Demand and supply of dispatchable generation in the power system of the Netherlands, 2030-2050

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Management samenvatting

Achtergrond en onderzoeksvraag

Nederland streeft naar een klimaatneutrale samenleving in 2050. Voor het elektriciteitssysteem betekent dit een sterke groei van de vraag naar elektriciteit die met name wordt voorzien door een nog sneller toenemend aanbod van elektriciteit uit zon en wind, zowel op land als op zee. Zon en wind zijn echter variabel en soms zelfs gedurende langere (‘*Dunkelflaute*’) periodes niet of nauwelijks beschikbaar. Dit roept de vraag op naar de toekomstige behoefte aan een kostenoptimale mix van aanvullend, regelbaar vermogen versus andere flexibiliteitsopties – zoals vraagresponse, opslag en buitenlandse handel – teneinde gedurende elk tijdsbestek van het jaar in de vraag naar elektriciteit te kunnen voorzien op een klimaatneutrale, betrouwbare en betaalbare wijze.

Aanpak en rapportage

Om deze vraag te kunnen beantwoorden heeft TNO een veelomvattend onderzoek uitgevoerd – in het bijzonder diverse scenario- en gevoeligheidsanalyses voor de periode 2030-2050 – met behulp van het model COMPETES-TNO (i.e., een kostenoptimalisatiemodel van het Europese elektriciteitsmarktsysteem). De aanpak en bevindingen – maar ook de beperkingen en onzekerheden – van dit onderzoek worden uiteengezet in onderhavig, Engelstalig rapport ‘*Demand and supply of dispatchable generation in the power system of the Netherlands, 2030-2050*’.

Referentie scenario (2030-2050): vraag naar regelbaar vermogen

Uit het onderzoek blijkt dat, onder de aannames van het referentie scenario, de totale behoefte aan regelbaar vermogen van het Nederlandse elektriciteitssysteem afneemt van circa 16 GW in 2030 tot 10 GW in 2040 en 5 GW in 2050. In termen van elektriciteitsproductie daalt de vraag naar regelbare opwekking zelf nog iets sterker van 29 TWh in 2030 tot 10 TWh in 2040 en 4 TWh in 2050 (i.e., van ongeveer 15% van de totale elektriciteitsproductie in 2030 tot slechts 1% in 2050). Ondanks de sterk groeiende vraag naar elektriciteit in deze periode (2030-2050) is deze dalende en relatief lage behoefte aan regelbaar vermogen/opwek – met name in 2050 – het gevolg van de volgende drie factoren:

i. het snel groeiende aanbod van elektriciteit uit zon en wind;
ii. de veronderstelde, groeiende beschikbaarheid van andere, alternatieve flexibiliteitsopties, in het bijzonder een groot potentieel aan vraagrespons en buitenlandse handel;
iii. de aanname van ‘normale’ (‘gemiddelde’) weersomstandigheden in de referentiejaren 2030, 2040 en 2050.

Gevoeligheidsanalyses (2050): behoefte aan regelbaar vermogen

Uit de onzekerheids-/gevoeligheidsanalyses voor het jaar 2050 resulteert dat de behoefte aan regelbaar vermogen varieert van 4 GW tot 18 GW en, in termen van elektriciteitsproductie, van 3 TWh tot 43 TWh (i.e., van 0.6% tot 10% van de totale stroomopwekking in 2050). Deze analyses laten zien dat de vraag naar regelbaar vermogen/opwek met name afhangt van de volgende factoren:

i. de veronderstelde beschikbaarheid en betrouwbaarheid van alternatieve flexibiliteitsopties zoals vraagresponse en buitenlandse handel;
ii. de veronderstelde weersomstandigheden, i.e. ‘normale’ (‘gemiddelde’) weercondities versus ‘extreme’ weersomstandigheden, inclusief een of twee ‘Dunkelflautes’ per jaar;
iii. de veronderstelde beleidscondities, met name óf – en in welke mate – bepaalde regelbare opwektechnologieën zijn toegestaan (fossiel aardgas; biomassa/CCS) dan wel beleidsmatig worden gestimuleerd (kernenergie).

Aanbod van regelbaar vermogen: bepalende factoren
Aan de andere kant hangt de *aanbodmix* van de benodigde, regelbare opwektechnologieën – naast de totale behoefte aan regelbaar vermogen/opwek – in het bijzonder af van de volgende factoren:

i. de investerings- en operationele (variabele) kosten van de betreffende technologieën;
ii. het technisch-economisch potentieel van de omschakeling ('retrofit') van bestaande, fossiele opwektechnologieën (kolen, aardgas) naar klimaatneutrale technologieën (biomassa/CCS; groene waterstof);
iii. de beschikbaarheid en maatschappelijke acceptatie van bepaalde regelbare technologieën en/of brandstoffen (biomassa, biogas) voor de opwekking van elektriciteit;
iv. de overige, specifieke beleidscondities voor de betreffende, regelbare opwektechnologieën.

Referentie scenario (2030-2050): aanbod van regelbaar vermogen
Meer specifiek, in de referentie-scenariojaren 2030 en 2040 bestaat de aanbodmix van regelbaar vermogen nog overwegend uit fossiele-gascentrales – i.e., respectievelijk, circa 15 GW en 8 GW – aangevuld met beperkte capaciteiten (0.1-0.5 GW) van voormalige kolen- naar omgeschakelde biomassa-installaties (met/zonder CCS), afvalcentrales, grootschalige kernenergie (Borssele) en – louter in 2040 – kleine, modulaire kernreactoren ('SMRs'). In 2050 daarentegen neemt het opgesteld vermogen van fossiele-gascentrales af tot 1.3 GW terwijl de totale benodigde opwekcapaciteit (5 GW) grotendeels bestaat uit omgeschakelde gascentrales (met name van fossiel gas naar groene waterstof), aangevuld met kleine hoeveelheden (0.1-0.5 GW) van voormalige kolen- naar omgeschakelde biomassa-installaties (met/zonder CCS), afvalcentrales en kleine, modulaire kernreactoren ('SMRs').[1]

Gevoeligheidsanalyses (2050): technologiemix van regelbaar vermogen
Uit de gevoeligheidsanalyses voor het jaar 2050 blijkt dat in de gevallen met een relatief hoge vraag naar regelbaar vermogen (12-18 GW) de aanbodmix van regelbare opwektechnologieën grotendeels bestaat uit zowel omgeschakelde (fossiel gas) als nieuwe waterstofcentrales (6-13 GW) aangevuld met beperkte hoeveelheden (0.3-3.1 GW) van voormalige kolen- naar omgeschakelde biomassa-installaties (met/zonder CCS), nieuwe biogascentrales, afvalcentrales, fossiele-gas centrales en kleine, modulaire kernreactoren ('SMRs'). Daarnaast is een specifieke gevoeligheidsanalyse uitgevoerd waarin exogeen 6.4 GW aan grootschalige kernenergie in 2050 wordt verondersteld. Door de grote verschillen in het aantal vollasturen tussen basislast-technologieën (met name kernenergie) en pieklasttechnologieën (fossiel gas; groene waterstof) is het aandeel van de basislasttechnologieën echter doorgaans veel hoger – en veelal zelfs dominant – in termen van elektriciteitsproductie (TWh) dan van opgesteld vermogen (GW).

Beperkingen en onzekerheden
De bevindingen van het onderzoek dienen met de nodige voorzichtigheid te worden gehanteerd vanwege zowel de beperkingen van het gebruikte kostenoptimalisatiemodel (COMPETES-TNO) als de verscheidenheid aan onzekerheden met betrekking tot het veronderstelde referentie scenario tot 2050 (die slechts ten dele zijn onderzocht door de uitgevoerde gevoeligheidsanalyses). Deze onzekerheden betreffen in het bijzonder de kosten en potentiëlen van de onderzochte, regelbare opwektechnologieën (met name van de omgeschakelde – 'retrofit' – technologieën), het verdienmodel van deze technologieën (in het bijzonder de pieklast-technologieën met een beperkt aantal vollasturen), de beschikbaarheid en maatschappelijke acceptatie van de benodigde brandstoffen (biomassa/CCS), alsmede zowel de totale omvang en de samenstelling van de toekomstige elektriciteitsvraag.

[1] Voor zover de inzet van fossiele-gascentrales in 2040/2050 leidt tot positieve CO_2-emissies in het Nederlandse elektriciteitssysteem worden die gecompenseerd door negatieve CO_2-emissies elders in het Nederlandse/-Europese (emissiehandels)systeem.

Summary

Background and key objectives

The Netherlands – being part of the EU – aims at a climate-neutral society in 2050. For the Netherlands, this implies a strong further electrification of the energy system by means of power-to-X (P2X) technologies, such as power-to-hydrogen ($P2H_2$) and power-to-heat (P2H), resulting in an expected increase of total electricity demand by a factor 3 to 4 over the period 2020-2050. On the supply side, this rapidly growing demand is, on balance, largely met by domestic power generation from variable renewable energy (VRE), in particular sun PV and (offshore) wind. The variability, however, of sun and wind – including in particular hours and even extended periods in which sun and wind are hardly or not available ('*Dunkelflautes*') – raises the need to optimise additional, dispatchable power generation and other flexibility options – such as storage, trade or demand response – in order to meet electricity demand over all hours of the years in a reliable and affordable way.

Against this background, the key objectives or research questions of the current study include:

- What is the expected future need ('demand') for dispatchable generation in the Netherlands over the years 2030-2050?
- What is the expected cost-optimal supply mix of dispatchable (CO_2-free) generation technologies in the Netherlands over the period 2030-2050 within an European-wide context (i.e., allowing cross-border electricity trade and compensating any positive CO_2 emissions somewhere in the European P2X system by negative CO_2 emissions elsewhere in the system) to achieve a climate-neutral European P2X system in 2040 and beyond?

Approach

In order to address the research questions outlined above, a variety of scenario and sensitivity analyses has been conducted by means of the COMPETES-TNO model. COMPETES-TNO is a European power market optimisation model covering (i) almost all European countries and regions, (ii) key P2X sectors, notably power generation, power-to-hydrogen ($P2H_2$), power-to-heat (P2H) and power-to-mobility (P2M), i.e. electric vehicles (EVs), (iii) all major power generation technologies, including in particular their major techno-economic parameters, and (iv) all major flexibility options, i.e., besides dispatchable generation also flexible demand, trade, VRE/demand curtailment and several energy storage options. The model can optimise both the capacity investments in the P2X system for a certain target year as well as the dispatch of the installed capacities over a certain target year on an hourly basis.

The reference scenario in this study is based on the so-called '*Distributed Energy*' *(DE)* scenario, developed by ENTSO-E and ENTSOG as part of their Ten Year Network Development Plan (TYNDP) 2022, notably on the energy demand assumptions up to 2050 and the assumed ('expected') installed capacities in 2030 of the major electricity demand and supply technologies across European countries and regions. Subsequently, the COMPETES-TNO model optimises the capacity investments and the hourly dispatch of the installed capacities for the years 2040 and 2050, within certain assumed constraints, such as (maximum available) VRE potentials.

The reference scenario includes a high potential of flexible demand to deal with varying levels of electricity demand versus VRE supply. More specifically, it includes the following types of flexible demand:

i. flexible, price-responsive demand by P2Heat in industry and P2Hydrogen (‘conversion’), implying that these technologies are only deployed during hours in which (VRE) electricity supply is relatively abundant and, hence, the electricity price is favourable (i.e., relatively low) to convert electricity into industrial heat/hydrogen;
ii. demand response (‘shifting’) by electric vehicles (EVs) and household heat pumps, implying that – within certain constraints – electricity demand can be partly shifted over a short-time period from hours with relatively higher electricity prices to hours with relatively lower prices (‘*short-duration demand shifting*’);
iii. ‘agreed’ or ‘voluntary’ industrial load shedding (ILS), up to a maximum of 3.5 GW in 2050;
iv. ‘forced’ or ‘involuntary’ demand curtailment, i.e. a ‘last resort’ option at a ‘value of lost load’ (VoLL) of 10,000 €/MWh.

For 2030, the greenhouse gas (GHG) reduction target of the reference scenario follows the EU Green Deal, i.e. 55% GHG reduction within the EU compared to 1990. In this study, which uses the European P2X optimisation model COMPETES-TNO, this target is translated (‘approached’) into a fixed CO_2 price for the European P2X system as a whole at about 100 €/tCO_2 in 2030.

For 2040 and 2050, the climate policy target for the P2X system is zero emissions. In this study, this target refers to the European P2X system as a whole (in order to minimise the total system costs). This implies that in 2040/2050 any remaining (positive) CO_2 emissions in one of the P2X subsectors in one of the European Member States is compensated by negative CO_2 emissions elsewhere in the system.[2]

Moreover, in order to study the impact of some major factors and uncertainties affecting the demand and supply of dispatchable generation in the Netherlands up to 2050, several sensitivity cases have been conducted for the year 2050 (which are all based on the reference scenario of that year). In brief, these 2050 sensitivity cases include:

i. ‘*Less Flexible Demand (LFD)’:* This case is similar to the reference scenario, excluding (i) the demand-shifting capabilities of EVs and household heat pumps and (ii) any industrial load shedding (ILS), but still including the demand response by P2Heat in industry and P2Hydrogen (‘*conversion*’) and – in hours of electricity supply shortages – demand curtailment at the value of lost load (VoLL);
ii. ‘*Power CO_2-free’:* In this case, power generation has to be fully CO_2-free – starting from 2035 – while no CCS is allowed in the electricity sector of those European countries that announced in late 2023 to aim at fully decarbonising their power system by 2035 (i.e., Austria, Belgium, France, Germany, Luxembourg, Switzerland and the Netherlands).[3] This implies that, starting from 2035, these countries are not allowed to have any remaining positive CO_2 emissions in their national power system or to compensate these emissions by negative CO_2 emissions elsewhere in the European P2X system (while the other European countries – not part of this announcement – still have this compensation option);

[2] At the EU policy level, this system of balancing positive and negative CO_2 emissions would require a revision of the current EU ETS system in the sense that negative CO_2 emissions should be awarded an equivalent amount of ETS allowances which can be sold on the market to parties having positive emissions (while the overall balance is zero emissions). According to the Clean Industrial Deal (EC, 2025), the remuneration of negative emissions is foreseen to be covered by the reform of the EU ETS in 2026.

[3] See the announcement of 18-12-2023 by the group of countries aiming to decarbonize their interconnected electricity system by 2035 (GoN, 2023). Recently (September 2025), the Dutch government has relaxed this ambition of a CO_2-free power system by 2035 (KGG, 2025).

iii. '*Power CO_2-free + LFD'*: This case is a combination of the previous two sensitivity cases;
iv. '*Climate Year 1987*': In this case, the hourly electricity demand and VRE supply profiles for 2050 are based on the profiles of the 'extreme' climate year 1987, including two 'Dunkelflaute' periods in the Netherlands (rather than on the profiles of the 'normal' climate year 2015 in the reference scenario);
v. '*Climate Year 1996*': In this case, the hourly electricity demand and VRE supply profiles for 2050 are based on the profiles of the 'extreme' climate year 1996, including a 'Dunkelflaute' period simultaneously in both Germany and the Netherlands;
vi. *Extra sun PV*': This case assumes a halving of the capital investment costs (CAPEX) of sun PV in 2040 and 2050 (compared to the baseline cost assumptions of the reference scenario);
vii. '*Extra nuclear*' : This case assumes exogenous investments in two large nuclear power plants in the Netherlands, operational in 2040 (total capacity: 3.2 GW) and two additional large nuclear power plants in 2050 (also 3.2 GW, resulting in 6.4 GW nuclear power capacity operational in 2050);[4]
viii. '*Extra trade:* This case assumes 9.8 GW extra interconnection capacity for the Netherlands in 2050, resulting in 22.6 GW interconnection capacity for the Netherlands in 2050 compared to 12.8 GW in the reference scenario;
ix. '*No trade'*: This case is similar to the reference scenario but no electricity imports or exports by the Netherlands are allowed.

Major results

Reference scenario (2030-2050)

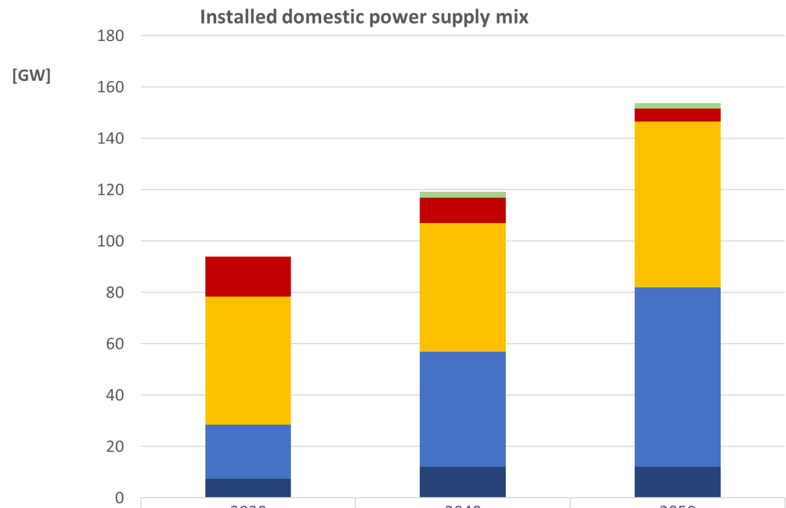
Figure S.1 presents the modelling results for the installed capacities of the power generation sector in the Netherlands according to the reference scenario over the period 2030-2050. The major findings of this figure include:

- For 2030, the installed generation capacities are assumed exogenously by the COMPETES-TNO model (except the capacities of the coal-retrofitted biomass installations, which are optimised endogenously). Regarding VRE power generation, the assumed capacities in 2030 include 21 GW offshore wind, 7.4 GW onshore wind and 50 GW sun PV.[5] Concerning dispatchable power generation, the assumed capacities in 2030 include about 14.7 GW for (natural, fossil) gas-fired installations, 0.5 GW for large-scale nuclear ('Borssele') and 0.3 GW for so-called 'Other RES-E' (i.e., mainly waste standalone), whereas the optimised capacity of coal-retrofitted biomass installations amounts to 0.1 GW in 2030.[6]

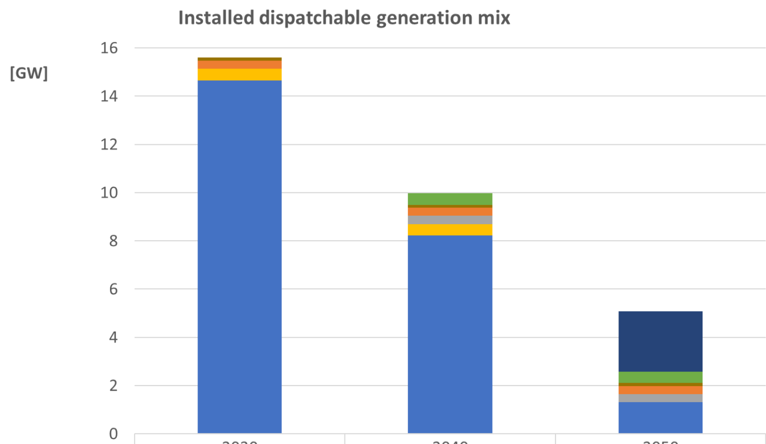
[4] This study assumes that, after 2033, the lifetime of the Borssele nuclear plant – with an installed capacity of 0.5 GW power generation - is extended by some 10 years up to the mid-2040s. The cost-optimisation run of the reference scenario by the COMPETES-TNO model did not show any new (endogenous) nuclear capacity investments in large-scale nuclear power plants in the Netherlands up to 2050 but only some investments (0.3 GW) in small modular reactors (SMRs) by 2040. The previous Dutch government (Rutte IV, 2022-2024), however, agreed to explore and promote investments in two new, large nuclear plants in the Netherlands. More recently, the current – demissionary - government (Schoof, 2024-present) even agreed to promote investments in *four* large nuclear plants. Therefore, as indicated in the main text above, we have included a separate sensitivity case, called '*Extra Nuclear*', assuming exogenous ('policy-induced') investments in two large nuclear power plants, operational from 2040 onwards, and two additional large plants, starting from 2050.

[5] Note that the exogenously assumed capacity of 21 GW offshore wind in 2030 is much larger than more recently anticipated to be realised in 2030 (but hardly or not affects the endogenously optimised capacities of offshore wind in 2040 and 2050). The assumed installed capacity of 50 GW for sun PV in 2030 is based on the most recent monitoring reports by DNE Research (2025) and RVO (2025) showing that the realised sun PV capacity in 2024 amounted already to 29 GW and that the anticipated increase of this capacity up to 2030 is about 3-4 GW per year.

[6] 0.1 GW capacity of coal-retrofitted biomass installations in 2030 is rather small (and, in practice, probably 'unrealistic' from a techno-economic point of view). In COMPETES-TNO, however, there is no minimum or lower limit of coal-retrofitted biomass capacity. The required capacity is optimised by the model for a certain target year from a total system cost perspective, resulting in a coal-retrofitted biomass capacity of 0.1 GW in 2030.



	2030	2040	2050
Li-ion battery storage	0.0	2.2	2.2
Dispatchable generation	15.6	10.0	5.1
Sun PV	50.0	50.0	64.5
Wind offshore	21.0	45.0	70.0
Wind onshore	7.4	12.0	12.0



	2030	2040	2050
H2 CCGT Retro	0.0	0.0	2.5
Biomass Retro (with CCS)	0.0	0.5	0.5
Biomass Retro (no CCS)	0.1	0.1	0.1
Other RES-E	0.3	0.3	0.3
Nuclear (SMR)	0.0	0.3	0.3
Nuclear (large)	0.5	0.5	0.0
Natural gas	14.7	8.2	1.3

Note: Figures on the required capacities of dispatchable generation and battery storage refer to the hourly spot market only but do not include the need for balancing/emergency reserves.

Figure S.1: Reference scenario, 2030-2050: Installed domestic power supply mix (upper graph), including a breakdown of the installed dispatchable generation mix (lower graph)

- For both 2040 and 2050, new capacity investments in the European P2X system are optimised by COMPETES-TNO. For the power generation sector in the Netherlands in 2040 this implies that the VRE installed capacity expands to about 45 GW offshore wind and reaches the maximum potential of 12 GW onshore wind, whereas the optimal capacity for sun PV remains the same over the years 2030-2040 at 50 GW. Regarding dispatchable power generation, the installed capacity of natural gas-fired plants declines from 14.7 GW in 2030 to 8.2 GW in 2040. The other dispatchable capacities in 2040 include (i) coal-retrofitted biomass installations, either with or without CCS (0.6 GW)[7], (ii) waste standalone (0.3 GW), and large-scale nuclear (0.5 GW, due to the assumed lifetime extension of the Borssele plant). In addition, the COMPETES-TNO optimisation run for 2040 shows some new nuclear capacity investments (0.3 GW) in small modular reactors (SMRs).

- In 2050, in order to meet the rapidly growing electricity demand in a carbon-free way, the optimised VRE generation capacity in the Netherlands is expanded to about 65 GW of sun PV and 70 GW of offshore wind, while the capacity of onshore wind remains at the (capped) level of 12 GW over the years 2040-2050. Regarding dispatchable generation, the installed capacity of gas-fired plants is largely decommissioned – for technical/economic reasons – from 8.2 GW in 2040 to 1.3 GW in 2050 (producing 0.2 TWh of electricity). In addition, the installed capacity of large nuclear plants drops to zero in 2050 due to the decommissioning of the (lifetime-extended) Borssele plant in the mid-2040s. The installed capacity of SMRs, however, - as well as of waste standalone and (coal-retrofitted) biomass plants without CCS – remains at the same level over the years 2040-2050, i.e. at 0.3 GW, 0.3 GW and 0.1 GW, respectively. On the other hand, the capacity of (coal-retrofitted) biomass installation with CCS expands slightly from 0.5 GW in 2040 to 0.8 GW in 2050. Moreover, the 2050 reference scenario shows significant new capacity investments in (CCGT-retrofitted) hydrogen plants of approximately 2.5 GW.

Figure S.2 presents the results of the reference scenario with regard to the full load hours (FLHs) of the major dispatchable generation technologies. A striking finding concerns natural gas-fired generation, which – besides a major drop in installed capacities over the years 2030-2050 (see Figure S.1 above) – shows also a large decline in FLHs, from 1670 hours in 2030 to only 122 hours in 2050, resulting in an even much larger fall in electricity supply – i.e., installed capacity times FLHs – from natural gas (see Figure S.3 below).

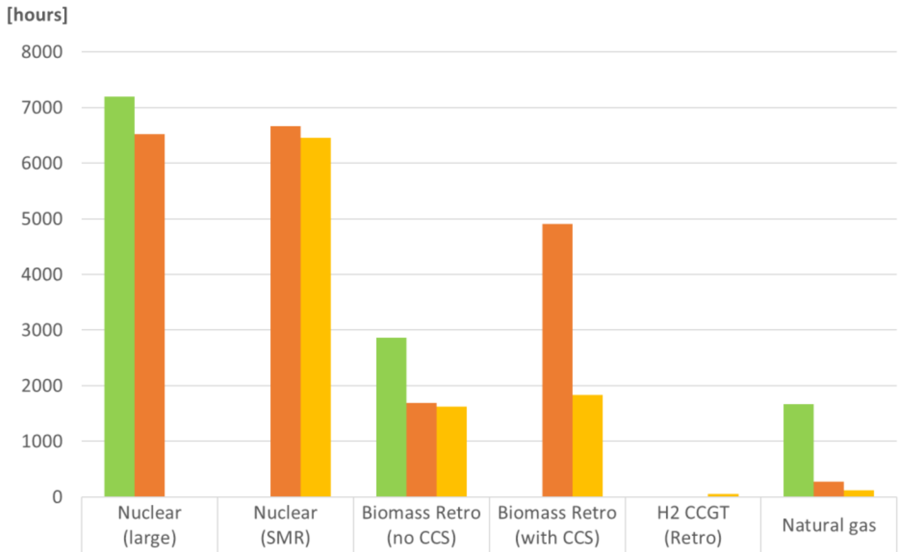
Other interesting findings of Figure S.2 include: (i) the FLHs of biomass retro (without CCS) decreases from almost 2900 hours in 2030 to approximately 1600 hours in 2050, (ii) the FLHs of biomass retro (with CCS) declines from about 4900 hours in 2040 to 1800 hours in 2050, and (iii) the FLHs of hydrogen-fired, CCGT-retrofitted plans amount to only 51 hours in 2050. These low FLHs in 2050 – and the resulting relatively low output of these technologies – raise questions regarding the riskiness and economic viability ('profitability') of investments in these technologies (see also section 'Discussion' below).

Figure S.3 shows the resulting electricity output by the major dispatchable generation technologies in the reference scenario years 2030, 2040 and 2050. As indicated above, the output from natural gas-fired power plants tumbles substantially, i.e. from almost 25 TWh in 2030 to 2.2 TWh in 2040 and only 0.2 TWh in 2050.[8] Electricity supply from coal-retrofitted biomass plants (with/without CCS) increases from 0.4 TWh in 2030 to 2.5 TWh in 2040, but declines to 1.1 TWh in 2050 (mainly because less output from dispatchable generation is needed in 2050 due to the large increase in VRE generation on the one hand and the large supply of other flexibility options – demand response, trade and storage – on the other hand). Similarly, the output from nuclear power generation increases from 3.5 TWh in 2050 (by the 'large' Borssele plant only) to 5.4 TWh in 2040 (by both 'Borssele' and new SMRs), but decreases to 2.1 TWh in 2050 (only SMRs, because of the decommissioning of the Borssele plant and no new investments in large nuclear power plants).

[7] In theory, the maximum potential of coal-retrofitted biomass capacity – with or without CCS – amounts to about 4 GW but in the model optimisation runs this capacity is particularly constrained by the (assumed) limited availability of biomass for electricity production.

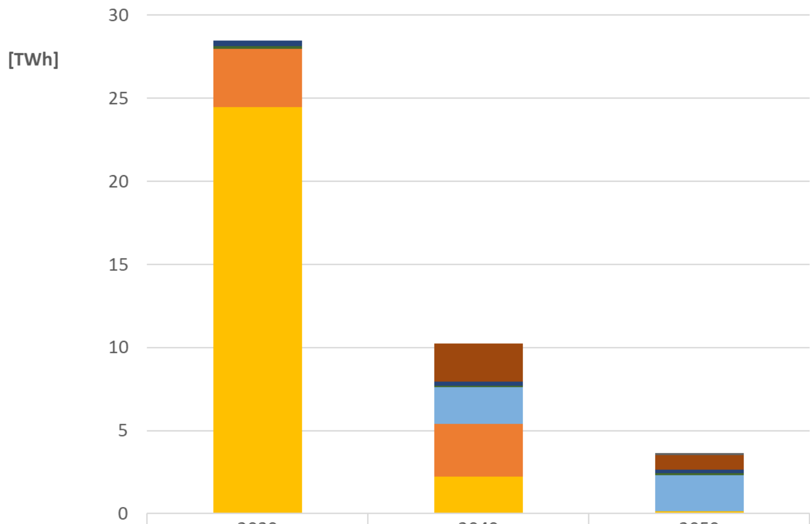
[8] Note that any remaining positive CO_2 emissions from natural gas-fired power generation in the Netherlands in 2040 and 2050 are compensated by negative CO_2 emissions elsewhere in the NL/European P2X system.

As a percentage of total dispatchable generation, the share of natural gas-fired plants decreases from 86% in 2030 to 22% in 2040 and 4% in 2050. For biomass retro (with/without CCS), these shares amount to 1%, 25% and 30%, respectively, while for nuclear (large/SMRs) they amount to 12%, 52% and 59%, respectively.



	Nuclear (large)	Nuclear (SMR)	Biomass Retro (no CCS)	Biomass Retro (with CCS)	H2 CCGT (Retro)	Natural gas
2030	7193		2860			1670
2040	6523	6669	1690	4909		272
2050		6451	1618	1828	51	122

Figure S.2: Reference scenario, 2030-2050: Full load hours (FLHs) of dispatchable generation technologies



	2030	2040	2050
H2 CCGT Retro	0.0	0.0	0.1
Biomass retro (with CCS)	0.0	2.3	0.9
Biomass retro (no CCS)	0.4	0.2	0.2
Other RES-E	0.2	0.1	0.1
Nuclear (SMR)	0.0	2.2	2.1
Nuclear (large)	3.5	3.2	0.0
Natural gas	24.5	2.2	0.2

Figure S.3: Reference scenario, 2030-2050: Electricity supply by dispatchable generation technologies

Overall, total output from all dispatchable generation technologies decreases from almost 29 TWh in 2030 to about 10 TWh in 2040 and 3.6 TWh in 2050. Since total supply from all generation technologies (including VRE) increases rapidly over these years, the share of dispatchable generation in total electricity production decreases even more significantly, i.e. from 15% in 2030 to 3% in 2040 and only 1% in 2050 (while the remaining, dominant part comes from VRE generation).

Sensitivity cases (2050): installed capacities
Figure S.4 presents the model optimisation results for the reference and sensitivity cases outlined above with regard to the installed power supply capacity mix of the Netherlands in 2050 – including the major VRE generation technologies, total dispatchable generation and battery storage (discharge) – whereas Figure S.5 provides a breakdown of the total dispatchable generation capacity into the underlying mix of power production technologies.

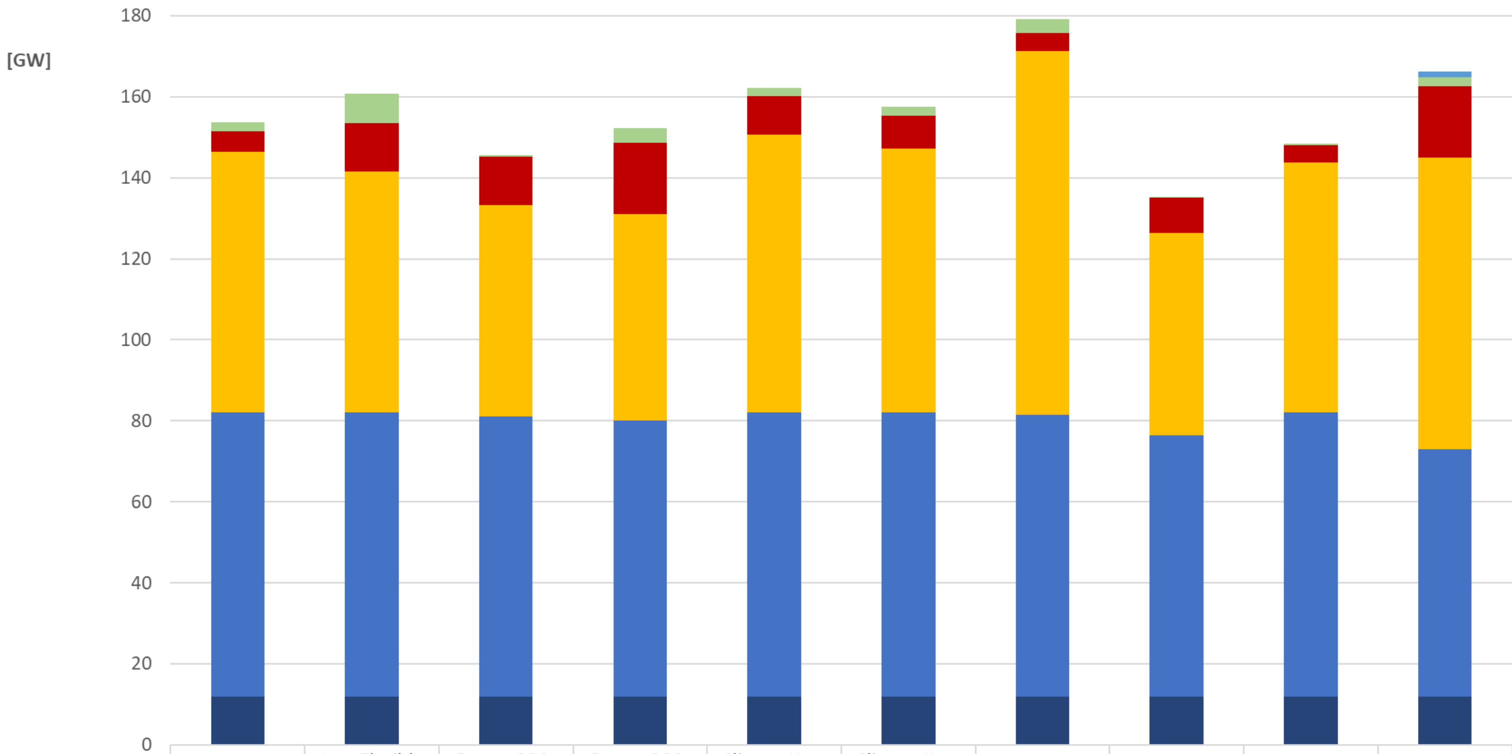
The major findings of Figure S.4 include:

- *VRE generation:* The installed capacity of offshore wind in 2050 amounts to 70 GW – i.e., the assumed maximum potential – in the reference scenario as well as in several sensitivity cases. Only in some cases, the offshore wind capacity is somewhat lower, namely in the cases '*Extra Nuclear*' (64 GW) and '*No Trade*' (61 GW). In all cases recorded in Figure S.4, the installed capacity of onshore wind is capped by the model at the assumed maximum potential of 12 GW. The installed capacity of sun PV in 2050 amounts to almost 65 GW in the reference scenario but ranges from about 50 GW in the case '*Extra Nuclear*' to approximately 90 GW in the case '*Extra sun PV*'.

- *Battery storage:* According to the COMPETES-TNO optimization runs, capacity investments in short-duration (4-8 hour) electrical storage – by means of Li-ion batteries – pop up in all cases recorded in Figure S.4. In the reference scenario, as well as in some sensitivity cases, however, these investments result in 2.2 GW (re)charging capacity only in 2050, mainly because of the large available potential of other (cheaper) short-duration flexibility options such as demand response by P2X technologies ('conversion') as well as hourly fluctuating foreign trade flows (imports/exports) of electricity.[9] In some cases, the cost-optimal battery storage capacity is even substantially lower, notably in the cases '*Extra Trade*' (0.4 GW) – due to higher interconnection capacities - and '*Extra Nuclear*' (0.3 GW) because of both the lower need for flexibility – due to less VRE capacity and, hence, smaller VRE output fluctuations – and the additional supply of flexibility offered by the extra nuclear capacity/output. On the other hand, in the case '*Less Flexible Demand (LFD)*' the Li-ion battery storage capacity in 2050 is significantly higher (7.3 GW), mainly due to less competition from other, short-term flexibility options such as demand shifting by EVs and household heat pumps.[10]

[9] It should be emphasized, however, that the COMPETES-TNO model covers only the hourly spot markets but not the electricity balancing ('reserve') and other, ancillary services markets and, therefore, may underestimate the role (business case, installed capacity, volume transactions) of battery storage.

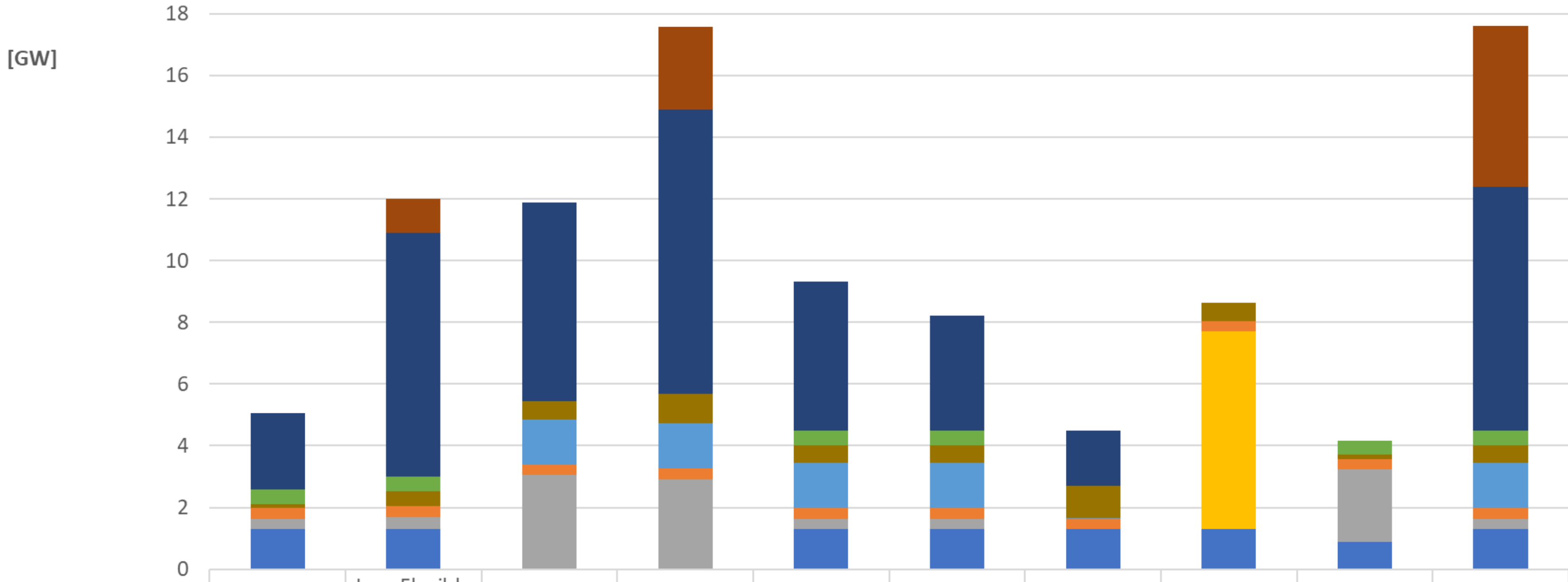
[10] The COMPETES-TNO model also allows investments in other batteries as well as in compressed air energy storage (CAES, both diabatic and adiabatic), but in nine out of ten scenario/sensitivity cases included in this study these investments turned out to be not cost-optimal. Only in one sensitivity case ('*No Trade*') some investments in diabetic CAES (about 1.3 GW in 2050) showed up to be attractive from a social cost perspective. In all cases, however, hydrogen storage – not recorded in Figure S.4 – plays a major role in balancing the energy system, including hydrogen produced by means of (converting) power-to-hydrogen ($P2H_2$) and, subsequently, stored for purposes such as hydrogen-to-heat, hydrogen-to-mobility or (re-converting) hydrogen-to-power. Moreover, in all cases, demand response by EV batteries also plays a major role in balancing the power system, including EV battery discharges to the power grid when electricity prices are relatively high (V2G, which in COMPETES-TNO is considered as 'demand response' rather than 'storage').



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Storage: Diabatic CAES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Storage: Li-ion batteries	2.2	7.3	0.5	3.6	2.2	2.2	3.5	0.3	0.4	2.2
Dispatchable generation	5.1	12.0	11.9	17.6	9.3	8.2	4.5	8.6	4.2	17.6
Sun PV	64.5	59.5	52.3	51.0	68.7	65.1	89.7	50.0	61.8	71.9
Wind offshore	70.0	70.0	69.0	68.1	70.0	70.0	69.5	64.4	70.0	61.0
Wind onshore	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Note: For a breakdown of the total dispatchable generation capacity, see Figure S.5.

Figure S.4: Reference and sensitivity cases, 2050: Installed capacities of VRE generation, total dispatchable generation and electrical storage



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
H2 CCGT (New)	0.0	1.1	0.0	2.7	0.0	0.0	0.0	0.0	0.0	5.2
H2 CCGT (Retro)	2.5	7.9	6.4	9.2	4.8	3.7	1.8	0.0	0.0	7.9
Biomass Retro (with CCS)	0.5	0.5	0.0	0.0	0.5	0.5	0.0	0.0	0.5	0.5
Biomass Retro (no CCS)	0.1	0.5	0.6	1.0	0.6	0.6	1.1	0.6	0.1	0.6
Biogas (New)	0.0	0.0	1.5	1.5	1.5	1.5	0.0	0.0	0.0	1.5
Other RES-E	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Nuclear (SMR)	0.3	0.4	3.1	2.9	0.3	0.3	0.0	0.0	2.4	0.3
Nuclear (large)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	0.0
Gas CCGT	1.3	1.3	0.0	0.0	1.3	1.3	1.3	1.3	0.9	1.3

Figure S.5: Reference and sensitivity cases, 2050: Breakdown of installed NL dispatchable generation capacity mix

- *Dispatchable generation:* In the reference scenario, the total need ('demand') for dispatchable generation in 2050 amounts to 5.1 GW, whereas in the sensitivity cases this need varies from 4.2 GW in the case '*Extra Trade*' to almost 18 GW in both the case '*Power CO_2-free + Less Flexible Demand (LFD)*' – where less capacity of sun PV is replaced by more capacity of dispatchable generation – as well as in the case '*No trade'* (where the loss of 12.6 GW of import capacity is compensated by domestic, flexible supply options, notably dispatchable generation). In addition, note that:

  - In the case '*Less Flexible Demand (LFD)*', the need for dispatchable generation capacity (12 GW) is substantially higher than in the reference scenario (5.1 GW). This extra need is predominantly covered by additional capacity investments in (CCGT-retrofitted) H_2-power plants (5.4 GW, on top of 2.5 GW in the reference case) as well as investments in new H_2 CCGT capacity (1.1 GW);

  - In the cases '*Climate Year 1987*' and '*Climate Year 1996'* – each including one or even two Dunkelflaute periods – the demand for dispatchable generation capacity increases from 5.1 GW in the reference case to 9.3 GW and 8.2 GW, respectively;

  - In the case '*Extra Sun PV*', the additional capacity of sun PV in 2050 (i.e., +25 GW, compared to the reference scenario) leads to a slightly lower need for dispatchable generation capacity only (-0.6 GW);

  - In the case '*Extra Nuclear'*, the additional nuclear capacity in 2050 (+6.4 GW) only partly replaces the need for other dispatchable generation capacity (-2.9 GW) and, therefore, results in an increase of total dispatchable generation capacity (+3.5 GW);

  - Finally, in the case '*Extra Trade'*, the expansion of the NL interconnection capacity (+9.8 GW) results only in a slightly lower need for dispatchable generation capacity in 2050 (-0.9 GW), whereas on the other hand, in the case '*No Trade'*, the non-availability of 12.8 GW interconnection capacity increases this need substantially (+12.5 GW).

Figure S.5 provides a more detailed breakdown of the dispatchable generation capacity in the Netherlands in 2050 for the various analysed cases. The major findings of this figure include:

- *Gas CCGT:* In both the reference scenario and most sensitivity cases (6 out of 9) the optimal capacity of natural gas-fired CCGT power plants in the Netherlands amounts to 1.3 GW in 2050. Only in the case '*Extra Trade'*, the need for flexible natural gas-fired plants is slightly lower (-0.4 GW) – mainly because of the additional (cheaper) flexibility offered by extra trade/interconnection capacities – whereas in the two '*Power CO_2-free'* cases the available natural gas-fired CCGT capacity is, by definition, zero (in both 2040 and 2050).

- *Large-scale nuclear:* Based on the COMPETES-TNO model scenario runs, the cost-optimal ('endogenous') capacity investments in large nuclear power plants turn out to be zero in both the reference scenario and all sensitivity cases. Only in the case '*Extra Nuclear'* 6.4 GW of large-scale nuclear power capacity is assumed exogenously in the model, notably to explore the impact on the installed capacity and deployment of other dispatchable generation technologies as well as other flexible options.

- *Small-scale nuclear (SMRs):* In 2050, the endogenous ('optimal') capacity in nuclear SMRs amounts to 0.3 GW in the reference scenario as well as in some sensitivity cases ('*No Trade'*, '*Climate Year 1997/1996*'). In the other cases recorded in Figure S.5, this capacity varies from zero in the cases '*Extra Sun PV*' and '*Extra Nuclear*' (large-scale) to approximately 3 GW in the two '*Power CO_2-free*' cases.[11]

- *Biogas*: In both the reference scenario and four out of nine sensitivity cases, the optimal installed capacity of new, biogas-fired power plants is zero in 2050. In the other five sensitivity cases, however, this capacity amounts to 1.5 GW (for details, see Figure S.5). The main reason for these varying outcomes is the total need for dispatchable generation in each case considered versus the costs and maximum potentials of electricity production by various dispatchable generation technologies, including biogas – as reflected in the merit order of dispatchable generation – as well as the assumed, limited availability of biogas for electricity production. In the reference scenario and four (out of nine) sensitivity cases, the relative low demand for dispatchable generation is met by other (cheaper) technologies than biogas (or, in the case '*Extra Nuclear*' by the exogenously assumed additional capacity of nuclear power generation). In the other five sensitivity cases, however, the need for dispatchable generation is relatively high, which is partly met by the higher merit-order ranked (i.e., more expensive) biogas technology.[12]

- *Biomass (coal-retro; with/without CCS)*: In both the reference scenario and some sensitivity cases (3 out of 9), the total optimal installed capacity of coal-retrofitted biomass installations with/without CCS amounts to 0.6 GW. In the other (6) sensitivity cases, this capacity is slightly higher, i.e., up to 1.1 GW. In each case, the cost-optimal demand and supply of coal-retrofitted biomass capacity depends on a complex mix of factors, including the total need for flexibility in general and for dispatchable generation in particular, the costs and technical potential of coal-retrofitted capacity, the costs and availability of biomass and CCS for electricity production, the eventual (financial) compensation of negative emissions by the P2X system and the related CO_2 price in each case considered.

- *Hydrogen CCGT (retro)*: In the reference scenario, the optimal capacity of CCGT-retrofitted, H_2-fuelled power plants amounts to 2.5 GW in 2050, whereas in the sensitivity cases this capacity varies from zero in the cases '*Extra Nuclear*' and '*Extra Trade*' to 9.2 GW in the case '*Power CO_2-free + Less Flexible Demand (LFD)*'.[13] Similar to biogas (as outlined above), the main reason for these varying hydrogen results is the total need for dispatchable generation in each case considered versus the costs and maximum potentials of electricity production by various dispatchable generation technologies, including hydrogen (as reflected in the merit order of dispatchable generation technologies).

- *Hydrogen CCGT (new):* besides retrofitted CCGT-H_2 power plants, there is a need for *new* CCGT H_2-fuelled generation capacity in 2050 in three sensitivity cases, i.e. '*Less Flexible Demand*' (1.1 GW), '*Power CO_2-free + LFD*' (2.7 GW) and, in particular, '*No Trade*' (5.2 GW). The main reasons for the new H_2 CCGT need – besides the already high demand for H_2 CCGT retro – are (i) the lower supply of flexibility by demand response (in the two LFD cases) or

[11] The COMPETES-TNO model includes only electricity production by SMRs – but excludes heat production for industry – and, therefore, most likely underestimates the potential role of SMRs in the energy system of the Netherlands (see Scheepers et al., 2025, for a recent analysis of the potential role of nuclear energy – including SMRs – in the Dutch energy system).

[12] Note that the upper limit of 1.5 GW biogas capacity is largely due to the assumed, limited availability of biogas for electricity production.

[13] The 'optimal' capacity of CCGT-retrofitted, H_2-fuelled power plants in the 2050 sensitivity case '*Power CO_2-free + LFD*' – i.e., 9.2 GW – is equal to the installed natural gas-fired CCGT capacity in 2030 obtained from the reference scenario runs by COMPETES-TNO. This capacity of 9.2 GW is assumed to be the technical maximum potential for CCGT retrofitting up to 2050. Note that in the cases '*Less Flexible Demand*' and '*No Trade*', there is still 1.3 GW of natural gas CCGT capacity installed in 2050 and, hence, the maximum available capacity of H_2 CCGT Retro is lower accordingly (7.9 GW) while the need for H_2 CCGT New is accordingly higher.

trade (in '*No Trade*'), (ii) the resulting higher need for flexibility by other sources, including dispatchable generation (and storage), and (iii) the fuel-availability/capacity-potential constraints of other, competing dispatchable generation technologies, notably biogas, biomass and H_2 CCGT retrofitted power plants.

- *Other RES-E:* In all reference and sensitivity cases included in this study, the installed capacity of electricity production by other renewable energy sources (RES-E) – i.e., predominantly waste standalone – amounts to 0.3 GW in 2050.

Sensitivity cases (2050): full load hours and electricity output of dispatchable generation
In terms of full load hours (FLHs), the sensitivity cases show some interesting variations both between the major dispatchable technologies and across the cases considered. In general, FLHs are highest for nuclear (large/SMRs) power plants – ranging from 6200 to 6800 hours across the cases analysed – 'medium' for biomass retro (with/without CCS), varying from 1400 to 4100 hours, and lowest for CCGT H_2-fuelled installations, ranging from only 23 to about 140 hours.

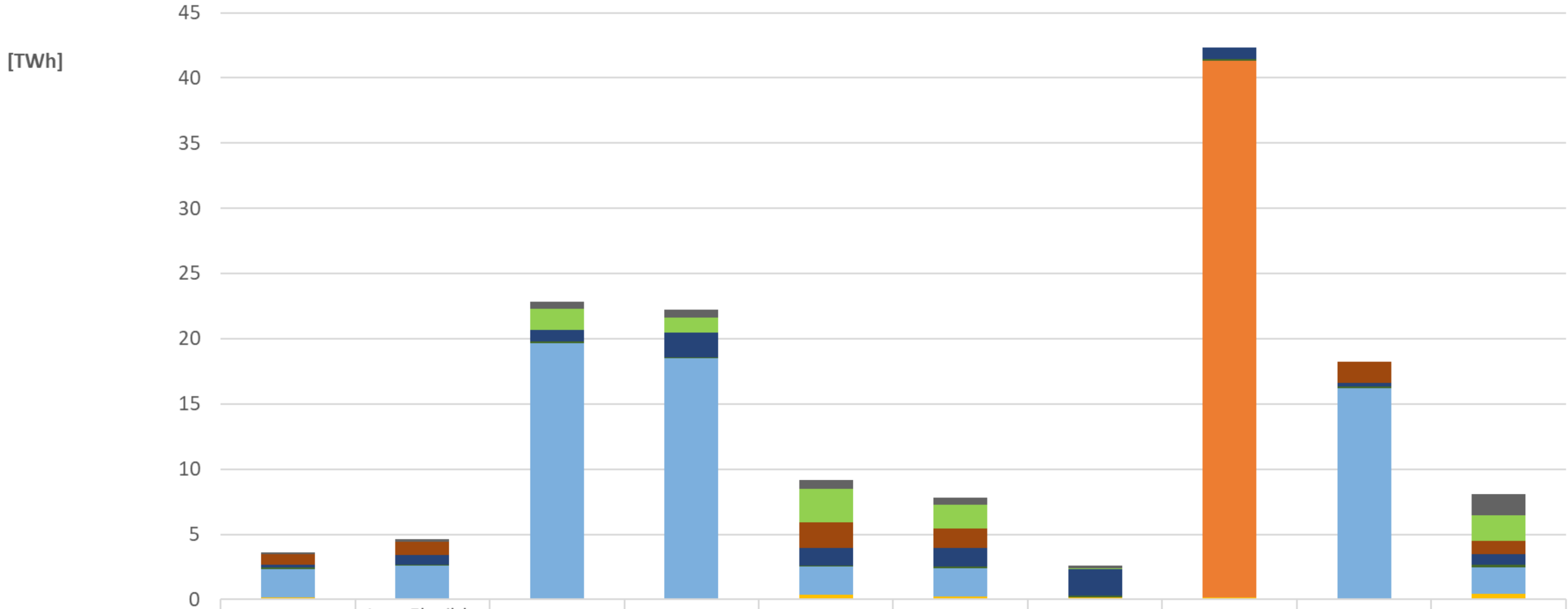
Figure S.6 presents the resulting outcomes (i.e., installed capacities times FLHs) in terms of electricity output by the major dispatchable generation (DG) technologies in the 2050 reference and sensitivity cases conducted. It shows that total electricity supply by all DG technologies in the cases considered varies substantially, i.e. from less than 3 TWh in the case '*Extra Sun PV*' to more than 42 TWh in the case '*Extra Nuclear*'. As a percentage of total electricity production (including VRE generation), the share of dispatchable generation ranges from 0.6% in the case '*Extra Sun PV*' to approximately 10% in the case '*Extra Nuclear*' (while the remaining, dominant share comes from VRE sources, notably offshore wind and sun PV).

Figure S.6 also shows some interesting findings regarding the *mix* of DG output across the cases considered. For instance, in the case '*Extra Sun PV*', the relatively low DG output (2.6 TWh) is dominated by biomass retro (2.1 TWh), whereas in the case '*Extra Nuclear*' the relatively high DG output (42.3 TWh) is dominated by – as expected – power production from large nuclear plants (41.2 TWh). In addition, note that the relatively high total DG supply in the two '*Power CO_2-free*' cases (22-23 TWh) – as well as in the case '*Extra Trade*' (18 TWh) – is largely met by output from small modular reactors (16-20 TWh).

In terms of installed capacities, the mix of dispatchable generation technologies in both the 2050 reference case and most sensitivity cases is dominated by H_2 CCGT installations (retro/new; see Figure S.5). In terms of electricity output, however, this mix is in most cases dominated by nuclear power plants (large/SMRs; see Figure S.6). The reason for this difference is, of course, that the capacity factor – i.e., the number of full load hours – is generally much higher (about 50 to 280 times) for nuclear than H_2 CCGT power plants.

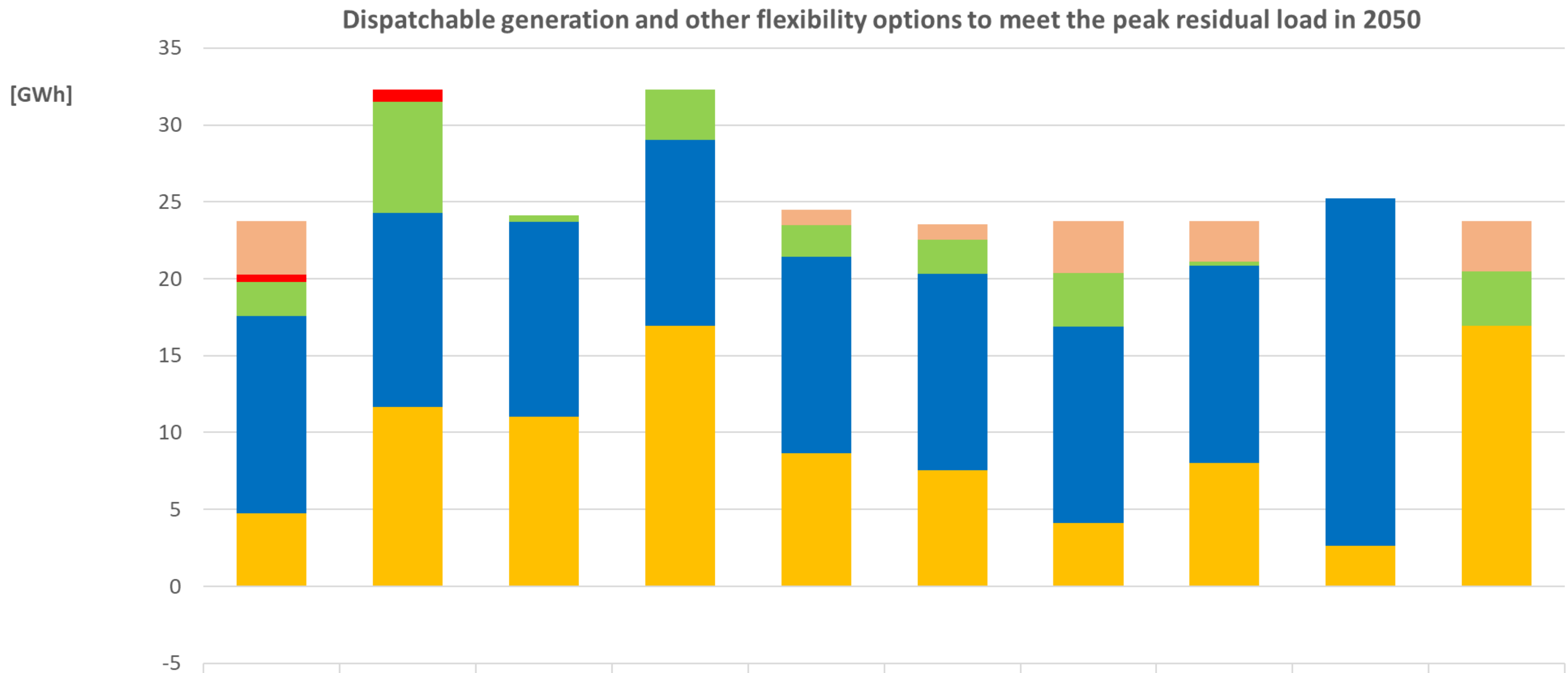
Sensitivity cases (2025): flexibility options to meet peak residual load
For both the reference scenario and all sensitivity cases, Figure S.7 shows the hour with the highest ('peak') residual load as well as the mix of flexibility options to cover this peak. To some extent, this figure provides further insights into (the major factors affecting) the need for dispatchable generation across the different cases recorded.

In this study, residual load (RL) is defined as the difference between total hourly domestic electricity demand (after demand shifting/conversion) and total hourly domestic VRE power generation (before VRE/demand curtailment). Figure S.7 shows that the peak RL of the Netherlands in 2050 varies from about 24 GW in the reference scenario to 32 GW in the two cases with '*Less Flexible Demand*' (LFD).



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
H2 CCGT (Retro/New)	0.1	0.2	0.5	0.6	0.7	0.5	0.2	0.0	0.0	1.6
Biogas (New)	0.0	0.0	1.6	1.2	2.6	1.8	0.0	0.0	0.0	2.0
Biomass Retro (with CCS)	0.9	1.0	0.0	0.0	1.9	1.5	0.0	0.0	1.6	1.0
Biomass Retro (no CCS)	0.2	0.7	0.9	1.9	1.3	1.4	2.1	0.9	0.3	0.9
Other RES-E	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear (SMR)	2.1	2.5	19.7	18.5	2.2	2.2	0.0	0.0	16.1	2.1
Nuclear (large)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.2	0.0	0.0
Natural gas (CCGT)	0.2	0.1	0.0	0.0	0.3	0.2	0.2	0.2	0.1	0.4

Figure S.6: Reference and sensitivity cases, 2050: Breakdown of electricity output by dispatchable generation technologies



	450 Reference	450 Less Flexible Demand (LFD)	450 Power CO2-free	450 Power CO2-free + LFD	464 Climate Year 1987	8169 Climate Year 1996	450 Extra Sun PV	450 Extra Nuclear	1667 Extra Trade	450 No Trade
Industrial load shedding	3.5	0.0	0.0	0.0	1.0	1.0	3.4	2.6	0.0	3.3
Demand curtailment ('lost load')	0.5	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage (discharge)	2.2	7.3	0.4	3.3	2.0	2.2	3.5	0.3	-0.1	3.5
Net trade (imports)	12.8	12.6	12.7	12.1	12.8	12.8	12.8	12.8	22.6	0.0
Dispatchable generation	4.8	11.6	11.0	16.9	8.6	7.5	4.1	8.0	2.6	16.9

Note: the number below each bar refers to the hour of the year in which the highest peak residual load occurs.

Figure S.7: Reference and sensitivity cases, 2050: Dispatchable generation and other flexibility options to meet the highest hourly ('peak') residual load

Apart from some VRE generation (even in peak RL hours), the main reason why the peak RL in Figure S.7 is relatively low – given the average power load of approximately 44 GW in 2050 – is that in the peak RL hours the electricity price is relatively (very) high. As a result, the electricity demand in these hours is substantially reduced due to (i) hardly or no demand from $P2H_2$ by focussing and shifting green hydrogen production from electrolysis to other hours with (much) lower electricity prices, (ii) hardly or no demand from P2Heat in industry by shifting heat generation from electricity to natural gas boilers, and, for the cases with high DR capabilities (iii) demand response ('shifting') by households heat pumps and electric vehicles (EVs). Actually, rather than demanding electricity, in peak RL hours EVs are usually, on balance, supplying electricity – i.e., negative demand – by partly discharging EV batteries to the grid (V2G), even up to net 3-4 GW

The differences in peak RL – notably between the two cases with '*Less Flexible Demand (LFD)*' versus the other cases with '*High Flexible Demand*' (including the reference scenario) – are primarily due to the assumed differences in flexible demand, including no industrial load shedding (ILS) and no DR capabilities by EVs and households heat pumps in the two LFD cases. As a result, in these LFD cases, there is less demand reduction ('shifting') in peak RL hours and, hence, a higher RL in these hours. In addition, the other, remaining differences in peak RL are due to (usually relatively small) differences in total hourly demand (before DR) and/or total hourly VRE generation.

As mentioned, besides the peak RL, Figure S.7 also shows how the RL is met by a cost-optimal mix of flexibility options, including: (i) 'agreed' or 'voluntary' industrial load shedding (ILS), (ii) 'forced' or 'involuntary' demand curtailment ('lost load'), (iii) storage, i.e. electricity discharges from short-duration Li-ion batteries[14], (iv) net trade, i.e. net electricity imports, and (v) dispatchable generation.

Some major observations from Figure S.7 include:

- *Industrial load shedding:* In most of the cases presented in Figure S.7 – i.e., in six out of ten cases – part of the peak RL is met by industrial load shedding (ILS), varying from 1.0 GW up to 3.5 GW in the hours concerned. In the two '*Less Flexible Demand (LFD)*' cases, this flexibility option is not used, simply because it is assumed to be not allowed ('unavailable'). Only in the cases '*Extra Trade*' and '*Power CO_2-free*', however, ILS is allowed ('available') but not used to address the peak RL due to the availability of other, cheaper flexibility options, notably net imports and dispatchable generation.

- *Demand curtailment ('lost load):* Besides the 'agreed' or 'voluntary' ILS (discussed above), in two cases/hours recorded in Figure S.7 part of the peak RL is covered by 'forced' or 'involuntary' demand curtailment ('lost load'). These two 2050 cases include (i) the reference scenario (0.5 GWh lost load) and (ii) the sensitivity case '*Less Flexible Demand*' (0.8 TWh).

- *Storage (discharge):* In the reference scenario, discharging from Li-ion battery storage covers about 2.2 GWh (9%) of the peak RL (almost 24 GWh). In the sensitivity cases, this contribution from electrical storage varies from -0.1 GWh in the case '*Extra Trade*' (i.e., actually some storage charging due to the ample supply of electricity imports) to 7.3 GWh in the case '*Less Flexible Demand*' (i.e., about 22% of the peak RL in hour 450).

[14] In the case '*No Trade*', about 1.3 GWh of electricity is discharged from diabatic CAES in hour 450 of 2050 (besides 2.2 GWh from Li-ion batteries).

- *Net trade (imports):* In almost all cases and all peak RL hours presented in Figure S.7, net foreign electricity trade (import) plays a key, dominant role in meeting the RL (in most peak hours up to the assumed potential interconnection capacity of the Netherlands in 2050, i.e. 12.8 GW). This indicates that – according to the model outcomes, at least for the presented peak RL hours – foreign trade (import) is a major, available (reliable) option to cover the RL in a cost-optimal way within a European-wide power system context.[15] The only exception is the case '*No trade*' where – by definition – no electricity imports and exports are allowed and, therefore, covering the peak RL has to rely fully on domestic flexibility options, including a higher reliance on dispatchable generation. Note, however, that for all the other cases the assumed potential interconnection capacity of the Netherlands in 2050 (12.8 GW) is rather conservative, including only already existing capacity and some new capacity that is already planned by the TSOs and in the pipeline to be realised. In the case '*Extra Trade*', where the interconnection capacity of the Netherlands is assumed to be almost doubled in 2050 (up to 22.6 GW), net electricity imports cover even a much higher part of the peak RL, thereby reducing the need for domestic flexibility options, notably dispatchable power generation.[16]

- *Dispatchable generation:* Figure S.7 shows that the *deployment* of dispatchable generation to meet the peak RL amounts to 4.8 GW in the reference scenario and varies in the recorded sensitivity cases from 2.6 GW in the case '*Extra Trade*' to 17 GW in the cases '*No trade*' and '*Power CO_2-free + Less Flexible Demand (LFD)*'. In general, both the *total deployment* of dispatchable generation and the *mix* of dispatchable generation technologies to meet the peak RL follows largely the same levels and patterns as the installed capacities of dispatchable generation in the respective reference and sensitivity cases – as outlined above (see, in particular, Figure S.4 and Figure S.5) – and, therefore, is not further discussed here.[17]

Dunkelflautes

The analysis of the reference scenario (and most sensitivity cases) is based on the hourly electricity demand and VRE supply profiles of the 'normal' ('average') climate year 2015. In addition, however, we have analysed two sensitivity cases based on hourly profiles of two 'extreme' climate years, 1996 and 1987, including one and even two '*Dunkelflaute*' periods, respectively, i.e. an extended period – lasting several days up to one or two weeks – in which the sun hardly shines and the wind hardly blows. This results in hardly or no VRE power generation over this period and, therefore, a relatively high residual load over an extended period of hours that has to be met by dispatchable power generation/other flexibility options.

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[15] Note that the COMPETES-TNO model accounts for both similarities and differences in electricity demand and (VRE) supply profiles between European countries and regions, including weather (VRE) dependencies and independencies between these profiles.

[16] Figure S.7 shows that in order to meet the peak RL the need for dispatchable generation declines from 4.8 GW in the reference scenario to 2.6 GW in the case '*Extra Trade*', whereas the role of net electricity imports increases from 12.8 GW to 22.6 GW, respectively. Note, however, that outside the presented peak RL hours, there may be hours in which the maximum import capacity of the Netherlands may not be available – but only part of it – for instance, due to all kinds of supply constraints in the interconnected countries. Nevertheless, Figure S.2 shows that over 2050 as a whole the total (cost-optimal) installed capacity of dispatchable power generation amounts to 4.2 GW in the case '*Extra Trade*' compared to 5.1 GW in the reference scenario.

[17] Note that the cost-optimal *deployment* (output) of dispatchable power generation recorded in Figure S.7 is usually (slightly) lower than the cost-optimal *installed capacity* of dispatchable power generation presented in Figure S.4. This is due to two reasons, i.e. (i) the average availability of some generation technologies is less than 1.0 (because of regular maintenance, etc.), and (ii) in the peak RL hour, the required, cost-optimal deployment of dispatchable generation may be less than the (maximum available) installed capacity of dispatchable generation because there are other, cheaper flexible options to meet the peak RL, such as trade or demand response, while in other hours – with a lower RL – a higher (maximum) deployment of dispatchable generation is needed because other, cheaper flexible options are not or less available.

Based on the load and VRE supply profiles of the 'extreme' climate years 1987 and 1996, the need for dispatchable generation in 2050 is still relatively low (i.e., about 8-9 GW installed capacity, compared to about 5 GW in the reference scenario based on the 'normal, average' climate year 2015). The main reason for this relatively low need for dispatchable generation is the high demand response of P2X technologies – such as $P2H_2$ or P2Heat in industry – during these climate years, notably much lower electricity demand by these technologies during low VRE supply hours in general and Dunkelflaute periods in particular. Moreover, a major part of the resulting (relatively low) residual load can be covered by net imports, even if there is a Dunkelflaute in a major neighbouring country (Germany) as well. As a result, the need for dispatchable generation is relatively low, even in extreme climate years with one or two Dunkelflaute periods.

Key findings and insights

In summary, the key findings and insights of the current study include:

1. Reference scenario (2030-2050)

In the reference scenario, the (endogenous, cost-optimal) demand for dispatchable generation capacity – excluding balancing/emergency reserves – drops from almost 16 GW in 2030 to 10 GW in 2040 and to 5 GW in 2050 (under the assumptions and limitations of the optimisation model COMPETES-TNO; see discussion below). In 2030-2040, the capacity mix ('supply') of dispatchable generation technologies consists still predominantly of natural gas-fired plants – i.e., by 14.7 GW (94%) and 8.2 GW (82%), respectively – supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (predominantly waste standalone), large nuclear (Borssele) and – in 2040 only – small modular reactors (SMRs). In 2050, on the other hand, the role of natural gas-fired plans falls to 1.3 GW (26%), while the main part of the required dispatchable generation capacity (5 GW) consists of gas-retrofitted, hydrogen-fired CCGTs (2.5 GW), supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (waste standalone), and small modular reactors (SMRs).

The two major reasons why the need for dispatchable generation capacity in 2050 is relatively low (5 GW) – despite the high, rapidly growing demand for electricity up to 2050 – are (i) the high potential of flexible demand in the 2050 reference case – notably by P2X technologies such as power-to-hydrogen, power-to-heat and power-to-mobility (EVs), as well as by means of industrial load shedding – and (ii) the opportunity to import large amounts of electricity (up to 12-13 GW) during hours with a low domestic supply of electricity from variable renewable energy (VRE, i.e. sun/wind).

In 2050, the number of full load hours ('capacity factor') is relatively low for both the mid-load (biomass retro) and peak-load technologies (notably H_2 CCGT), resulting in relatively low electricity output levels by these technologies. This raises serious questions regarding the riskiness and economic viability (profitability) of both retrofit and new investments in these technologies (see discussion below).

2. Sensitivity cases (2050)

In the (nine) sensitivity cases conducted for the year 2050, the (endogenous, cost-optimal) demand for dispatchable generation capacity varies from 4.2 GW in the case '*Extra Trade*' to almost 18 GW in the cases '*No Trade*' and '*Power CO_2-free + Less Flexible Demand*'. More specifically, the most striking findings regarding the sensitivity cases include (see also point 3 below):

- In the two sensitivity cases with '*Less Flexible Demand (LFD)*' - i.e., assuming less demand response by both EVs and household heat pumps as well as no industrial load shedding – the need for dispatchable generation is increased by about 6-7 GW.

- In the two cases assuming '*Power CO_2-free*', the higher need for dispatchable generation (also approximately 6-7 GW) is primarily due to the outcomes of these cases in 2040. More specifically, in these latter cases natural-gas fired installations (and CCS) are not allowed, implying that the natural gas capacity in the 2040 reference case (8.2 GW) is replaced by additional capacities of H_2 CCGT (retro), nuclear (SMRs) and biogas (new). In the 2050 reference case, however, 6.9 GW of natural gas-fired capacity is decommissioned, whereas in the 2050 sensitivity cases assuming '***Power CO_2-free***' the (additional) capacities of H_2 CCGT, SMRs and biogas required in 2040 remain installed in 2050.

- In the case '*Extra Trade',* the total need for dispatchable generation capacity in 2050 is only slightly lower, i.e. 4.2 GW (compared to 5 GW in the reference case), whereas in the case '*No Trade*', this need is substantially higher, i.e. 17.6 GW. This implies that if the total interconnection capacity of the Netherlands is assumed to be expanded substantially in 2050 – i.e., by almost 10 GW in the case '*Extra Trade*' – the need for dispatchable generation capacity is reduced by less than 1 GW (most likely because during some critical peak residual load hours the total, expanded import capacity from neighbouring countries is actually not available and, hence, this load has to be met by other flexibility options, including dispatchable generation). On the other hand, if the total interconnection capacity of the Netherlands is assumed to be zero ('*No Trade*'), the loss of this trade capacity (-12.8 GW) is almost fully compensated by a similar increase in dispatchable generation (+12.5 GW). These findings indicate that up to a certain level (approximately 12-13 GW), trade (import) seems to be a rather reliable flexibility option – even during peak residual load hours – but beyond this level it looks like becoming far less reliable.

In the sensitivity cases with a relatively high demand for dispatchable generation (12-18 GW), the capacity mix of dispatchable generation technologies consists largely of (both new and gas-retrofitted) hydrogen-fired CCGTs (6-13 GW), supplemented by small amounts (0.3-3.1 GW) of coal-retrofitted biomass installations (with/without CCS), new biogas plants, other RES-E (waste standalone), natural gas-fired CCGTs, and small modular reactors (SMRs).

Due to large differences in the number of full load hours between baseload technologies (notably nuclear) and peak-load technologies (natural gas/H_2 CCGTs), however, the share of baseload technologies in the mix of dispatchable generation technologies is generally much higher – and even dominant in most cases considered – in terms of electricity output (TWh) rather than installed capacities (GW). For instance, in the 2050 reference case total dispatchable generation (3.6 TWh) comes mainly from SMRs (2.1 TWh) and hardly from natural gas/H_2 CCGTs (0.3 TWh), while in the case '***Power CO_2-free***' these figures amount to 22.9, 19.7 and 0.5 TWh, respectively.

3. Dunkelflaute periods (2050)

Two sensitivity cases for the year 2050 are based on the hourly electricity demand and VRE supply profiles of two 'extreme' climate years, 1996 and 1987, including one and even two '*Dunkelflaute*' periods, respectively. In these two cases, the (endogenous, cost-optimal) demand for dispatchable generation capacity amounts to approximately 8-9 GW, compared to about 5 GW in the 2050 reference case based on the 'normal' ('average') climate year 2015. The main reason for this relatively low need for dispatchable generation is the high demand response of P2X technologies – such as P2H_2 and P2Heat – during these climate years, notably much lower electricity demand by these technologies during low VRE supply hours in general and Dunkelflaute periods in particular. Moreover, a major part of the resulting (relatively low) residual load can be covered by net imports, even if there is a Dunkelflaute in a major neighbouring country (Germany) as well. As a result, the need for dispatchable generation is relatively low, even in extreme climate years with one or two Dunkelflaute periods.

Model limitations and qualifications

Some model limitations and other qualifications have to be added to the study findings outlined above.

Firstly, COMPETES-TNO is a so-called 'cost-optimisation' model, i.e. it analyses how a certain energy demand (electricity, hydrogen) over a certain period – usually a full target year – is met within certain techno-economic and policy constraints at the lowest social costs. A major characteristic of such models is that they are based on 'perfect foresight', i.e. they assume the availability of full, free knowledge for investment decisions – notably concerning future costs, prices and market transaction volumes – and, therefore, these models hardly or not consider any uncertainties or risks regarding these investment decisions.

In practice, however, investments in the power system are characterized by high risks and uncertainties, notably regarding future electricity prices and sales volumes in power systems with a high share of VRE generation. This applies in particular to both retrofit and new investments in dispatchable peak-load technologies – with a small number of full load hours – as well as to 'back-up' dispatchable generation technologies to address extreme weather conditions, including Dunkelflaute periods, which may occur only once or twice in a decade.

Due to these risks and uncertainties, private parties are generally hesitant to invest in such technologies and, therefore, they usually require a high profit ('discount') rate – including a high risk premium – which, in general, is significantly higher than the discount rate used in a cost-optimisation model such a COMPETES-TNO.[18] As a result, retrofit/new investments in dispatchable generation may pop-up as 'optimal' from a social cost modelling perspective but may lack economic viability ('profitability') from a private investor's point of view and, therefore, may not be realised. For policy makers, this may imply that they decide to support these investments – for instance, by investment or operational subsidies, contracts-for-differences, or capacity mechanisms – in order to safeguard a reliable and adequate power system at affordable (social/private) costs.

In addition, it should be realised that, in practice, investments in dispatchable generation depend not only on social cost-optimisation or simple private cost-benefit considerations but often also on other considerations. This applies, for instance, in particular to both retrofit and new investments in biomass-fuelled power plants (with/without CCS), depending on the socio-political acceptance of using biomass/CCS for generating electricity (rather than other renewable energy/GHG mitigation purposes).

Secondly, analyses by COMPETES TNO are based on a so-called 'Energy-Only-Market' approach. The core of such an EOM approach is that (private) investors in power generation capacity should cover the costs of their investments solely from market revenues of their electricity output (and not from additional subsidies or any other compensations, e.g. for safeguarding the availability of a certain back-up capacity). Therefore, COMPETES does not include any subsidies and, as a result, no hours with negative electricity prices. In practice, however, the Dutch power system is characterised by a wide variety and growing amounts of

[18] COMPETES-TNO uses a uniform (social) discount rate of 6.5% whereas the required profit rate on risky private capital investments varies usually between 7-15%, depending on the risk profile of these investments.

subsidies, notably on VRE and dispatchable, CO_2-free generation technologies, resulting in a growing number of hours with negative electricity prices and affecting both the total demand and supply mix of dispatchable generation versus other flexibility options.

Moreover, EOM analyses by COMPETES-TNO refer to the hourly spot market only but do not include markets for balancing/emergency reserves or other ancillary services such as reactive power, redispatch or black start facilities. As a result, these analyses underestimate the total future need for dispatchable generation – and/or electricity storage – to safeguard a reliable and adequate power system.

Thirdly, as mentioned above, investments in the power system are characterized by large uncertainties. In this scenario study, a specific category of these uncertainties concerns the capital costs (CAPEX) of both retrofit and new investments in dispatchable generation technologies in the years 2030, 2040 and 2050 as well as the operational (mainly fuel) costs of these technologies in these future years, notably for power plants fuelled by biomass, biogas or hydrogen.[19] In addition, related uncertainties apply for the (socio-political) availability of these fuels – notably biomass and biogas – for producing electricity and, to some extent, the techno-economic potentials of retrofit generation technologies. Moreover, there is a wide variety of other relevant uncertainties, notably regarding the future demand for electricity, including the distinction between 'direct' electricity demand and 'indirect' electrification by means of power-to-hydrogen or other E-fuels.

In this study, specific assumptions regarding the above-mentioned uncertainties have been used – specified largely in Chapter 2 – based on specific sources. Over time and across other, alternative sources, however, similar assumptions usually vary substantially. Changing one or more of these assumptions may have a significant impact on both the total need for dispatchable generation and the cost-optimal supply mix of the required dispatchable technologies versus other flexibility options.

Fourthly, this study has conducted a selected variety of (nine) sensitivity cases to explore the impact of some of the uncertainties mentioned above on the demand and supply of dispatchable generation in the power system of the Netherlands. These uncertainties refer in particular to the potential and reliability of competing flexible options such as foreign trade and demand response (including industrial load shedding), the impact of extreme weather conditions, the capital investment costs (CAPEX) of sun PV, and the impact of exogenous policy decisions such as enabling the instalment of a certain capacity of nuclear power generation by 2050 or not allowing dispatchable generation options such as natural gas-fired plants or biomass installations with CCS (for instance, by not allowing trade of positive versus negative CO_2 emissions within the European/NL energy system).

A large number of other uncertainties, however, have not been addressed by means of conducting corresponding sensitivity cases. These refer in particular to the uncertainties mentioned above, notably (i) the capital costs (CAPEX) of both retrofit and new investments in dispatchable generation technologies in the years 2030, 2040 and 2050 as well as the operational (mainly fuel) costs of these technologies in these years, (ii) the availability and socio-political acceptance of fuels such as biomass and biogas (including CCS) for power generation, (iii) the techno-economic potentials of retrofit generation technologies, and (iv) the size and structure of future demand for electricity.

[19] Note, however, that similar cost uncertainties apply to other dispatchable generation technologies (e.g., nuclear) or VRE generation technologies such as sun PV and offshore wind.

Moreover, most sensitivity cases – i.e., 8 out of 9 – have analysed the impact of the incidence of a single uncertainty only. In practice, however, a variety of uncertainties applies at the same time. As a result, the need for dispatchable generation (or electricity storage) may be significantly higher to address the incidence of multiple uncertainties simultaneously (rather than each single uncertainty separately).

Finally, COMPETES-TNO includes the high-voltage transmission lines and interconnections between European countries, but the model does not cover the distribution networks at the regional and local levels. As a result, it does not consider congestion issues at these sub-national levels and, therefore, may underestimate the need for flexible options such as (re)dispatchable generation or electricity storage over the years 2030-2050 (although it is unclear whether – and to which extent – congestion may still occur in long-term future years such as 2040 or 2050).

Conclusions

Under the assumed conditions of the 'climate-neutral' reference scenario, the total need ('demand') for dispatchable generation capacity in the Dutch power system decreases from approximately 16 GW in 2030 to 10 GW in 2040 and to 5 GW in 2050. In terms of electricity output, the need for dispatchable generation declines even stronger from about 29 TWh in 2030 to 10 TWh in 2040 and to 4 TWh in 2050 (i.e., from approximately 15% of total electricity production in 2030 to 1% in 2050). Despite the rapidly growing demand for electricity over the years 2030-2050, this decreasing and relatively low need for dispatchable generation – notably in 2050 – is mainly due to (i) the rapidly growing supply of VRE generation over this period, (ii) the (assumed, growing) availability of other flexible options, notably a high level of demand response – including industrial load shedding – and foreign trade (interconnections), and (iii) the assumption of 'normal' ('average') weather conditions in the reference target years.

In the (nine) sensitivity cases conducted for the year 2050, the need for dispatchable generation varies from 4.2 GW to 18 GW and, in terms of electricity output, from 2.6 TWh to more than 43 TWh (i.e. ranging from 0.6% to 10% of total electricity generation in the 2050 cases considered). These cases show that, as indicated above, the need for dispatchable generation depends in particular on (i) the (assumed) availability of other flexibility options, notably the availability/reliability of demand response and foreign trade, (ii) the (assumed) weather conditions, i.e. assuming either 'normal' ('average') weather conditions or 'extreme weather conditions, including one or two '*Dunkelflaute'* periods (i.e., with hardly any sun and wind), and (iii) the (assumed) policy conditions, notably whether – and to which extent – certain dispatchable generation technologies (natural gas, biomass/CCS) are allowed or primarily policy-induced, i.e. assumed exogenously (nuclear).

On the other hand, the mix ('supply') of the required dispatchable generation technologies depends – besides the total need ('demand') for dispatchable generation capacity/output – mainly on (i) the investment and operational (fuel) costs of these technologies, (ii) the techno-economic potential of retrofitted generation technologies, (iii) the availability and socio-political acceptance of dispatchable fuels (biomass, biogas), (iv) the GHG mitigation target concerned and the resulting CO_2 price, and (v) the incidence of other policy conditions regarding the dispatchable generation technologies considered.

In 2030-2040, the capacity mix of dispatchable generation technologies consists still predominantly of natural gas-fired plants – i.e., by 14.7 GW (94%) and 8.2 GW (82%), respectively – supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (predominantly waste standalone), large nuclear

(Borssele) and – in 2040 only – small modular reactors (SMRs). In 2050, on the other hand, the role of natural gas-fired plans falls to 1.3 GW (26%), while the main part of the required dispatchable generation capacity (5 GW) consists of gas-retrofitted, hydrogen-fired CCGTs (2.5 GW), supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (waste standalone), and small modular reactors (SMRs).

In the sensitivity cases with a relatively high demand for dispatchable generation (12-18 GW), the capacity mix of dispatchable generation technologies consists largely of (both new and gas-retrofitted) hydrogen-fired CCGTs (6-13 GW), supplemented by small amounts (0.3-3.1 GW) of coal-retrofitted biomass installations (with/without CCS), new biogas plants, other RES-E (waste standalone), natural gas-fired CCGTs, and small modular reactors (SMRs). Due to large differences in the number of full load hours between baseload technologies (notably nuclear) and peak-load technologies (natural gas/H_2 CCGTs), however, the share of baseload technologies in the mix of dispatchable generation technologies is generally much higher – and even dominant in most cases considered – in terms of electricity output (TWh) rather than installed capacities (GW).

The findings and conclusions outlined above, however, have to be treated with due care, mainly because of the limitations of the applied cost-optimisation model (COMPETES-TNO) and the large variety of uncertainties regarding the assumed scenario runs up to 2050 (which have only been partially covered by the conducted sensitivity cases).

1 Introduction

Background and key research questions

The Netherlands – being part of the EU – aims at a climate-neutral energy system in 2050. For the Netherlands, this implies a strong further electrification of the energy system by means of power-to-X (P2X) technologies, such as power-to-hydrogen ($P2H_2$), power-to-heat (P2H) and power-to-mobility (P2M), resulting in an expected swift increase of total electricity demand by a factor 3 to 4 over the period 2020-2050. On the supply side, this rapidly growing demand is, on balance, largely met by domestic power generation from variable renewable energy (VRE), in particular sun PV and (offshore) wind. The variability, however, of sun and wind – including in particular hours and even extended (‘*Dunkelflaute*’) periods in which sun and wind are hardly or not available – raises the need to optimise additional, dispatchable power generation and other flexibility options – such as storage, trade or demand response – in order to meet electricity demand over all hours of the years in a reliable and affordable way.

Against this background, the key objectives or research questions of the current study include:

- What is the expected future need (‘demand’) for dispatchable generation in the Netherlands over the years 2030-2050?
- What is the expected cost-optimal supply mix of dispatchable (CO_2-free) generation technologies in the Netherlands over the period 2030-2050 within an European-wide context (i.e., allowing cross-border electricity trade and compensating any positive CO_2 emissions somewhere in the European P2X system by negative CO_2 emissions elsewhere in the system) to achieve a climate-neutral European P2X system in 2040 and beyond?

Approach

In order to address the research questions outlined above, a variety of scenario and sensitivity cases has been analysed by means of the COMPETES-TNO model, i.e. a European power system optimisation model covering (i) almost all European countries and regions, (ii) all key P2X sectors, (iii) all major power generation technologies, and (iv) all major flexibility options. The model can optimise both the capacity investments in the P2X system for a certain target year as well as the dispatch of the installed capacities over a certain target year on an hourly basis.

Over the past years, several studies have addressed the future need for dispatchable (carbon-free) power generation in the Netherlands (see, among others, Aurora, 2021; CE Delft, 2022; TenneT, 2023; De Wildt et al., 2023; Berenschot and TNO, 2023; CE Delft and Witteveen+Bos, 2024). Some of them focus on the business case and the technical barriers of dispatchable power generation technologies (Aurora, 2021; CE Delft, 2022), whereas others focus more on the quantification of the future need for dispatchable generation in the Netherlands (TenneT, 2023; De Wildt et al., 2023; CE Delft and Witteveen+Bos, 2024).[20]

Besides some interesting findings and insights, the studies mentioned above suffer from some limitations and weaknesses such as a limited time horizon (e.g., looking only up to 2035) or lacking an integrated power system optimisation approach, including key flexibility options

[20] For a recent review of these and other, related studies, see Hers et al. (2025, forthcoming). This review study also considers the policy implications of achieving a carbon-neutral power system in the Netherlands. See also Sijm (2024), notably Section 3.6 (pp. 23-39).

such as demand response and trade. This study tackles these shortcomings largely by providing an integrated European P2X system optimisation approach to analyse both the demand and supply of dispatchable (CO_2-free) generation in the power system of the Netherlands over the period 2030-2050. In addition, it analyses the implications of extreme weather conditions – notably the occurrence of so-called 'Dunkelflaute' periods – on the need for dispatchable generation versus other flexibility options such as demand response, trade and storage.

Report structure

The structure of this report runs as follows. The next Chapter 2 provides a brief explanation of the approach applied by this study, notably of the key characteristics of the COMPETES-TNO model and the major scenario parameters assumed for the years 2030-2050. Subsequently, Chapter 3 presents the main results of the reference scenario over this period, whereas Chapter 4 discusses similar findings of the sensitivity cases for the year 2050. Next, Chapter 5 focuses on a specific, but interesting topic, i.e. the need for dispatchable power generation during so-called '*Dunkelflaute*' periods. Finally, Chapter 6 summarises the key findings, qualifications and conclusions of the current study.

2 Approach of the study

This chapter outlines the approach followed in this study, firstly with a brief description of the applied model COMPETES-TNO (Section 2.1). Next, we discuss the reference scenario for the period 2030-2050 used in this study to assess the need for dispatchable generation in the Netherlands over this period (Section 2.2). Subsequently, Section 2.3 describes the system boundary of this study. Finally, Section 2.4 discusses the major model scenario parameters and assumptions for the period 2030-2050, notably with regard to the expected growth of electricity demand, the potentials and costs of available power generation technologies as well as the major fuel and CO_2 prices up to 2050.

2.1 Description of COMPETES-TNO model

COMPETES (‘*Competition and Market Power in Electric Transmission and Energy Simulator*’) is a power system optimisation and economic dispatch model that seeks to meet European power demand at minimum social costs (maximizing social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of power generation units and transmission interconnections across European countries and regions.[21]

COMPETES-TNO consists of two major modules that can be used to perform hourly simulations for two types of purposes:
- A transmission and generation capacity expansion module to determine and analyse least-cost capacity expansion with perfect competition, formulated as a linear program to optimise generation capacity additions in the system;
- A unit commitment and economic dispatch module to determine and analyse least-cost unit commitment (UC) and economic dispatch with perfect competition, formulated as a relaxed mixed integer program considering flexibility and minimum load constraints and start-up costs of generation technologies.

The COMPETES-TNO model covers all EU Member States and some non-EU countries (referred as EU+) – i.e. Norway, Switzerland, the UK and the Balkan countries (grouped into a single Balkan region) – including a representation of the cross-border power transmission capacities interconnecting these European countries and regions (see Figure 2.1). The model runs on an hourly basis, i.e. it optimises the European power system over all 8760 hours per year.

For each scenario year, the major inputs of COMPETES-TNO include parameters regarding the following exogenous variables:
- Electricity demand across all European countries/regions, including conventional power demand and additional demand due to further sectoral electrification of the energy system by means of Power-to-X technologies;
- Power generation technologies, transmission interconnections and flexibility options, including their techno-economic characteristics;

[21] The COMPETES model was originally (since 2001) developed by the Energy research Centre of the Netherlands (ECN). When ECN joined TNO (in 2018), the model was officially handed over to the Netherlands Environmental Assessment Agency (PBL) but, in addition, further developed and used by TNO. So, currently there are two (slightly) different versions of COMPETES, i.e. COMPETES-PBL and COMPETES-TNO. One of the major differences between these two versions is that the (power-to-)hydrogen sector in COMPETES-TNO is more advanced.

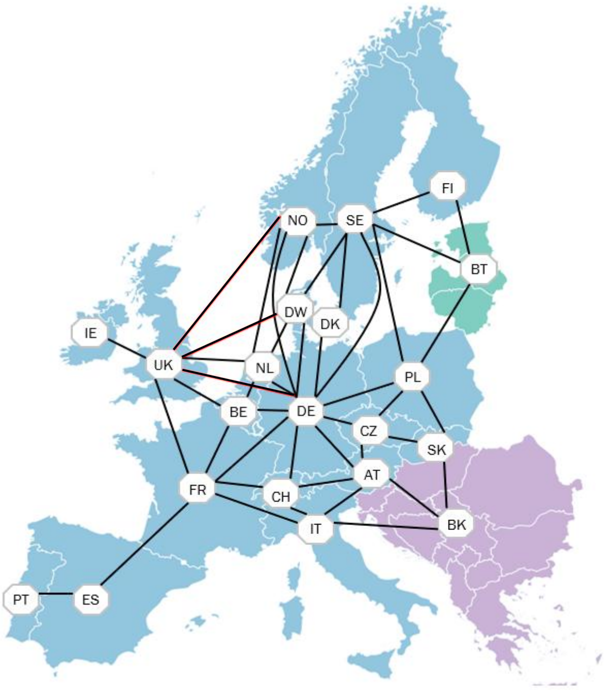


Figure 2.1: COMPETES-TNO geographical scope

- Hourly profiles of various electricity demand categories and renewable energy technologies (notably sun, wind, and hydro), including the full load hours of these technologies;
- Assumed (e.g., policy-driven) installed capacities of power generation technologies, notably from nuclear/renewable energy sources (RES);
- Expected future fuel and CO_2 prices;
- Policy targets/restrictions, such as meeting certain greenhouse gas (GHG) targets or forbidding the use of certain technologies in certain countries (for instance, coal, nuclear or biomass/CCS for generating power).

As indicated above, COMPETES-TNO includes a variety of flexibility options. More specifically, these options include:

- Flexible ('dispatchable') power generation, including:
  - Conventional electricity production, notably by means of natural gas and to some extent, coal/nuclear energy. For the purpose of this study, an addition of technology options has been developed to integrate the retrofit potential of certain carbon-intensive generation technologies, such as coal and gas plants. The logic behind the retrofit is that coal plants could be retrofitted into biomass or biomass coupled with Carbon Capture and Storage (BECCS). On the other hand, gas plants could be retrofitted to use carbon-neutral fuels, such as green (bio)gas or green hydrogen (for information on the techno-economic parameters of these technologies, see Sub-Section 2.4.2 below);
  - Curtailment of renewable electricity generation from sun/wind.

- Cross-border power trade and H_2 trade:
  - Power trade is based on Network Transfer Capacities (NTCs);
  - H_2 trade is based on existing natural gas infrastructure which can be converted for hydrogen transport (Morales-Espana et al., 2024).

- Storage, in particular:
  - Pumped hydro (notably in other European countries besides the Netherlands);
  - Compressed air energy storage (CAES), including both diabatic and advanced adiabatic CAES.
  - Batteries, including lead-acid (PB) batteries, vanadium redox (VR) batteries, lithium-ion (Li-ion) batteries, as well as batteries for running electric vehicles (EVs);
  - Underground storage of hydrogen;

- Conversion technologies (Power-to-X), such as:
  - Power-to-hydrogen ($P2H_2$);
  - Power-to-heat in industry (P2H-i), notably hybrid (electricity/natural gas) boilers to generate industrial heat;

- Demand response (DR), notably by means of:
  - Power-to-heat in households (P2H-h), in particular all-electric heat pumps for household space heating and hot water purposes;
  - Power-to-mobility (P2M), especially passenger electric vehicles (EVs).

For this particular study, an additional flexibility option was modelled, indicated as *Industrial Load Shedding* (ILS). This option represents the flexible operation of certain industries to perform DR capabilities by shedding their power demand in certain hours. The capacity and cost (price) assumptions regarding ILS are resumed in Table 2.1.

Table 2.1: Capacity and cost assumptions regarding Industrial Load Shedding (ILS), 2030-2050

2030		2040		2050	
Capacity (MW)	Price (€/MWh)	Capacity (MW)	Price (€/MWh)	Capacity (MW)	Price (€/MWh)
0-350	500	0-700	500	0 -1000	500
350-1000	1500	700-2000	1500	1000-3000	1500
1000-1500	8000	2000-2500	8000	3000-3500	8000

Source: Based on DNV GL (2020), TenneT (2023) and Berenschot and Kalavasta (2023).

The major outputs ('results') of COMPETES-TNO, for each scenario year and European country/region, include:

- Investments and disinvestments ('decommissioning') in power generation technologies, interconnection capacities, and flexibility options;
- Hourly allocation ('dispatch') of installed power generation and interconnection capacities, resulting in the hourly and annual power generation mix – including related CO_2 emissions and power trade flows – for each European country/region;
- Demand and supply of flexibility options;
- Hourly electricity prices;
- Annual power system costs for each European country/region.

For a more detailed description of the COMPETES-TNO model, see Özdemir et al. (2020) and Sijm et al. (2022). For a more specific discussion of the reference scenario, 2030-2050, quantified and analysed by COMPETES-TNO – including in particular the major scenario input parameters used – see sections 2.2 and 2.4 below.

2.2 Reference scenario

In this study, the reference scenario refers to the scenario defined and quantified by COMPETES-TNO for the 2030-2050 period to analyse the demand and supply of dispatchable power generation. This scenario is based on the scenario *Distributed Energy* (DE) in the Ten-Year Network Development Plan (TYNDP-22; ENTSO-E & ENTSOG, 2022). The story line of the DE scenario follows a decentralized focus to achieve system decarbonization, with priority in achieving European energy autonomy targets. The abatement target of CO_2 emissions follows the EU Fit-for-55 target of 55% emissions reduction in 2030, compared to 1990, and carbon neutrality in 2050.[22] The objective to enhance EU energy autonomy is achieved through the maximization of electrification of the energy system as well as installation of RES capacities on the supply side.

For the purpose of this study, the initial power generation capacities of the DE scenario in 2030 are used to obtain the optimal installed capacities in 2040 and 2050 for all modelled European countries. For the Netherlands, a more detailed database of the installed capacities for gas units is used, based on Standard & Poor's data used in the KEV22 (PBL, 2022). In addition, the (assumed) installed capacity of sun PV in the Netherlands by 2030 is updated from the most recent '*National solar trend report*' (RNE Research, 2025).

COMPETES-TNO can invest in new capacities, as well as decommission installed capacities due to either economic considerations (a certain technology is no longer profitable from a system perspective) or technical reasons (the lifetime of a unit is reached).
Figure 2.2 represents the investment and decommissioning workflow of the capacities followed in our reference scenario building approach. In 2030, new investments for VRE and dispatchable technologies are deactivated, with the exception of the potential retrofit of coal capacity into biomass capacity. This retrofit potential is based on the current phase-out of coal plans for the different European countries. Flexibility options, such as power-to-H_2 technologies, power-to-heat boilers and H_2 and electrical storage, are already optimized by the model in 2030.

The resulting capacities serve as input for the baseline capacities of 2040, when capacity expansion for variable renewable energy (VRE) and dispatchable technologies is now allowed. The resulting optimization again serves as initial baseline for 2050.

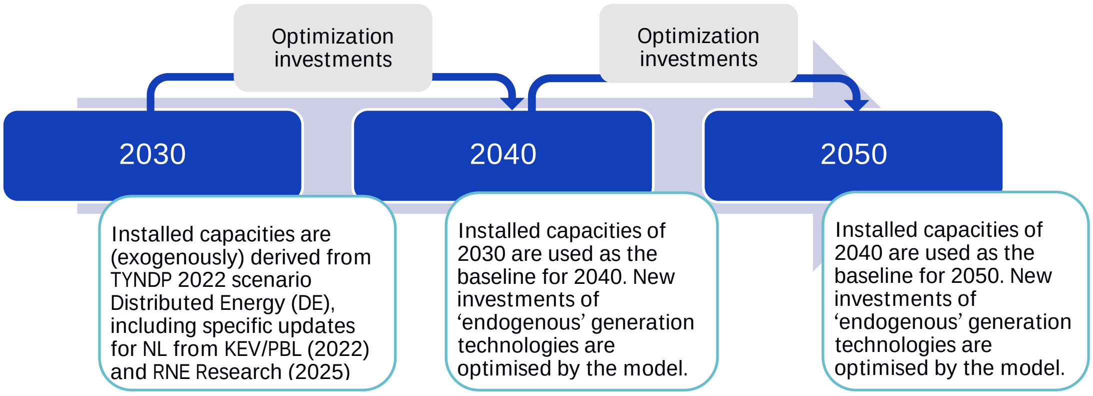


Figure 2.2: Workflow diagram on the optimization process for the installed capacities in this study

[22] See Section 2.4.4 below for the resulting implications regarding the CO_2 emission reduction targets of the European/NL power system.

2.3 System boundary

As outlined in Section 2.1, this study considers the European electricity market with a certain degree of sector coupling. Besides the power sector, the other sectors incorporated within the system boundary of the COMPETES-TNO model include:

- *Hydrogen sector*: the model optimizes hydrogen production to meet an exogenously hydrogen demand through two different processes: electrolysis (Power-to-H_2) and Steam Methane Reform (SMR). Additionally, the transport of H_2 is also simulated in the model, with potential imports and exports within the geographical scope of Figure 2.1., as well as hydrogen storage in salt caverns. Whereas the domestic demand for hydrogen is exogenously fixed into the model, it is met endogenously in a flexible way from different sources, including domestic production of hydrogen from electricity/natural gas, as well as by hydrogen imports and hydrogen storage, depending on the costs of these sources (including varying electricity and natural gas prices). So, both hydrogen production, imports, and storage – as well as hydrogen infrastructure (networks) – are flexible and optimised by the model, based on their respective cost parameters (see Section 2.4 below).

- *Heat sector*: the heat sector included in COMPETES-TNO comprises only the (flat, static) heat demand from industrial heat processes that is met through the use of hybrid boilers, i.e. natural gas and/or electric boilers, but does not include industrial heat demand met by other sources or technologies such as kilns, furnaces or CHP installations. Industrial heat production through electric boilers ('power-to-heat-i') is activated when electricity prices are lower than the marginal cost of using alternative fuels, in this case, natural gas.

The European P2X system boundary of the COMPETES-TNO model, therefore, comprises the power sector together with the hydrogen and heat sectors described above. In this study, this European P2X system is optimised by the model COMPETES-TNO in order to become climate neutral in 2040 and beyond at the lowest social cost. This means that the total CO_2 emissions from these three combined sectors must be zero, starting from 2040. While each individual sector and each individual country/region within the European P2X system is allowed to generate positive GHG emissions in 2040 or beyond – such as CO_2 from producing hydrogen by SMR or using natural gas in hybrid boilers or power generation plants – these emissions must be offset by negative emissions elsewhere in the system in order to meet the climate neutrality goal.[23] In this study, negative emissions in the power sector can be achieved through the combination of biogenic power generation coupled with carbon capture and storage (CCS), such as biomass or biogas with CCS power plants.

It is important to emphasize that, therefore, the methodology used in this study for the reference scenarios (and most sensitivity cases) does not consider individual national/sectoral CO_2 targets, but rather an EU P2X system-wide optimization approach. In 2023, however, the government of the Netherlands (among other countries) has announced the ambition to fully decarbonize the Dutch power system by 2035 (GoN, 2023). It is not clear yet whether and when this ambition will be transferred into an official, binding policy target. Recently (September 2025), the Dutch government has relaxed this ambition by putting the aims of

[23] At the EU policy level, this system of balancing positive and negative CO_2 emissions would require a revision of the current EU ETS system in the sense that negative CO_2 emissions should be awarded an equivalent amount of ETS allowances which can be sold on the market to parties having positive emissions (while the overall balance is zero emissions). According to the Clean Industrial Deal (EC, 2025), the remuneration of negative emissions is foreseen to be covered by the reform of the EU ETS in 2026.

security of supply and affordability of electricity above the *strive* for a fully CO_2-free power system by 2050 (KGG, 2025). In addition, it is also not clear whether reaching this national-sectoral target – when becoming official – will allow offsetting any remaining positive GHG emissions by negative emissions from other countries/sectors. Nevertheless, given the potential significant implications of the ambition mentioned above, we have conducted two sensitivity cases (for the year 2050) in which the resulting GHG emissions of the Dutch power system are zero in 2050 (for further details on these sensitivity cases, see Chapter 4).[24]

2.4 Major model scenario parameters

2.4.1 Energy demand

In the DE scenario, final energy demand includes two main energy carriers: electricity and hydrogen. The electricity demand modelled in COMPETES-TNO is classified into the following categories:

- *Conventional power demand*: it corresponds to all inflexible electricity use from all sectors. The profile of this demand is based on the demand profile from the weather year 2015.

- *Flexible power demand*: includes the demand of Power-to-X technologies as a result of the future electrification of the energy system. This flexible demand is sub-divided into:

  - *Power-to-hydrogen*: represents specifically the electricity demand by electrolyser-type technologies. This demand profile is flexible and optimised endogenously by the model according to hourly electricity prices, i.e. producing more hydrogen when electricity prices are low, and shedding or reducing production when prices are high.

  - *Power-to-heat-i:* represents the electricity demand to meet the need for industrial heat by flexible, hybrid (electricity/natural gas) boilers. The final power-to-heat demand by industry (P2H-i) depends on the fluctuating hourly electricity price (as determined endogenously by the model) compared to the (fixed, exogenous) natural gas price.

  - *Power-to-heat-h*: consists of the space and water heating from all-electric heat pumps of the residential sector; it is considered to be flexible through demand shifting capabilities.

  - *Power-to-mobility*: represents the electricity demand by electric passenger vehicles (EVs); it includes both vehicle-to-grid (V2G) and grid-to-vehicle (G2V), acting as demand shifting and storage technology.

Table 2.2 shows the (exogenous) final energy demand assumptions for the Netherlands in the three target years (2030, 2040 and 2050), derived from the TYNDP-2022 scenario '*Distributed Energy*' (DE). Electricity demand and installed capacities of power-to-hydrogen and power-to-heat in industry are endogenous to the COMPETES-TNO model and, therefore, a result of the model optimisation. Hence, the final demand by these conversion technologies is not

[24] The COMPETES-TNO model includes only the input and output data for the target years 2030, 2040 and 2050, but not for the year 2035. Moreover, whereas analyses of the reference scenario have been conducted for all three target years, all sensitivity cases have only been performed for the ultimate – but highly uncertain – target year 2050.

recorded explicitly in Table 2.2 (as an assumed input variable) but rather as a model outcome (see Chapter 3, notably Figure 3.1).

Table 2.2: Exogenous energy demand assumptions for the Netherlands, 2030-2050, derived from the TYNDP-2022 scenario '*Distributed Energy*' (DE)

Parameter	DE2030	DE2040	DE2050
Conventional power demand (TWh)	130	142	161
Total flexible power demand (TWh)[a]	15	25	30
○ Power-to-heat-h (residential heat pumps)	11	17	19
○ Power-to-mobility (passenger EVs)	4	8	11
Total (exogenous) power demand (TWh)	**145**	**167**	**191**
Total (exogenous) hydrogen demand (TWh)[b]	**21**	**60**	**111**
Total (maximum) power-to-heat demand by industry (TWh)[c]	**35**	**50**	**59**

a) Total flexible power demand includes also electricity demand by power-to-hydrogen and power-to-heat in industry but this demand is not recorded explicitly in the table as it is assessed endogenously (as an output result) by the COMPETES-TNO model (see Chapter 3, notably Figure 3.1).
b) Total hydrogen demand is fixed and can be met by domestic production of green/blue hydrogen, foreign imports of hydrogen and/or hydrogen storage, depending on the (varying) costs of these hydrogen sources. So, the domestic demand and supply of green hydrogen ('power-to-hydrogen') can vary depending on, for instance, the cost (price) of electricity versus natural gas (to produce blue hydrogen) compared to the cost of importing or storing hydrogen.
c) Total power-to-heat demand by industry represents the total (maximum) demand for industrial heat that can be met by hybrid (electricity/gas) boilers, depending on the relative prices of electricity versus natural gas. Hence, it excludes other types of (high-temperature) heat demand by industry met by, for instance, kilns or furnaces.

2.4.2 Energy supply: sources and technologies

COMPETES-TNO includes a vast variety of competing energy sources and energy conversion technologies. Its investment module is used to meet the demand for both electricity and hydrogen at all periods considered. The model assesses new investments and decommissioning endogenously, based on technical (i.e., end of lifetime) and economic reasons. COMPETES-TNO considers a single discount rate for all technologies of 6.5%.

Table 2.3 provides an overview of the technologies covered by COMPETES-TNO. The columns 'Exogenous' and 'Endogenous' indicate if the investments in capacity are inputs to COMPETES-TNO or determined by the model, respectively. In the case of 'Endogenous' investment, the column deactivated determines if investments in that technology are allowed (or not). The reason behind the deactivation of certain technologies is to represent certain political decisions, for example, investments in coal capacities are deactivated to represent the phase-out of coal and lignite in the European power system. The hydro reservoir investments are also deactivated given that the realization of these new capacities is highly restricted and reliable information on potentials for hydro installations is hardly available.

Table 2.3: Power generation technologies included in COMPETES-TNO

Fuel	Technology	Abbreviation	Exogenous	Endogenous	Deactivated	Availability[a]	Efficiency[a]
Biomass	Co-firing	Bio-Co		X		0.8	0.46
Biomass	Standalone	Bio-St		X		0.7	0.40

Fuel	Technology	Abbreviation	Exogenous	Endogenous	Deactivated	Availability[a]	Efficiency[a]
Biomass	Carbon capture and storage	BECCS		X		0.8	0.36
Biomass	Retrofit	Bio-Retro		X		0.8	0.40
Biomass	Retrofit	Bio-Retro BECCS		X		0.8	0.30
Coal	Pulverized coal	Coal PC			X	0.8	0.49
Coal	Carbon capture and storage	Coal CCS			X	0.8	0.48
Derived gas	Internal combustion	DGas IC			X	0.9	0.40
Derived gas	Combined heat and power	DGas CHP			X	0.9	0.50
Gas	Gas turbine	GT		X		0.9	0.40
Gas	Combined cycle gas turbine	CCGT		X		0.9	0.60
Gas	Combined heat and power	CHP		X		0.9	0.35
Gas	CCGT + Carbon capture and storage	CCS CCGT		X		0.9	0.57
Geo	Geothermal power	Geo	X			0.9	0.26
Green gas	Combined cycle gas turbine	Bio-CCGT		X		0.8	0.55
Hydro	Conventional - Run-of-River	Hydro RoR			X	-	-
Hydro	Pump storage	HPS			X	-	-
Hydrogen	Combined cycle gas turbine	H_2-CCGT		X		1.0	0.55
Hydrogen	Combined cycle gas turbine retrofitted	H_2-CCGT-Retro				1.0	0.52
Lignite	Pulverized coal	Lignite PC			X	0.8	0.44
Nuclear	Nuclear Gen III	Nuclear		X		1.0	0.35
Nuclear	Small Modular Reactor	Nuclear-SMR		X		1.0	0.40
Oil	Oil	Oil			X	0.8	0.34
RES-E	Other renewable energy sources	Other RES-E		X		0.8	0.40
Solar	Photovoltaic solar power	PV		X		-	-
Solar	Concentrated solar power	CSP	X			-	-
Waste	Standalone	Waste	X			0.7	0.36
Wind	Onshore	Wind onshore		X		-	-
Wind	Offshore	Wind offshore		X		-	-

a) Technologies with no availability or efficiency values use profiles to represent their production output and, therefore, no single value of availability or efficiency is used in the model.

2.4.2.1 CO_2-free carbon technologies

The major CO_2-free power generation technologies that can offer dispatchable capabilities are primarily power plants using zero-carbon fuels such as biomass, nuclear energy, or hydrogen from renewable energy sources. Each technology is characterised by its specific barriers and challenges from either a techno-economic or socio-political point of view (Sijm, 2024). For this study, we consider the following dispatchable technologies to achieve climate-neutrality in the power generation system:

- *Biomass power plants, either coal-retrofitted or new installations, with or without CCS*. These power plants can provide dispatchable mid-load and base-load services while cutting carbon emissions. Additionally, the coupling with CCS – although economically more intensive in terms of investments and operation, as it requires additional infrastructures and efforts for CO_2 capture, transport, and storage – results even in negative emissions, which are key for achieving overall system climate neutrality. On the other hand, using biomass and/or CCS for power generation is controversial from a socio-political perspective, either because their sustainability is questioned or because it is argued that these scarce resources could be better used for other (non-electrical) purposes of which the related GHG emissions are much harder to abate. Therefore, applying biomass/CCS for producing electricity may lack adequate socio-political support.

- *Gas turbines, either natural gas-retrofitted or new (CCGT) power plants, using zero-carbon fuels*, such as hydrogen or green gas (i.e., biogas or biomethane) to provide dispatchable peak-load services. In the case of hydrogen, this can be either blue (through SMR-CCS) or green (by means of electrolysis). Besides newly invested installations, CO_2-free gas turbines can also be retrofitted from natural gas-fired (CCGT) power plants (with an assumed maximum retro potential of 9.2 GW over the years 2030-2050).[25] In principle, hydrogen-to-power has a large potential up to 2050 (and beyond). One of the main bottlenecks for this technology, however, is the high energy conversion losses, which result in high variable costs and limited operational hours. In the case of green gas, a similar debate concerning its biomass counterpart can be seen regarding its (scarce) availability and use for other (non-electrical) purposes. Additionally, a common barrier for both technologies (hydrogen, green gas) is the transport and storage infrastructure needed to be in place in order to deliver peak-load services.

- *Nuclear energy* provides base-load operation, which can cover extended periods when VRE production is low. There is a growing interest in this technology in some European nations, considering it strategic for achieving their decarbonization goals. A re-birth of the technology through Small Modular Reactors (SMRs) – which promises flexibility of operation – has gained attention, also for its capabilities to provide co-generation (heat and power), notably for industrial purposes. On the other hand, nuclear energy faces several barriers and challenges – which makes it a highly socio-political sensitive issue – such as high cost uncertainties, nuclear waste problems, and long duration periods before nuclear power plants get actually operational.

- *Fossil gas plants coupled with CCS*. It could be argued that this technology does not provide 100% free-carbon electricity, as the maximum capture efficiencies of CCS technologies range between 80-90%. However, for this study, we consider this technology as part of the decarbonization options for dispatchable capacity to achieve carbon neutrality in the electricity system, in order to assess the optimality of this technology

[25] The assumed maximum CCGT retro potential of 9.2 GW is equal to the installed natural gas-fired CCGT capacity in 2030 obtained from the reference scenario runs by COMPETES-TNO.

within the European P2X system as a whole. The main barriers of this technology refer to the continued use of natural gas and the CCS infrastructure needs, including the resulting societal and political opposition against this technology.

2.4.2.2 Cost parameters of key technologies

Table 2.4 provides the cost parameters assumed for the new investment of power generation technologies in COMPETES-TNO. The model can invest in these technologies as newly built capacity or as retrofitted capacity, which leads to different cost parameters. Values for the year 2040 were obtained by the interpolation of the 2030 and 2050 cost parameters. Table 2.5 presents the assumed cost parameters for electrical storage technologies, and Table 2.6 for power-to-X (P2X) technologies as well as for SMR + CCS.

Table 2.4: Assumed cost parameters for power generation technologies

Technology	Type of investment	Overnight Capital Cost (€/kW)		Fixed O&M (€/kW/yr)	Variable O&M (€/MWh)	Source
		2030	2050	2030-2050	2030-2050	
Wind onshore	New	1090	980	10	2	Beurskens (2021a)
Wind offshore	New	2400	2200	23	2	Beurskens (2021b)
Sun PV	New	464	311	8	1	Beurskens (2019)
Natural gas CCGT + CCS	New	1390	1280	32	6	Tsiropoulos et al. (2019)
H_2 CCGT	New	700	480	11	2	De Wildt et al. (2023)
	Retrofit from natural gas plant	350	350	11	2	De Wildt et al. (2023)[a]
Green gas	New	700	675	11	2	De Wildt et al. (2023)
	Retrofit from natural gas plant	750	750	11	2	De Wildt et al. (2023)
Biomass	New	1900	1450	68	2	TNO (n.d.)
	Retrofit from coal plant	500	500	34	1	DEA (2024)[b]
Biomass + CCS	New	5380	3840	80	2	Tsiropoulos et al. (2019)
	Retrofit from coal plant	935	935	75	3	Aurora (2021)
Nuclear conventional	New	7080	6088	110	18 (incl. fuel costs)	Zandt et al. (2024)
Nuclear SMR	New	7097	6104	100	18 (incl. fuel costs)	Zandt et al. (2024)

a) The cost parameters for H_2 CCGT power plants retrofitted from natural gas-fired installations are derived from De Wildt et al. (2023). These (average) parameters, however, are highly uncertain and may vary substantially depending on the specific characteristics and conditions of the CCGT installations concerned. Alternative sources on these cost parameters – including information on the technical potential of H_2 CCGT retrofitted plants – are provided by Berenschot and TNO (2023) and Hers et al. (2023 and 2025).

b) The cost parameters for biomass power plants retrofitted from coal-fired installations are derived from DEA (2024). These (average) parameters, however, are highly uncertain and may vary substantially depending on the specific characteristics and conditions of the coal plants concerned. Alternative sources on these cost parameters include EC (2016), CE Delft (2016), ARBAHEAT (2019), Frontier Economics (2029) and Hers et al. (2025).

Table 2.5: Assumed cost parameters for electrical storage technologies

Technology	Power/Energy ratio	Overnight Capital Cost (€/kW)		Fixed O&M (€/kW/yr)	Variable O&M (€/MWh)	Source
		2030	2050	2030-2050	2030-2050	
Battery Li-Ion	4	704	528	10	1.6	Lamboo (2021a)
Battery VRB	6	2140	1440	42	0.8	Lamboo (2021b)
Battery PB	5	1140	1010	16	0.3	Lamboo (2021c)
CAES (Adiabatic)	5	1300	1200	16	2	TNO (n.d.)
CAES (Diabatic)	12	1000	900	12	2 + Natural gas price	TNO (n.d.)

Table 2.6: Assumed cost parameters for power-to-X (P2X) technologies and Steam Methane Reforming + Carbon Capture & Storage (SMR + CCS)

Technology	Overnight Capital Cost (€/kW)		Fixed O&M (€/kW/yr)	Variable O&M (€/MWh)	Source
	2030	2050	2030-2050	2030-2050	
Electrolyser	2603	1666	10	-	Eblé & Weeda (2024)
Hybrid boiler	250	250	4	-	TNO (n.d.)
SMR + CCS	1330	1330	62	-	TNO (n.d.)

All cost data in the current report are presented in euro values of 2015. As the price index for the Netherlands (2015 = 100) has increased to about 135 in 2025, this implies that costs and prices in 2025-euro values are approximately 35% higher than presented in this report.

2.4.2.3 Availability of biomass and biogas

Because of the debate on the availability and use of biomass and biogas for the production of electricity (see Section 2.4.2.1 above), this availability has been limited in the COMPETES-TNO model runs. Table 2.7 provides data on the assumed availability of biomass and biogas for power generation in the Netherlands in the three reference target years (2030, 2040 and 2050).

Table 2.7: Assumed availability of biomass and biogas for producing electricity in the Netherlands, 2030-2050 (in TWh)

	2030	2040	2050
Biomass	3.3	6.7	10.0
Biogas	13.9	13.9	13.9

Source: Based on Ruiz (2019).

2.4.2.4 Interconnection capacities

Table 2.8 presents the (assumed) interconnection capacities for trading electricity between the Netherlands and its neighbouring countries in the target years over the period 2020-2030.

Table 2.8: Interconnection capacities of electricity trade between the Netherlands and its neighbouring countries, 2020-2050

	2020	2030	2040	2050
Netherlands-Germany	4.3	5.0	5.0	5.0
Netherlands-Belgium	2.4	3.4	3.4	3.4
Netherlands-UK	1.0	1.0	3.0	3.0
Netherlands-Denmark	0.7	0.7	0.7	0.7
Netherlands-Norway	0.7	0.7	0.7	0.7
Total	**9.1**	**10.8**	**12.8**	**12.8**

Source: TenneT (2023): 2020 data; ENTSO-E & ENTSOG (2022): 2030-2050 data.

2.4.3 Hourly electricity demand and VRE supply profiles

COMPETES-TNO uses a variety of hourly electricity demand and supply profiles as inputs. The conventional electricity demand profile is based on the climate year 2015. The flexible (P2X) profiles are determined endogenously by the model according to the corresponding, dynamic hourly electricity price profile.

On the supply side, sun and wind profiles are based on the historical capacity factors profiles obtained from the Renewable.ninja dataset (Staffel & Pfenninger, 2016a and 2016b). The historical profiles have been updated in terms of the expected (higher) full load hours (FLHs) for these technologies through the TNO's open source Tulipa Profile Fitting tool (Morales-España et al., n.d.). In the climate year 2015, the average FLHs for offshore and onshore wind are 2786 and 2006 hours, respectively. The (increased) average FLHs for these technologies in the 2030-2050 period are assumed to be 4735 hours for wind offshore, and 2750-3000h for wind onshore in 2040 and 2050, respectively. These FLHs are based on the estimated capacity factors of these technologies in Beurskens (2021 a, b). For sun PV, the FLHs are assumed to be constant at 1067 hours over the period 2030-2050.

2.4.4 CO_2 emission reduction targets

COMPETES-TNO focusses on the whole European P2X sector, where the power production and the resulting CO_2 emissions are primarily driven by the emission target of the EU Emissions Trading System (ETS). For the target year 2030, the assumed (exogenous) CO_2 price of an emissions allowance is therefore an input to the model. The resulting CO_2 emissions of the different European countries' power sectors are, therefore, an output of COMPETES-TNO, with no particular CO_2 emissions targets applied at national levels.

For the target years 2040 and 2050, on the contrary, a net zero CO_2 emission constraint is set exogenously into the COMPETES-TNO model for the European P2X system as a whole in both the reference scenario and most sensitivity cases analysed in this study.[26] This constraint results in an (endogenous) CO_2 shadow price for 2040 and 2050, respectively, which affects the other model scenario outcomes of these years.

[26] In two sensitivity cases, however, a separate, zero CO_2 emission constraint for the power generation system in the Netherlands (and some other, West-European countries) has been set for the target year (2050) of these cases. For further details, see Chapter 4.

So, for the target year 2030, an exogenous CO_2 price is assumed for the European P2X system as a whole (affecting the CO_2 emissions and other scenario results of this system), whereas for the target years 2040 and 2050 an exogenous zero CO_2 constraint is set for the European P2X system (resulting in an endogenous CO_2 shadow price, affecting the other model scenario outcomes for these years).

2.4.5 Fuel and CO_2 prices

Table 2.9 presents an overview of the main fuel and CO_2 prices assumed for the target years 2030, 2040 and 2050 of this study. As explained in the previous section (2.4.4), an exogenously assumed CO_2 price has not been applied for the years 2040 and 2050 but rather a zero CO_2 emission constraint for the European P2X system as a whole.

Table 2.9: Fuel and CO_2 prices assumed for the study target years 2030, 2040 and 2050

	Unit	2030	2040	2050
Biomass	€/GJ	8.5	8.5	8.5
Natural gas	€/GJ	10.7	10.7	10.7
Coal	€/GJ	3.0	2.1	2.0
Lignite	€/GJ	1.4	1.0	1.0
Oil	€/GJ	13.9	10.4	9.9
Green gas	€/GJ	19.4	18.2	13.1
CO_2 price	€/tCO_2-eq	101.1		

Source: KEV22 (PBL, 2022), TYNDP-22 (ENTSO-E & ENTSOG, 2022).[27]

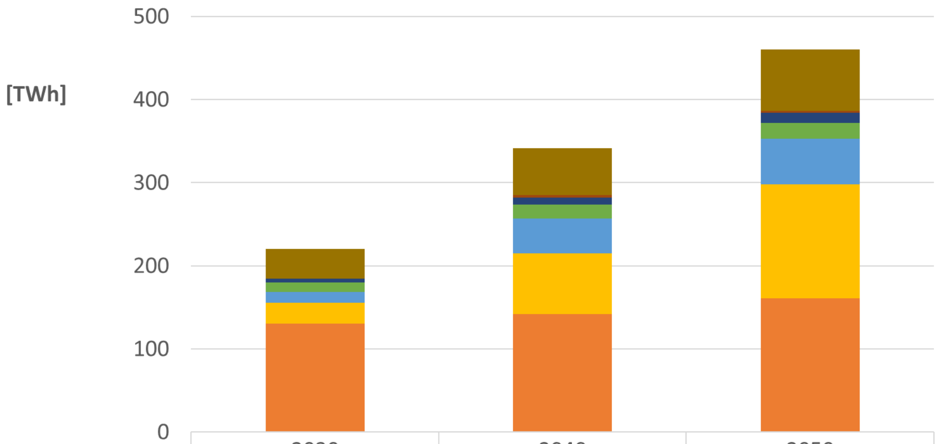
[27] The main fuel and CO_2 prices are based on the KEV22, with the exception of the green gas price, which is based on the biomethane price assumption of the TYNDP-22 scenarios.

3 Reference scenario (2030-2050)

This chapter presents the major results of the reference scenario for the Netherlands in the three target years (2030, 2040 and 2050).[28] More specifically, the following topics are addressed in the sections below:

1. Electricity demand (Section 3.1);
2. Electricity supply (Section 3.2);
3. Installed power supply mix (Section 3.3);
4. Full load hours of power system technologies (Section 3.4);
5. Flexibility options to meet peak residual load (Section 3.5);
6. Electricity prices (Section 3.6);
7. CO_2 prices and emissions (Section 3.7);
8. System costs (Section 3.8).

3.1 Electricity demand



	2030	2040	2050
Exports	36.1	56.5	73.6
Storage (charge)	0.0	3.1	2.6
P2Mobility (EVs)	4.3	8.0	11.5
P2Heat (households)	11.2	16.8	19.3
P2Heat (industry)	13.1	42.2	54.9
P2Hydrogen	25.2	72.9	136.9
Conventional	130.4	142.1	161.0

Figure 3.1: Reference scenario, 2030-2050: NL electricity demand

Figure 3.1 presents the major outcomes of the reference scenario regarding the demand side of the NL electricity balance over the years 2030-2050. In particular, it shows that the total *domestic* electricity demand is expected to grow from about 180 TWh in 2030 to 390 TWh in 2050 (compared to an actual electricity use of approximately 120 TWh in 2020).[29] This rapid

[28] To some extent, Annex A shows similar results for all the European countries as a whole ('EU27+'), notably with regard to the demand and supply side of the electricity balance and the installed (dispatchable) power generation mix.

[29] Actual figures for 2019/2020 mentioned in this chapter are obtained from Sijm (2024), based on CBS (2022).

growth of electricity demand is mainly due to the further electrification of the Dutch energy system, notably by P2X technologies such as P2Heat, P2Hydrogen and P2Mobility. For instance, electricity demand by P2H_2 is expected to increase from approximately 25 TWh in 2030 to 137 TWh in 2050 (compared to zero in 2020).

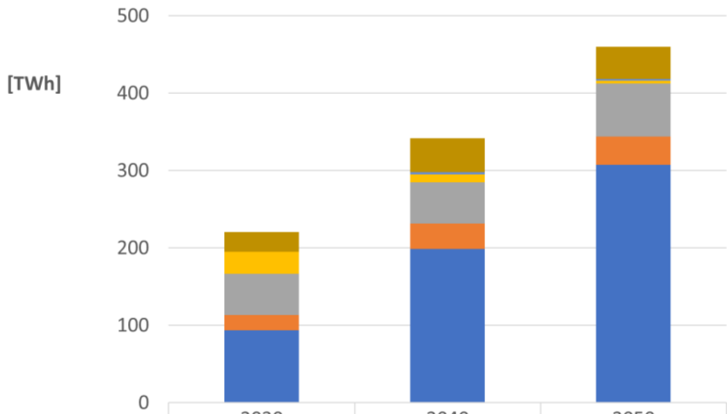
In addition, *foreign* electricity demand – i.e., gross electricity exports by the Netherlands – is projected to double from 36 TWh in 2030 to 74 TWh in 2050 (compared to 20 TWh in 2020).

3.2 Electricity supply

Figure 3.2 presents the results of the reference scenario concerning the supply side of the NL electricity balance, 2030-2050 – including the total dispatchable generation mix – whereas Figure 3.3 provides a further breakdown of this mix over these years. Figure 3.2 illustrates that *domestic* electricity supply – similar to domestic electricity demand – is expected to grow rapidly from about 195 TWh in 2030 to 420 TWh in 2050 (compared to 120 TWh in 2020). This rapid growth of electricity supply is predominantly due to the large increase in power generation from variable renewable energy (VRE) sources, notably sun PV and (offshore) wind.

More specifically, total VRE power supply is projected to increase from almost 170 TWh in 2030 to 410 TWh in 2050 (compared to less than 20 TWh in 2020). As a percentage of total domestic power generation, these figures correspond to about 85% in 2030 and 99% in 2050 (compared to approximately 15% in 2020).

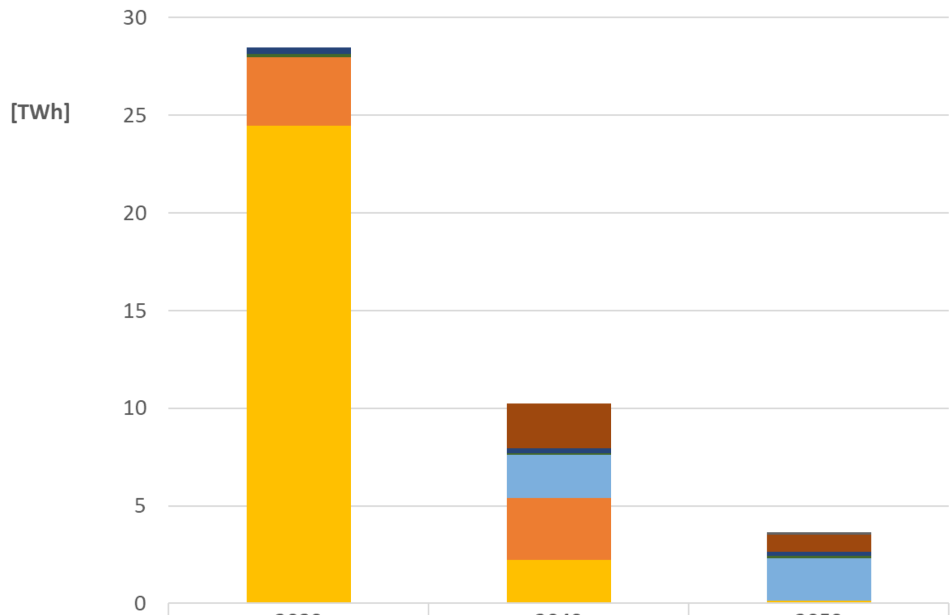
On the other hand, according to the reference scenario, total dispatchable power generation is expected to decrease from more than 28 TWh in 2030 to less than 4 TWh in 2050 (compared to more than 100 TWh in 2020), corresponding to about 15% of total domestic electricity production in 2030 and less than 1% in 2050 (compared to more than 85% in 2020).



	2030	2040	2050
Imports	25.6	43.6	41.7
Storage (discharge)	0.0	2.8	2.5
Dispatchable generation	28.5	10.3	3.6
Sun PV	52.9	53.3	68.8
Wind onshore	20.2	32.9	36.0
Wind offshore	93.2	198.6	307.4

Note: A breakdown of the dispatchable generation mix is provided in Figure 3.3 below.

Figure 3.2: Reference scenario, 2030-2050: NL electricity supply



	2030	2040	2050
H2 CCGT Retro	0.0	0.0	0.1
Biomass retro (with CCS)	0.0	2.3	0.9
Biomass retro (no CCS)	0.4	0.2	0.2
Other RES-E	0.2	0.1	0.1
Nuclear (SMR)	0.0	2.2	2.1
Nuclear (large)	3.5	3.2	0.0
Natural gas	24.5	2.2	0.2

Figure 3.3: Reference scenario, 2030-2050: Breakdown of NL dispatchable power generation mix

As mentioned, Figure 3.3 provides a further breakdown of the dispatchable generation mix in the reference scenario, 2030-2050. In particular, it shows that – due to the decarbonisation of the Dutch power system – electricity production from natural gas declines rapidly from about 25 TWh in 2030 to 0.2 TWh in 2050 (compared to 60-70 TWh in 2019-2020).[30]

In addition, due to the decommissioning of the Borssele nuclear power plant – with an assumed, extended lifetime up to the mid-2040s, and no new (endogenous) investments in large nuclear installations in the COMPETES-TNO cost-optimal reference scenario, electricity production from large-scale nuclear also declines from about 3.5 TWh in 2020-2030 to zero in 2050.

On the other hand, the reference scenario model runs show some endogenous (cost-optimal) investments in new, small modular reactors (SMRs) in 2040 (see Section 3.3 below), resulting in some power production – i.e., about 2 TWh – over the years 2040-2050.

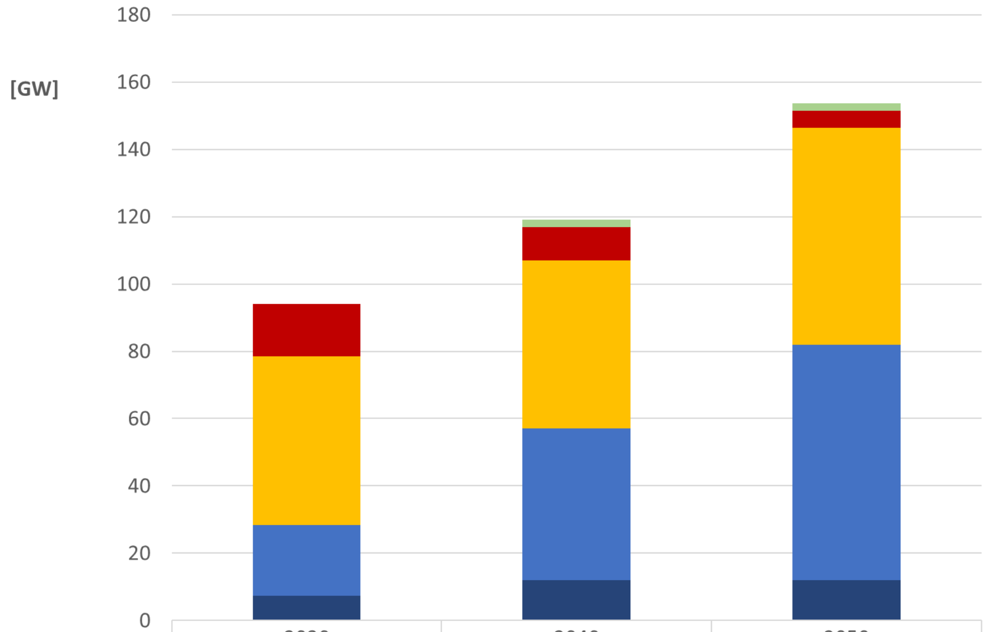
In addition, electricity generation from (coal-retrofitted) biomass installations – either with or without CCS – increases from 0.4 TWh in 2030 to 1.1 TWh in 2050. Moreover, Figure 3.3 shows that some tiny power generation – about 0.1 TWh – from CCGT-retrofitted, hydrogen-to-power plants, as well as from so-called 'Other RES-E' (i.e., mainly waste standalone).

[30] Note that electricity production from natural gas in 2040 and 2050 results in some remaining CO_2 emissions in the NL power system over these years (which is further clarified in Section 3.7 below).

Electricity imports
Figure 3.2 indicates that, besides domestic electricity generation, *foreign* power supply – i.e., gross electricity imports by the Netherlands – increases from approximately 26 TWh in 2030 to more than 40 TWh in 2040-2050 (compared to 20 TWh in 2020). In *net trading terms*, however, the Netherlands is expected to become a major *net exporter* of electricity in 2030, with a net export surplus of approximately 10 TWh, growing to about 32 TWh in 2050 (compare to major net electricity *imports* in the first two decades of the 21st century, and a nearly net zero trade position at the end of these decades).

3.3 Installed power capacity

Figure 3.4 present the results of the reference scenario with regard to the installed capacities of the power supply mix in the Netherlands – notably for VRE generation, total dispatchable generation and electrical storage – whereas Figure 3.5 provides a further breakdown of the installed dispatchable generation mix.



	2030	2040	2050
Li-ion battery storage	0.0	2.2	2.2
Dispatchable generation	15.6	10.0	5.1
Sun PV	50.0	50.0	64.5
Wind offshore	21.0	45.0	70.0
Wind onshore	7.4	12.0	12.0

Notes: A breakdown of the dispatchable generation mix is provided in Figure 3.5 below. Figures on the required capacities of dispatchable generation and battery storage refer to the hourly spot market only but do not include the need for balancing/emergency reserves.

Figure 3.4: Reference scenario, 2030-2050: Installed capacities of VRE generation, electrical storage and total dispatchable generation in the Netherlands

VRE generation
Figure 3.4 shows that over the period 2030-2050 the power supply mix in the Netherlands is dominated by the installed capacities of VRE generation, notably of offshore wind and sun PV. According to the COMPETES-TNO model scenario runs, the installed capacity of offshore wind is projected to grow from (the exogenously assumed) 21 GW in 2030, to (the endogenous

optimised) 45 GW in 2040, and (the optimised, but model-capped) 70 GW in 2050.[31] For onshore wind, the installed capacity increases from (the exogenously assumed) 7.4 GW in 2030 to (the optimised, but model-capped) 12 GW in both 2040 and 2050.[32]

Regarding sun PV, the exogenously assumed installed capacity of 50 GW in 2030 is based on the most recent '*National Solar Trend Report*' (DNE Research, 2025). For 2040 and 2050, decommissioned/additional capacity of sun PV is optimised by COMPETES-TNO. Up to 2040, however, the model does not show any additional investments, implying that the installed capacity of sun PV in 2040 remains at the same level as in 2030 (i.e., 50 GW).[33] Up to 2050, on the contrary, the model expects new, additional investments in sun PV of about 15 GW, resulting in a total installed sun PV capacity of approximately 65 GW in that year.

Dispatchable generation
Figure 3.4 indicates that the (assumed) installed capacity mix of dispatchable power generation technologies amounts to almost 16 GW in 2030, i.e., a major decrease, compared to the total dispatchable generation capacity of about 26 GW in 2019/2020 (Sijm, 2024).[34] Up to 2040, the installed capacity of the dispatchable generation mix diminishes further to 10 GW and in the years thereafter to only 5.1 GW in 2050 (according to the assumed model reference scenario for these years).[35]

As mentioned, Figure 3.5 provides a further breakdown of the installed dispatchable generation mix in the years 2030-2050. It shows that the exogenously assumed capacity of natural gas-fired technologies amounts to almost 15 GW in 2030 – compared to about 20 GW in 2020 – resulting from capacity decommissioning due to technical (lifetime), economic and/or decarbonisation reasons over the years 2020-2030. Due to further decommissioning of natural gas-fired power plant and no new capacity investments beyond 2030, the installed capacity of this technology diminishes steadily to 8.2 GW in 2040 and only 1.3 GW in 2050.

With regard to nuclear energy, the lifetime of the existing (0.5 GW) Borssele power plant is assumed to be extended up to the mid-2040s. According to the COMPETES-TNO outcomes for the reference scenario, however, there are no new (endogenous, cost-optimal) investments in large nuclear plants by either 2040 or 2050, but the model runs result in some capacity investments (0.3 GW) in small modular reactors (SMRs) in 2040.

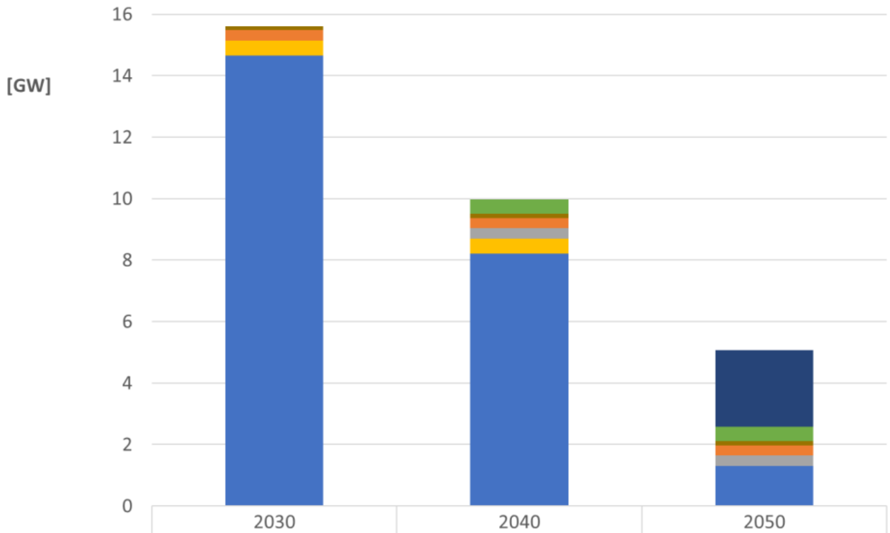
[31] The assumed maximum potential capacity of 70 GW for offshore wind in 2050 is based on the target of the Dutch government for this technology in that year (RVO, 2023). The cap of 70 GW is set exogenously as a constraint into COMPETES-TNO. The model, however, allows a lower offshore wind capacity than 70 GW in 2050 – if this outcome turns out to be cost-optimal – but no additional investments beyond this cap.

[32] The (socio-political) maximum potential capacity of 12 GW for onshore wind is obtained from Beurskens (2021a).

[33] Given the expected large increase in electricity demand over the years 2030-2040, and the stringent sharpening of the decarbonisation target for the NL power system over this period, this finding – i.e., no additional investments in sun PV between 2030 and 2040 – suggests that the exogenously assumed ('expected') capacity of sun PV is 2030 (50 GW) is likely not cost optimal from a European P2X system perspective.

[34] As outlined in Chapter 2 (notably Section 2.2), installed capacities of dispatchable power generation technologies in 2030 are set exogenously into COMPETES-TNO, except the capacities of (coal-retrofitted) biomass installations (which are optimised by the model). In addition, it should be noted that the 26 GW of dispatchable generation capacity in 2020 includes balancing/emergency reserves required for a reliable, adequate power system (which in future years can also be met by other, additional flexibility options, notably storage). In 2020, these reserves amounted to about 1.4 GW (TenneT, 2025). Estimates of the required capacities of dispatchable generation (and battery storage) in the reference scenario years 2030, 2040 and 2050 refer to the hourly spot market only but do not include the need for balancing/emergency reserves.

[35] A clarification of the (capacity) need for dispatchable generation (versus other flexibility options to meet the peak residual power load) is outlined in Section 3.5 below, whereas Chapter 4 discusses the impact of various sensitivity cases on the need for dispatchable generation (and other flexibility options).



	2030	2040	2050
H2 CCGT Retro	0.0	0.0	2.5
Biomass Retro (with CCS)	0.0	0.5	0.5
Biomass Retro (no CCS)	0.1	0.1	0.1
Other RES-E	0.3	0.3	0.3
Nuclear (SMR)	0.0	0.3	0.3
Nuclear (large)	0.5	0.5	0.0
Natural gas	14.7	8.2	1.3

Figure 3.5: Reference scenario, 2030-2050: Breakdown of NL installed dispatchable generation capacity mix

In addition,, Figure 3.5 shows that – besides the assumed capacity for 'Other RES-E' (0.3 GW) – there are some additional, new investments in dispatchable (carbon-free) generation capacity over the years 2030-205, notably in (i) coal-retrofitted, biomass-fuelled installations without CCS (0.1 GW in 2030), (ii) coal-retrofitted, biomass-fired plants + CCS (0.5 GW) in 2040, and (iii) CCGT-retrofitted, hydrogen-to-power plants (2.5 GW in 2050).[36]

Electrical storage

In addition to optimised investments in power generation capacity, COMPETES-TNO also allows cost-optimal investments in electrical storage. Figure 3.4, however, shows only some capacity investments in Li-ion battery storage by 2040 (2.2 GW).[37] Although the model also allows investments in other batteries as well as in compressed air energy storage (CAES, both diabatic and adiabatic), these investments turned out to be not cost-optimal and, hence, did not pop up. In the reference scenario, however, hydrogen storage – not recorded in Figure 3.4 – plays a major role in balancing the energy system, including hydrogen produced by means of (converting) power-to-hydrogen ($P2H_2$) and, subsequently, stored for purposes such as industrial feedstock, e-fuel production, hydrogen-to-heat, hydrogen-to-mobility and (re-converting) hydrogen-to-power. Moreover, in all cases, demand response by EV batteries also plays a major role in balancing the power system, including EV battery discharges to the power grid when electricity prices are relatively high (V2G, which in this model study is considered as 'demand response' rather than 'storage').[38]

[36] Note, however, that the full load hours of the hydrogen-to-power capacity are rather low in 2050 (i.e., only 51 hours; See Section 3.4 below), resulting in a relatively small output from this capacity (i.e., only 0.1 TWh in 2050; see Section 3.2 above).

[37] It should be emphasized, however, that the COMPETES-TNO model covers only the hourly spot markets but not the electricity balancing ('reserve') and other, ancillary service markets and, therefore, may underestimate the role (business case, installed capacity, volume transactions) of battery storage.

[38] In 2050, hourly power load by EVs varies from +7.5 GW (EV battery charge) to -6.1 GW (EV battery discharge).

Flexible demand

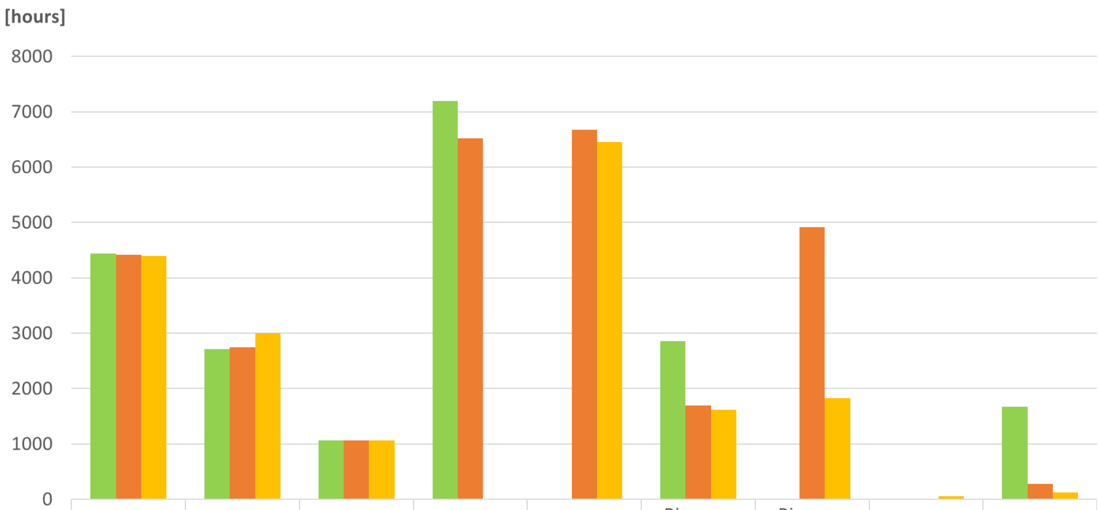
Table 3.1 presents the installed capacities of two major flexible demand technologies, i.e. power-to-hydrogen and power-to-heat in industry, which have been optimized by COMPETES-TNO, starting from 2030 up to 2050. These capacities increase substantially over these years – up to 35 GW in 2050 – notably for power-to-hydrogen (28 GW). Together, they offer a large potential for flexible electricity demand, in particular in 2040 and 2050, having a major impact on the hourly peak residual load as well as on the need for dispatchable generation and other flexibility options to meet this residual load (for a further analysis, see Section 3.5 below).

Table 3.1: Reference scenario, 2030-2050: Installed capacities of major flexible demand ('conversion') technologies

[in GW]	2030	2040	2050
Power-to-hydrogen	3.6	16.2	27.9
Power-to-heat (industry)	4.0	5.7	6.7

3.4 Full load hours of generation technologies

Figure 3.6 presents the full load hours (FLHs) of the major power generation technologies in the Netherlands for the three target years of the reference scenario (2030, 2040 and 2050). For the VRE generation technologies, these FLHs basically reflect the updated capacity factors for these years, as outlined in the previous chapter (Section 2.4.3). In some cases, however, the actually resulting FLHs of these technologies – as recorded in Figure 3.6 – are slightly lower than the capacity factors/FLHs mentioned in Section 2.4.3 due to the curtailment of VRE generation in the model optimisation runs. For instance, at full capacity the FLHs of offshore wind amount to 4735 hours over the years 2030-2050 (Section 2.4.3). According to Figure 3.6, however, the FLHs of offshore wind in 2050 are actually slightly less than 4400 hours, indicating that the model dispatch optimisation has resulted in a curtailment of offshore wind by approximately 7%.



	Wind offshore	Wind onshore	Sun PV	Nuclear (large)	Nuclear (SMR)	Biomass Retro (no CCS)	Biomass Retro (with CCS)	H2 CCGT Retro	Natural gas
2030	4438	2712	1058	7193		2860			1670
2040	4412	2745	1066	6523	6669	1690	4909		272
2050	4392	3000	1067		6451	1618	1828	51	122

Figure 3.6: Reference scenario, 2030-2050: Full load hours of major power generation technologies

Figure 3.6 shows that for the (baseload) nuclear power technologies the FLHs are – as expected – relatively high, i.e. about 6500-7200 for the large Borssele plant (in 2030-2040) and, on average, 6500-6700 hours for the SMRs (in 2040-2050). Coal-retrofitted biomass plants – either with or without CCS – turn out to be a mid-load technology, with FLHs ranging between, on average, 1600 and 4900 hours in 2030-2050.

In addition, Figure 3.6 illustrates that power generation from natural gas – as far as any installed capacity is remaining – becomes a real peak load technology over the years 2030-2050. More specifically, the FLHs of this (mainly CCGT) technology falls substantially from about 1700 hours in 2030 to approximately 270 hours in 2040 and only 120 hours in 2050.

A part of the natural gas-fired CCGTs is retrofitted into hydrogen-to-power plants (about 2.5 GW in 2050). Due to the high H_2 costs, however, the FLHs of these H_2-CCGTs turn out to be rather low, i.e. only some 51 hours in 2050 (Figure 3.6). This indicates that this technology is highly risky from a private investor point of view since it is quite uncertain whether this amount of hours – and the related revenues to cover the investment costs – are actually realised.

Flexible demand

Table 3.2 presents the FLHs of the two major flexible demand technologies, i.e. power-to-hydrogen and power-to-heat in industry. It shows that the FLHs of power-to-hydrogen ranges between 4900 and 7000 hours, whereas the FLHs of power-to-heat in industry increases from about 3300 hours in 2030 to approximately 8200 hours in 2050 (mainly due to the rising natural gas/CO_2 prices, which stimulates a shift from gas to electricity boilers). These figures indicate that these technologies, notably power-to-hydrogen, offer ample room for electricity demand shifting – between hours with high versus low electricity prices – which has a major impact on the (peak) residual load and the need for dispatchable generation and other flexibility options to deal with this load (as further analysed in Section 3.5 below).

Table 3.2: Reference scenario, 2030-2050: Full load hours (FLHs) of major flexible demand ('conversion') technologies

[in GW]	2030	2040	2050
Power-to-hydrogen	6963	4494	4901
Power-to-heat (industry)	3306	7737	8141

3.5 Flexibility options to meet peak residual load

In Section 3.3 above, Figure 3.3 showed that in the reference scenario the total capacity of dispatchable generation amount to 'only' 5.1 GW in 2050. This section provides an explanation for this relatively low amount of dispatchable generation capacity in 2050 by analysing the (peak) residual load in this year as well as the flexibility options – including, among others, dispatchable generation – to meet this residual load.

In this study, residual load (RL) is defined as the difference between total hourly electricity demand (after demand shifting/conversion) and total hourly domestic VRE supply (before any VRE/demand curtailment). So, more specifically, this definition of residual load already accounts for the impact of flexible demand by means of the P2X technologies covered by COMPETES-TNO (i.e., power-to-heat, power-to-hydrogen and power-to-mobility) but excludes the impact of both 'voluntary' demand curtailment (i.e., 'industrial load shedding') and 'forced' demand curtailment (i.e., lost load).

First of all, to indicate the impact of flexible demand on the hourly residual load, Figure 3.7 presents the duration curve of the hourly residual load for two different flexible demand cases in 2050: (i) '*No Flexible Demand (NFD)*' at all, and (ii) '*High Flexible Demand (HFD)*', i.e. including the flexible electricity demand by the P2X technologies covered by the model.[39] It shows that, due to the flexible demand of the P2X technologies, the duration curve of the '*High Flexible Demand*' case is much flatter than the duration curve of the '*No Flexible Demand*' case, i.e. at the left of the duration curve, the values of the (high, positive) RLs are generally substantially lower in the HFD case (than in the NFD case), whereas on the right of this curve, the values of the (low, negative) RLs are usually significantly higher in the HFD case. More specifically, at the full left of the duration curve, the highest hourly RL ('peak') in 2050 amounts to almost 55 GW in the NFD case versus only 24 GW in the HFD case (indicating that, due to the flexible P2X demand, the peak RL in the 2050 reference scenario has been reduced by 31 GW).

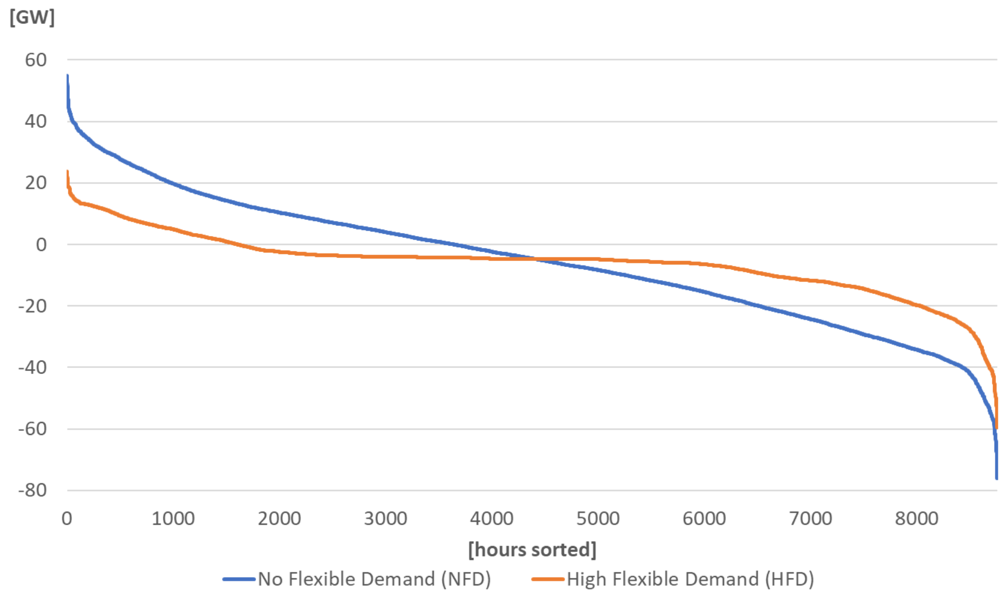


Figure 3.7: Reference scenario, 2050: Duration curves of the hourly residual load in two different cases, i.e., No Flexible Demand (NFD) and High Flexible Demand (HFD)

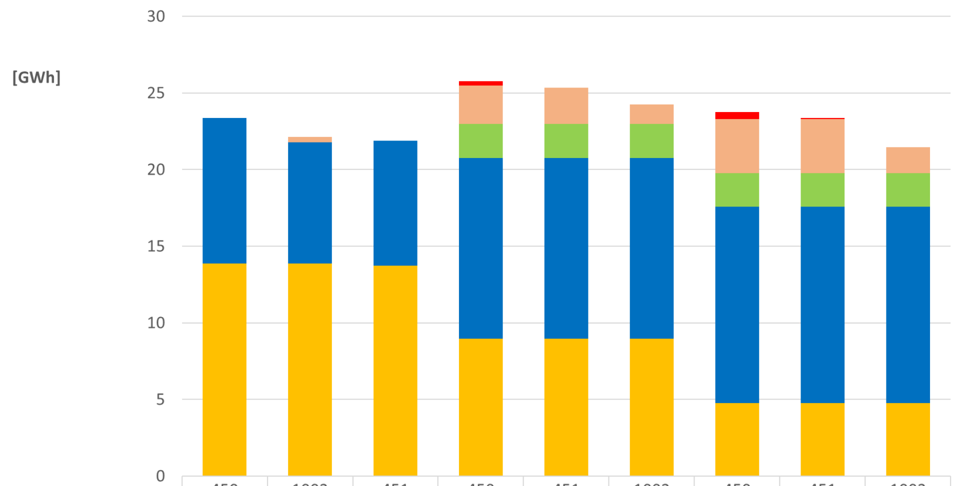
Dispatchable generation versus other flexibility options to meet the peak residual load

Figure 3.8 presents the mix of total dispatchable generation and other flexibility options to meet the highest ('peak') residual load in three hours of each target year considered in the reference scenario (2030, 2040 and 2050), while Figure 3.9 provides a further breakdown of the dispatchable generation mix during these hours.[40] Some major observations and findings from these two figures include:[41]

[39] As outlined in Chapter 2, the reference scenario is based on the '*High Flexible Demand*' case. Note that the '*No Flexible Demand* (NFD)' case is a rather 'extreme' (unrealistic) case – for illustrative, clarifying purposes only – as it assumes no flexible (price-responsive) electricity demand at all, implying that, for instance, the demand curve for power-to-hydrogen is completely flat (regardless the level of the hourly electricity price). Actually, power-to-hydrogen – but also power-to-heat in industry – must be flexible (price-responsive) as otherwise it cannot be competitive and economically feasible during a large number of hours during the year. In Chapter 4, we will analyze the impact of a less extreme (more realistic) sensitivity case, called '*Less Flexible Demand (LFD)*', compared to the '*High Flexible Demand (HFD)*' reference scenario case.

[40] Note that, for 2050, the three peak RL hours in Figure 3.8 correspond to the first three hours of the HFD duration curve presented in Figure 3.7.

[41] Note that for dispatchable generation the hourly output data recorded in Figure 3.8 and Figure 3.9 correspond highly to the (annual) installed capacity data presented in Figure 3.4 and Figure 3.5, respectively. However, the



	450	1002	451	450	451	1002	450	451	1002
	Reference 2030			Reference 2040			Reference 2050		
Demand curtailment ('lost load')	0.0	0.0	0.0	0.3	0.0	0.0	0.5	0.1	0.0
Industrial load shedding (ILS)	0.0	0.3	0.0	2.5	2.4	1.3	3.5	3.5	1.7
Storage (discharge)	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2
Net trade (imports)	9.5	7.9	8.1	11.8	11.8	11.8	12.8	12.8	12.8
Dispatchable generation	13.9	13.9	13.7	9.0	9.0	9.0	4.8	4.8	4.8

Notes: A breakdown of the dispatchable generation mix is provided in Figure 3.9 below. The numbers below the bars refer to the hours of the year in which the peak RL occurs.

Figure 3.8: Reference scenario, 2030-2050: Mix of flexibility options in the Netherlands to deal with the highest residual load in three hours of each target year considered

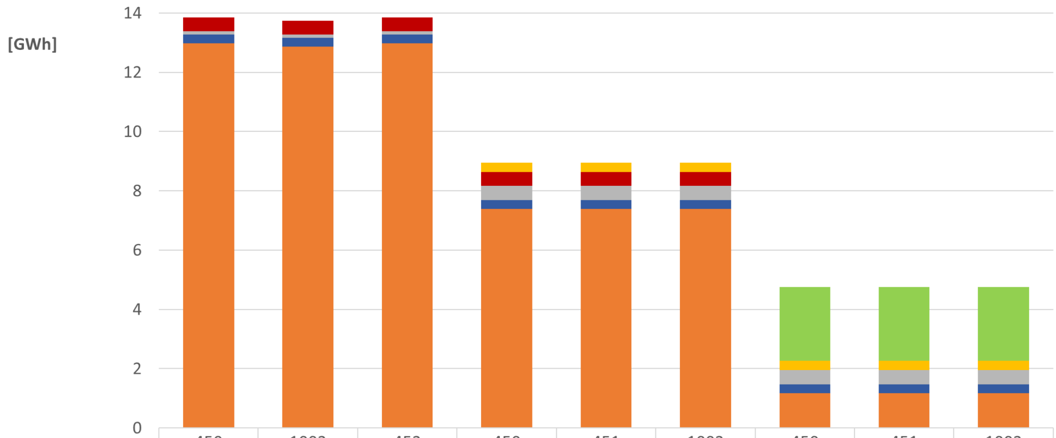
- *Residual load (RL) versus (flexible) electricity demand:* Although total annual electricity demand grows rapidly over the years 2030-2050 (see Section 3.1/Figure 3.1), the peak residual load during this period remains on more or less the same level over this period (Figure 3.8). In particular, whereas the average (domestic) electricity demand over the year as a whole increases from 21 GW in 2030 to 44 GW in 2050, the average RL in the three peak hours recorded in Figure 3.8 is nearly the same in these years at almost 23-25 GW. Apart from some increase in VRE generation in these peak hours, this stabilisation of the peak RL over the years 2030-2050 is primarily due to the flexible demand of the P2X technologies, which shift electricity demand from hours when VRE generation is low (and electricity prices are high) to hours with high VRE generation (and low electricity prices).[42]

- *Dispatchable generation:* The contribution of dispatchable generation to meeting the RL in the three highest peak hours declines from almost 14 GW in 2030 to 9 GW in 2040 and even to less than 5 GW in 2050. As a percentage of the RL in these hours, these figures correspond to 62%, 36% and 21%, respectively. Figure 3.9 shows that in 2030 and 2040 dispatchable generation in the three peak RL hours is still predominantly derived from gas-fired plants (CCGTs), while in 2050 this share declines to approximately 25% (i.e., about 1.2

cost-optimal deployment (output) of dispatchable generation recorded in Figure 3.8 and Figure 3.9 is usually slightly lower than the installed capacity data presented in Figure 3.4 and Figure 3.5, respectively. This is due to two reasons, i.e. (i) the average availability of some generation technologies is less than 1.0 (because of regular maintenance, etc.), and (ii) in the peak RL hour, the required, cost-optimal deployment of dispatchable generation may be less than the (maximum available) installed capacity of dispatchable generation because there are other, cheaper flexible options to meet the peak RL, such as trade or demand response, while in other hours – with a lower RL – a higher (maximum) deployment of dispatchable generation is needed because other, cheaper flexible options are not or less available.

[42] In some peak hours (with very high electricity prices), EVs even discharge, on balance, electricity to the grid ('negative electricity demand'). In COMPETES-TNO, this is considered as 'flexible demand' (rather than 'storage transactions').

GWh of natural gas-fired generation in the 2050 peak RL hours considered). In 2050, the main part (more than 50%) of the dispatchable generation in the three peak RL hours comes from CCGT-retrofitted hydrogen-to-power plants, while the remaining shares are obtained from biomass-retro (10%), nuclear SMRs (7%) and other RES-E (6%).



	Reference 2030			Reference 2040			Reference 2050		
	450	1002	452	450	451	1002	450	451	1002
H2 CCGT	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5
Nuclear (SMR)	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Nuclear (large)	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass Retro	0.1	0.1	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Other RES-E	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural gas (CCGT)	13.0	12.9	13.0	7.4	7.4	7.4	1.2	1.2	1.2

Figure 3.9: Reference scenario, 2030-2050: Breakdown of dispatchable generation mix in the Netherlands to deal with the highest residual load in three hours of each target year considered

- *Net trade (imports):* In 2030, the contribution of (net) electricity imports in dealing with the RL during the three highest peak hours amounts to, on average, 8.5 GW (i.e., 38% of the average RL over these hours). This contribution increases to almost 12 GW in 2040 and to 12.8 GW – i.e., reaching the total maximum interconnection capacity of the Netherlands – in 2050 (corresponding to 47% and 56% of the average RL during the three highest peak hours in these years, respectively). This implies that, over the years 2040-2050, net trade becomes the main flexibility options to address the peak RL of the Dutch power system (thereby reducing the need for and role of dispatchable generation to meet this load).

- *Storage (discharge):* In the reference scenario year 2030, the role of (battery) storage in meeting the (peak) RL is zero, but in both 2040 and 2050 the contribution of (li-ion battery) storage to deal with the RL in the three highest peak hours amounts to 2.2 GW, i.e. approximately 9-10% of the RL in these hours.

- *Industrial load shedding (ILS):* In 2030, some small industrial load shedding (0.3 GWh) occurs in only one of the three peak RL hours recorded in Figure 3.8. In 2040, however, ILS takes place in all three hours recorded, varying from 1.3 to 2.5 GWh, i.e. the maximum ILS potential assumed for 2040 (see Table 2.1 in Chapter 2, Section 2.1). In 2050, ILS occurs also in all three hours recorded, ranging from 1.7 to 3.5 GWh, i.e. the maximum ILS potential assumed for 2050, corresponding to, on average, about 13% of the RL in these hours.

- *Demand curtailment ('lost load):* In addition to the 'agreed' or 'voluntary' demand curtailment (i.e., ILS) mentioned above, there is also – very occasionally – some 'forced' or 'involuntary' demand curtailment, called '*lost load*' or '*energy-not-served'* (ENS), notably in stringent peak RL hours. Figure 3.8 shows, however, that in 2030 forced demand curtailment does not occur in any the three peak RL hours recorded, while in 2040 it takes place in only on the three hours presented – to a level of 0.3 GWh – and in 2050 in two of the three hours considered (ranging from 0.1 to 0.5 GWh). Hence, the role of forced demand curtailment ('lost load') in meeting the peak RL is generally rather small, although in some critical hours it is more cost-optimal – from a system perspective – to rely, to some extent, on this option rather than other (flexibility) options such as additional (costly) capacity investments in dispatchable generation, electrical storage or cross-border interconnection, which are required and used for only a few hours per year (see also further considerations on this topic below).

Duration curves of flexibility options in 2050

Figure 3.10 presents the duration curves of dispatchable generation and other flexibility options to meet the hourly residual load over the reference scenario year 2050 as a whole. In the upper graph, it shows that dispatchable generation reaches its peak output (2.3-4.8 GW) – including largely electricity from natural gas/H_2-CCGTs – only during some 100 hours of the year. Up to 2000 hours, dispatchable generation amounts to about 0.8 GW only, mainly from biomass-retro (0.5 GW) and nuclear SMRs (0.3 GWh). Between 2000 and 7000 hours, dispatchable generation is obtained from nuclear SMRs only (0.3 GW), whereas it is zero during the remaining (about 2000) hours of the year 2050.

The middle graph of Figure 3.10 illustrates the duration curves for both (net electricity) trade and storage in 2050. Net electricity imports (see upper – 'positive' – part of the graph) and net electricity exports (lower – 'negative' – part) reach the maximum interconnection capacity in 2050 (12.8 GW) only during a limited number of hours of the year. In other hours of 2050, net electricity trade – either imports or exports – varies between zero and this maximum interconnection capacity, although during most hours of the year there is a net export surplus (often at a net export level of 5 GW).

Similarly, net electricity storage – i.e., storage discharges at the upper ('positive') part of the graph and storage charges at the lower ('negative') part – also reach the maximum (Li-ion battery) storage capacity in 2050 (2.2 GW) only during a limited number of hours of the year. In the other hours of 2050, however, net electricity storage – either charges or discharges – ranges between zero and this maximum storage capacity, albeit it is (nearly) zero during most hours of the year.

Finally, the lower graph of Figure 3.10 presents the duration curves of both VRE curtailment and demand curtailment in 2050, where demand curtailment covers both 'voluntary' demand curtailment (i.e., industrial load shedding) and 'forced' demand curtailment (i.e., lost load/-energy-not served). VRE curtailment is zero for almost 7000 hours of the year, whereas it varies between zero and more than 60 GW in the remaining hours of 2050. Demand curtailment is even zero during almost all hours of 2050, except for some hours in which it varies between 0.3 and 3.8 GW (see also Table 3.3 below).

Figure 3.10: Reference scenario, 2050: Duration curves of flexibility options to meet the hourly residual load, including (i) dispatchable generation (upper graph), (ii) trade and storage (middle graph), and (iii) VRE curtailment and demand curtailment (lower graph)

Table 3.3: Reference scenario, 2030-2050: Demand curtailment (in GW)

	Voluntary/agreed demand curtailment (i.e., Industrial load shedding)			Involuntary/forced demand curtailment (i.e., Lost load/Energy not served)		
#hour	2030	2040	2050	2030	2040	2050
1	1.5	2.5	3.5	2.3	0.3	0.5
2	1.5	2.4	3.5	1.6		0.1
3	0.4	1.3	2.6			
4	0.3	0.6	1.7			
5		0.5	1.5			
6		0.5	1.2			
7		0.1	1.0			
8			1.0			
9			1.0			
10			1.0			
11			1.0			
12			1.0			
13			1.0			
14			1.0			
15			1.0			
16			1.0			
17			1.0			
18			1.0			
19			1.0			
20			1.0			
21			1.0			
22			1.0			
23			1.0			
24			1.0			
25			1.0			
26			0.9			
27			0.9			
28			0.9			
29			0.8			
30			0.7			
31			0.2			
32			0.2			
Total (GWh)	3.7	7.9	37.7	3.9	0.3	0.6

Demand curtailment
Table 3.3 provides more detailed information on demand curtailment – including both industrial load shedding (ILS) and lost load/energy-not-served (ENS) – in the three target years of the reference scenario (2030, 2040 and 2050). It shows that ILS occurs in four hours in

2030, with a maximum curtailment of 1.5 GW and a total curtailment of 3.7 GWh over these four hours. In 2050, the number of ILS hours increases to 32, with a maximum curtailment of 3.5 GW and a total curtailment of almost 38 GWh (i.e., about ten times more than in 2030).

In addition, Table 3.3 shows that forced demand curtailment (ENS) occurs only in two hours in both 2030 and 2050 – and only one hour in 2040 – with a total curtailment of 3.9, 0.6 and 0.3 GWh is these years, respectively.

Although in absolute terms total demand curtailment by ILS/ENS is relatively small in 2030-2050 (compared to total electricity demand) in some critical hours it makes a significant contribution to reducing the (peak) residual load and, hence, the need for (more expensive) dispatchable generation or other flexibility options to meet this load.

3.6 Electricity prices

Figure 3.11 shows the duration curves of the hourly electricity prices on the wholesale ('spot') market of the Netherlands for the three target years of the reference scenario, whereas Table 3.4 presents the weighted average electricity price over each of these years.[43] More specifically, the figure shows that during most hours of each target year the electricity price ranges between 50 and 100 €/MWh. However, in a limited number of hours – about 500-1000 hours – the electricity price is substantially higher than 100 €/MWh (see also below) while in a large, growing number of hours (1500-2500) over the years considered, the electricity price is significantly lower than 50 €/MWh or even close to zero (largely due to the growing importance of low-cost VRE generation over these years).[44]

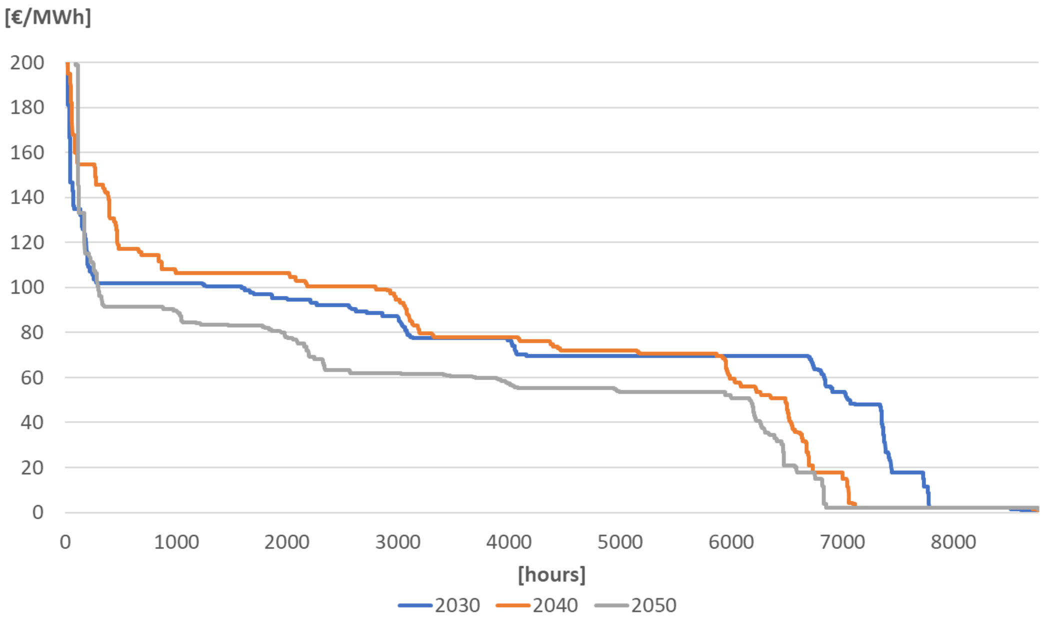


Figure 3.11: Reference scenario, 2030-2050: Duration curves of hourly electricity prices in the Netherlands

[43] In COMPETES-TNO, electricity (and hydrogen) prices are the result of the dynamic optimisation process by the model. These prices correspond to the shadow price definition of how costly it would be to produce an additional marginal unit of the demand for the commodity concerned.

[44] The COMPETES-TNO model does not generate negative electricity prices as it does not include any operational support for power production (in contrast to reality where subsidies to VRE generation may result in negative electricity prices during periods of abundant VRE supply).

In addition, Figure 3.11 shows that the price duration curve in 2050 is generally lower than in 2030/2040. This is confirmed by Table 3.4, which indicates that the average electricity price declines from 70 €/MWh in 2030 to 62 €/MWh in 2040 and even to 46 €/MWh in 2050. This decreasing average price trend is – as already noted above – largely due to the growing role of low-cost VRE power generation over these years, including the lower capital investment costs (CAPEX) of sun PV and the higher efficiency (capacity factor) of offshore wind over time.

Table 3.4: Reference scenario, 2030-2050: Weighted average electricity prices[a]

Unit	2030	2040	2050
€/MWh	70	62	46

a) Hourly electricity prices have been weighted by hourly total domestic electricity demand volumes.

Note that in Figure 3.11 the electricity price is capped at 200 €/MWh. In several hours of each target year, however, the electricity price is substantially higher than 200 €/MWh, as indicated (partially) by Table 3.5. Notably, in a few hours the electricity price amounts to even 10,000 €/MWh, i.e. the value of lost-load (VoLL) assumed exogenously by the COMPETES-TNO model.

Table 3.5: Reference scenario, 2030-2050: Electricity prices (€/MWh) in the 30 highest price-ranked hours

#hour	2030	2040	2050
1	10000	10000	10000
2	10000	8000	10000
3	1500	1500	1500
4	500	500	1500
5	229	500	1500
6	209	500	1500
7	209	500	1435
8	209	500	586
9	209	239	586
10	209	239	586
11	209	239	586
12	209	239	582
13	209	239	551
14	209	226	539
15	209	209	539
16	209	209	539
17	209	209	539
18	209	209	539
19	209	209	539
20	209	209	539
21	208	209	500
22	196	209	500
23	196	209	500

#hour	2030	2040	2050
24	181	209	500
25	181	209	500
26	181	209	500
27	181	198	500
28	181	195	500
29	181	195	500
30	181	195	500
#h(>150 €)[a]	**43**	**273**	**115**

a) Number of hours in which the electricity price is 150 €/MWh or higher.

In addition, in some hours, the electricity price amounts to either 8000, 1500 or 500 €/MWh, i.e. the value or cost assumed for different levels of industrial load shedding over the years 2030-2050 (see Chapter 2, Section 2.1, Table 2.1). Finally, in a restricted number of hours, the electricity price ranges between 150 and 250 €/MWh. In these hours, the electricity price is usually primarily set by either natural gas-fired CCGTs – including high (shadow) CO_2 prices, notably in 2040 (see below) – or CCGT-retrofitted, hydrogen-to-power plants (in 2050).[45]

Hydrogen prices

Table 3.6 presents the average hydrogen price in the Netherlands for the three target years of the reference scenario. It shows that over the period 2030-2050 the average price of hydrogen ranges between 83 and 89 €/MWh (or, equivalently, between 2.8 and 3.1 €/kg-H_2).

Table 3.6: Reference scenario, 2030-2050: Average hydrogen prices

Unit	2030	2040	2050
€/MWh	83	89	85
€/kg-H_2	2.8	3.1	2.9

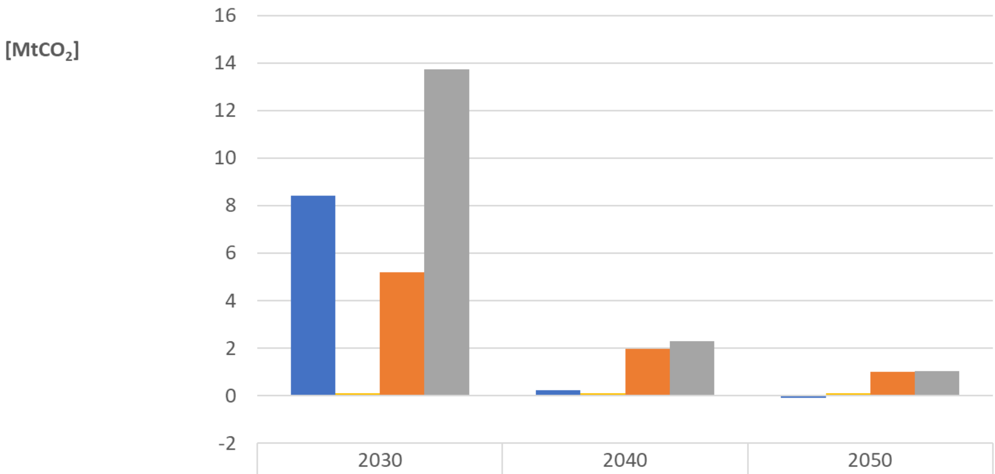
3.7 CO_2 prices and emissions

Table 3.7 presents the CO_2 price of the NL/European P2X system during the three target years of the reference scenario. In 2030, this price is set exogenously into COMPETES-TNO at an assumed level of 101 €/tCO_2 (KEV/PBL, 2022). For 2040 and 2050, however, the (shadow) CO_2 price is determined endogenously by the model, based on the target objective of reaching zero CO_2 emissions in the European P2X system as a whole (see Chapter 2, notably Section 2.3). This results in a shadow price of 253 €/tCO_2 in 2040 and 193 t/CO_2 in 2050.

Figure 3.12 shows the resulting CO_2 emissions by the NL-P2X system over the years 2030-2050, including the distinguished sectors of this system. In 2030, the Dutch power generation sector still emits 8.4 Mt of CO_2 while the other two P2X sectors in the Netherlands – i.e.,

[45] A further explanation of the electricity prices over the years 2030-2050 is beyond the scope of the present study as over these years the determination of the hourly electricity price by a dynamic optimisation model such as COMPETES-TNO becomes far more complicated due to the growing role of flexibility options such as storage, trade and – in particular – different types of demand response (and, hence, requires further, detailed analysis to explain the variation of the electricity price over the year considered).

hydrogen production and industrial heat – account for 0.1 and 5.2 $MtCO_2$ emissions, respectively. The total CO_2 emissions of the NL-P2X system amounts to almost 14 $MtCO_2$ in 2030. By 2040, this total amount of emissions decreases to approximately 2.3 $MtCO_2$, consisting of 0.2 $MtCO_2$ by the power generation sector, 0.1 $MtCO_2$ by the H_2 production sector and 2.0 $MtCO_2$ by the industrial heat sector. In 2050, total CO_2 emissions by the NL-P2X system diminishes even further to about 1 Mt, predominantly by the industrial heat sector, while the Dutch power generation sector even shows negative CO_2 emissions in 2050 (i.e., -0.1 $MtCO_2$).[46]



	2030	2040	2050
Power generation sector	8.4	0.2	-0.1
H2 production sector	0.1	0.1	0.1
Industrial heat sector	5.2	2.0	1.0
Total NL-P2X system	13.7	2.3	1.0

Figure 3.12: Reference scenario, 2030-2050: CO_2 emissions of NL-P2X system

Table 3.7: Reference scenario, 2030-2050: CO_2 prices in the NL/European P2X system

Unit	2030	2040	2050
€/$MtCO_2$	101	253	193

3.8 System costs

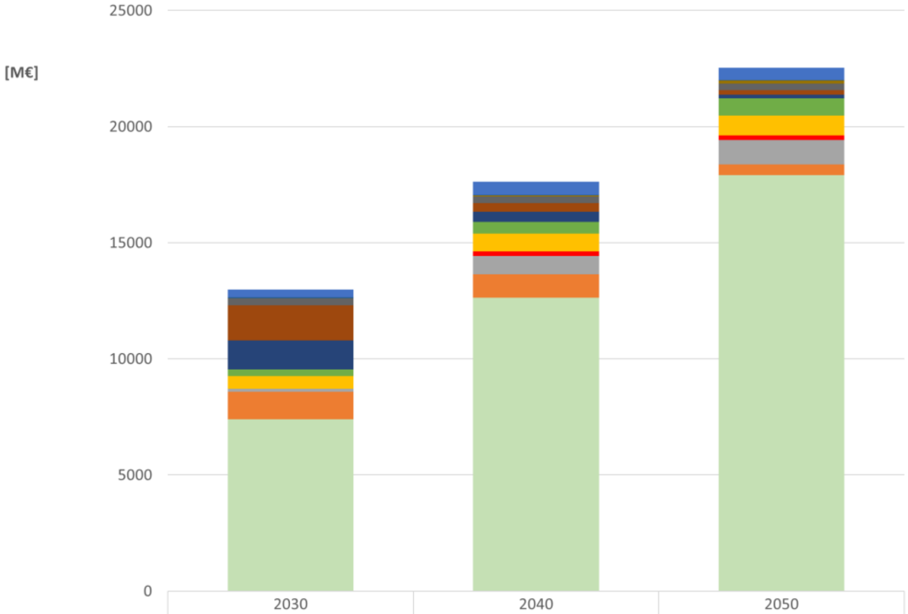
Figure 3.13 presents a breakdown of the NL-P2X system costs in the three target years of the reference scenario. These costs include in particular the investment costs of both dispatchable and VRE power generation capacity, $P2H_2$ capacity, storage capacity as well as the costs of other P2X capacity investments in hybrid industrial boilers, H_2 sector assets and transmission networks (both onshore – including cross-border interconnections – and offshore).[47]

[46] Note that (total) positive CO_2 emissions by the NL-P2X sectors in 2040/2050 are compensated by negative CO_2 emissions elsewhere in the European P2X system (in order to achieve the zero-emission target for this system in these years). Appendix A – notably Figure A.6 – provides data on CO_2 emissions by the P2X sectors in 2030-2050 for all European countries and regions covered by COMPETES-TNO as a whole (indicated as 'EU27+'). This figure shows, among others, that the total CO_2 emissions of the European P2X system as a whole drop from nearly 180 Mt in 2030 to zero in both 2040 and 2050. In these latter years, however, the European industrial heat sector as well as the European H_2 production sector still account for small, but significant amounts of (positive) CO_2 emissions but these are compensated by substantial negative CO_2 emissions of the European power generation sector (for details, see Appendix A, Figure A.6).

[47] Investment (and variable) costs of distribution networks at the regional and local level, however, are not included in the system costs calculated by COMPETES-TNO.

Investment costs refer to the annualised capital costs (CAPEX) of both past and new capacity investments, including both fixed operational and maintenance (O&M) costs of these assets as well as a uniform discount rate of 6.5% for all capital investments considered.

In addition, system costs also include the variable costs of all technologies and (flexibility) services dispatched by the P2X system, the costs of demand curtailment, and the net trading costs of electricity and hydrogen. These trading costs are positive in the case of electricity/hydrogen imports but negative – i.e., actually 'benefits' or 'revenues' – in the case of electricity/hydrogen exports as the domestic costs of generating these exports are already captured by other cost components such as the investment or variable costs of generating electricity/hydrogen exports. So, if the trading cost of electricity/hydrogen are – on balance – negative, they are considered as 'revenues' and, hence, subtracted from total system cost.[48]



	2030	2040	2050
Net trade costs (electricity & H2)	331	576	519
Demand curtailment	50	16	39
Other variable costs	9	48	127
Variable H2 costs	302	290	291
Variable gas-to-heat costs	1503	370	189
Variable dispatchable generation costs	1260	432	151
Variable VRE generation costs	270	500	738
Other investment costs	550	761	852
Investments costs of storage capacity	0	211	211
Investment costs of P2H2 capacity	147	772	1036
Investment costs of dispatchable capacity	1172	1025	475
Investment costs of VRE generation capacity	7399	12624	17906

Notes: Investment costs refer to the annualised capital costs (CAPEX) of both past and new capacity investments, including a uniform discount (interest) rate of 6.5%. Other investment cost includes in particular the annualised capital costs of capacity investments in H_2/energy storage, H_2 Steam Methane Reforming (SMR) installations, H_2 power generation installations, hybrid industrial boilers, and HVDC transmission networks (both onshore – including cross-border interconnections – and offshore). Other variable costs refer notably to the variable costs of storage (dis)charges and storage losses. Net trade costs refer to the costs (or benefits) of net electricity/hydrogen trade.

Figure 3.13: Reference scenario, 2030-2050: Breakdown of the NL-P2X system costs

[48] The (positive) net trade costs of electricity/hydrogen recorded in Figure 3.13 are due to net electricity imports (and no hydrogen trade) in 2030 and to large net hydrogen imports in 2040 and 2050 (which are only partially compensated by the revenues from net electricity exports in these years).

Figure 3.13 shows that the total NL-P2X system costs increase from almost 13 billion euro (b€) in 2030 to about 18 b€ in 2040 and to approximately 23 b€ in 2050. The main cost component over these years is the (annualised capital) investment cost of VRE power generation (including fixed O&M costs) , which increases from 7.4 b€ in 2030 – i.e., about 57% of the total NL-P2X system costs – to approximately 13 b€ in 2040 (72%) and to almost 18 b€ in 2050 (79%). The variable costs of VRE power generation, however, are much lower, increasing from 270 million euro (m€) in 2030 to almost 740 m€ in 2050. On the other hand, the (annualised capital) investment costs of dispatchable generation decreases rapidly over the period considered – i.e., from approximately 1200 m€ in 2030 to 480 m€ in 2050 – while its variable costs decline even faster over these years from 1300 m€ to 150 m€, respectively.

Power generation costs

It has to be noted that, over the years 2030-2050, the rapid increase in total NL-P2X system costs – as presented in Figure 3.13 – is primarily due to a rapid increase in system activities and resulting output – mainly in terms of electricity, industrial heat and hydrogen production – rather than to an increase in the average cost per unit output (on the contrary, as these average costs overall tend to fall over the period considered). This is illustrated by Table 3.8, which provides data on total and average power generation costs in the Netherlands – distinguished by VRE and dispatchable generation costs – for the three target years of the reference scenario.

More specifically, Table 3.8 shows that the total VRE power generation costs increase from about 7.7 b€ in 2030 to almost 19 b€ in 2050. As VRE generation output, however, increases even faster over this period (i.e., from 166 to 412 TWh, respectively), the average VRE generation costs *decrease* slightly from 46 to 45 €/MWh, respectively.

Table 3.8: Reference scenario, 2030-2050: Total and average power generation costs in the Netherlands

	Unit	2030	2040	2050
Total power generation costs[a]				
VRE generation	m€	7668	13124	18644
Dispatchable generation	m€	2431	1457	626
Total generation	*m€*	*10100*	*14581*	*19269*
Power generation output				
VRE generation	TWh	166.3	284.8	412.2
Dispatchable generation	TWh	28.5	10.3	3.6
Total generation	*TWh*	*194.8*	*295.1*	*415.8*
Average power generation costs				
VRE generation	€/MWh	46.1	46.1	45.2
Dispatchable generation	€/MWh	85.3	142.1	172.1
Total generation	€/MWh	51.9	49.4	46.3

a) Total power generation costs include both the (annualised) investments cost and the variable costs of power generation as defined and recorded in Figure 3.13

On the other hand, total dispatchable power generation cost decline from approximately 2.4 b€ in 2030 to 0.6 b€ in 2050. As dispatchable generation output, however, drops much faster over this period (i.e., from 29 to 3.6 TWh, respectively), the average dispatchable generation costs *increase* significantly, i.e. they double from 85 €/MWh in 2030 to more than 170 €/MWh, respectively.

Table 3.8 shows, however, that dispatchable generation represents only a minor – and rapidly declining – share of total power generation output over the period considered, i.e. from 15% in 2030 to less than 1% in 2050. As a result, whereas total power generation costs increase from approximately 10 b€ in 2030 to 19 b€ in 2050 – and the related power generation output from 195 to 416 TWh, respectively – the average costs of total power generation decreases from 52 €/MWh in 2030 to 46 €/MWh in 2050.

4 Sensitivity cases (2050)

In addition to the reference scenario (2030-2050), a variety of sensitivity cases of this scenario has been conducted for 2050 (given the large uncertainties for this long-term target year). In the sections below, we will first provide a brief description of the sensitivity cases conducted (Section 4.1), followed by a presentation of the major results of these cases compared to the results of the reference scenario in 2050.

More specifically, in line with the structure and section headings of Chapter 3 (dealing with the major findings of the reference scenario, 2030-2050), Sections 4.2 up to 4.9 below discuss the related model results of the sensitivity cases for 2050 with regard to the following topics:
1. Electricity demand (Section 4.2);
2. Electricity supply (Section 4.3);
3. Installed power supply mix (Section 4.4);
4. Full load hours of power system technologies (Section 4.5);
5. Flexibility options to meet peak residual load (Section 4.6);
6. Electricity prices (Section 4.7);
7. CO_2 prices and emissions (Section 4.8);
8. System costs (Section 4.9).

4.1 Brief description of sensitivity cases

Based on the reference scenario (2030-2050), the following sensitivity cases of this scenario have been selected and analysed for the year 2050:

i. '*Less Flexible Demand (LFD)*': This case is similar to the reference scenario, excluding (i) the demand-shifting capabilities of EVs and household heat pumps and (ii) any industrial load shedding (ILS), but still including the demand response by P2Heat in industry and P2Hydrogen ('*conversion*') and – in hours of electricity supply shortages – demand curtailment at the value of lost load (VoLL);

ii. '*Power CO_2-free*': In this case, power generation has to be fully CO_2-free – starting from 2035 – while no CCS is allowed in the electricity sector of those European countries that announced in late 2023 to aim at fully decarbonising their power system by 2035 (i.e., Austria, Belgium, France, Germany. Luxembourg, Switzerland and the Netherlands).[49] This implies that, starting from 2035, these countries are not allowed to have any remaining positive CO_2 emissions in their national power system or to compensate these emissions by negative CO_2 emissions elsewhere in the European P2X system (while the other European countries – not part of this announcement – still have this compensation option);

iii. '*Power CO_2-free + LFD*': This case is a combination of the previous two sensitivity cases;

[49] See the announcement of 18-12-2023 by the group of countries aiming to decarbonize their interconnected electricity system by 2035 (GoN, 2023). Recently (September 2025), the Dutch government has relaxed this ambition by putting the aims of security of supply and affordability of electricity above the strive for a fully CO_2-free power system by 2035 (KGG, 2025).

iv. '*Climate Year 1987'*: In this case, the hourly electricity demand and VRE supply profiles of both the Netherlands and all other European countries and regions covered by COMPETES-TNO are based on the profiles of the 'extreme' climate year 1987, including two '*Dunkelflaute'* periods in the Netherlands, rather than on the profiles of the 'normal' climate year 2015 in the reference scenario;

v. '*Climate Year 1996'*: In this case, the hourly electricity demand and VRE supply profiles of both the Netherlands and all other European countries and regions covered by COMPETES-TNO are based on the profiles of the 'extreme' climate year 1996, including a '*Dunkelflaute'* period simultaneously in both Germany and the Netherlands, rather than on the profiles of the 'normal' climate year 2015 in the reference scenario;[50]

vi. *Extra sun PV':* This case is similar to the reference scenario but assumes a halving of the capital investment costs (CAPEX) of sun PV in 2040 and 2050, (compared to the baseline cost assumptions of the reference scenario);

vii. '*Extra nuclear'* : This case is similar to the reference scenario but assumes exogenous investments in two large nuclear power plants in the Netherlands, operational in 2040 (total capacity: 3.2 GW) and two additional large nuclear power plants in 2050 (also 3.2 GW, resulting in 6.4 GW nuclear power capacity operational in 2050);[51]

viii. '*Extra trade:* This case is similar to the reference scenario but assumes 9.8 GW extra interconnection capacity for the Netherlands in 2050, resulting in 22.6 GW interconnection capacity for the Netherlands in 2050 compared to 12.8 GW in the reference scenario (see Table 4.1);

ix. '*No trade':* This case is similar to the reference scenario but no electricity imports or exports by the Netherlands are allowed;

4.2 Electricity demand

Figure 4.1 presents the model results of the reference and sensitivity cases for the demand side of the electricity balance of the Netherlands in 2050. Overall, the differences in the main electricity demand categories between the sensitivity cases and the reference scenario are relatively small (except exports, i.e. foreign demand for electricity).

More specifically, the major differences per electricity demand category in 2050 include:

- *Conventional:* The conventional demand for electricity is fixed in all cases at the reference scenario level of 161 TWh.

[50] See Chapter 5 of this study for a further analysis of the potential impact of Dunkelflaute periods – based on the climate years 1987 and 1996 – on the demand and supply of dispatchable generation (and other flexibility options) in the power system of the Netherlands in 2050.

[51] This study assumes that, after 2033, the lifetime of the Borssele nuclear plant – with an installed capacity of 0.5 GW power generation - is extended by some 10 years up to the mid-2040s. The cost-optimisation run of the reference scenario by the COMPETES-TNO model did not show any new (endogenous) nuclear capacity investments in large-scale nuclear power plants in the Netherlands up to 2050 but only some investments (0.3 GW) in small modular reactors (SMRs) by 2040. The previous Dutch government (Rutte IV, 2022-2024), however, agreed to explore and promote investments in two new, large nuclear plants in the Netherlands. More recently, the current – demissionary - government (Schoof, 2024-present) even agreed to promote investments in *four* large nuclear plants. Therefore, as indicated in the main text above, we have included a separate sensitivity case, called '*Extra Nuclear*', assuming exogenous ('policy-induced') investments in two large nuclear power plants, operational from 2040 onwards, and two additional large plants, starting from 2050.

Table 4.1: Interconnections assumed between the Netherlands and neighbouring countries in the sensitivity case '*Extra trading capacities'* (in GW)

	2020*	2030	2040	2050
Netherlands-Germany	4.3	5.0	7.50	10.00
Netherlands-Belgium	2.4	3.4	5.10	6.80
Netherlands-UK	1.0	1.0	3.00	3.00
Netherlands-Denmark	0.7	0.7	1.05	1.40
Netherlands-Norway	0.7	0.7	1.05	1.40
Total	**9.1**	**10.8**	**17.70**	**22.60**

**Approximated capacity. Source: Adequacy Report (TenneT 2023).*

- *P2Hydrogen:* The demand for electricity to produce (green) hydrogen amounts to 137 TWh in the 2050 reference case and increases slightly in some sensitivity cases up to 145 TWh (+6%) in the case '*Extra Sun PV*'.[52]

- *P2Heat (industry)*: In the reference scenario, the demand for electricity by (hybrid) industrial heat boilers amounts to 55 TWh in 2050, whereas in most sensitivity cases this demand is either slightly lower or higher (54-56 TWh), except in the case '*Climate Year 1987*' where it declines to 48 TWh (-16%).[53]

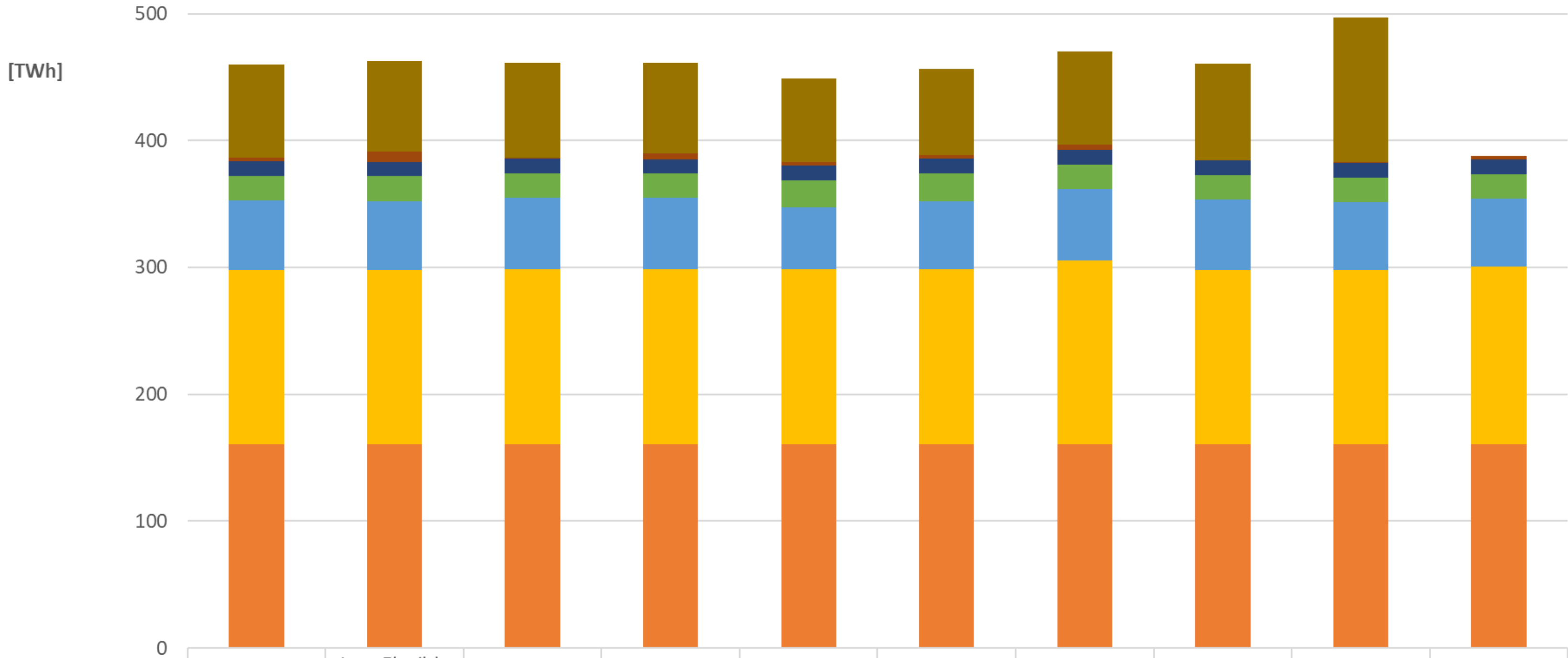
- *P2Heat (households):* The demand for electricity by (all electric/hybrid) heat pumps in households amounts to 19 TWh in the 2050 reference scenario (and most sensitivity cases). It increases only modestly to 22 TWh (+16%) over the year as a whole in two sensitivity cases based on alternative ('extreme') climate years, i.e. 1987 and 1986), including periods of relatively low temperatures (such as '*kaltes Dunkelflautes*') and, hence, relatively high household heating demand (and relatively low heat pump efficiencies).[54]

- *P2Mobility (EVs):* In 2050 the demand for power by, in particular, electric passenger cars amounts to 12 TWh in the reference scenario and most sensitivity cases. In three cases, however, this demand is slightly lower (i.e., by 0.1-0.5 TWh), notably in the '*Less Flexible Demand'* and '*Extra Trade'* cases due to lower flexible storage transactions by EVs – including Vehicle-to Grid (V2G) discharges – and, hence, lower storage losses in these cases.

[52] As outlined in Section 2.4.1, total hydrogen demand is fixed and can be met by domestic production of green/blue hydrogen, foreign imports of hydrogen and/or hydrogen storage, depending on the (varying) costs of these hydrogen sources. So, the domestic demand and supply of green hydrogen ('power-to-hydrogen') can vary depending on, for instance, the cost (price) of electricity versus natural gas (to produce blue hydrogen) compared to the cost of importing or storing hydrogen.

[53] As explained in Section 2.3, the heat sector included in COMPETES-TNO comprises only the (flat, static) heat demand from industrial heat processes that is met through the use of hybrid boilers, i.e. natural gas and/or electric boilers. Industrial heat production through electric boilers ('power-to-heat-i') is activated when electricity prices are lower than the marginal cost of using alternative fuels, in this case, natural gas. So, total industrial heat demand does not change but there are only shifts in heat supply between electric and gas boilers depending on the relative electricity and gas prices.

[54] Note, however, that in certain (extremely) cold hours, the increase of the demand for electricity by all-electric household heat pumps is substantially higher compared to the average increase in household P2Heat demand over the climate years 1987 and 1996 as a whole.



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Exports	74	71	75	71	66	68	74	76	114	0
Storage (charge)	2.6	8.4	0.6	4.5	2.8	2.9	4.2	0.3	0.5	2.7
P2Mobility (EVs)	12	11	12	11	12	12	12	12	11	12
P2Heat (households)	19	19	19	19	22	22	19	19	19	19
P2Heat (industry)	55	54	56	56	48	54	56	56	54	54
P2Hydrogen	137	137	138	137	138	138	145	137	137	140
Conventional	161	161	161	161	161	161	161	161	161	161

Figure 4.1: Reference and sensitivity cases, 2050: The demand side of the electricity balance in the Netherlands

- *Storage (charge)*: Electricity demand by storage charges in 2050 amounts to almost 3 TWh in the reference scenario.[55] In the sensitivity cases, this demand category varies from nearly zero (0.3 TWh) in the case '*Extra Nuclear*' to more than 8 TWh in the case '*Less Flexible Demand*' (where less short-run demand shifting by EVs and household heat pumps is compensated by more short-duration battery storage transactions).

- *Exports:* In the 2050 reference scenario, total annual exports of electricity amount to 74 TWh. In the sensitivity cases, these exports vary significantly from zero in the case '*No trade*' to 114 TWh (+55%) in the case '*Extra Trade*. In most other cases, however, the variation in electricity exports is relatively modest, except for the cases '*Climate Year 1987*' and '*Climate Year 1996*' where electricity exports are a bit lower (66-68 TWh, respectively).

4.3 Electricity supply

Figure 4.2 present the results of the reference and sensitivity cases for the supply side of the electricity balance of the Netherlands in 2050 – including total dispatchable generation – whereas Figure 4.3 provides a further breakdown of the dispatchable generation mix per technology in these cases. Overall, the differences between the reference scenario and some sensitivity cases are quite substantial for some electricity supply categories, notably for (i) electricity from sun PV/offshore wind, (ii) electricity imports, and (iii) electricity from dispatchable generation technologies such as nuclear, biomass retro and hydrogen-to-power.

More specifically, Figure 4.2 shows that the major similarities and differences between the 2050 reference and sensitivity cases per electricity supply category include:

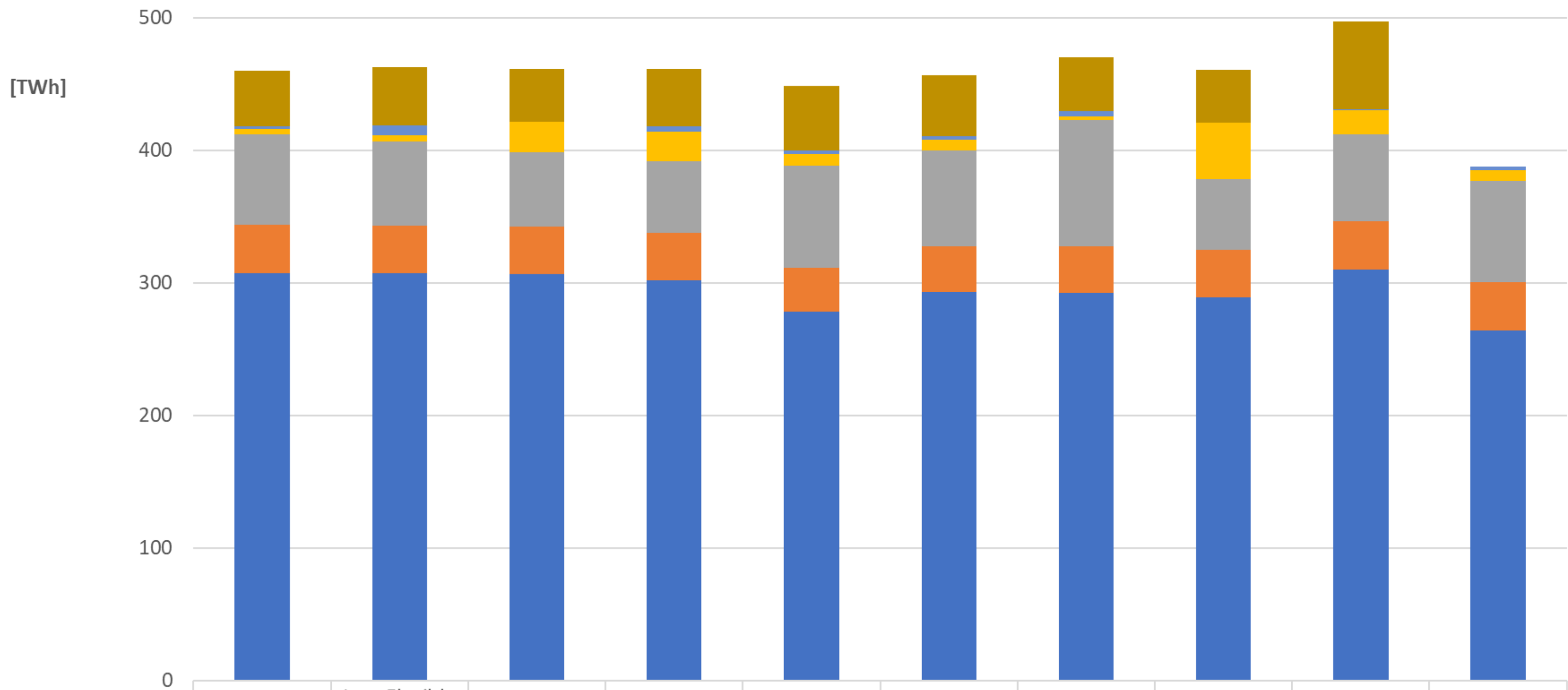
- *Wind offshore:* In the 2050 reference scenario, power generation by offshore wind amounts to 307 TWh, whereas in the sensitivity cases it ranges from 264 TWh (-14%) in the case '*No Trade*' to 310 TWh (+1%) in the case '*Extra Trade*'. This indicates that power production from offshore wind depends – besides domestic demand – significantly on opportunities to export (surpluses of) offshore wind energy.

- *Wind onshore*: In both the 2050 reference scenario and all sensitivity cases, the installed capacity of onshore wind is optimised up to the maximum cap of 12 GW. As a result, with some 3000 full load hours, the power generation by onshore wind amounts to about 36 TWh in almost all cases considered, except in the cases based on more extreme climate years (1987 and 1996) as well as in the case '*Extra sun PV*', where electricity supply from onshore wind is slightly lower (about 33-35 TWh) due to a lower average capacity factor, i.e. less full load hours (in climate years 1987 and 1996), or to more curtailment of onshore wind (in '*Extra sun PV*').

- *Sun PV*: In the reference scenario, power generation by sun PV amounts to almost 69 TWh, whereas it varies from 53 TWh (-22%) in the case '*Extra Nuclear*' to 95 TWh (+39%) in the case '*Extra sun PV*'.

- *Total VRE generation*: In the reference scenario, total VRE generation amounts to 412 TWh, whereas it ranges from 377 TWh (-9%) in the case '*No Trade*' to 423 TWh (+3%) in the case '*Extra Sun PV*'. As a percentage of total power generation, total VRE generation amounts to 99.1% in the reference scenario, whereas it varies from 90% in the case '*Extra nuclear*' to 99.4% in the case '*Extra Sun PV*'.

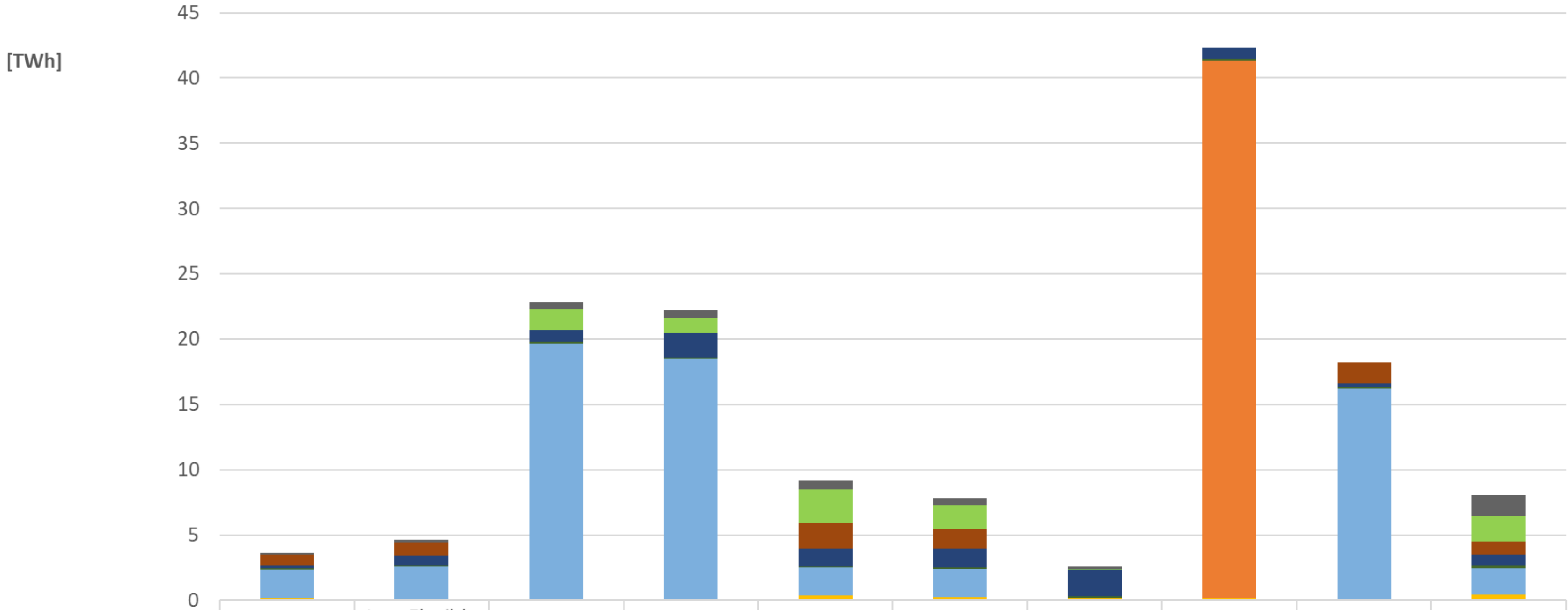
[55] Note that electricity storage demand refers to charges by (Li-ion) batteries only, excluding battery charges by EVs (which are included in electricity demand by P2Mobility).



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Imports	42	43	40	43	49	46	41	40	66	0
Storage (discharge)	2.5	7.8	0.5	4.2	2.6	2.7	3.9	0.3	0.5	2.8
Dispatchable generation	3.6	4.6	22.9	22.2	9.1	7.8	2.6	42.3	18.2	8.1
Sun PV	69	63	56	54	77	73	95	53	66	77
Wind onshore	36	36	36	36	33	34	35	36	36	36
Wind offshore	307	307	307	302	278	293	292	289	310	264

Note: For a breakdown of total dispatchable generation, see Figure 4.3 below.

Figure 4.2: Reference and sensitivity cases, 2050: The supply side of the electricity balance in the Netherlands



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
H2 CCGT (Retro/New)	0.1	0.2	0.5	0.6	0.7	0.5	0.2	0.0	0.0	1.6
Biogas (New)	0.0	0.0	1.6	1.2	2.6	1.8	0.0	0.0	0.0	2.0
Biomass Retro (with CCS)	0.9	1.0	0.0	0.0	1.9	1.5	0.0	0.0	1.6	1.0
Biomass Retro (no CCS)	0.2	0.7	0.9	1.9	1.3	1.4	2.1	0.9	0.3	0.9
Other RES-E	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear (SMR)	2.1	2.5	19.7	18.5	2.2	2.2	0.0	0.0	16.1	2.1
Nuclear (large)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.2	0.0	0.0
Natural gas (CCGT)	0.2	0.1	0.0	0.0	0.3	0.2	0.2	0.2	0.1	0.4

Figure 4.3: Reference and sensitivity cases, 2050: Breakdown of the dispatchable generation output mix

- *Total dispatchable generation*: In the reference scenario, power production from total dispatchable generation – including natural gas, nuclear, biomass, hydrogen and biogas – amounts to 3.6 TWh, whereas it ranges from 2.6 TWh (-29%) in the case '*Extra Sun PV*' to more than 42 TWh (+1060%) in the case '*Extra nuclear*' (notably due to, as expected, the additional dispatchable power generation from nuclear). As a percentage of total power production (including VRE generation), total dispatchable generation amounts to almost 1% in the reference scenario, whereas it varies from 0.6% in the case '*Extra Sun PV*' to 10% in the case '*Extra nuclear*'. Note that in the two '*Power CO_2-free*' cases as well as in the case '*Extra Trade*', total electricity supply from dispatchable generation is substantially higher (18-23 TWh) than in the reference case (3.6 TWh), in particular electricity supply by SMRs (16-20 TWh; see below for a further breakdown and more detailed analysis of dispatchable generation in all cases considered).[56]

- *Storage (discharge)*: Similar to electricity demand by battery storage charges, electricity supply through storage discharges amounts to almost 3 TWh in the 2050 reference case, whereas it varies from nearly zero (0.3 TWh) in the case '*Extra nuclear*' to about 8 TWh in the case '*Less Flexible Demand (LFD)*'. The variation in (battery) storage transactions is mainly due to variations in the total need for flexibility versus the available supply of flexibility by other sources. For instance , in the case '*Extra Nuclear*' storage transactions are relatively low because of both the lower need for flexibility – due to less VRE capacity and, hence, smaller VRE output fluctuations – and the additional supply of flexibility offered by the extra nuclear capacity/output. On the other hand, in the case '*Less Flexible Demand (LFD)*' battery storage transactions in 2050 are relatively high mainly due to less competition from other, short-term flexibility options such as demand shifting by EVs and household heat pumps.

- *Imports*: In the 2050 reference scenario, total annual imports of electricity amount to 42 TWh. In the sensitivity cases, these imports vary substantially from zero in the case '*No trade*' to 66 TWh (+59%) in the case '*Extra Trade*'. In most other sensitivity cases, however, the variation in electricity imports is relatively modest compared to the 2050 reference case.

Breakdown of dispatchable generation mix
As indicated above, Figure 4.3 provides a breakdown of the dispatchable generation mix in the reference and sensitivity cases for the year 2050. The major observations and findings from this figure include:

- *Natural gas (CCGT):* In the reference scenario, electricity output from natural gas-fired CCGTs amounts to 0.2 TWh in 2050. In the two sensitivity cases '*Power CO_2-free*' and '*Power CO_2-free + Less Flexible Demand (LFD)*', this technology is not allowed and, hence, its output is, by definition, zero. In the other sensitivity cases, however, power generation from natural gas-fired CCGTs varies slightly from 0.1 TWh in the cases '*Less Flexible Demand (LFD)*' and '*Extra Trade*' to 0.4 TWh in the case '*No Trade*'.

- *Nuclear (large):* In the reference scenario and almost all (8 out of 9) sensitivity cases there are neither endogenous ('new') capacity investments in large-scale nuclear power generation in 2050 nor ('old') installed, operational capacities of this technology from

[56] In addition, note that also in the two cases with extreme weather conditions, including one or two Dunkelflaute periods – i.e., '*Climate Year 1987*' and '*Climate Year 1996*' – total electricity supply by dispatchable generation is significantly higher (8-9 TWh) than in the 2050 reference case (3.6 TWh). For a further, detailed analysis of these two extreme weather years in general and the respective Dunkelflaute periods in particular, see Chapter 5 of the current study.

previous decades. As a result, electricity supply from large-scale nuclear is zero in all these 2050 cases. Only in one case (i.e., '*Extra Nuclear*'), however, new investments in large-scale nuclear capacity are assumed exogenously, totalling 6.4 GW in 2050 in 2050 and resulting in about 41 TWh electricity output in that year.

- *Nuclear (SMRs):* In contrast to large-scale nuclear considered above, the cost-optimization runs by COMPETES-TNO show some endogenous capacity investments in small-scale nuclear (i.e., SMRs). In the reference scenario, these investments amount to 0.3 GW in 2040, while in some sensitivity cases – notably '*Extra Trade*' and the two '*Power CO_2-free*' cases – this capacity is expanded to approximately 2-3 GW in 2050 (for further details, see Section 4.4, notably Figure 4.5). On the other hand, in two sensitivity cases – i.e., '*Extra Sun PV*' and '*Extra Nuclear*' – there are no endogenous capacity investments in SMRs in either 2040 or 2050 (because there is already a large additional capacity of sun PV and large-scale nuclear, respectively, in these two cases in both years considered). As a result, electricity supply from SMRs amount to 2.1 TWh in the reference case for 2050, whereas it varies from zero in the cases '*Extra Sun PV*' and '*Extra Nuclear*' to 19-20 TWh in the two '*Power CO_2-free*' cases.

- *Biomass retro*: Power generation from coal-to-biomass retrofitted plants (both with and without CCS) amounts to about 1.1 TWh in the reference scenario, whereas in the sensitivity cases it varies between 0.9 TWh in the case '*Extra Nuclear*' and 3.3 TWh in the case '*Climate Year 1987*'.

- *Biogas*: Power generation production from new investments in biogas-fired installations is (close to) zero in the 2050 reference case as well as in four (out of nine) sensitivity cases for that year. In the other five sensitivity cases, however, output from this technology ranges from 1.2 TWh in the case '*Power CO_2-free + Less Flexible Demand (LFD)*' to 2.6 TWh in the case '*Climate Year 1987*'.

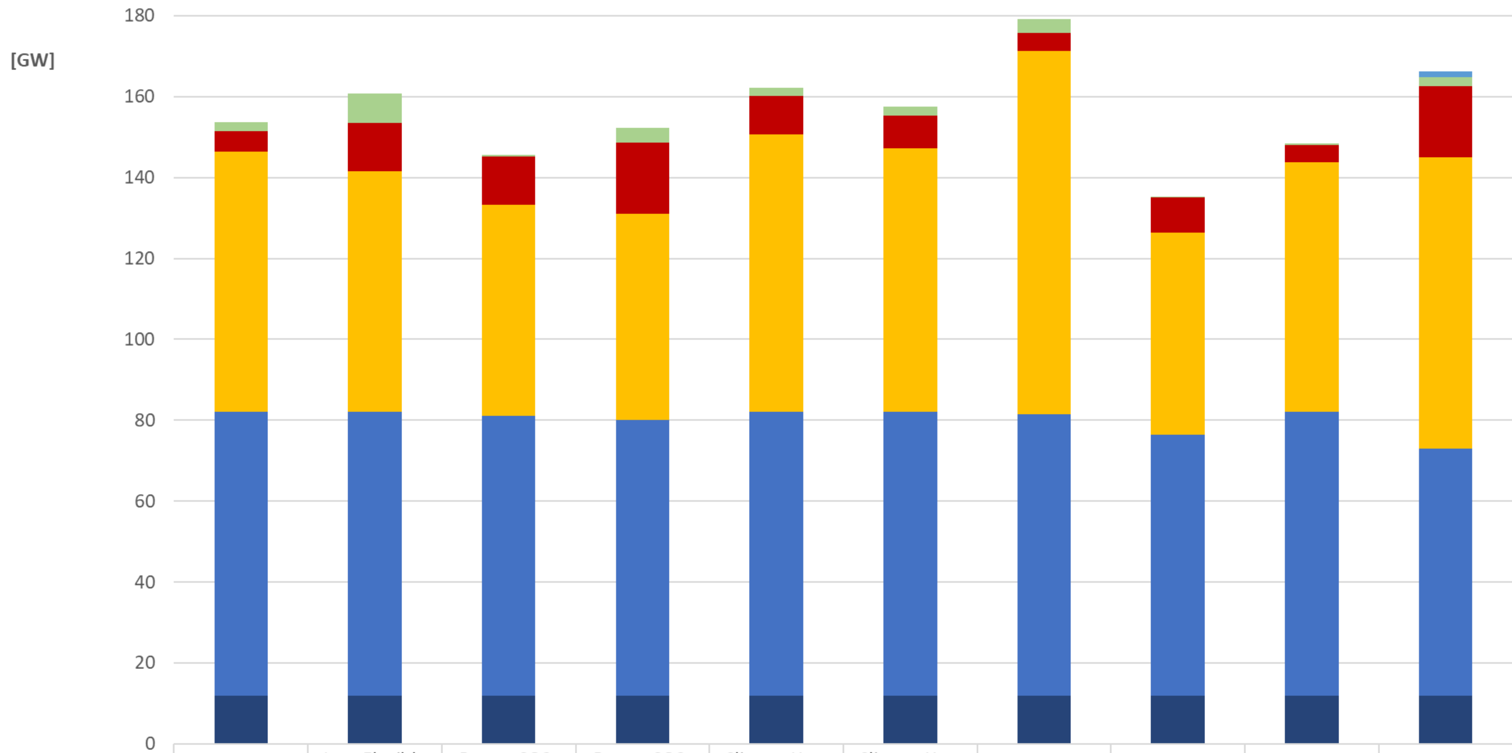
- *H_2 CCGT*: In 2050, electricity generation from CCGT hydrogen-to-power plants (retro/new) amounts to only 0.1 TWh in the reference scenario, whereas in the sensitivity cases it varies from zero in the cases '*Extra Nuclear*' and '*Extra Trade*' to 1.6 TWh in the case '*No Trade*' (where CCGT H_2 plants partially replace the flexibility from trading electricity). This implies that in all 2050 cases considered, power production from hydrogen – as a percentage of total electricity output – amounts to 0.4% or less. Note, however, that during some critical load hours of the years the installed (back-up) capacity output of H_2 CCGTs is far more important to meet the peak residual demand (see Sections 4.4 and 4.6 below).

4.4 Installed power capacity

Figure 4.4 shows the installed domestic power supply capacity mix in both the 2050 reference case and the sensitivity cases per major supply category – including total dispatchable generation – whereas Figure 4.5 provides a further breakdown of the installed dispatchable generation mix per technology in these cases.

Similar to the changes in electricity supply discussed in the previous section, the differences in installed power capacity between the 2050 reference case and some sensitivity cases are occasionally quite substantial, in particular for (i) sun PV/offshore wind , and (ii) dispatchable generation technologies such as nuclear, biomass retro and hydrogen-to-power.

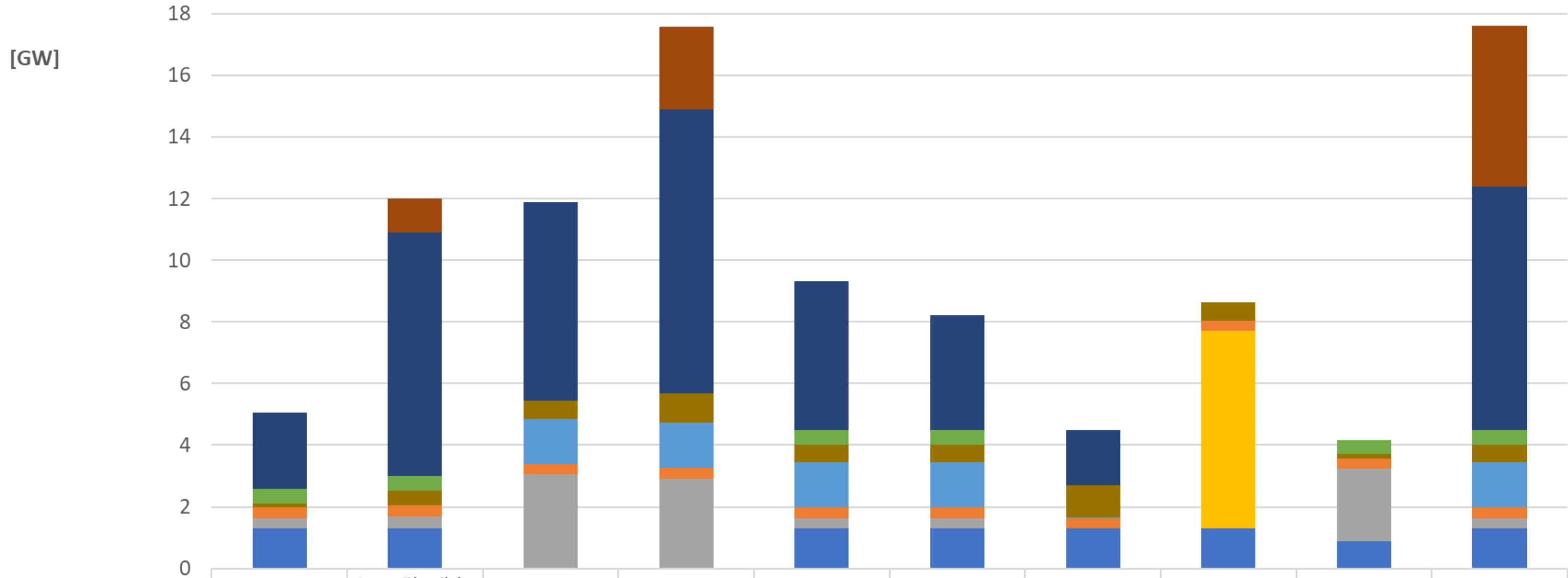
More specifically, Figure 4.4 indicates that the major similarities and differences per category ('technology') of installed domestic power supply capacity include:



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Storage: Diabatic CAES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Storage: Li-ion batteries	2.2	7.3	0.5	3.6	2.2	2.2	3.5	0.3	0.4	2.2
Dispatchable generation	5.1	12.0	11.9	17.6	9.3	8.2	4.5	8.6	4.2	17.6
Sun PV	64.5	59.5	52.3	51.0	68.7	65.1	89.7	50.0	61.8	71.9
Wind offshore	70.0	70.0	69.0	68.1	70.0	70.0	69.5	64.4	70.0	61.0
Wind onshore	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Note: For a breakdown of the total dispatchable generation capacity, see Figure 4.5 below.

Figure 4.4: Reference and sensitivity cases, 2050: Installed power supply mix



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
H2 CCGT (New)	0.0	1.1	0.0	2.7	0.0	0.0	0.0	0.0	0.0	5.2
H2 CCGT (Retro)	2.5	7.9	6.4	9.2	4.8	3.7	1.8	0.0	0.0	7.9
Biomass Retro (with CCS)	0.5	0.5	0.0	0.0	0.5	0.5	0.0	0.0	0.5	0.5
Biomass Retro (no CCS)	0.1	0.5	0.6	1.0	0.6	0.6	1.1	0.6	0.1	0.6
Biogas (New)	0.0	0.0	1.5	1.5	1.5	1.5	0.0	0.0	0.0	1.5
Other RES-E	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Nuclear (SMR)	0.3	0.4	3.1	2.9	0.3	0.3	0.0	0.0	2.4	0.3
Nuclear (large)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	0.0
Gas CCGT	1.3	1.3	0.0	0.0	1.3	1.3	1.3	1.3	0.9	1.3

Figure 4.5: Reference and sensitivity cases, 2050: Breakdown of installed dispatchable power generation capacity

- *Wind offshore:* In the reference scenario, the installed capacity of offshore wind in 2050 is optimised but capped by the model at the maximum assumed potential of 70 GW by that year. Similarly, in four out of nine sensitivity cases, offshore wind capacity is also capped at 70 GW. In the other five cases, however, the installed capacity of offshore wind in 2050 is optimised below the maximum cap, notably in the cases '*Extra Nuclear'* (64 GW) and '*No Trade'* (61 GW), albeit for different reasons. In the case '*Extra Nuclear'*, less offshore wind is needed because of the substantial additional electricity output from nuclear energy, whereas in the case '*No Trade'* offshore wind is less attractive ('profitable') because of the lower opportunities to export surpluses of offshore wind at affordable prices.

- *Wind onshore:* In both the reference scenario and all sensitivity cases, the installed capacity of onshore wind in 2050 is optimised but capped at 12 GW (which is set exogenously into the COMPETES-TNO model).

- *Sun PV:* In the reference scenario, the installed capacity of sun PV in 2050 amounts to almost 65 GW, whereas it ranges from about 50 GW (-22%) in the case '*Extra Nuclear*' to almost 90 GW (+39%) in the case '*Extra sun PV'*.

- *Total VRE generation:* In the reference scenario, the installed capacity of total VRE generation (including both sun and wind) amounts to 147 GW in 2050, whereas it ranges from 126 GW (-14%) in the case '*Extra Nuclear*' to 171 GW (+37%) in the case '*Extra Sun PV'*. In all cases, the installed capacity of total VRE generation (even of total wind alone) is more than enough to meet (hourly) peak demand in 2050, implying that over a large number of hours in 2050 there will be a (large) surplus of VRE power generation.

- *Total dispatchable generation:* In the 2050 reference case, the total need for dispatchable generation amounts to 5.1 GW, whereas in the sensitivity cases it ranges from 4.2 GW (-18%) in the case '*Extra Trade'* to 17.6 GW (+247%) in the cases '*No Trade' and 'Power CO_2-free + Less Flexible Demand (LFD)*'. In addition, note that (see also the discussion below on the breakdown of the total dispatchable generation capacity mix):

  - In both the case '*Less Flexible Demand (LFD)*' and '*Power CO_2-free'*, the need for dispatchable generation capacity in 2050 is almost 7 GW (+137%) higher than in the reference case, whereas in the combination of these two sensitivity cases – i.e., '*Power CO_2-free + LFD'* – this need is, as indicated above, even 12.5 GW (+247%) higher. In the case '*Less Flexible Demand'*, the higher need for dispatchable generation (about 6-7 GW) is due to the (assumed) lower availability of demand response by EVs and household heat pumps as well as the absence (non-availability) of industrial load shedding (IDS). In the case '*Power CO_2-free'*, the higher demand for dispatchable generation (also approximately 6-7 GW) is primarily due to the outcomes of this case in 2040. More specifically, in this latter case, natural-gas fired installations (and CCS) are not allowed, implying that the natural gas capacity in the 2040 reference case (8.2 GW) is replaced by additional capacities of H_2 CCGT (retro), nuclear (SMRs) and biogas (new). In the 2050 reference case, however, 6.9 GW of natural gas-fired capacity is decommissioned, whereas in the 2050 sensitivity case '*Power CO_2-free*' the (additional) capacities of H_2 CCGT, SMRs and biogas required in 2040 remain installed in 2050;

  - In both the two sensitivity cases with more extreme weather conditions – including one or even two Dunkelflaute periods – the need for dispatchable generation capacity in 2050 is significantly higher than in the reference case (although in an absolute sense still 'relatively modest'), i.e. 8.2 GW (+62%) in the case '*Climate Year 1996*' and 9.3 GW (+84%) in the case *'Climate Year 1987'*;

- In the case '*Extra Sun PV*', the total need for dispatchable generation capacity is only slightly lower than in the 2050 reference case, i.e. 4.5 GW (-12%), whereas in the case '*Extra Nuclear'* this need – including the extra, large nuclear plant – is significantly higher, i.e. 8.6 GW (+71%; see also the discussion below on the breakdown of the total dispatchable generation capacity mix);

- In the case '*Extra Trade',* the total need for dispatchable generation capacity in 2050 is only slightly lower, i.e. 4.2 GW (compared to 5 GW in the reference case), whereas in the case '*No Trade'*, this need is substantially higher, i.e. 17.6 GW. This implies that if the total interconnection capacity of the Netherlands is assumed to be expanded substantially in 2050 – i.e., by almost 10 GW in the case '*Extra Trade*' – the need for dispatchable generation capacity is reduced by less than 1 GW (most likely because during some critical peak residual load hours the total, expanded import capacity from neighbouring countries is actually not available and, hence, this load has to be met by other flexibility options, including dispatchable generation). On the other hand, if the total interconnection capacity of the Netherlands is assumed to be zero ('*No Trade*'), the loss of this trade capacity (-12.8 GW) is almost fully compensated by a similar increase in dispatchable generation (+12.5 GW). These findings indicate that up to a certain level (approximately 12-13 GW), trade (import) seems to be a rather reliable flexibility option – even during peak residual load hours – but beyond this level it looks like becoming far less reliable.

- *Storage: Li-ion batteries:* In the 2050 reference case, the need for Li-ion battery storage amounts to 2.2 GW, whereas in the sensitivity cases it ranges from 0.5 GW – or less – in the cases *'Power CO_2-free'*, *'Extra Trade'* and *'Extra Nuclear'* to approximately 7.3 GW in the case *'Less Flexible Demand (LFD)'*.

- *Storage: Diabetic CAES*: Apart from Li-ion batteries, there is no need for any additional (*energy*) storage capacity in the reference and sensitivity cases 2050, except in the case *'No Trade'*, where the optimisation runs by COMPETES-TNO result in an endogenous capacity need of 1.3 GW in 2050 for diabatic compressed air energy storage (CAES).

Breakdown of dispatchable generation capacity
As mentioned, Figure 4.5 provides a further breakdown of the need for dispatchable generation capacity in the reference and sensitivity cases for 2050. In brief, the major observations and findings from this figure include:

- *Gas CCGT:* In the 2050 reference case, as well as in six out of nine sensitivity cases, the optimised capacity of natural gas-fired CCGT plans amounts to 1.3 GW. Only in the case '*Extra Trade'*, this capacity is slightly lower (0.9 GW), whereas in the two '*Power CO_2-free*' cases it is – by definition zero. As far as the actual dispatch of these natural gas-fired plants results in any CO_2 emissions (in 2040/2050) it is compensated by negative emissions in the Dutch power generation system – notably by biomass + CSS – and/or in the other sub-sectors of the European P2X system (see also Section 4.8 below).

- *Nuclear (large):* According to the COMPETES-TNO model runs, the endogenous (cost-optimal) capacity of large nuclear plants in the Netherlands amounts to zero in both the reference and all sensitivity cases for 2050. Only in the case '*Extra Nuclear'* 6.4 GW of large nuclear capacity has been assumed exogenously by the model (mainly to assess the impact of this ‘policy-intended’ capacity on the Dutch power system in general and the need for dispatchable generation in particular).

- *Nuclear (SMR):* In contrast to the large nuclear plants discussed above, COMPETES-TNO identified some endogenous (cost-optimal) capacity investments in small modular reactors (SMRs) in the reference scenario, amounting to 0.3 GW in 2040 (and continued to be operational in 2050). In three sensitivity cases (‘*No Trade*’, ‘*Climate Year 1987*’ and ‘*Climate Year 1996*’), the optimal SMR capacity in 2050 amounts also 0.3 GW. In some other cases, however, this capacity is significantly higher, notably in *‘Extra Trade’* (2.4 GW) and in the two ‘*Power CO_2-free*’ cases (about 3 GW). On the other hand, in two cases – i.e., *‘Extra Sun PV’* and *‘Extra Nuclear’* (large) – the optimal SMR capacity is zero (in both 2040 and 2050), notably because of the (assumed) extra capacity of sun PV and large nuclear, respectively, there is no additional, cost-optimal need for SMR capacity is these years.

- *Other RES-E:* In both the 2050 reference and all sensitivity cases, the capacity of ‘Other RES-E’ (largely waste standalone) amounts to 0.3 GW (resulting from exogenously assumed investments in previous years).

- *Biogas:* The installed capacity of *retrofitted* biogas plants amounts to zero in the 2050 reference case and all sensitivity cases. Similarly, the installed capacity of *new* biogas plants is also zero in the 2050 reference case as well as in four (out of nine) sensitivity cases. In five sensitivity cases, however, the optimal capacity of new biogas-fired power plants is 1.5 GW. The reason why in these latter cases there are investments in new biogas plants rather than in retrofitted biogas plants is that the CAPEX of biogas-retro in 2050 is slightly higher than the CAPEX of a new biogas plant (750 vs 675 €/kW). In addition, the efficiency of a retrofitted biogas plant is a bit lower than a new installation (which affects the variable costs of these units in favour of the new biogas plant).[57]

- *Biomass Retro (no CCS):* In the 2050 reference case, the optimal capacity of coal-to-biomass retrofitted power plants *without* CCS is only 0.1 GW. In most sensitivity cases, however, this capacity need is slightly higher, running up to 1.1 GW in the case ‘*Extra Sun PV*’.

- *Biomass Retro (with CCS):* In the 2050 reference case, as well as in five (out of nine) sensitivity cases, the optimal capacity of coal-to-biomass retrofitted plants *with* CCS amounts to 0.5 GW. In the other our sensitivity cases, however, this capacity is zero.

- *H_2 CCGT (Retro)*: In the 2050 reference case, the endogenous capacity of (natural) gas-to-hydrogen retrofitted CCGT plants amounts to 2.5 GW (i.e., almost half of the total dispatchable generation in this reference case). Although in three sensitivity cases this (H_2 CCGT Retro) capacity is significantly lower – or even zero – it is substantially higher in the other six sensitivity cases, notably in the two ‘*Less Flexible Demand*’ cases (8-9 GW) as well as in the case ‘*No Trade*’ (7.9 GW).

- *Hydrogen CCGT (new):* besides retrofitted CCGT-H_2 power plants, there is a need for *new* CCGT H_2-fuelled generation capacity in 2050 in three sensitivity cases, i.e. ‘*Less Flexible Demand*’ (1.1 GW), ‘*Power CO_2-free + LFD*’ (2.7 GW) and, in particular, ‘*No Trade*’ (5.2 GW). The main reasons for the new H_2 CCGT need – besides the already high demand for H_2 CCGT retro – are (i) the lower supply of flexibility by demand response (in the two LFD cases) or

[57] Another reason that might affect the potential capacity of retrofitted biogas plants is the competition with retrofitted H_2 turbines as both power generation technologies compete for the same retrofit potential.

trade (in '*No Trade*'), (ii) the resulting higher need for flexibility by other sources, including dispatchable generation (and storage), and (iii) the fuel-availability/capacity-potential constraints of other, competing dispatchable generation technologies, notably biogas, biomass and H_2 CCGT retrofitted power plants.

4.5 Full load hours of generation technologies

Figure 4.6 presents an overview of the full load hours (FLHs) of the major power generation technologies in both the 2050 reference and sensitivity cases.[58] In brief, the major observations and findings of this figure include:

- *Wind offshore:* The maximum full load hours (FLHs) of offshore wind in 2050 – i.e., without any curtailment – is assumed to amount approximately 4735 hours (see Chapter 2, notably Section 2.4.3). Figure 4.6, however, shows that in the 2050 reference case as well as in seven sensitivity cases – all based on the reference ('normal') climate year 2015 – the actual FLHs of offshore wind are often a bit lower, ranging from about 4200 hours in the case '*Extra Sun PV*' to almost 4500 hours in the case '*Extra Nuclear*'. These lower actual FLHs are due to the curtailment of offshore wind in the cases concerned.[59] In addition, in the sensitivity cases based on the 'extreme' climate years 1987 and 1996 – including one or even two Dunkelflaute periods – the actual FLHs of offshore wind are even slightly lower, i.e. less than 4000 and 4200 hours, respectively.[60]

- *Wind onshore*: In both the 2050 reference case and the seven sensitivity cases based on the reference climate year 2015, the maximum FLHs of onshore wind – i.e., without any curtailment – are assumed to some 3000 hours (Section 2.4.3). Figure 4.6 shows that in both the reference case and five (out of seven) sensitivity cases, the actual FLHs of onshore wind indeed amount to 3000 hours. In two cases, however, the actual FLHs of onshore wind are slightly lower – i.e., in '*Extra Sun PV*' (2946 hours) and in '*Extra Trade*' (2996) hours, indicating at some curtailment of onshore wind. In addition, in the sensitivity cases based on the climate years 1987 and 1996, the (actual) FLHs of onshore wind are significantly lower, i.e., 2756 and 2825 hours, respectively.[61]

- *Sun PV:* In both the 2050 reference case and the seven sensitivity cases based on the reference climate year 2015, the maximum FLHs of sun PV – i.e., without any curtailment – are assumed to about 1067 hours (Section 2.4.3). Figure 4.6 illustrates that in both the reference case and six (out of seven) sensitivity cases, the actual FLHs of sun PV indeed amount to 1067 hours. In one case, however, the actual FLHs of sun PV are a bit lower – i.e., in the case '*Extra Sun PV*' the FLHs of sun PV amount to 1062 hours, indicating at a curtailment of sun PV of approximately 0.5% in this case. In addition, in the sensitivity cases based on the climate years 1987 and 1996, the (actual) FLHs of sun PV are slightly higher (about 1120 hours).[62]

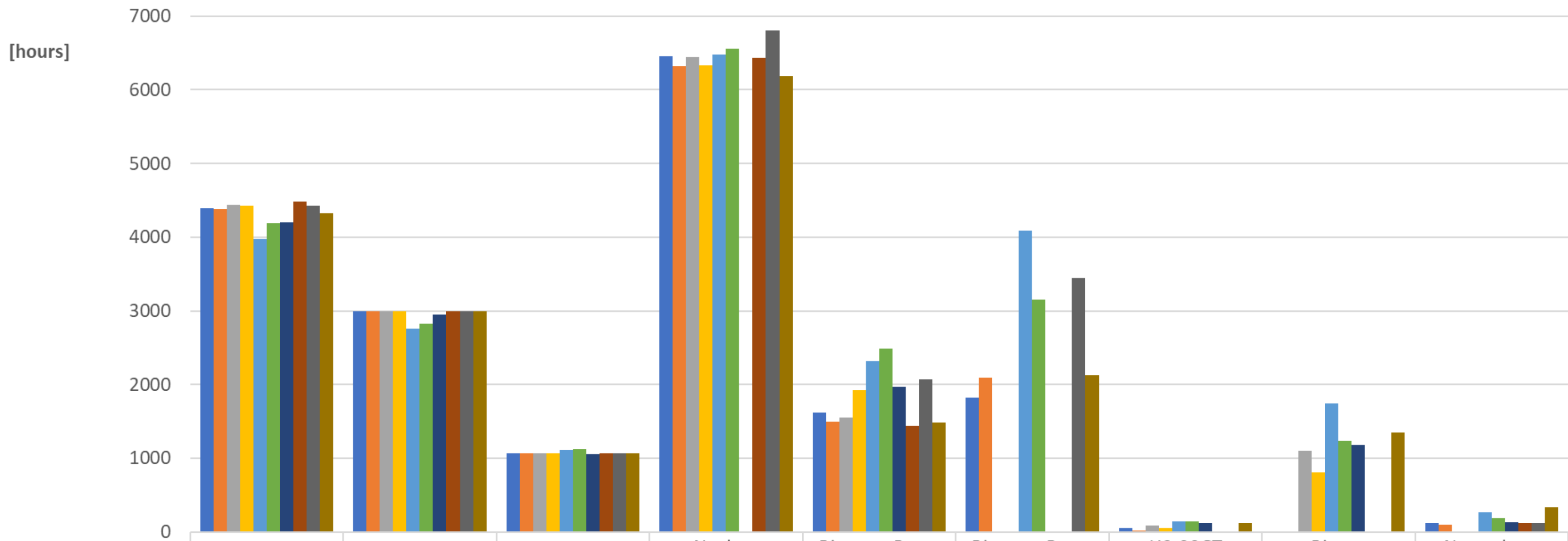
58 To some extent, the number of FLHs of a generation technology is an indicator of the business case and risk profile of that technology, in particular of the number of hours in which the capital investment costs can or should be recovered.

59 For instance, in the case '*Extra Sun PV*', the actual FLHs of offshore wind amounts to 4204 hours – compared to a maximum of 4735 FLHs in 2050 – indicating to a curtailment of offshore wind of approximately 11% in this case.

60 The maximum FLHs of offshore wind – i.e., without any curtailment – in 2050, based on the extreme climate years 1987 and 1996, amount to 4405 and 4573, respectively, whereas the actual FLHs amount to 3972 and 4190 hours, respectively, indicating at a curtailment of offshore wind of 10% and 8%, respectively.

61 Since there is no curtailment of onshore wind in the cases '*Climate Year 1987*' and '*Climate Year 1996*' the actual FLHs of onshore wind recorded in Figure 4.6 are similar to the maximum FLHs of onshore wind.

62 Since there is no curtailment of sun PV in the cases '*Climate Year 1987*' and '*Climate Year 1996*' the actual FLHs of sun PV recorded in Figure 4.6 are similar to the maximum FLHs of sun PV .



	Wind offshore	Wind onshore	Sun PV	Nuclear (large/SMR)	Biomass Retro (no CCS)	Biomass Retro (with CCS)	H2 CCGT (Retro/New)	Biogas (New)	Natural gas (CCGT)
Reference	4392	3000	1067	6451	1618	1828	51		122
Less Flexible Demand (LFD)	4386	3000	1067	6316	1491	2098	23		94
Power CO2-free	4443	3000	1067	6441	1558		85	1096	
Power CO2-free + LFD	4427	3000	1067	6332	1920		50	807	
Climate Year 1987	3972	2756	1118	6479	2316	4088	140	1747	263
Climate Year 1996	4190	2825	1119	6554	2486	3148	142	1241	189
Extra Sun PV	4204	2946	1062		1968		115	1184	128
Extra Nuclear	4488	3000	1067	6435	1435				115
Extra Trade	4430	2996	1067	6806	2073	3443			125
No Trade	4328	3000	1067	6190	1485	2132	119	1354	335

Figure 4.6: Reference and sensitivity cases, 2050: Full load hours (FLHs) of power generation technologies

- *Nuclear (total):* Figure 4.6 shows that in the 2050 reference case, the FLHs of nuclear power plants – including both large nuclear and SMRs – amount to about 6450 hours, whereas in the sensitivity cases this number ranges from almost 6200 hours (-4%) in the case '*No Trade'* to more than 6800 hours (+6%) in the case '*Extra Trade'*. [63]

- *Biomass Retro (no CCS)*: In the 2050 reference case, the FLHs of coal-retrofitted biomass plants without CCS amount to about 1620 hours, whereas in the sensitivity cases this number ranges from almost 1440 hour (-11%) in the case '*Extra Nuclear'* to nearly 2500 (+54%) hours in the case '*Climate Year 1996'*.

- *Biomass Retro (with CCS)*: In the 2050 reference case, the FLHs of coal-retrofitted biomass plants with CCS amount to about 1830 hours, whereas in the sensitivity cases this number ranges from almost 2100 hour (+15%) in the case '*Less Flexible Demand'* to more than 4000 (+120%) hours in the case '*Climate Year 1987'*.

- *H_2 CCGT (retro/new):* In the 2050 reference case, the FLHs of H_2-fired CCGTs – including retrofitted/new plants – amount to approximately 51 hours, whereas in the sensitivity cases this number varies from only 23 hours (-56%) in the case '*Less Flexible Demand*' to 142 hours (+180%) in the case '*Climate Year 1996'*.[64]

- *Biogas New*: In the 2050 reference case, no (new) biogas-fired plants are installed. In six out of nine sensitivity cases, however, we notice capacity investments in new biogas-fired installations (see Figure 4.5). Figure 4.6 shows that the FLHs of these installations ranges from about 800 in the case '*Power CO_2-free + Less Flexible Demand'* to almost 1750 hours in the case '*Climate Year 1987'*.

- *Gas CCGT*: Finally, in the 2050 reference case, the FLHs of natural gas-fired CCGTs amount to 122 hours, whereas in the sensitivity cases this number varies from 94 hours (-23%) in the case '*Less Flexible Demand'* to almost 340 hours (+174%) in the case '*No Trade'*.

4.6 Flexibility options to meet peak residual load

In line with Section 3.5 in the previous chapter, the current section (4.6) provides an explanation for the required amount of dispatchable generation in the 2050 reference and sensitivity cases by analysing the peak residual load in these cases as well as the flexibility options - including, among others, dispatchable generation – to meet this residual load (RL).

Both the 2050 reference case as well as seven (out of nine) sensitivity cases are based on the assumption of a '*High Flexible Demand (HFD)*' potential (see Section 3.5). Two sensitivity cases, however, assume a lower potential of demand response, indicated as '*Less Flexible Demand (LFD)'*. More specifically, as outlined in Section 4.1, compared to the HFD cases, the two LFD sensitivity cases exclude (i) the demand-shifting capabilities of EVs and household heat pumps and (ii) any industrial load shedding (ILS), but still include (iii) the demand response by P2Heat in industry and P2Hydrogen ('*conversion*') and – in hours of electricity supply shortages – (iv) demand curtailment at the value of lost load (VoLL).

[63] Note that in Figure 4.6, the case '*Extra Nuclear'* refers to large nuclear only, whereas in the other cases recorded in Figure 4.6 the FLHs presented refer to SMRs only (see also Figure 4.3 and Figure 4.5).

[64] Note that in Figure 4.6, the FLHs of H_2 CCGT (total) refers to 'H_2 CCGT Retro' only in almost all cases recorded, except in the cases "*Less Flexible Demand (LFD)*', '*Power CO_2-free + LFD'* and '*No Trade'*, where it includes both 'H_2 CCGT Retro' and 'H_2 CCGT New' (see also Figure 4.5).

Figure 4.7 presents the duration curve of the hourly residual load for two different flexible demand cases in 2050: (i) '*High Flexible Demand (HFD)*', and (ii) '*Less Flexible Demand (LFD)*'. It shows that, due to the difference in flexible demand, the duration curve of the '*High Flexible Demand'* case is slightly flatter than the duration curve of the '*Less Flexible Demand'* case. More specifically, at the full left of the duration curve, the highest hourly RL ('peak') in 2050 amounts to about 24 GW in the HFD case versus approximately 32 GW in the LFD case, indicating that – due to the difference in flexible demand – the peak RL in the LFD case is about 8 GW higher than in the HFD case.

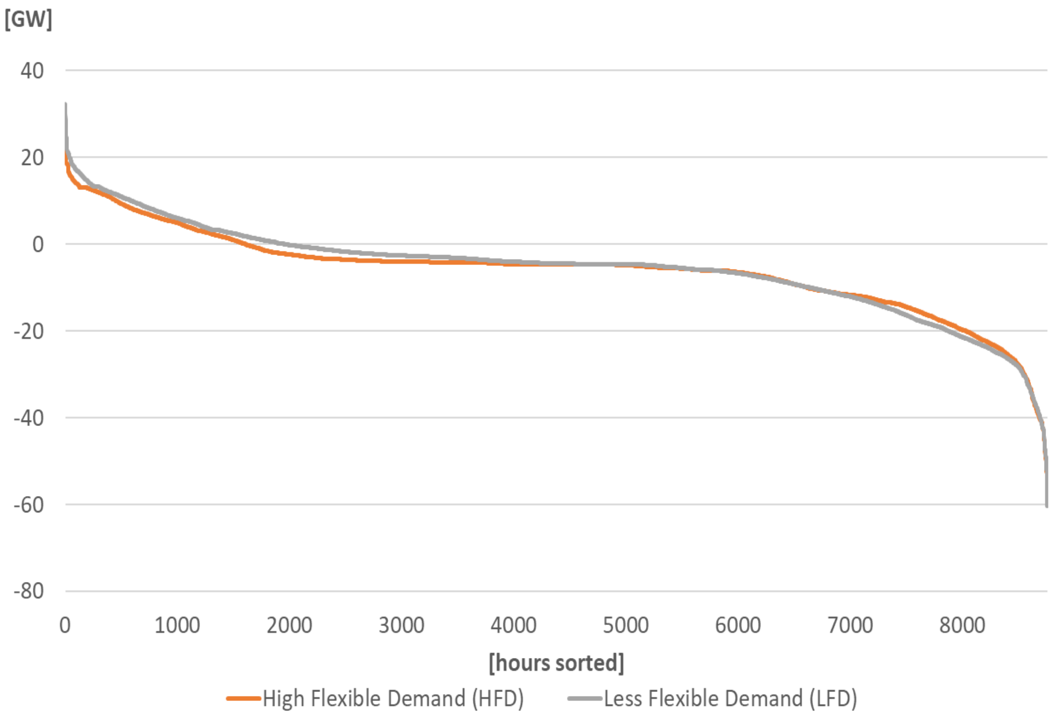


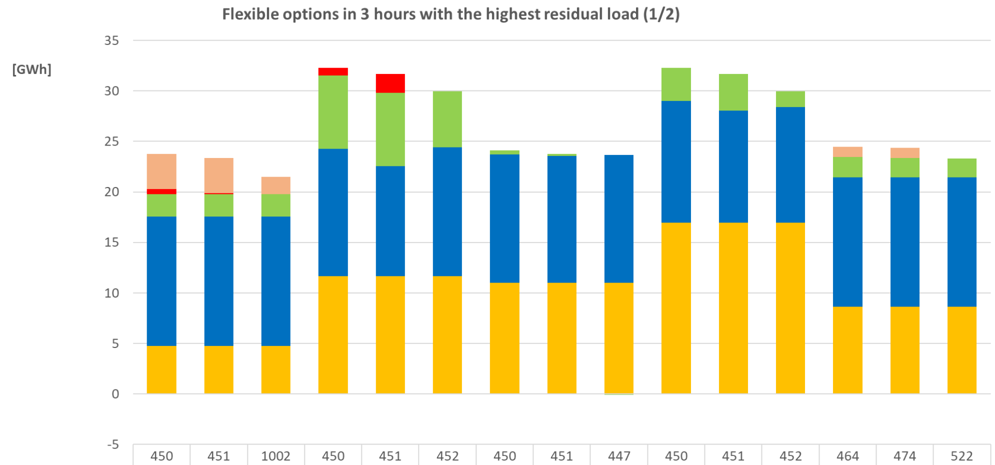
Figure 4.7: Reference and sensitivity cases, 2050: Duration curves of the hourly residual load in two different cases, i.e., High Flexible Demand (HFD) and Less Flexible Demand (LFD)

Dispatchable generation versus other flexibility options to meet the peak residual load

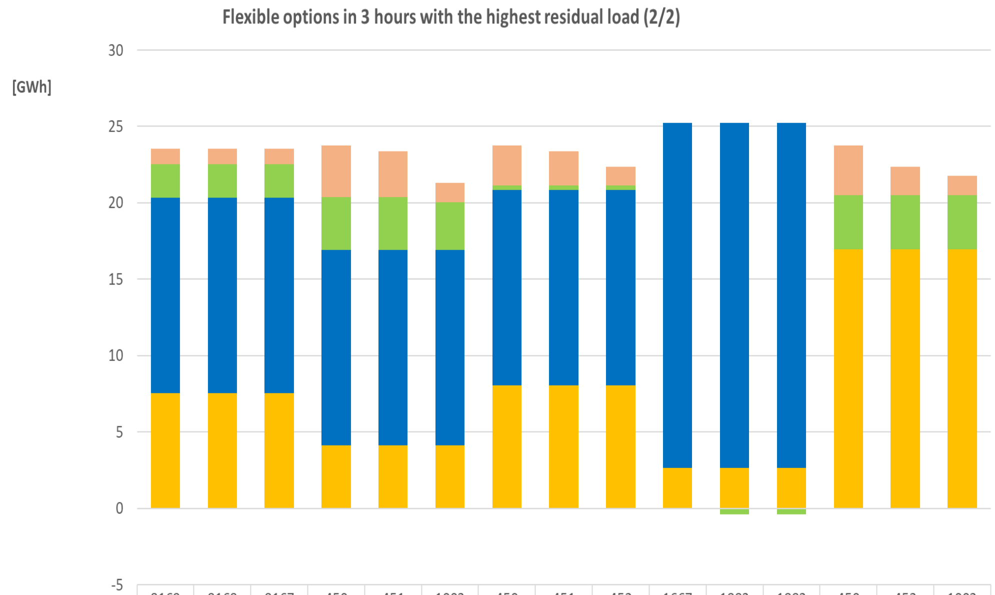
Figure 4.8 presents the mix of total dispatchable generation and other flexibility options to meet the residual load (RL) during the three highest ('peak') RL hours of the 2050 reference and sensitivity cases, while Figure 4.9 provides a further breakdown of the dispatchable generation mix during these hours.[65] Some major observations and findings from these two figures include:[66]

[65] Note that in Figure 4.8 the three peak RL hours in the 2050 reference case correspond to the first three hours of the HFD duration curve presented in Figure 4.7, while the three peak RL hours in the 2050 sensitivity case '*Less Flexible Demand*' corresponds to the first three hours of the LFD duration curve.

[66] Note that for dispatchable generation the hourly output data recorded in Figure 4.8 and Figure 4.9 correspond highly to the (annual) installed capacity data presented in Figure 4.4 and Figure 4.5, respectively. However, the cost-optimal deployment (output) of dispatchable generation recorded in Figure 4.8 and Figure 4.9 is usually slightly lower than the installed capacity data presented in Figure 4.4 and Figure 4.5, respectively. This is due to two reasons, i.e. (i) the average availability of some generation technologies is less than 1.0 (because of regular maintenance, etc.), and (ii) in the peak RL hour, the required, cost-optimal deployment of dispatchable generation may be less than the (maximum available) installed capacity of dispatchable generation because there are other, cheaper flexible options to meet the peak RL, such as trade or demand response, while in other hours – with a lower RL – a higher (maximum) deployment of dispatchable generation is needed because other, cheaper flexible options are not or less available.



	Reference			Less Flexible Demand (LFD)			Power CO2-free			Power CO2-free + LFD			Climate Year 1987		
	450	451	1002	450	451	452	450	451	447	450	451	452	464	474	522
Industrial load shedding	3.5	3.5	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	0.0
Demand curtailment ('lost load')	0.5	0.1	0.0	0.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage (discharge)	2.2	2.2	2.2	7.3	7.3	5.6	0.4	0.2	-0.1	3.3	3.6	1.6	2.0	1.9	1.9
Net trade (imports)	12.8	12.8	12.8	12.6	10.9	12.8	12.7	12.5	12.6	12.1	11.1	11.5	12.8	12.8	12.8
Dispatchable generation	4.8	4.8	4.8	11.6	11.6	11.6	11.0	11.0	11.0	16.9	16.9	16.9	8.6	8.6	8.6



	Climate Year 1996			Extra Sun PV			Extra Nuclear			Extra Trade			No trade		
	8169	8168	8167	450	451	1003	450	451	452	1667	1883	1882	450	452	1002
Industrial load shedding	1.0	1.0	1.0	3.4	3.0	1.3	2.6	2.2	1.2	0.0	0.0	0.0	3.3	1.9	1.3
Demand curtailment ('load load')	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage (discharge)	2.2	2.2	2.2	3.5	3.5	3.1	0.3	0.3	0.3	-0.1	-0.4	-0.4	3.5	3.5	3.5
Net trade (imports)	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	22.6	22.6	22.6	0.0	0.0	0.0
Dispatchable generation	7.5	7.5	7.5	4.1	4.1	4.1	8.0	8.0	8.0	2.6	2.6	2.6	16.9	16.9	16.9

Notes: The number below the bars refers to the hour of the year in which the peak residual load occurs (e.g., hour 450 of the year 2050). Figure 4.9 below provides a further breakdown of the dispatchable generation mix

Figure 4.8: Reference and sensitivity cases, 2050: Mix of flexibility options to meet the residual load in the three highest peak hours

- *Peak residual load:* The total height of each bar in Figure 4.8 indicates the level of the (peak) residual load for each case/hour recorded. Figure 4.8 shows that, as already observed above (Figure 4.7), the peak RL in the two sensitivity cases assuming '*Less Flexible Demand*' (30-32 GW) is approximately 8 GW higher than in the 2050 reference and (seven) sensitivity cases assuming '*High Flexible Demand'* (22-24 GW).[67]

- *Net trade (imports):* In almost all cases and all peak RL hours presented in Figure 4.8, net foreign electricity trade (import) plays a key, dominant role in meeting the RL (in most peak hours up to the assumed potential interconnection capacity of the Netherlands in 2050, i.e. 12.8 GW). This indicates that – according to the model outcomes, at least for the presented peak RL hours – foreign trade (import) is a major, available (reliable) option to cover the RL in a cost-optimal way within an EU-wide power system context.[68] The only exception is the case '*No Trade'* where – by definition – no electricity imports and exports are allowed and, therefore, covering the peak RL has to rely fully on domestic flexibility options, including a higher reliance on dispatchable generation. It should be noted, however, that for all the other cases the assumed potential interconnection capacity of the Netherlands in 2050 (12.8 GW) is rather conservative, including only already existing capacity and some new capacity that is already planned by the TSOs and in the pipeline to be realised. In the case '*Extra Trade'*, where the interconnection capacity of the Netherlands is assumed to be almost doubled in 2050 (up to 22.6 GW), net electricity imports cover even a much higher part of the RL in the three peak hours, thereby reducing the need for domestic flexibility options, notably dispatchable power generation.[69]

- *Storage (discharge):* Figure 4.8 shows that in all cases recorded the maximum installed storage (discharge) capacity – see Figure 4.4 – is used to meet the peak RL in these cases, varying from (less than) 0.5 GW in the case '*Power CO_2-free'* to 7.3 GW in the case '*Less Flexible Demand (LFD)*'.

- *Industrial load shedding*: Figure 4.8 indicates that the maximum potential of industrial load shedding (ILS) in 2050 – i.e., 3.5 GW – is used in two (out of three) peak RL hours in the 2050 reference case (i.e., in hours 450 and 451). In all sensitivity cases, however, the role of ILS to meet the peak RL is either zero or substantially lower than the maximum potential (3.5 GW), with the major exception of hour 450 in the case *'Extra Sun PV'* (3.4 GW) and hour 450 in the case *'No Trade'* (3.3 GW).[70]

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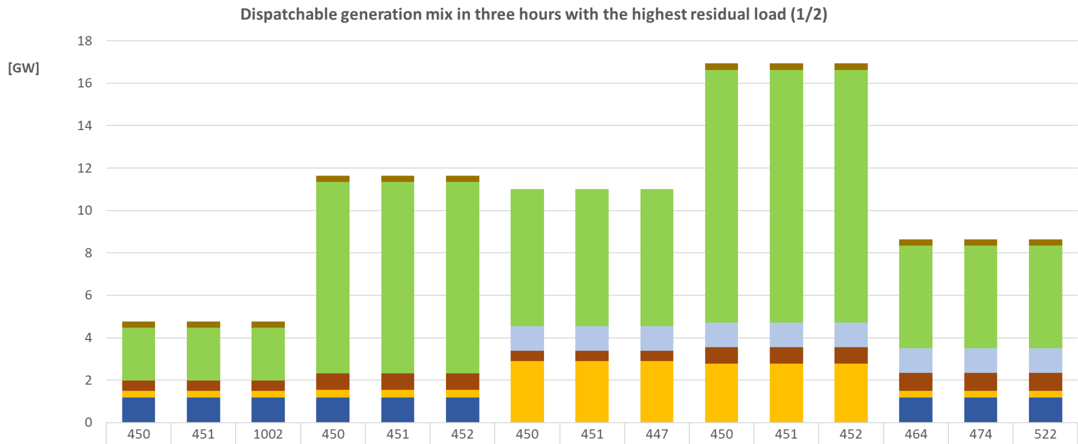
[67] The (usually relatively small) differences in peak RL between the cases assuming 'High Flexible Demand' are due to (usually relatively small) differences in total hourly demand (before demand response) and/or total hourly VRE generation (resulting mainly from differences in electricity prices and VRE installed capacities between these cases).

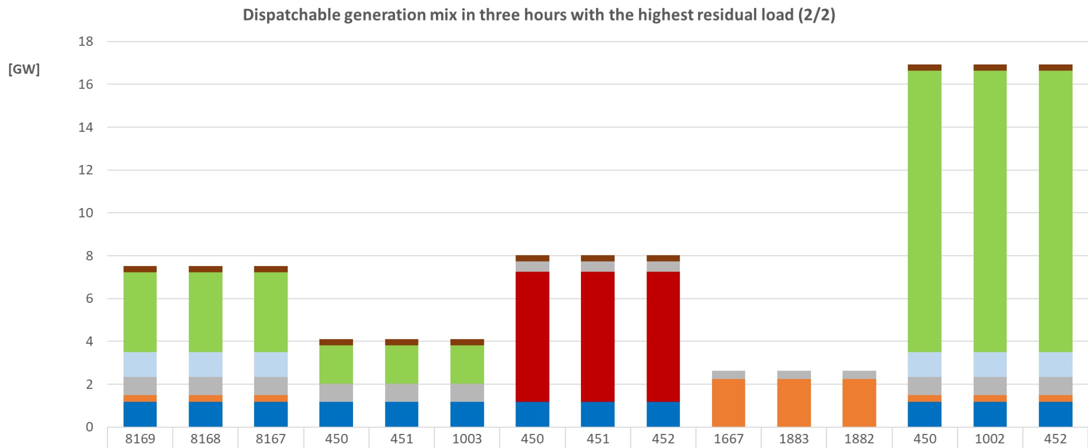
[68] Note that the COMPETES-TNO model accounts for both similarities and differences in electricity demand and (VRE) supply profiles between EU countries and regions, including weather (VRE) dependencies and independencies between these profiles.

[69] Figure 4.8 shows that in order to meet the RL in the three peak hours the need for dispatchable generation declines from 4.8 GW in the 2050 reference case to 2.6 GW in the case '*Extra Trade'*, whereas the role of net electricity imports increases from 12.8 GW to 22.6 GW, respectively. Note, however, that outside the three presented peak hours, there may be hours in which the maximum import capacity of the Netherlands may not be available – but only part of it – for instance, due to all kinds of supply constraints in the interconnected countries. Nevertheless, Figure 4.4 (Section 4.4) shows that over 2050 as a whole the total (cost-optimal) installed capacity of dispatchable power generation amounts to 4.2 GW in the case '*Extra Trade'* compared to 5.1 GW in the 2050 reference case. So, even when the interconnection capacity of the Netherlands is expanded by almost 10 GW in 2050, it will only slightly reduce the need for installed capacity power generation capacity by less than 1 GW.

[70] In the two sensitivity cases with '*Less Flexible Demand'* the option of industrial load shedding has been (assumed to be) excluded. In addition, note that besides the three peak RLs, some ILS occurs in some hours in some 2050 reference/sensitivity cases (as indicated by the corresponding high 'ILS-related' electricity prices; see Table 4.2 below in Section 4.7).



	Reference			Less Flexible Demand (LFD)			Power CO2-free			Power CO2-free + LFD			Climate Year 1987		
	450	451	1002	450	451	452	450	451	447	450	451	452	464	474	522
Other RES-E	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
H2 CCGT	2.5	2.5	2.5	9.0	9.0	9.0	6.4	6.4	6.4	11.9	11.9	11.9	4.8	4.8	4.8
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Biomass Retro	0.5	0.5	0.5	0.8	0.8	0.8	0.5	0.5	0.5	0.8	0.8	0.8	0.8	0.8	0.8
Nuclear (SMR)	0.3	0.3	0.3	0.4	0.4	0.4	2.9	2.9	2.9	2.8	2.8	2.8	0.3	0.3	0.3
Nuclear (large)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CCGT	1.2	1.2	1.2	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2



	Climate Year 1996			Extra Sun PV			Extra nuclear			Extra trade			No trade		
	8169	8168	8167	450	451	1003	450	451	452	1667	1883	1882	450	1002	452
Other RES-E	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.3	0.3	0.3
H2 CCGT	3.7	3.7	3.7	1.8	1.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0	13.1	13.1	13.1
Biogas	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2
Biomass Retro	0.8	0.8	0.8	0.8	0.8	0.8	0.5	0.5	0.5	0.4	0.4	0.4	0.8	0.8	0.8
Nuclear (SMR)	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	0.3	0.3	0.3
Nuclear (large)	0.0	0.0	0.0	0.0	0.0	0.0	6.1	6.1	6.1	0.0	0.0	0.0	0.0	0.0	0.0
Gas CCGT	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.0	0.0	0.0	1.2	1.2	1.2

Note: The number below the bars refers to the hour of the year in which the peak residual load occurs (e.g., hour 450 of the year 2050).

Figure 4.9: Reference and sensitivity cases, 2050: Breakdown of dispatchable generation technology mix to meet the residual load in the three highest peak hours

- *Demand curtailment ('lost load*): Figure 4.8 illustrates that in the 2050 reference case the role of 'forced' demand curtailment – i.e., 'lost load' or 'energy-not-served (ENS)' – in meeting the peak RL is relatively low in two (out of three) hours recorded (0.1-0.5 GW). In the sensitivity case *'Less Flexible Demand'* this role – also in two hours only – is slightly higher (0.8-1.8 GW). In all other sensitivity cases, however, the contribution of forced demand curtailment in addressing the RL in the three peak hours recorded is zero (see also Table 4.2 in Section 4.7 below).

- *Dispatchable generation:* Figure 4.8 shows that in the 2050 reference case the need for dispatchable generation to meet the RL in the three peak hours amounts to 4.8 GW, i.e. slightly lower than the total installed dispatchable generation capacity recorded in Figure 4.4 (5.1 GW).[71] In the nine sensitivity cases, this need for dispatchable generation ranges from 2.6 GW in the case '*Extra Trade*' to almost 17 GW in the cases '*No Trade*' and '***Power** CO_2-free + Less Flexible Demand (LFD)*'.

Breakdown of the need for dispatchable generation
As mentioned, Figure 4.9 provides a further breakdown of the need for dispatchable generation – per technology – to meet the residual load in the three peak hours of the 2050 reference and sensitivity cases. It shows that in most cases power generation from H_2-fired CCGTs is the main – or even dominant – dispatchable technology to meet the RL. The major exceptions are the case '*Extra Nuclear*' – where the need for dispatchable generation is primarily covered by large nuclear plants – and the case '*Extra Trade*', where this need is largely met by small nuclear reactors (SMRs).[72]

4.7 Electricity prices

Figure 4.10 presents the weighted average annual electricity price in the reference and sensitivity cases for 2050. In the reference case, this average price amounts to approximately 46 €/MWh, whereas in the sensitivity cases it ranges from 44 €/MWh in the case '*Extra Nuclear*' to 56 €/MWh in the case '*Climate Year 1987*'.[73]

Figure 4.11 presents the duration curves of the hourly electricity prices in the 2050 reference and sensitivity cases. For the 2050 reference case, it shows that (i) over some 1000 hours the electricity price is about 90 €/MWh or higher (and during more than 100 hours even 150 €/MWh or higher, (ii) between 1000 and 3000 hours, the electricity price varies from 60 to 90 €/MWh, (iii) between 3000 and 6000 hours, the electricity price is relatively stable at a level of 50-60 €/MWh, (iv) between 6000 and 7000 hours, the electricity price declines substantially from about 50 to 2 €/MWh, and (v) over the remaining 1760 hours of the year, the electricity price is very stable at the minimum level of approximately 2 €/MWh (i.e., the marginal, variable costs of generating power from sun/wind).

Compared to the 2050 reference case, the price duration curve of most sensitivity cases follows more or less a similar pattern (as outlined above). Some sensitivity cases, however, show some interesting differences. In brief, these cases/differences include in particular:

- *Climate Year 1987*: Overall, the price duration curve of the case '*Climate Year 1987*' lies generally (much) higher than the 2050 reference curve, notably during the first 4000 hours of the curve (see middle graph of Figure 4.11). As a result, the weighted average electricity price in the case '*Climate Year 1987*' (56 €/MWh) is substantially higher than in the 2050 reference case (46 €/MWh; see Figure 4.10).

[71] For an explanation of the (small) differences between the installed capacities of dispatchable generation (Figure 4.4 and Figure 4.5) and the actual demand ('need') for dispatchable generation to meet the RL in the three peak hours (Figure 4.8 and Figure 4.9) see Footnote 66 above.

[72] The breakdown of the need for dispatchable generation in Figure 4.9 roughly shows the same pattern – with some minor differences – as the breakdown of the installed dispatchable generation capacity in Figure 4.5. Therefore, for a further analysis of Figure 4.9, we refer to the analysis of Figure 4.5 in Section 4.4 above.

[73] The average high electricity price in the case *'Climate Year 1987'* results largely from the relatively high number of hours (375) in which the electricity price is 150 €/MWh or – much – higher (see Table 4.2 below).

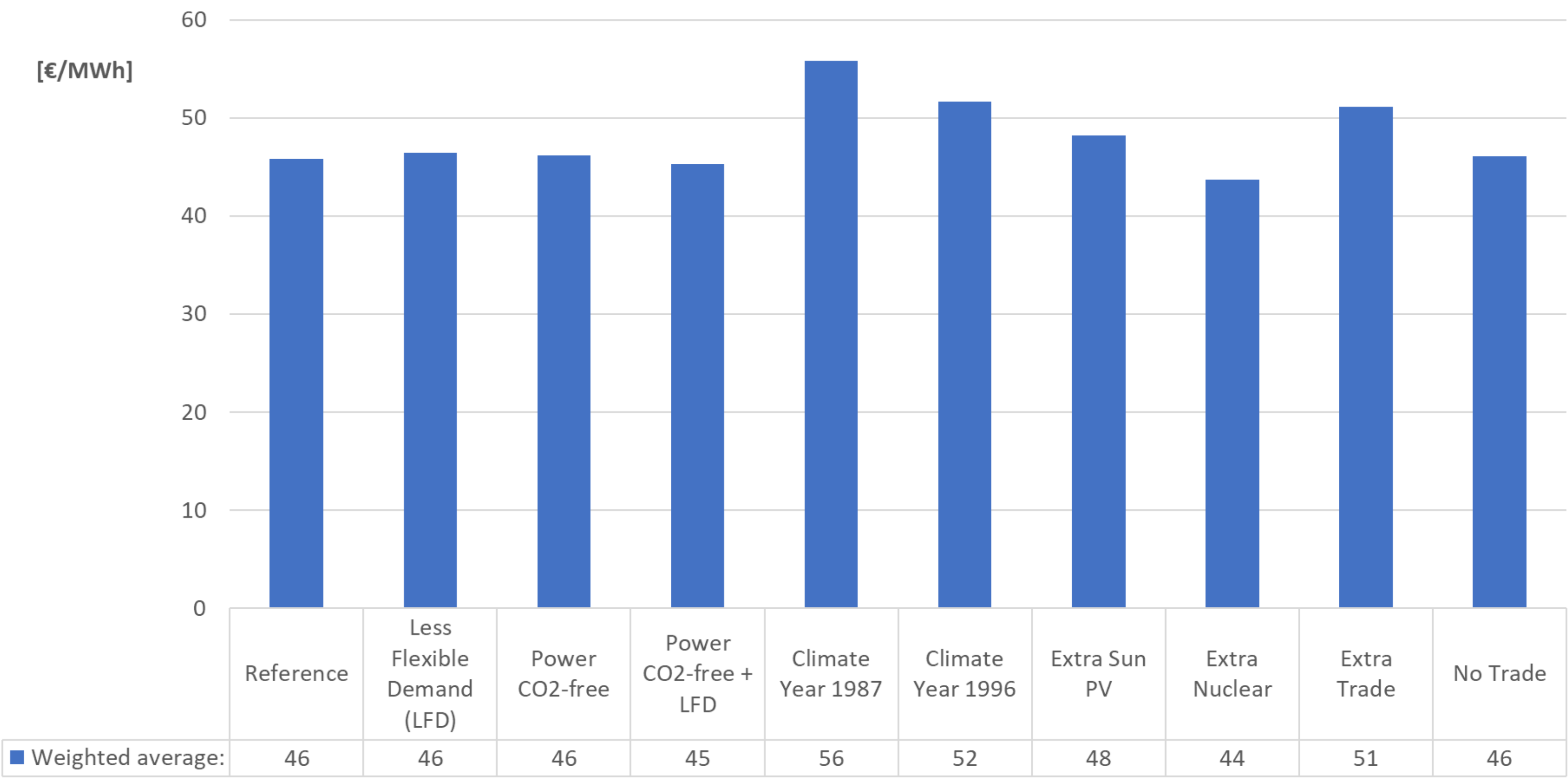


Figure 4.10: Reference and sensitivity cases, 2050: Weighted average electricity prices

Figure 4.11: Reference and sensitivity cases, 2050: Duration curves of hourly electricity prices

- *Climate Year 1996*: Also, in the case '*Climate Year 1996'*, the price duration curve lies usually higher than in the 2050 reference case (although lower than in the case '*Climate Year 1987*'). Consequently, the weighted average electricity price in the case '*Climate Year 1996'* (52 €/MWh) is significantly higher than in the 2050 reference case (46 €/MWh).

- *Extra Sun PV:* Up to the first 3000 hours, the price duration curve of the case '*Extra Sun PV*' is generally (much) higher than in the 2050 reference case, whereas between 3000 and 7000 hours it is usually – significantly – lower (see middle graph of Figure 4.11). Overall, the weighted average electricity price in the case '*Extra Sun PV'* (48 €/MWh) is slightly higher than in the 2050 reference case (46 €/MWh).

- *Extra Nuclear*: Up to the first 6800 hours, the price duration curve in the case '*Extra Nuclear*' is either more or less similar or slightly lower than in the 2050 reference case. Only between 6800 and 7200 hours, the '*Extra Nuclear'* curve is significantly higher than the reference curve (see lower part of Figure 4.11). Overall, the weighted average electricity price in the case '*Extra Nuclear'* (44 €/MWh) is slightly lower than in the 2050 reference case (€46 €/MWh).

- *Extra Trade*: Except for the first 100 hours and last 1500 hours, the price duration curve in the case '*Extra Trade'* is usually (much) higher than in the 2050 reference case. Overall, the weighted average electricity price in the case '*Extra Trade'* (51 €/MWh) is significantly higher than in the 2050 reference case (46 €/MWh). This is due to the fact that in the reference case, during a considerable number of hours, the power export potential of the Netherlands is restricted by the interconnection capacity, resulting in relatively lower electricity prices in the Netherlands (compared to higher prices in neighbouring countries). In the case '*Extra Trade'*, however, the interconnection capacity of the Netherlands is substantially expanded, resulting in higher export volumes during these hours at relatively high export prices and, hence, in – on average – higher electricity prices in the Netherlands (while the electricity prices in neighbouring countries are, on average, somewhat lower).

- *No Trade*: Finally, compared to the 2050 reference case, the price duration curve in the case '*No Trade* is (i) usually (much) higher during the first 2000 hours of the curve, (ii) more or less similar between 2000 and 4000 hours as well as between 6900 and 8760 hours, and (iii) generally (slightly) lower between 4000 and 6900 hours (see lower part of Figure 4.11). Overall, the weighted average electricity price in the case '*No Trade'* is similar to the 2050 reference case (46 €/MWh; see Figure 4.10).

For visual reasons, Figure 4.11 presents only electricity prices up to a level of 200 €/MWh. In both the 2050 reference and sensitivity cases, however, there is a considerable number of hours in which the electricity price is (substantially) much higher than 200 €/MWh. Table 4.2 provides the electricity prices during the 18 highest ranked hours in 2050 for both the 2050 reference and sensitivity cases. In addition, the bottom-line of this table indicates the number of hours in which the electricity price is 150 €/MWh or higher. For instance, in the 2050 reference case, this number of hours amounts to 115 whereas in the case '*No Trade'* it is 347.

Table 4.2 shows that in two cases - i.e., the 2050 reference case and the sensitivity case '*Less Flexible Demand (LFD)*', the electricity price runs up to the maximum level of 10,000 €/MWh during two hours of the year. The maximum price level of 10.000 €/MWh represents the so-called 'Value of Lost Load' (VoLL), as set within the model COMPETES-TNO. It implies that in these hours total electricity demand in the Netherlands cannot be fully met by total electricity supply and that, hence, (a small) part of total demand is involuntary curtailed.

Table 4.2: Reference and sensitivity cases, 2050: Electricity prices in the 18 highest price ranked hours in 2050

Hour	Reference	Less Flexible Demand (LFD)	Power CO_2-free	Power CO_2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
1	10000	10000	337	598	1598	545	8000	1500	500	8000
2	10000	10000	337	598	1598	545	1738	1500	499	1500
3	1500	290	337	598	1598	545	1738	1500	499	1500
4	1500	290	337	598	1598	545	1628	500	494	1500
5	1500	290	337	598	1598	545	1615	248	494	588
6	1500	290	337	598	1598	545	1615	244	494	584
7	1435	268	337	554	1598	545	1615	244	494	582
8	586	268	337	554	1585	545	1615	244	494	545
9	586	268	337	554	1584	545	1615	244	494	545
10	586	216	327	240	1582	545	1615	244	494	545
11	586	216	327	240	1500	545	1615	244	487	545
12	582	216	327	240	1500	545	1615	239	487	500
13	551	216	327	240	1500	545	1615	226	452	500
14	539	216	307	240	1500	545	1615	226	452	500
15	539	216	307	240	1500	545	1615	223	452	500
16	539	216	307	240	1500	545	1615	223	452	500
17	539	216	307	240	1500	540	1615	223	452	500
18	539	216	307	240	1500	540	1615	223	452	500
#h (>150 €)[a]	115	66	212	98	375	186	178	126	109	347

a) Number of hours in which the electricity price is 150 €/MWh or higher.

Table 4.2 also shows that in both the 2050 reference case and several sensitivity cases, the electricity price amounts to either 500, 1500 or 8000 €/MWh. These prices refer to the agreed price levels and the related (maximum) capacity of industrial load shedding as outlined in Section 2.1, notably Table 2.1. It implies that in these hours part of the industrial electricity demand is curtailed and that the related electricity price is set by the agreed price level to compensate the corresponding level of industrial load shedding.

4.8 CO_2 prices and emissions

Figure 4.12 shows the CO_2 (shadow) price in the NL/European P2X system for the 2050 reference and sensitivity cases. In the reference case, the CO_2 price amounts to 193 €/MtCO_2, whereas in the sensitivity cases it ranges from 205 €/MtCO_2 in the case '*Less Flexible Demand*' to 318 €/MtCO_2 in the case '*No Trade*'.

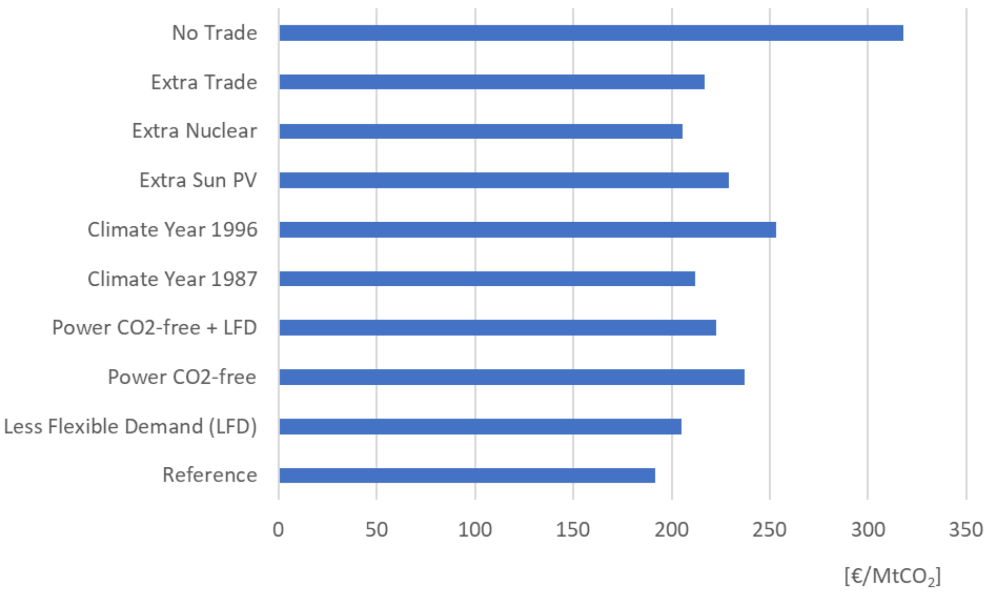
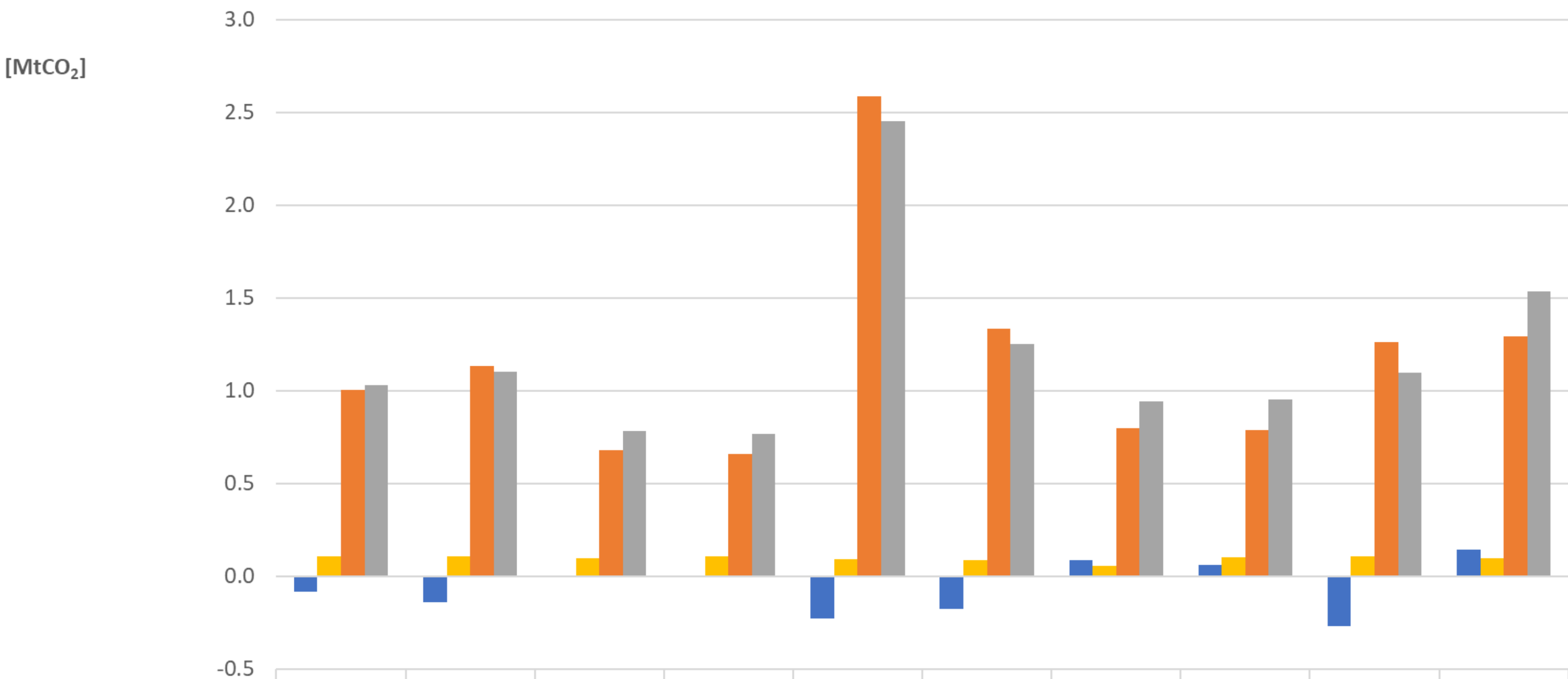


Figure 4.12: Reference and sensitivity cases, 2050: CO_2 (shadow) price in the NL/EU P2X system

Figure 4.13 presents the resulting CO_2 emissions of the NL-P2X system in the 2050 reference and sensitivity cases. It shows that in most cases total CO_2 emissions of the NL-P2X system in 2050 are – on balance – still slightly positive, varying from 0.8 MtCO_2 in the case '*Power CO_2-free*' to 2.5 MtCO_2 in the case '*Climate Year 1987*'. These (remaining) emissions are primarily due to the industrial heat sector where fossil gas is still allowed to fuel hybrid industrial boilers during a limited number of hours in which the electricity price is relatively higher than the fossil gas price (including CO_2 costs).

In the Dutch power generation sector, the CO_2 emissions in 2050 are also, on balance, slightly negative (minus 0.1-0.2 MtCO_2) – due to electricity production from biomass + CCS – in both the reference and four sensitivity cases (see Figure 4.13). In three sensitivity cases, however, these emissions are slightly positive (0.1 MtCO_2). Finally in the two '*Power CO_2- free*' sensitivity cases, the CO_2 emissions of the Dutch power generation sector are – by definition – zero since in these two cases power generation has to be fully CO_2-free – starting from 2035 – while no CCS is allowed in the electricity production sector of those European countries, including the Netherlands, that announced in late 2023 to aim at fully decarbonising their power system by 2035 (see Section 4.1 above).



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Power generation sector	-0.1	-0.1	0.0	0.0	-0.2	-0.2	0.1	0.1	-0.3	0.1
H2 production sector	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial heat sector	1.0	1.1	0.7	0.7	2.6	1.3	0.8	0.8	1.3	1.3
Total NL-P2X system	1.0	1.1	0.8	0.8	2.5	1.3	0.9	1.0	1.1	1.5

Figure 4.13: Reference and sensitivity cases: CO_2 emissions of the NL-P2X system

As outlined in Chapter 2 (notably Section 2.3), the (remaining) positive CO_2 emissions of the NL-P2X system in 2040/2050 are due to the fact that for the reference scenario and most (7 out of 9) sensitivity cases the zero emission constraint – in both 2040 and 2050 – is set at the European P2X system as a whole and not at the level of individual European countries and/or individual P2X sub-systems ('sectors') in order to optimise the European P2X system as a whole, i.e. to minimise total European P2X system costs. This implies that CO_2 emissions in individual P2X sectors or in the whole P2X system of an individual European country can be positive as far as these positive emissions are compensated by negative emissions elsewhere in the system (so that the total CO_2 emissions of the European P2X system as a whole are, on balance, zero in 2040 and 2050).

4.9 System costs

Figure 4.14 presents a breakdown of the total NL-P2X system costs in the 2050 reference and sensitivity cases.[74] In the 2050 reference case, the total NL-P2X system costs amount to about 22.5 b€, whereas in the sensitivity cases they vary from approximately 22.1 b€ (-2%) in the case *'Extra Trade'* to 24.6 b€ (+9%) in the case '*Climate Year 1987*'. Although in absolute figures the total cost differences between the reference and sensitivity cases are occasionally 'substantial' (up to 2.1 b€), in percentage terms these differences are relatively low (up to 9%) and may even be considered 'hardly or not significant' given the limitations inherent to model scenario analyses and, in particular, the major uncertainties of the underlying cost assumptions of key technologies up to 2050.

The breakdown of the total system costs shows some interesting differences across the cases included in Figure 4.14. For instance, compared to the 2050 reference case, the annualised investment costs of dispatchable power generation capacity increase substantially in the case '*Extra Nuclear'* – i.e., by 2.5 b€, largely compensated by lower investment costs of VRE generation capacity (-1.6 b€) and less trade costs of electricity/hydrogen (-0.8 b€).[75] On the other hand, in the case *'Extra Sun PV'*, the investment costs of VRE generation capacity increase by 0.8 b€ whereas the investment costs of dispatchable generation capacity declines by 0.2 b€.

Power generation costs

It has to noted that the variation in total system costs – as presented in Figure 4.14 – is to some extent due to some variation in total system activities and resulting output – mainly in terms of electricity, industrial heat and hydrogen production as well as system flexibility services – across the cases recorded. This is illustrated by Table 4.3, which provides data on total and average power generation costs in the Netherlands – distinguished by VRE and dispatchable generation costs – for the 2050 reference and sensitivity cases.

More specifically, Table 4.3 shows that in the 2050 reference case the total VRE power generation costs amount to 18.6 b€, whereas in the sensitivity cases they range from 17 b€ (-9%) in the case '*Extra Nuclear'* to 19.5 b€ in the case '*Extra Sun PV'*. As VRE generation output, however, varies over the cases recorded in Table 4.3 (i.e., from 377 TWh in the case '*No Trade'* to 423 TWh in the case '*Extra Sun PV'*), the ***average*** VRE generation costs amount to approximately 45 €/MWh in the 2050 reference case as well as in six (out of nine) sensitivity

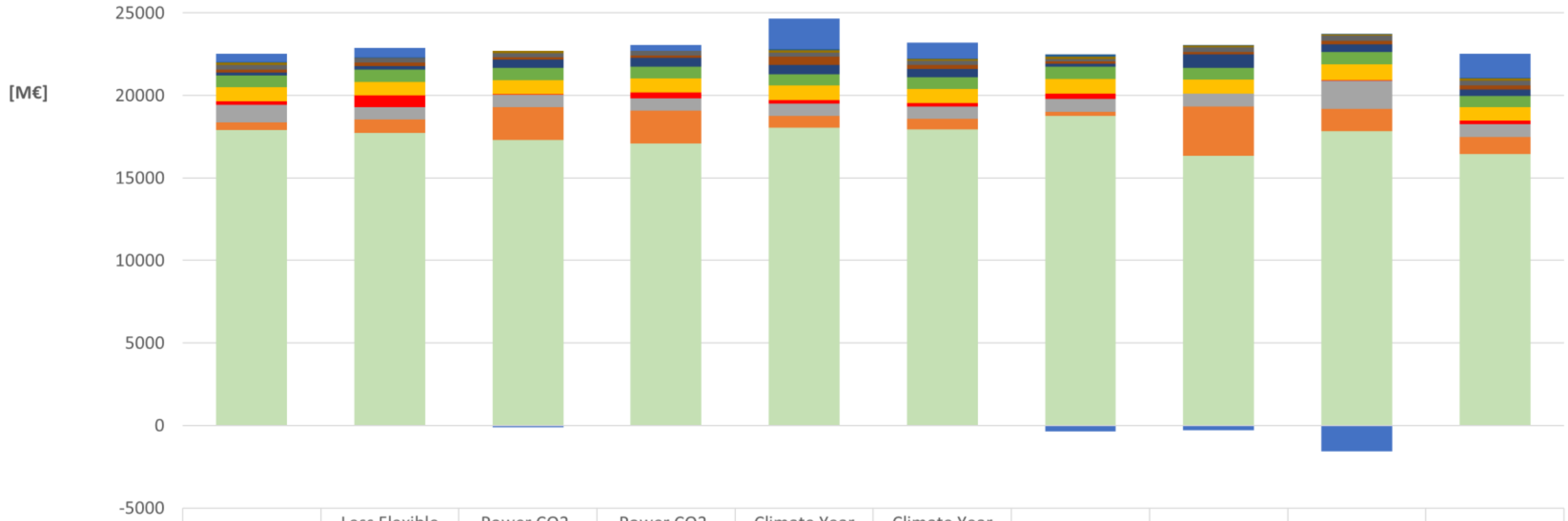
[74] For a definition and explanation of the various P2X system costs, see Chapter3, notably Section 3.8, as well as the notes below Figure 4.14.

[75] In the case *'Extra Nuclear'*, 'less trade costs' actually means 'higher trade revenues, notably by exporting higher volumes of electricity.

cases, whereas they are (slightly) higher in the three other sensitivity cases, notably in the case '*Climate Year 1987*' (48.3 €/MWh, i.e. +7%).

On the other hand, total dispatchable generation costs amount to 0.63 b€ in the 2050 reference case, whereas they range from 0.44 b€ (-30%) in the case '*Extra Sun PV*' to 3.8 b€ (+500%) in the case '*Extra Nuclear*'. As dispatchable generation output, however, varies over the cases presented in Table 4.3 (i.e., from 2.6 TWh in the case '*Extra Sun PV*' to more than 42 TWh in the case '*Extra Nuclear*'), the *average* dispatchable generation costs amount to 172 €/MWh in the 2050 reference case, whereas they vary substantially in the sensitivity cases from 89 €/MWh (-48%) in the case '*Extra Nuclear*' to almost 220 €/MWh (+27%) in the case '*Less Flexible Demand (LFD)*'.

Table 4.3 shows, however, that dispatchable generation accounts for only a minor share of total power generation output in the cases considered, i.e. varying from about 1% in the reference case – and several sensitivity cases – to approximately 10% in the case '*Extra Nuclear*'. Consequently, both the height and the variation of the *average* costs of total power generation is much lower (compared to the average dispatchable generation costs), ranging from 46.3 €/MWh in the 2050 reference case to 50.4 €/MWh in the case '*Climate Year 1987*'.



	Reference	Less Flexible Demand (LFD)	Power CO2-free	Power CO2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Net trade costs (electricity & H2)	519	572	-117	361	1844	977	-365	-285	-1586	1471
Demand curtailment	39	26	0	0	82	35	150	6	0	24
Other variable costs	127	12	120	7	126	119	134	115	97	154
Variable H2 costs	291	290	275	291	250	240	154	278	290	275
Variable gas-to-heat costs	189	213	128	124	487	252	151	148	238	244
Variable dispatchable generation costs	151	207	508	554	586	476	173	811	441	407
Variable VRE generation costs	738	732	723	711	683	710	733	686	740	659
Other investment costs	852	849	853	848	884	871	880	855	980	847
Investments costs of storage capacity	211	691	48	348	211	211	327	26	38	211
Investment costs of P2H2 capacity	1036	747	726	733	749	739	784	782	1683	761
Investment costs of dispatchable capacity	475	806	2002	2002	697	650	267	2960	1379	1048
Investment costs of VRE generation capacity	17906	17740	17304	17091	18049	17928	18743	16350	17818	16437

Notes: Investment costs refer to the annualised capital costs (CAPEX) of both past and new capacity investments. Other investment cost includes in particular the annualised capital costs of capacity investments in H_2/energy storage, H_2 steam Methane Reforming (SMR) installations, H_2 power generation installations, HVDC transmission networks and hybrid boilers. Other variable costs refer notably to variable storage costs such as the costs of storage (dis)charges and storage losses. Net trade costs refer to the costs (or benefits) of net electricity trade (if the figure is negative it refers to the benefits or revenues of net electricity exports).

Figure 4.14: Reference and sensitivity cases, 2050: Breakdown of the NL-P2X system costs

Table 4.3: Reference scenario, 2030-2050: Total and average power generation costs in the Netherlands

	Unit	Reference	Less Flexible Demand (LFD)	Power CO_2-free	Power CO_2-free + LFD	Climate Year 1987	Climate Year 1996	Extra Sun PV	Extra Nuclear	Extra Trade	No Trade
Total power generation costs[a]											
VRE generation	m€	18644	18471	18026	17802	18731	18639	19476	17036	18558	17096
Dispatchable generation	m€	626	1013	2510	2555	1284	1126	440	3770	1820	1455
Total generation	*m€*	*19269*	*19484*	*20536*	*20357*	*20015*	*19765*	*19915*	*20806*	*20378*	*18551*
Power generation output											
VRE generation	TWh	412.2	406.5	398.3	391.9	388.0	400.1	422.9	378.4	412.0	376.9
Dispatchable generation	TWh	3.6	4.6	22.9	22.2	9.1	7.8	2.6	42.3	18.2	8.1
Total generation	*TWh*	*415.8*	*411.2*	*421.2*	*414.1*	*397.1*	*407.9*	*425.5*	*420.7*	*430.2*	*385.0*
Average power generation costs											
VRE generation	€/MWh	45.2	45.4	45.3	45.4	48.3	46.6	46.1	45.0	45.0	45.4
Dispatchable generation	€/MWh	172.1	218.6	109.8	115.1	140.5	143.9	171.0	89.1	99.9	180.6
Total generation	*€/MWh*	*46.3*	*47.4*	*48.8*	*49.2*	*50.4*	*48.5*	*46.8*	*49.5*	*47.4*	*48.2*

a) Total power generation costs include both the (annualised) investments cost and the variable costs of power generation as defined and recorded in Figure 4.14.

5 Dunkelflautes

The analysis of the reference scenario (and most sensitivity cases) is based on the hourly electricity demand and VRE supply profiles of the 'normal, average' climate year 2015. In addition, however, we have analysed two sensitivity cases based on hourly profiles of two 'extreme' climate years, 1996 and 1987, including one and even two '*Dunkelflaute*' periods, respectively, i.e. an extended period – lasting several days up to one or two weeks – in which the sun hardly shines and the wind hardly blows. This results in hardly or no VRE power generation over this period and, therefore, a relatively high residual load over an extended period of hours that has to be met by dispatchable power generation/other flexibility options.[76]

In the previous sections of this chapter, we have already analysed the 2050 scenario outcomes for the sensitivity cases '*Climate Year 1987*' and '*Climate Year 1996*' over all hours of these years. In this section, we focus our analysis more specifically on the Dunkelflaute periods of these climate years, in particular on the impact and implications of these Dunkelflaute periods on the residual load (RL) over these periods as well as on the need for dispatchable power generation/other flexibility options to meet this RL.

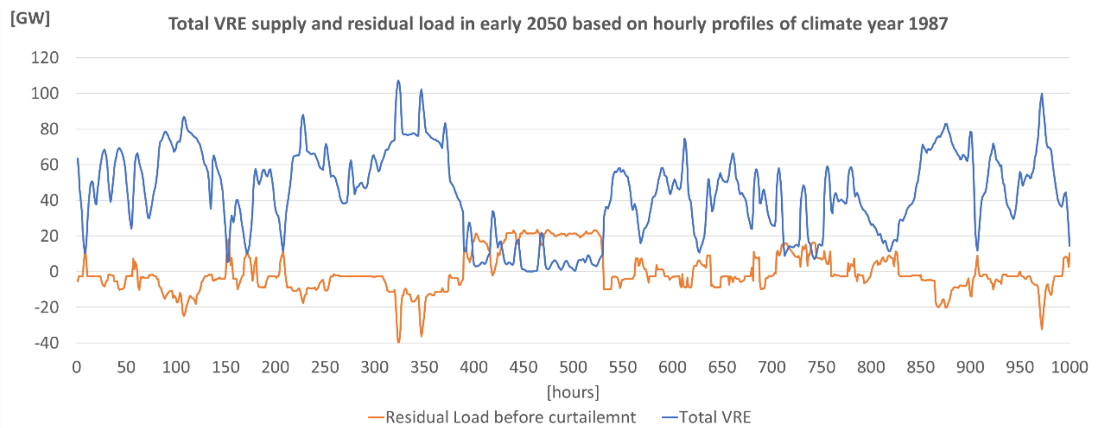
5.1 Identifying '*Dunkelflaute*' periods

Figure 5.1 identifies the Dunkelflaute periods of the climate years 1987 and 1996 by showing the total VRE generation and residual load in 2050 based on the hourly load and VRE supply profiles of these climate years on the one hand and the (assumed) electricity demand and (optimised) VRE installed capacities of the sensitivity cases '*Climate Year 1987*' and '*Climate Year 1996*' for the year 2050 on the other hand. This figure shows that the projected VRE power generation in 2050 fluctuates heavily between 0 and 100 GW while the residual load (after demand response, but before any curtailment) usually hovers around 0 GW. During certain Dunkelflaute periods, however, VRE power generation is, on average, relatively low – even close to zero – while the residual load is, on average, relatively high, i.e. between 15-25 GW during most hours of these periods.

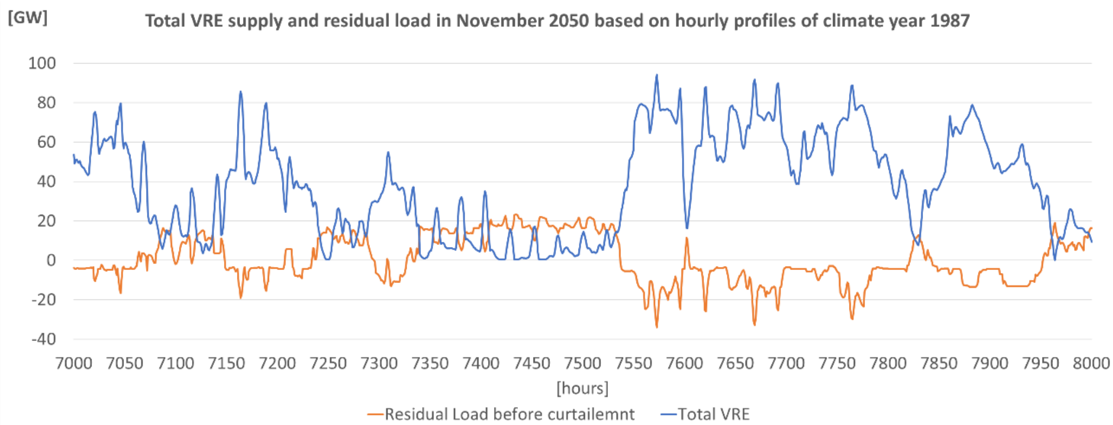
The upper part of Figure 5.1 shows that in mid-January 1987, the Dunkelflaute lasted from about hour 390 up to hour 530, i.e. 141 hours or, approximately, 6 consecutive days. In early November, there was a second Dunkelflaute in 1987 that occurred from about hour 7340 up to hour 7530, i.e. 191 hours or almost 8 days (middle of Figure 5.1). Finally, the lower part of Figure 5.1 indicates that in mid-December 1996 a Dunkelflaute period took place that lasted from about hour 8140 up to hour 8395, i.e. 196 hours or slightly more than 8 days.[77]

[76] If the 'Dunkelflaute' occurs during a period with relatively low outside temperatures – resulting in a relatively high, additional demand of power-to-heat, notably in the built environment – it is sometimes called a '*kaltes Dunkelflaute*' (TenneT, 2023).

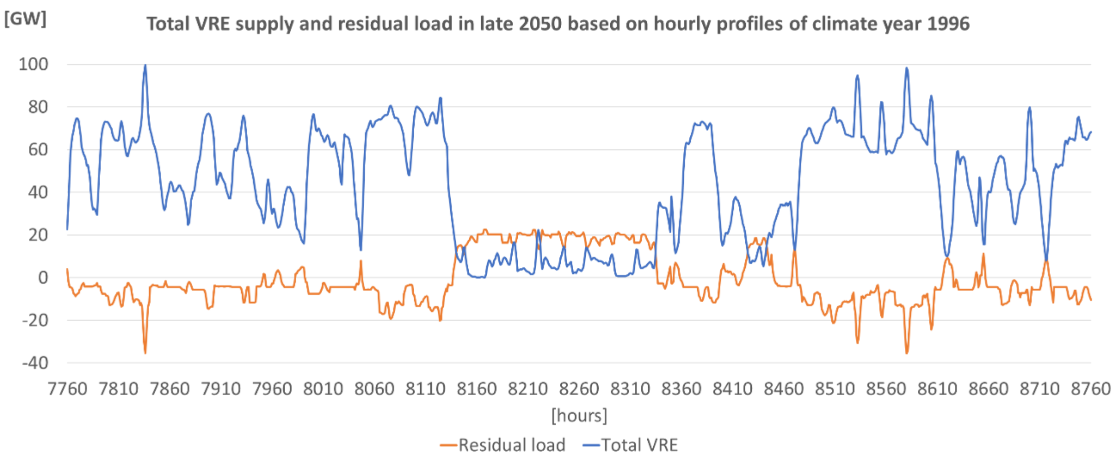
[77] The Dunkelflaute in mid-December 1996 is particularly interesting because it occurred not only in the Netherlands but also in Germany, i.e. the major electricity trading country of the Netherlands.



Note: The Dunkelflaute in mid-January 1987 lasted from about hour 390 up to hour 530, i.e. 141 hours or, approximately, 6 days



Note: The Dunkelflaute in early November 1987 lasted from about hour 7340 up to hour 7530, i.e. 191 hours or, approximately, 8 days



Note: The Dunkelflaute in mid-December 1996 lasted from about hour 8140 up to hour 8395, i.e. 196 hours or, approximately, 8 days

Figure 5.1: Identifying Dunkelflautes: Total VRE generation and residual load in 2050 based on the hourly load and VRE profiles of climate years 1987 and 1996, including Dunkelflautes in mid-January 1987, early November 1987 and mid-December 1996, respectively

5.2 Flexible options to meet the residual load during a Dunkelflaute

Figure 5.2 presents the mix of flexible options to address the residual load (RL) in 2050 during the three Dunkelflaute periods identified above. As noted, during most hours of these periods the RL in 2050 amounts to 15-25 GW (see green lines in Figure 5.2). Despite the relatively low VRE power generation during these Dunkelflaute periods (Figure 5.1), the residual load – i.e., total load minus VRE generation – is nevertheless also relatively low, primarily due to the flexible, price-responsive demand by power-to-hydrogen ($P2H_2$) and power-to-heat in industry (P2H-i) during these periods and, to some extent, the (high) demand response by EVs and household heat pumps.[78]

Figure 5.2 shows that the residual load during the Dunkelflaute periods (after demand response, but before any VRE/demand curtailment) is mainly met by dispatchabele power generation and foreign net imports of electricity but hardly or not by demand curtailment or net storage (discharge) transactions. Based on the hourly load and VRE supply profiles of the climate years 1996 and 1987, respectively, dispatchable power generation in 2050 covers, on average, about 33% of the residual load during the Dunkelflaute period based on mid-December 1996, 35% during the Dunkelflaute of mid-January 1987 and 27% over the Dunkelflaute based on November 1987 (see also Table 5.1 below).

In order to meet the RL over all the hours of the two Dunkelflaute periods of 1987, the (maximum) need for the total available capacity of dispatchable generation in 2050 amounts to about 12.4 GW over the first Dunkelflaute (based on mid-January 1987) and approximately 12.0 GW over the second period (referring to the Dunkelflaute of November 1987). Based on the total load and VRE supply profiles of the climate year 1996, however, this (maximum) capacity need for dispatchable generation in 2050 is significantly lower, i.e. about 8.5 GW over the Dunkelflaute referring to December 1996 (see blue lines in Figure 5.2).

After dispatchable generation, the remaining part of the RL in 2050 during the three identified Dunkelflautes is mainly met by net electricity imports, i.e., on average, about 46% of the RL in 2050 over the period based on the first Dunkelflaute of 1987, 38% on the second Dunkelflaute of 1987, and even 58% of the Dunkelflaute of mid-December 1996. In a large number of hours during these Dunkelflaute periods, the net imports of electricity reach the mamimum interconnection capacity of the Netherlands in 2050 (12.8 GW), notably during the Dunkelflautes of mid-January 1987 and mid-December 1996 (see grey lines in Figure 5.2).[79]

Due to the high demand response in the 2050 scenario and the high contributions of dispatchable generation and net imports in meeting the RL during the identified Dunkelflaute periods, there is hardly or no need for other (more expensive) flexibility options – notably net storage discharges and demand curtailment – over these periods. Only during the second half of the Dunkelflaute of mid-January, some need for demand curtailment – up to 1.0 GW – is notified (see yellow and orange lines in Figure 5.2).

[78] In almost all hours of the three identified Dunkelflaute periods, the demand by $P2H_2$ and P2H-I is even (close to) zero in 2050.

[79] As noted, the Dunkelflaute in mid-December 1996 occurred not only in the Netherlands but also in Germany. Nevertheless, as indicated in the lower part of Figure 5.2, during the period based on the Dunkelflaute of mid-December 1996 the Netherlands are able to cover the main part of the RL over this period in 2050 – after demand response – by net imports (in many hours up to 12.8 GW). As a result, the need for dispatchable generation over this period is relatively low (up to 8.5 GW), while the need for net storage and demand curtailment is even zero.

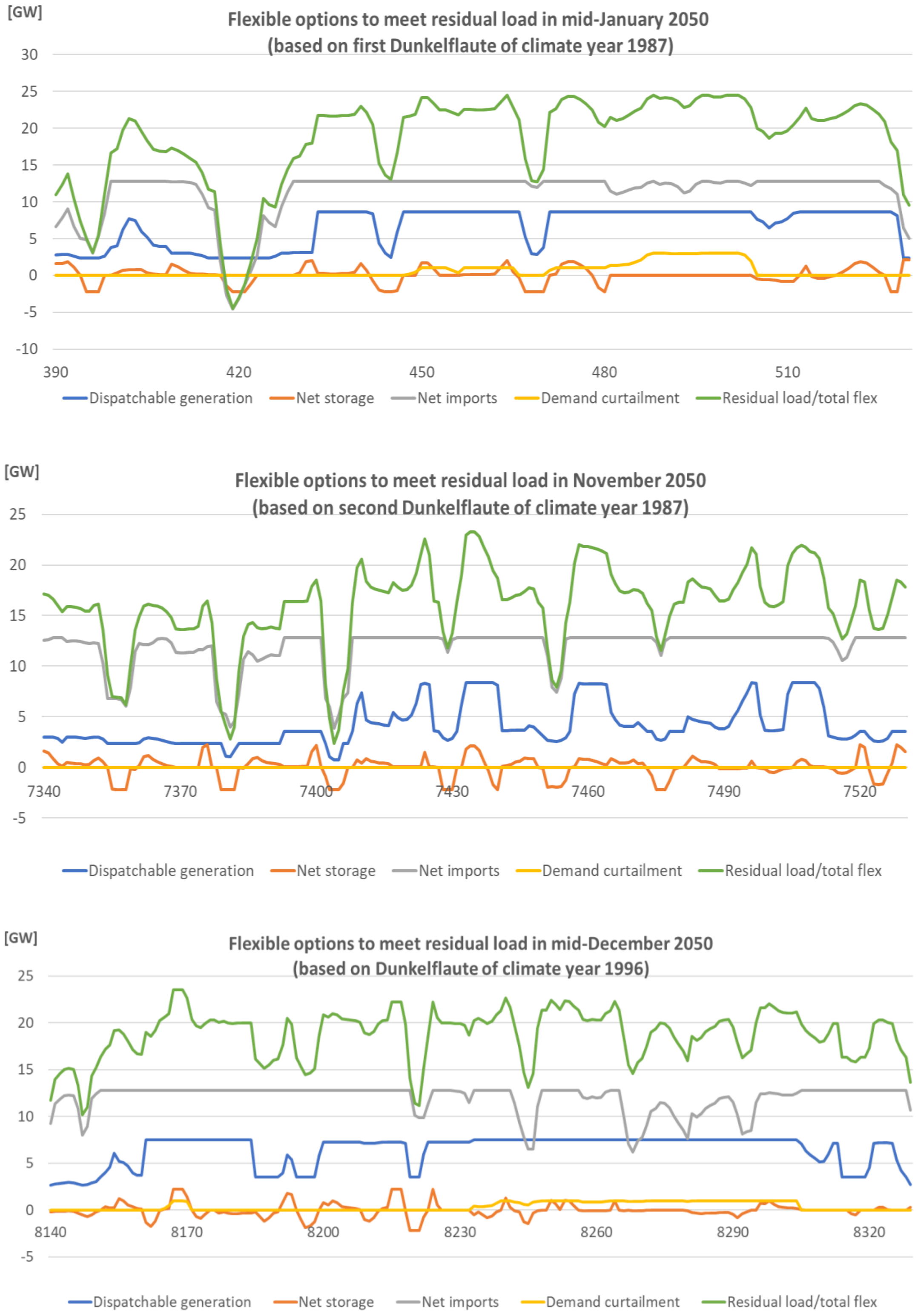


Figure 5.2: Mix of flexible options to address the residual load during Dunkelflautes in 2050 based on the hourly load and VRE profiles of climate years 1987 and 1996, including Dunkelflautes in mid-January 1987, early November 1987 and mid-December 1996, respectively

Table 5.1 provides a summary overview of the mix of dispatchable generation and other flexibility options to address the aggregated residual load – after demand response – over various periods in 2050, based on the load and VRE supply profiles of the climate years 1987, 1996 and 2025, including – for comparative reasons – both the Dunkelflaute and the full annual periods of these years. This table shows, for instance, that over the 141 hours representing the first Dunkelflaute of 1987 (DF1) the aggregated total domestic load in 2050 amounts to 3.7 TWh. Of this total load, 1.1 TWh (about 29%) is met by VRE generation, resulting in a residual load – after demand response – of 2.6 TWh (71% of total load). In turn, the aggregated RL over DF1-1987 is covered predominantly by dispatchable generation (0.9 TWh) and net imports (1.6 TWh) and, to a small extent, by demand curtailment (0.1 GW).

As mentioned, for comparative reasons, the lower part of Table 5.1 also includes aggregated figures for 2050 based on the climate years 1987, 1996 and 2015 as a whole. For instance, based on the load and VRE supply profiles of the full year (FY) 1987, the total domestic load of the Netherlands in 2050 amounts to about 380 TWh, whereas total VRE generation (before curtailment) amounts to 418 TWh, i.e. resulting in a surplus VRE generation – or negative residual load (RL) – of 38 TWh (before any demand/VRE curtailment). A small amount of this RL is curtailed (0.1 TWh), notably – as indicated above – during the Dunkelflaute periods with relatively high RL hours, whereas on the other hand 30.3 TWh of VRE generation is curtailed, resulting in a higher total annual residual load (after demand/VRE curtailment) of -7.8 TWh. In addition to this 'negative' demand, there is a 'positive' supply of dispatchable generation of 9.1 TWh, resulting in a total annual (domestic) surplus of 16.9 TWh, which is predominantly covered by net exports (16.7 TWh) and, additionally, a small amout of net storage losses (0.2 TWh).

Figure 5.3 presents the average numbers of the total load, VRE generation and residual load over various (Dunkelflaute) periods in 2050, based on the load and VRE supply profiles of the climate years 1987, 1996 and 2015. It shows that the average load in the three indentified Dunkelflaute periods (about 24-26 GW) is substantially lower than over the three mentioned climate years as a whole (approximately 43-44 GW). As mentioned, this is primarily due to the high demand response of the P2X technologies during the Dunkelflaute periods.

Over the three climate years as a whole, the average load in 2050 (43-44 GW) is more than fully met by the average VRE power generation – before any VRE curtailment – over this year (48-50 GW). During the three identified Dunkelflaute periods, however, the – lower – average load (24-26 GW) is only partially covered by the average VRE power generation over these periods (6-8 GW), i.e. by about 25-33%. As a result, the average residual load over the Dunkelflaute periods (16-19 GW) is much higher than over the three climate years considered as a whole (about minus 4-6 GW).

Finally, Figure 5.4 presents the average mix of flexible options to address the average RL over various (Dunkelflaute) periods in 2050, based on the load and VRE supply profiles of the climate years 1987, 1996 and 2015. As also observed above, it shows that over the three identified Dunkelflaute periods the average RL (16-19 GW) is met primarily by dispatchable generation (4-6 GW) and net imports (11-12 GW) but hardly or not by demand curtailment or storage transactions (for details, see left part of Figure 5.4).

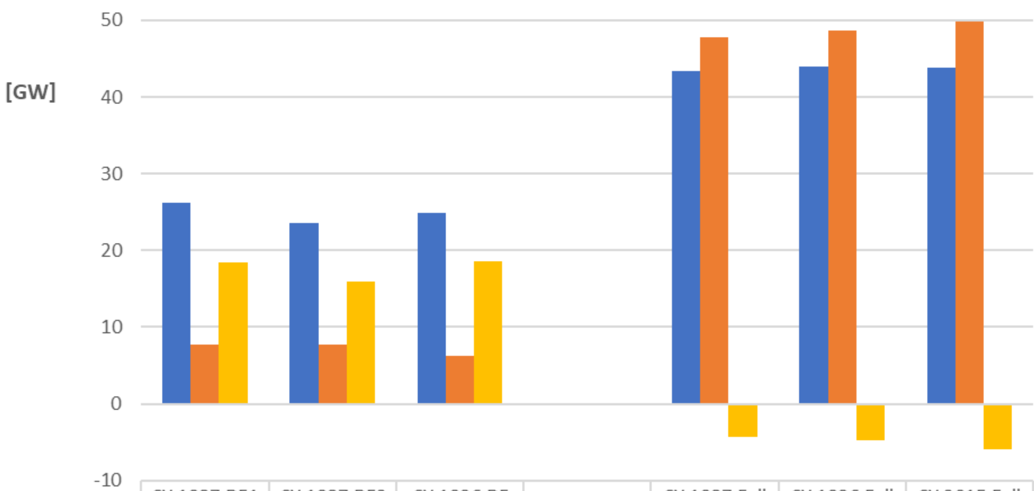
On the other hand, Figure 5.4 shows also that over the three selected climate years as a whole the average dispatchable generation is significantly lower (0.4-1.0 GW), but still substantially surpassing the average RL over these years (minus 4-6 GW). Besides curtailing some VRE power generation (on average, about 3 GW), the resulting domestic production surplus is addressed by, on balance, net electricity exports (2-4 GW; see right part of Figure 5.4).

Table 5.1: Summary overview of mix of flexible options to address the aggregated residual load over various Dunkelflaute periods in 2050 based on the hourly load and VRE profiles of climate years (CY) 1987, 1996 and 2015, including Dunkelflautes in mid-January 1987, early November 1987 and mid-December 1996

	Residual load			Flexible options to address residual load							
[TWh]	Total load[a]	Total VRE generation[b]	Residual load	Dispatchable generation	Storage production[c]	Storage consumption[d]	Imports	Exports	Demand curtailment	VRE curtailment	Total flex
CY 1987 DF1 (141h)	3.7	1.1	2.6	0.9	0.1	0.0	1.7	-0.1	0.1	0.0	2.6
CY 1987 DF2 (191h)	4.5	1.5	3.0	0.8	0.1	0.1	2.3	-0.1	0.0	0.0	3.0
CY 1996 DF (196h)	4.9	1.2	3.6	1.2	0.0	0.0	2.4	-0.1	0.1	0.0	3.6
CY 1987 Full (8760h)	380.3	418.3	-38.0	9.1	2.6	-2.8	48.9	-65.6	0.1	-30.3	-38.0
CY 1996 Full (8760h)	385.7	426.9	-41.2	7.8	2.7	-2.9	46.1	-68.1	0.1	-26.9	-41.2
CY 2015 Full (8760h)	383.7	436.2	-52.5	3.6	2.5	-2.7	41.7	-73.6	0.0	-24.0	-52.5

a) Total domestic load (i.e., excluding exports);
b) Before VRE curtailment;
c) Storage discharges;
d) Storage charges.

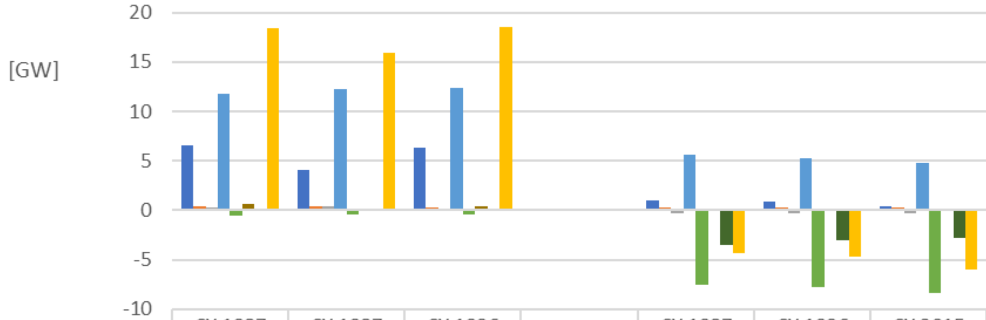
Notes: 1987, 1996 and 2015 refer to the load and VRE generation profiles of the climate years 1987, 1996 and 2015, respectively. 1987 DF1 and 1987 DF2 refer to the first and second Dunkelflaute in mid-January and early November 1987, respectively, while 1996 DF refers to the Dunkelflaute of mid-December 1996 (see also Figure 5.1 and Figure 5.2). Figures between brackets refer to the number of hours of the Dunkelflaute periods and full years concerned.



	CY 1987 DF1	CY 1987 DF2	CY 1996 DF		CY 1987 Full	CY 1996 Full	CY 2015 Full
Load	26.2	23.6	24.9		43.4	44.0	43.8
VRE generation	7.7	7.7	6.3		47.7	48.7	49.8
Residual load	18.5	15.9	18.6		-4.3	-4.7	-6.0

Notes: See notes below Table 5.1.

Figure 5.3: Average load, VRE generation and residual load in 2050 based on the hourly load and VRE profiles of climate years 1987, 1996 and 2015, including Dunkelflautes in mid-January 1987, early November 1987 and mid-December 1996, respectively



	CY 1987 DF1	CY 1987 DF2	CY 1996 DF		CY 1987 Full	CY 1996 Full	CY 2015 Full
Dispatchable generation	6.6	4.1	6.3		1.0	0.9	0.4
Storage production	0.4	0.4	0.2		0.3	0.3	0.3
Storage consumption	0.3	0.4	0.2		-0.3	-0.3	-0.3
Imports	11.8	12.2	12.4		5.6	5.3	4.8
Exports	-0.6	-0.4	-0.4		-7.5	-7.8	-8.4
Demand curtailment	0.6	0.0	0.4		0.0	0.0	0.0
VRE curtailment	0.0	0.0	0.0		-3.5	-3.1	-2.7
Residual load/Total flex	18.5	15.9	18.6		-4.3	-4.7	-6.0

Notes: See notes below Table 5.1

Figure 5.4: Average mix of flexible options to address the average residual load in 2050 based on the hourly load and VRE profiles of climate years 1987, 1996 and 2015, including Dunkelflautes in mid-January 1987, early November 1987 and mid-December 1996, respectively

Conclusion
Based on ‘extreme’ climate years, such as 1987 or 1996, including one or even two Dunkelflaute periods, the need for dispatchable generation in 2050 is not very much higher (maximum 8-9 GW installed capacity, compared to about 5 GW in the reference scenario based on the ‘normal, average’ climate year 2015). The main reason for this ‘moderate’ need for dispatchable generation is the high demand response of P2X technologies – such as P2H$_2$, P2Heat and EVs – during these climate years, notably much lower electricity demand by these technologies during low VRE supply hours in general and Dunkelflaute periods in particular. Moreover, a major part of the resulting (relatively low) residual load can be covered by net imports, even if there is a Dunkelflaute in a major neighbouring country (Germany) as well. As a result, the need for dispatchable generation is relatively low, even in extreme climate years with one or two Dunkelflaute periods.[80]

[80] Note, however, that from a social optimization point of view, the estimated need for dispatchable generation in 2050 – i.e., about 8-9 GW installed capacity – is most likely even an ‘overestimate’ as for the sensitivity cases ‘*Climate Year 1987*’ and ‘*Climate Year 1996*’ the COMPETES-TNO model assumes that the electricity demand and VRE supply profiles of these ‘extreme’ climate years – including the Dunkelflaute periods – are more or less representative for all the years over which capacity investments ore optimized. In practice, however, an ‘extreme’ climate year/Dunkelflaute period happens only once in 5-10 years, alternated by ‘normal’ or even ‘favorable’ climate years. Hence, optimizing capacity years over a series of alternated climate years results (most likely) in a lower need for dispatchable generation capacity than over an (implicitly) assumed series of ‘extreme’ climate years only.

6 Key findings, qualifications & conclusions

This chapter summarises first of all the key findings and insights of the current study (Section 6.1), followed by a brief discussion of these findings and insights (Section 6.2). Subsequently, Section 6.3 discusses some model limitations and other qualifications to both the approach (methodology) and results of the study. Finally, Section 6.4 presents the major conclusions.

6.1 Key findings and insights

In summary, the key findings and insights of the current study include:

1. **Reference scenario (2030-2050)**

In the reference scenario, the (endogenous, cost-optimal) demand for dispatchable generation capacity – excluding balancing/emergency reserves – drops from almost 16 GW in 2030 to 10 GW in 2040 and to 5 GW in 2050 (under the assumptions and limitations of the optimisation model COMPETES-TNO; see Section 6.3 below). In 2030-2040, the capacity mix ('supply') of dispatchable generation technologies consists still predominantly of natural gas-fired plants – i.e., by 14.7 GW (94%) and 8.2 GW (82%), respectively – supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (predominantly waste standalone), large nuclear (Borssele) and – in 2040 only – small modular reactors (SMRs). In 2050, on the other hand, the role of natural gas-fired plans falls to 1.3 GW (26%), while the main part of the required dispatchable generation capacity (5 GW) consists of gas-retrofitted, hydrogen-fired CCGTs (2.5 GW), supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (waste standalone), and small modular reactors (SMRs).

The two major reasons why the need for dispatchable generation capacity in 2050 is relatively low (5 GW) – despite the high, rapidly growing demand for electricity up to 2050 – are (i) the high potential of flexible demand in the 2050 reference case – notably by P2X technologies such as power-to-hydrogen, power-to-heat and power-to-mobility (EVs), as well as by means of industrial load shedding – and (ii) the opportunity to import large amounts of electricity (up to 12-13 GW) during hours with a low domestic supply of electricity from variable renewable energy (VRE, i.e. sun/wind).

In 2050, the number of full load hours ('capacity factor') is relatively low for both the mid-load (biomass retro) and peak-load technologies (notably H_2 CCGT), resulting in relatively low electricity output levels by these technologies. This raises serious questions regarding the riskiness and economic viability (profitability) of both retrofit and new investments in these technologies (see also Section 6.3 below).

2. **Sensitivity cases (2050)**

In the (nine) sensitivity cases conducted for the year 2050, the (endogenous, cost-optimal) demand for dispatchable generation capacity varies from 4.2 GW in the case '*Extra Trade*' to almost 18 GW in the cases '*No Trade*' and '*Power CO_2-free + Less Flexible Demand'*. More specifically, the most striking findings regarding the sensitivity cases include (see also point 3 below):

- In the two sensitivity cases with '*Less Flexible Demand (LFD)'* - i.e., assuming less demand response by both EVs and household heat pumps as well as no industrial load shedding – the need for dispatchable generation is increased by about 6-7 GW.

- In the two cases assuming '*Power CO_2-free'*, the higher need for dispatchable generation (also approximately 6-7 GW) is primarily due to the outcomes of these cases in 2040. More specifically, in these latter cases natural-gas fired installations (and CCS) are not allowed, implying that the natural gas capacity in the 2040 reference case (8.2 GW) is replaced by additional capacities of H_2 CCGT (retro), nuclear (SMRs) and biogas (new). In the 2050 reference case, however, 6.9 GW of natural gas-fired capacity is decommissioned, whereas in the 2050 sensitivity cases assuming '*Power CO_2-free*' the (additional) capacities of H_2 CCGT, SMRs and biogas required in 2040 remain installed in 2050.

- In the case '*Extra Trade',* the total need for dispatchable generation capacity in 2050 is only slightly lower, i.e. 4.2 GW (compared to 5 GW in the reference case), whereas in the case '*No Trade'*, this need is substantially higher, i.e. 17.6 GW. This implies that if the total interconnection capacity of the Netherlands is assumed to be expanded substantially in 2050 – i.e., by almost 10 GW in the case '*Extra Trade*' – the need for dispatchable generation capacity is reduced by less than 1 GW (most likely because during some critical peak residual load hours the total, expanded import capacity from neighbouring countries is actually not available and, hence, this load has to be met by other flexibility options, including dispatchable generation). On the other hand, if the total interconnection capacity of the Netherlands is assumed to be zero ('*No Trade*'), the loss of this trade capacity (-12.8 GW) is almost fully compensated by a similar increase in dispatchable generation (+12.5 GW). These findings indicate that up to a certain level (approximately 12-13 GW), trade (import) seems to be a rather reliable flexibility option – even during peak residual load hours – but beyond this level it looks like becoming far less reliable.

In the sensitivity cases with a relatively high demand for dispatchable generation (12-18 GW), the capacity mix of dispatchable generation technologies consists largely of (both new and gas-retrofitted) hydrogen-fired CCGTs (6-13 GW), supplemented by small amounts (0.3-3.1 GW) of coal-retrofitted biomass installations (with/without CCS), new biogas plants, other RES-E (waste standalone), natural gas-fired CCGTs, and small modular reactors (SMRs).

Due to large differences in the number of full load hours between baseload technologies (notably nuclear) and peak-load technologies (natural gas/H_2 CCGTs), however, the share of baseload technologies in the mix of dispatchable generation technologies is generally much higher – and even dominant in most cases considered – in terms of electricity output (TWh) rather than installed capacities (GW). For instance, in the 2050 reference case total dispatchable generation (3.6 TWh) comes mainly from SMRs (2.1 TWh) and hardly from natural gas/H_2 CCGTs (0.3 TWh), while in the case '*Power CO_2-free*' these figures amount to 22.9, 19.7 and 0.5 TWh, respectively.

3. Dunkelflaute periods (2050)

Two sensitivity cases for the year 2050 are based on the hourly electricity demand and VRE supply profiles of two 'extreme' climate years, 1996 and 1987, including one and even two '*Dunkelflaute*' periods, respectively. In these two cases, the (endogenous, cost-optimal) demand for dispatchable generation capacity amounts to approximately 8-9 GW, compared to about 5 GW in the 2050 reference case based on the 'normal' ('average') climate year 2015. The main reason for this relatively low need for dispatchable generation is the high demand response of P2X technologies – such as P2H_2 and P2Heat – during these climate years, notably much lower electricity demand by these technologies during low VRE supply hours in general and Dunkelflaute periods in particular. Moreover, a major part of the resulting (relatively low) residual load can be covered by net imports, even if there is a Dunkelflaute in a major neighbouring country (Germany) as well. As a result, the need for dispatchable generation is relatively low, even in extreme climate years with one or two Dunkelflaute periods.

6.2 Discussion

Domestic capacity of dispatchable (CO_2-free) power generation plays a critical role in safeguarding both power system adequacy and climate neutrality. As discussed above, simulations by means of the European P2X system optimisation model COMPETES-TNO indicate, however, that in six out of ten reference/sensitivity cases analysed the total need for dispatchable generation capacity by the Netherlands in 2050 is relatively low, i.e., about 5-9 GW, compared to an average Dutch load of approximately 44 GW in 2050. The main reasons – and underlying considerations – for this relatively low demand for dispatchable generation capacity are:

i. By 2050, the Netherlands has a large potential of VRE power generation that is usually more competitive than dispatchable power generation or electricity imports. VRE supply, however, is rather volatile and often hardly or not available during several hours of the day, week, month, or year. Therefore, in order to safeguard system adequacy, VRE power generation has to be supplemented by flexibility options such as dispatchable generation, storage, trade, or flexible demand. Considering available potentials and specific abilities of these options, dispatchable generation is often more expensive, however, than electricity imports and, notably, flexible demand – in particular, demand shifting and conversion by P2X technologies – but cheaper than electrical storage and demand curtailment.

ii. The peak residual load in most cases analysed is generally relatively low (24-25 GW), even in hours with hardly or no VRE supply. This is primarily due to the high level of flexible demand in the P2X system, notably by P2X technologies such as P2Hydrogen, P2Heat and P2Mobility (EVs). As a result, the residual load (RL) is relatively low when there is hardly or no VRE supply and relatively high when VRE supply is abundant, while over the year 2050 as a whole the main part (90-99%) of total domestic power generation is derived from VRE sources.

iii. A major part of the (peak) RL in 2050 can be covered by net electricity imports, up to the assumed interconnection capacity of the Netherlands (i.e., 12.8 GW in 2050), even during a Dunkelflaute period in both the Netherlands and Germany. So, the need for dispatchable generation to meet the remaining RL – i.e., after flexible demand and net imports – is relatively low (as said, about 5-9 GW in most cases analysed).

Hence, in a power system with a very high share of VRE generation by 2050 (90% or more), the residual – highly fluctuating – electricity demand in the Netherlands is expected to be met mainly by flexible demand and electricity trade, while the remaining demand – if any – is largely covered by dispatchable generation with hardly or no need for other, more expensive flexibility options such as electricity storage or demand curtailment.

A major question, however, is whether – and to what extent – flexible demand and electricity trade are reliable ('firm') flexibility options, notably during 'extreme' demand/supply conditions such as, for instance, a major (*kaltes*) Dunkelflaute period that affects not only the Netherlands but also Germany/other major EU electricity producing and trading countries.

Flexible demand by power-to-heat in industry and, notably, power-to-hydrogen is highly reliable ('firm') as these technologies are primarily driven by strong economic incentives, i.e. highly focussed on benefitting from low electricity prices by enhancing power demand and, on the other hand, avoiding high electricity prices by lowering or even nullifying demand in order to maximise profits and minimise losses. Actually, P2hydrogen can only be competitive and survive commercially if it responds flexibly to fluctuating electricity prices.

Demand response by EVs and household heat pumps, however, is usually a less reliable flexibility option, in particular during longer *kaltes Dunkelflaute* periods, as usually it is more a short-run flexibility option – i.e., shifting demand over a limited number of hours (heat pumps) or, maximally, a limited number of days (EVs) – which is less driven by economic (price) incentives and more by other, behavioural considerations such as comfort or transport ('range') security.

Foreign trade, notably electricity imports, appears to be a reliable ('firm') flexibility option to address the (positive, peak) residual load *up to a certain level*, i.e. in almost all 2050 cases analysed up to the assumed interconnection capacity of the Netherlands in 2050 (12.8 GW), even if there is a Dunkelflaute in both the Netherlands and Germany (thereby significantly reducing the need for dispatchable generation/other, more expensive flexibility options). Beyond that level, however, electricity imports seem to become less reliable as a flexibility option or, in any case, an expansion of the interconnection capacity does not result in a similar (proportional) reduction in the need for dispatchable generation/other flexibility capacity. More specifically, in the case '*Extra Trade*' – where the interconnection capacity of the Netherlands in 2050 is enlarged by 9.8 GW, i.e. to 22.6 GW, compared to 12.8 GW in the reference scenario – the need for dispatchable generation capacity is reduced by only 0.9 GW, i.e. to 4.2 GW, compared to 5.1 GW in the reference scenario.

High demand cases for dispatchable generation
In four out of ten reference/sensitivity cases analysed, the total demand for dispatchable generation capacity is substantially higher, varying from 12 to 18 GW. This higher need can be attributed to one of the following factors:

- *Flexible demand*: In two cases, less flexible demand by the P2X system is assumed, i.e. excluding both industrial load shedding (ILS) and demand response (DR) by EVs and household heat pumps. As a result, the need for dispatchable generation in 2050 increases significantly, notably by almost 7 GW in the case '*Less Flexible Demand*' (compared to the 2050 reference case).
- *CO_2-free power generation*: In two sensitivity cases, a target of zero CO_2 emissions – starting from 2040 – is assumed for the power generation sector of the Netherlands (and some other West-European countries), including no balancing of negative and positive CO_2 emissions across the P2X sectors of these countries. As a result, the demand for dispatchable generation in 2050 increases by nearly 7 GW in the case '*Power CO_2-free*' (compared to the reference scenario) and even by 12.5 GW in the mixed case '*Power CO_2-free + Less Flexible Demand*'.
- *Electricity trade*: in one sensitivity case, no foreign trade of electricity is assumed. Consequently, the interconnection capacity of the Netherlands in the 2050 reference scenario (12.8 GW) is replaced primarily by more dispatchable generation capacity (+12.5 GW).

In addition to the total need ('demand') for dispatchable generation capacity in 2050, the technology mix ('supply') of this capacity also varies significantly across the cases analysed, depending on their underlying assumptions, in particular regarding the (exogenously assumed) potentials and costs of the available generation technologies as well as to the specific CO_2 constraints of the cases analysed. For instance, if the zero CO_2 emission constraint is set at the European P2X system as a whole, most cases analysed show that even in 2050 there is still some room – up to 1.3 GW – to deploy some remaining fossil-gas-fired power plants in the Netherlands in a cost-optimal way (with the resulting CO_2 emissions compensated by negative emissions from biomass + CCS in the Dutch power generation sector or elsewhere in the European P2X system). In these cases, the remaining need for dispatchable generation is met by CO_2-free technologies, in particular (i) H_2 CCGT-retro (varying from zero to 13 GW), (ii) biogas-new (0-1.5 GW), (iii) biomass-retro, either with CCS (0-0.5 GW) or without CCS (0.1-1.1 GW), (iv) other RES-E, i.e. predominantly waste standalone (0.3 GW) and (v) nuclear, i.e. small modular reactors (0-3.1 GW). In all these cases, however, the COMPETES-TNO model optimisation runs do not result in any endogenous capacity investments of either large-scale nuclear, biogas-retro or biomass + CCS in 2040/2050 as these options turn out to be less cost-optimal by the model (given the underlying cost parameters and other scenario assumptions up to 2050).

6.3 Model limitations and qualifications

Some model limitations and other qualifications have to be added to the study findings outlined above.

Firstly, COMPETES-TNO is a so-called 'cost-optimisation' model, i.e. it analyses how a certain energy demand (electricity, hydrogen) over a certain period – usually a full target year – is met within certain techno-economic and policy constraints at the lowest social costs. A major characteristic of such models is that they are based on 'perfect foresight', i.e. they assume the availability of full, free knowledge for investment decisions – notably concerning future costs, prices and market transaction volumes – and, therefore, these models hardly or not consider any uncertainties or risks regarding these investment decisions.

In practice, however, investments in the power system are characterized by high risks and uncertainties, notably regarding future electricity prices and sales volumes in power systems with a high share of VRE generation. This applies in particular to both retrofit and new investments in dispatchable peak-load technologies – with a small number of full load hours – as well as to 'back-up' dispatchable generation technologies to address extreme weather conditions, including Dunkelflaute periods, which may occur only once or twice in a decade.

Due to these risks and uncertainties, private parties are generally hesitant to invest in such technologies and, therefore, they usually require a high profit ('discount') rate – including a high risk premium – which, in general, is significantly higher than the discount rate used in a cost-optimisation model such a COMPETES-TNO.[81] As a result, retrofit/new investments in dispatchable generation may pop-up as 'optimal' from a social cost modelling perspective but may lack economic viability ('profitability') from a private investor's point of view and, therefore, may not be realised. For policy makers, this may imply that they decide to support these investments – for instance, by investment or operational subsidies, contracts-for-differences, or capacity mechanisms – in order to safeguard a reliable and adequate power system at affordable (social/private) costs.

[81] COMPETES-TNO uses a uniform (social) discount rate of 6.5% whereas the required profit rate on risky private capital investments varies usually between 7-15%, depending on the risk profile of these investments.

In addition, it should be realised that, in practice, investments in dispatchable generation depend not only on social cost-optimisation or simple private cost-benefit considerations but often also on other considerations. This applies, for instance, in particular to both retrofit and new investments in biomass-fuelled power plants (with/without CCS), depending on the socio-political acceptance of using biomass/CCS for generating electricity (rather than other renewable energy/GHG mitigation purposes).

Secondly, analyses by COMPETES TNO are based on a so-called 'Energy-Only-Market' approach. The core of such an EOM approach is that (private) investors in power generation capacity should cover the costs of their investments solely from market revenues of their electricity output (and not from additional subsidies or any other compensations, e.g. for safeguarding the availability of a certain back-up capacity). Therefore, COMPETES does not include any subsidies and, as a result, no hours with negative electricity prices. In practice, however, the Dutch power system is characterised by a wide variety and growing amounts of subsidies, notably on VRE and dispatchable, CO_2-free generation technologies, resulting in a growing number of hours with negative electricity prices and affecting both the total demand and supply mix of dispatchable generation versus other flexibility options.

Moreover, EOM analyses by COMPETES-TNO refer to the hourly spot market only but do not include markets for balancing/emergency reserves or other ancillary services such as reactive power, redispatch or black start facilities. As a result, these analyses underestimate the total future need for dispatchable generation – and/or electricity storage – to safeguard a reliable and adequate power system.

Thirdly, as mentioned above, investments in the power system are characterized by large uncertainties. In this scenario study, a specific category of these uncertainties concerns the capital costs (CAPEX) of both retrofit and new investments in dispatchable generation technologies in the years 2030, 2040 and 2050 as well as the operational (mainly fuel) costs of these technologies in these future years, notably for power plants fuelled by biomass, biogas or hydrogen.[82] In addition, related uncertainties apply for the (socio-political) availability of these fuels – notably biomass and biogas – for producing electricity and, to some extent, the techno-economic potentials of retrofit generation technologies. Moreover, there is a wide variety of other relevant uncertainties, notably regarding the future demand for electricity, including the distinction between 'direct' electricity demand and 'indirect' electrification by means of power-to-hydrogen or other E-fuels.

In this study, specific assumptions regarding the above-mentioned uncertainties have been used – specified largely in Chapter 2 – based on specific sources. Over time and across other, alternative sources, however, similar assumptions usually vary substantially. Changing one or more of these assumptions may have a significant impact on both the total need for dispatchable generation and the cost-optimal supply mix of the required dispatchable technologies versus other flexibility options.

Fourthly, this study has conducted a selected variety of (nine) sensitivity cases to explore the impact of some of the uncertainties mentioned above on the demand and supply of dispatchable generation in the power system of the Netherlands. These uncertainties refer in particular to the potential and reliability of competing flexible options such as foreign trade and demand response (including industrial load shedding), the impact of extreme weather conditions, the capital investment costs (CAPEX) of sun PV, and the impact of exogenous policy

[82] Note, however, that similar cost uncertainties apply to other dispatchable generation technologies (e.g., nuclear) or VRE generation technologies such as sun PV and offshore wind.

decisions such as enabling the instalment of a certain capacity of nuclear power generation by 2050 or not allowing dispatchable generation options such as natural gas-fired plants or biomass installations with CCS (for instance, by not allowing trade of positive versus negative CO_2 emissions within the European/NL energy system).

A large number of other uncertainties, however, have not been addressed by means of conducting corresponding sensitivity cases. These refer in particular to the uncertainties mentioned above, notably (i) the capital costs (CAPEX) of both retrofit and new investments in dispatchable generation technologies in the years 2030, 2040 and 2050 as well as the operational (mainly fuel) costs of these technologies in these years, (ii) the availability and socio-political acceptance of fuels such as biomass and biogas (including CCS) for power generation, (iii) the techno-economic potentials of retrofit generation technologies, and (iv) the size and structure of future demand for electricity.

Moreover, most sensitivity cases – i.e., 8 out of 9 – have analysed the impact of the incidence of a single uncertainty only. In practice, however, a variety of uncertainties applies at the same time. As a result, the need for dispatchable generation (or electricity storage) may be significantly higher to address the incidence of multiple uncertainties simultaneously (rather than each single uncertainty separately).

Finally, COMPETES-TNO includes the high-voltage transmission lines and interconnections between European countries, but the model does not cover the distribution networks at the regional and local levels. As a result, it does not consider congestion issues at these sub-national levels and, therefore, may underestimate the need for flexible options such as (re)dispatchable generation or electricity storage over the years 2030-2050 (although it is unclear whether – and to which extent – congestion may still occur in long-term future years such as 2040 or 2050).

6.4 Conclusions

Under the assumed conditions of the 'climate-neutral' reference scenario, the total need ('demand') for dispatchable generation capacity in the Dutch power system decreases from approximately 16 GW in 2030 to 10 GW in 2040 and to 5 GW in 2050. In terms of electricity output, the need for dispatchable generation declines even stronger from about 29 TWh in 2030 to 10 TWh in 2040 and to 4 TWh in 2050 (i.e., from approximately 15% of total electricity production in 2030 to 1% in 2050). Despite the rapidly growing demand for electricity over the years 2030-2050, this decreasing and relatively low need for dispatchable generation – notably in 2050 – is mainly due to (i) the rapidly growing supply of VRE generation over this period, (ii) the (assumed, growing) availability of other flexible options, notably a high level of demand response – including industrial load shedding – and foreign trade (interconnections), and (iii) the assumption of 'normal' ('average') weather conditions in the reference target years.

In the (nine) sensitivity cases conducted for the year 2050, the need for dispatchable generation varies from 4.2 GW to 18 GW and, in terms of electricity output, from 2.6 TWh to more than 43 TWh (i.e. ranging from 0.6% to 10% of total electricity generation in the 2050 cases considered). These cases show that, as indicated above, the need for dispatchable generation depends in particular on (i) the (assumed) availability of other flexibility options, notably the availability/reliability of demand response and foreign trade, (ii) the (assumed) weather conditions, i.e. assuming either 'normal' ('average') weather conditions or 'extreme weather conditions, including one or two '*Dunkelflaute*' periods (i.e., with hardly any sun and wind), and (iii) the (assumed) policy conditions, notably whether – and to which extent –

certain dispatchable generation technologies (natural gas, biomass/CCS) are allowed or primarily policy-induced, i.e. assumed exogenously (nuclear).

On the other hand, the mix ('supply') of the required dispatchable generation technologies depends – besides the total need ('demand') for dispatchable generation capacity/output – mainly on (i) the investment and operational (fuel) costs of these technologies, (ii) the techno-economic potential of retrofitted generation technologies, (iii) the availability and socio-political acceptance of dispatchable fuels (biomass, biogas), (iv) the GHG mitigation target concerned and the resulting CO_2 price, and (v) the incidence of other policy conditions regarding the dispatchable generation technologies considered.

In 2030-2040, the capacity mix of dispatchable generation technologies consists still predominantly of natural gas-fired plants – i.e., by 14.7 GW (94%) and 8.2 GW (82%), respectively – supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (predominantly waste standalone), large nuclear (Borssele) and – in 2040 only – small modular reactors (SMRs). In 2050, on the other hand, the role of natural gas-fired plans falls to 1.3 GW (26%), while the main part of the required dispatchable generation capacity (5 GW) consists of gas-retrofitted, hydrogen-fired CCGTs (2.5 GW), supplemented by small amounts (0.1-0.5 GW) of coal-retrofitted biomass installations (with/without CCS), other RES-E (waste standalone), and small modular reactors (SMRs).

In the sensitivity cases with a relatively high demand for dispatchable generation (12-18 GW), the capacity mix of dispatchable generation technologies consists largely of (both new and gas-retrofitted) hydrogen-fired CCGTs (6-13 GW), supplemented by small amounts (0.3-3.1 GW) of coal-retrofitted biomass installations (with/without CCS), new biogas plants, other RES-E (waste standalone), natural gas-fired CCGTs, and small modular reactors (SMRs). Due to large differences in the number of full load hours between baseload technologies (notably nuclear) and peak-load technologies (natural gas/H_2 CCGTs), however, the share of baseload technologies in the mix of dispatchable generation technologies is generally much higher – and even dominant in most cases considered – in terms of electricity output (TWh) rather than installed capacities (GW).

The findings and conclusions outlined above, however, have to be treated with due care, mainly because of the limitations of the applied cost-optimisation model (COMPETES-TNO) and the large variety of uncertainties regarding the assumed scenario runs up to 2050 (which have only been partially covered by the conducted sensitivity cases).

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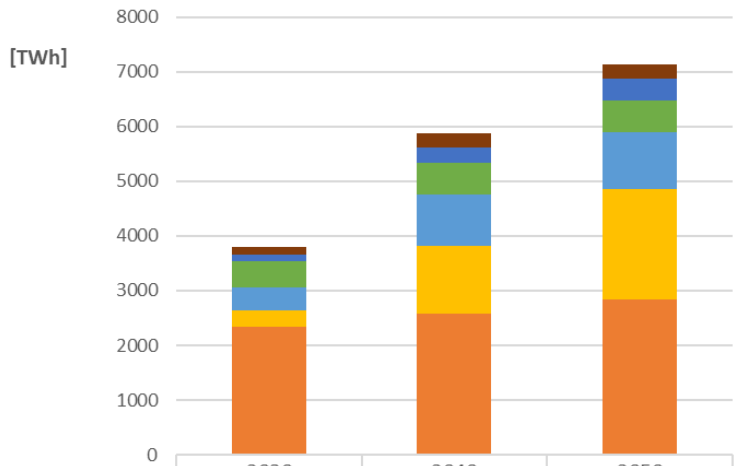
Appendix A

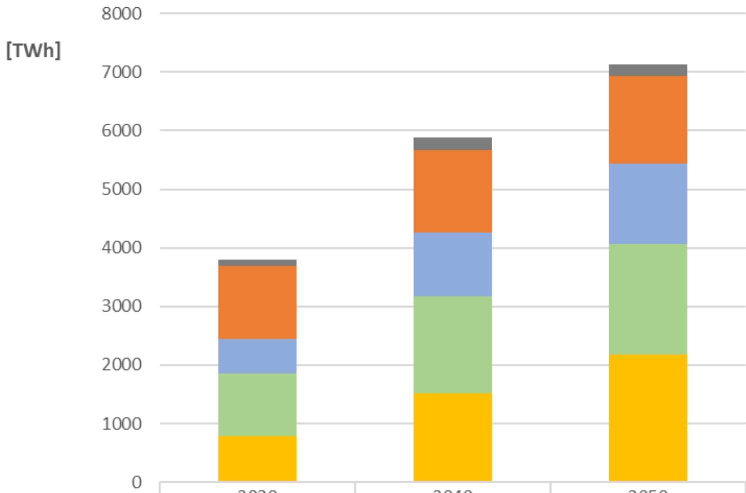
Reference scenario (2030-2050) – Some results for the EU27+

As background information to the reference scenario results for the Netherland (as discussed in Chapter 3 of the current report), this Appendix provides some similar results – without further explanation – for the European countries and regions covered by the COMPETES-TNO model as a whole, indicated as 'EU27+', i.e. including the 27 EU Member States plus some other European countries and regions covered by the model (see Chapter 2, notably Figure 2.1, for the European geographical coverage of COMPETES-TNO).



	2030	2040	2050
Storage (charge)	140	265	251
P2Mobility (EVs)	115	283	405
P2Heat (households)	479	579	589
P2Heat (industry)	420	927	1031
P2Hydrogen	300	1251	2021
Conventional	2347	2574	2835

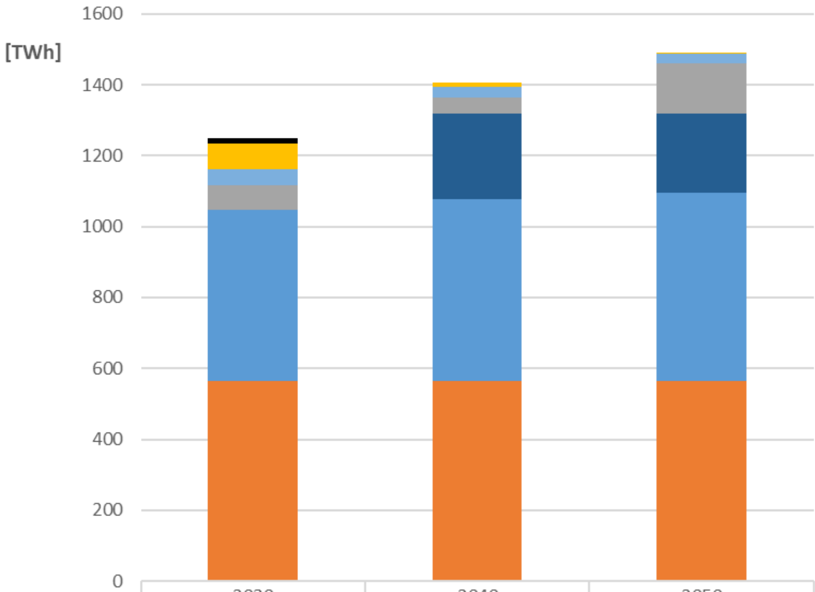
Figure A.1: Reference scenario, 2030-2050: Electricity demand in the EU27+



	2030	2040	2050
Storage (discharge)	107	212	203
Dispatchable generation	1248	1405	1492
Wind offshore	580	1080	1376
Wind onshore	1074	1670	1882
Sun PV	791	1512	2180

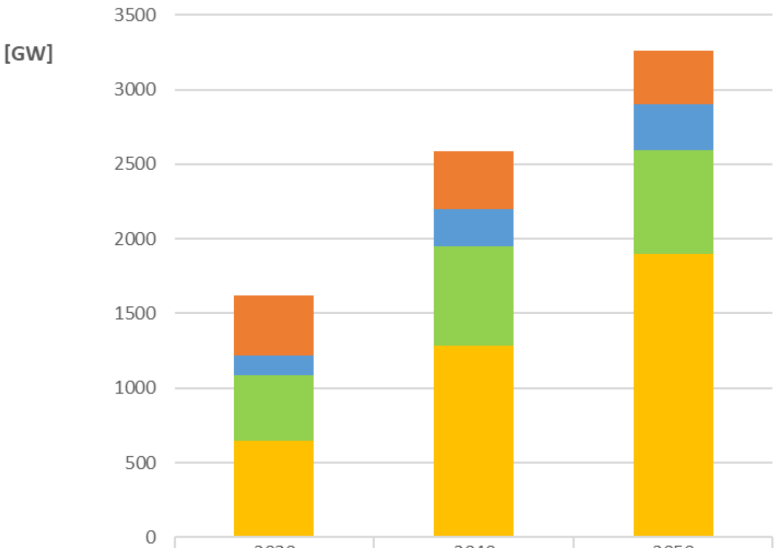
Note: A breakdown of the dispatchable power supply mix is provided in Figure A.3 below.

Figure A.2: Reference scenario, 2030-2050: Electricity supply in the EU27+



	2030	2040	2050
Coal	14	0	0
Gas	74	12	5
Other RES-E	44	28	28
Biomass	68	48	140
Biomass CCS	0	241	225
Nuclear	485	513	531
Hydro	563	563	563

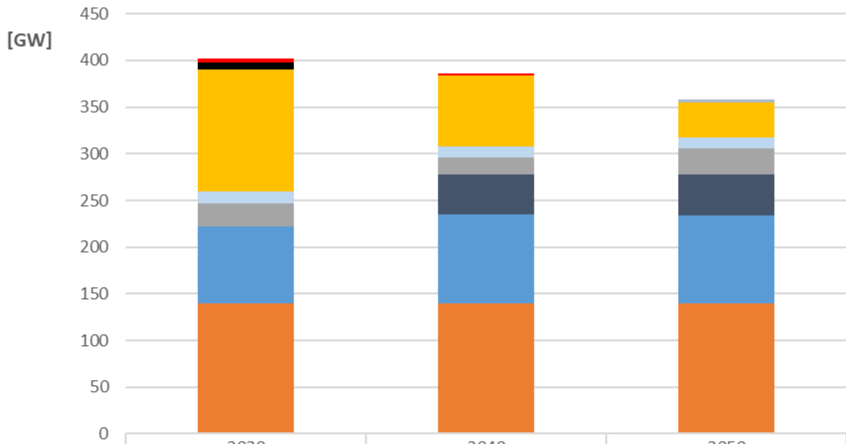
Figure A.3: Reference scenario, 2030-2050: Breakdown of the dispatchable power supply mix in the EU27+



	2030	2040	2050
Dispatchable generation	401	385	358
Wind offshore	134	251	311
Wind onshore	440	663	690
Sun PV	646	1284	1900

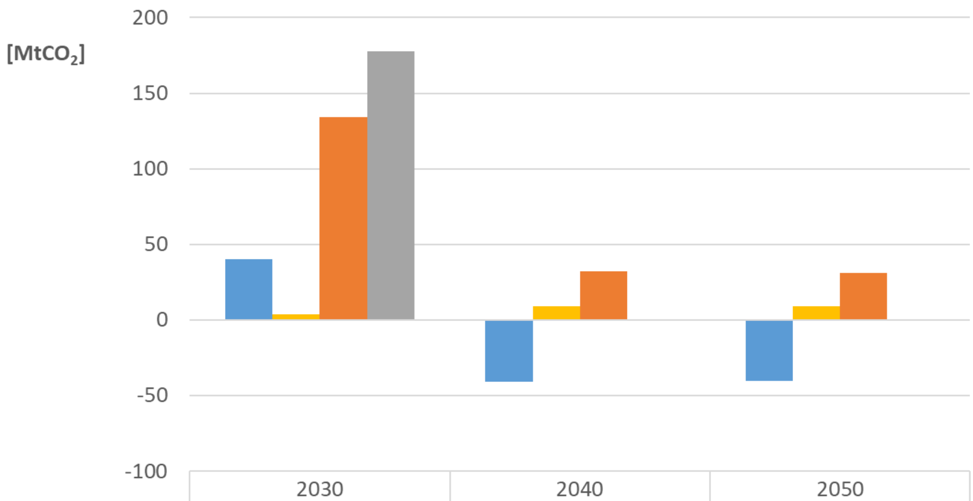
Note: A breakdown of the dispatchable power supply mix is provided in Figure A.5 below.

Figure A.4: Reference scenario, 2030-2050: Installed power generation capacity mix in the EU27+



	2030	2040	2050
H2-2-Power	0	0	2
Oil	4	1	0
Coal	8	0	0
Gas	130	76	38
Other RES-E	13	12	12
Biomass	24	18	28
Biomass CCS	0	43	43
Nuclear	83	95	95
Hydro	139	139	139

Figure A.5: Reference scenario, 2030-2050: Breakdown of the installed dispatchable generation capacity mix in the EU27+



	2030	2040	2050
Power generation sector	40.2	-41.2	-40.5
H2 production sector	3.4	9.1	9.3
Industrial heat sector	134.1	32.1	31.3
Total	177.7	0.0	0.0

Figure A.6: Reference scenario, 2030-2050: CO_2 emissions of the P2X system in the EU27+

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