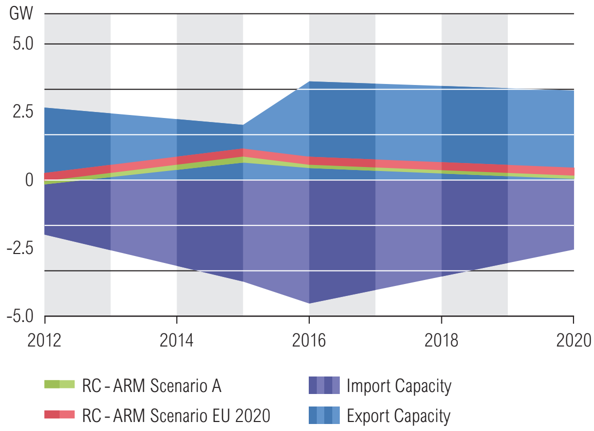


Figure 7.53:
RC - ARM Comparison Slovakia,
Scenarios A and EU 2020, January 7 p.m.

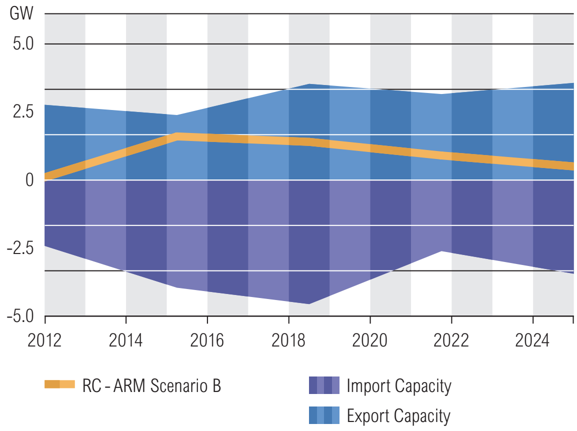


Figure 7.54:
RC - ARM Slovakia,
Scenario B, January 7 p.m.

Generating Capacity

The biggest generation increase in the monitoring period in each scenario is expected from nuclear power plants (NPP) due to two new blocks in NPP Mochovce, expected to be put into operation in 2014. The NGC in fossil fuels is expected to decrease till 2020 (mainly lignite and hard coal units; only a (slight) increase is expected from gas by the 2025 horizon (in Scenario B).

The renewable power plants' development in Scenarios A & B is subjected to the best estimates of SEPS, a.s., as the Slovak TSO, whereas the development of RES in Scenario EU 2020 is overtaken from Slovak NREAP. The evolution of conventional units in Scenario EU 2020 is in line with Scenario A.

Concerning decommissioning, up to 2017, some units of existing thermal power plants are expected to be put out of their operation due to environmental factors.

Unavailable capacity is influenced by the weather conditions (photovoltaic power plants, hydro power plants) and the typical outage's regimes in all thermal power plants (including smaller industrial generation and/or CCGTs), according to the weather season.

Load

In load and a consumption forecast, the influence of an upcoming economical crisis is considered. Load values for Scenario EU 2020 are based on the Slovak NREAP. These values are a bit higher than load expected by TSO.

Generation Adequacy

Generation adequacy will be maintained during the whole forecasted period in each scenario. The shape of the RC-ARM curve in the figures above is influenced by the continual reduction of fossil fuel power plants from the Slovak generation mix and the increase of the NPP in 2013.

The load management parameter is not used in Slovakia in a frame of transmission system operation. Values reported in this SO&AF 2012 report aim only to assure consistency with the rest of the SO&AF report and ENTSO-E countries.

Interconnection Capacity

In each scenario, a new double circuit 400 kV line and new single circuit 400 kV line from Slovakia to Hungary were considered to be in operation in 2016. A new 400 kV double circuit line to Hungary is expected after 2020 and a new 400 kV line to Poland is expected after 2025 as well.

Export/import values, however, have to be considered only as indicative and are highly dependent on actual topology of the Slovak transmission grid (and also on the topology of neighboring countries/power systems), the generation mix within the Slovak and the neighboring power system(s) and also on the methodology used for their calculation. These values should be considered as informative and not binding values, and thus treated in this respect.

Abbreviations

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power Generation
DC	Direct Current
EIP	Energy Infrastructure Package
ELF	Extremely Low Frequency
EMF	Electromagnetic Field
ETS	Emission Trading System
ENTSO-E	European Network of Transmission System Operators for Electricity (see § A2.1)
FACTS	Flexible AC Transmission System
FLM	Flexible Line Management
GTC	Grid Transfer Capability (see § A2.6)
HTLS	High Temperature Low Sag Conductors
HV	High Voltage
HVAC	High Voltage AC
HVDC	High Voltage DC
KPI	Key Performance Indicator
IEM	Internal Energy Market
LCC	Line Commutated Converter
LOLE	Loss of Load Expectation
NGC	Net Generation Capacity
NRA	National Regulatory Authority
NREAP	National Renewable Energy Action Plan
NTC	Net Transfer Capacity
OHL	Overhead Line
PEMD	Pan European Market Database
PCI	Project of Common Interest (see EIP)
PST	Phase Shifting Transformer
RAC	Reliable Available Capacity
RC	Remaining Capacity
RES	Renewable Energy Sources
RG BS	Regional Group Baltic Sea
RG CCE	Regional Group Continental Central East
RG CCS	Regional Group Continental Central South
RG CSE	Regional Group Continental South East
RG CSW	Regional Group Continental South West
RG NS	Regional Group North Sea
SEW	Social and Economic Welfare
SO&AF	Scenario Outlook & Adequacy Forecast
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VSC	Voltage Source Converter

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