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The role of large-scale energy storage in the energy system of the Netherlands, 2030-2050

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Preface

This report presents and discusses the results of the activities performed in Work Package 1 of the research project "Large-Scale Energy Storage in Salt Caverns and Depleted Gas Fields", abbreviated as LSES. The project, which was given subsidy by RVO, had two main goals:

1. Improve insights into the role that large-scale subsurface energy storage options can play in providing flexibility to the current and future transitioning energy system;
2. Address techno-economic challenges, identify societal and regulatory barriers to deployment, and assess risks associated with selected large-scale subsurface energy storage technologies, in particular Compressed-Air Energy Storage (CAES) and Underground Hydrogen Storage (UHS).

The research was carried out by TNO in close collaboration with project partners EBN, Gasunie, Gasterra, NAM and Nouryon. Activities were divided over 4 work packages that ran in parallel:

1. Analysis of the role of large-scale storage in the future energy system: what will be the demand for large-scale storage, when in time will it arise, and where geographically in our energy system will it be needed?
2. Techno-economic modelling (performance, cost, economics) of large-scale energy storage systems, focusing in CAES and UHS in salt caverns, and UHS in depleted gasfields - analogous to UGS (Underground natural Gas Storage).
3. Assessment of the current policy and regulatory frameworks and how they limit or support the deployment of large-scale energy storage, and stakeholder perception regarding energy storage.
4. Risk identification and screening for the selected large-scale subsurface energy storage technologies.

In this report, the results of the activities performed in work package 1 on the role of large-scale energy storage in the Dutch energy system in 2030 and 2050 are detailed. The results of the other work packages are detailed in three other reports.

Project details

Subsidy reference:	TGEO118002
Project name:	Large-Scale Energy Storage in Salt Caverns and Depleted Gas Fields
Project period:	April 16, 2019 until August 30, 2020
Project participants:	TNO (executive organization), EBN, Gasunie, Gasterra, NAM and Nouryon

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Summary

Background
The transition towards a climate-neutral energy system in the Netherlands implies, among others, a larger share of electricity from variable renewable energy (VRE), notably sun and wind, as well as a shift from natural gas to green gases such as hydrogen produced from VRE generated electricity. In turn, these changes may have significant implications for the future role of energy storage in the Dutch energy system.

Objective and scope
In this study, the role of energy storage in the future, low-carbon energy system of the Netherlands is analysed from an integrated, national energy system perspective, including cross-border energy trade relationships with neighbouring countries. Specific focus is paid to large-scale energy storage (LSES) such as compressed air energy storage (CAES) and underground hydrogen storage (UHS). Besides analysing the potential role of LSES, the study considers also other storage technologies – such as batteries or hydrogen storage in cars, filling stations or vessels – as well as other flexibility options such as demand response or cross-border energy trade.

Approach
In order to reach the objective mentioned above, the study defines and uses two reference scenarios, one for 2030 and one for 2050. For 2030, the reference scenario is based on the targets and policy measures of the Climate Agreement (CA) of June 2019 and designated briefly as CA2030. For 2050, the reference scenario is based on the National Management (NM) scenario, developed recently by Berenschot and Kalavasta (2020), and designated briefly as NM2050.

The NM2050 scenario is characterised by a strong governance by the Dutch national administration as well as by a high level of national energy self-sufficiency (i.e. with minimal energy imports). Moreover, it shows a strong further electrification of all energy-use sectors, enabled by a very large installed capacity of solar PV and offshore wind. In addition, both industry and freight transport rely on a substantial deployment of domestically produced green hydrogen. Imbalances of the energy system are met by national storage – among others of hydrogen – in combination with flexible power plants fuelled by green (bio)gas and green hydrogen that can (re)generate electricity on-demand, thus providing back-up capacity for periods of low production from variable renewable energy (VRE) sources such as sun or wind.[1]

The reference scenarios for 2030 and 2050 as well as a variety of sensitivity cases for 2050 are analysed by means of two optimisation models, i.e. a European electricity market model (COMPETES) and a national integrated energy system model of the Netherlands (OPERA). Both models can use a one-hour temporal resolution and are therefore well equipped to study flexibility and storage issues in

[1] It should be noted that back-up, hydrogen fuelled power plants play a dominant role in NM2050 as developed by Berenschot and Kalavasta (2020) and analysed by means of the (simulation) Energy Transition Model (ETM), but hardly or not in the NM2050 scenario analysed in the current study by the (optimisation) models OPERA and COMPETES. This issue is further explored in Chapter 5 of this report.

an energy system with a large amount of VRE. Whereas COMPETES focuses on flexibility of the electrical power system in the Netherlands in connection to other countries, OPERA deals with integrated energy system issues of the Netherlands, including the demand, supply and storage of electricity and hydrogen in competition with other energy sources and energy carriers. By using two models, it is possible to show and, to some extent, explain the impact of different model characteristics on modelling outcomes regarding energy storage.

Both models minimise the social cost of the power (COMPETES) or energy (OPERA) system while satisfying demand and emission requirements. A limitation of both models is that they optimise over a single year only and not over a time horizon. Moreover, as the models aim for minimal cost, they do not allow for any redundancy in the system to cover for events that jeopardize the security of supply (e.g. exceptional weather conditions, supply disruption, etc.) and to meet other policy-strategic considerations (e.g. strategic reserves, energy independence, etc.). Although not a real limitation of the models, in this study we use supply and demand profiles for a typical year, which implies that results do not pertain to exceptional weather years, e.g. with a Dunkelflaute.[2]

Storage in the CA2030 scenario
For CA2030, COMPETES and OPERA foresee a different role for hydrogen. Following the ambitions of the Climate Agreement of June 2019, a modest additional 2 GW of electrolysis capacity has been assumed in both models. COMPETES assumes a correspondingly (policy-supported) high demand for H_2 from electrolysis of 24 PJ (6.7 TWh) whereas OPERA determines endogenously that the (market-based) demand for H_2 in CA2030 is much lower (6.7 PJ) and is predominantly supplied by Steam Methane Reforming (SMR, without CCS). Note, that this is new H_2 demand for mobility (high-duty vehicles) and for heating in the built environment, which is on top of 162 PJ of H_2 demand being part of conventional industrial processes such as oil-refining and ammonia production.

The difference in hydrogen use and production has a direct effect on both electricity and hydrogen storage requirements, which are shown in Table 1. Both models foresee a large contribution for storage in electric vehicles (EVs), but this electricity is primarily used for propulsion of vehicles, although COMPETES also includes some EV battery storage for Vehicle-to-Grid (V2G) transactions. In OPERA, additional stationary battery storage capacity provides the flexibility to match the variability in VRE supply, whereas in COMPETES this variability is mainly matched by hydrogen production and underground hydrogen storage. The additional H_2 storage foreseen by OPERA is for H_2 produced by SMR and serves end-use functions such as the H_2 demand by high-duty vehicles in the transport sector and H_2 boilers for (seasonal) heating in the built environment, as endogenously determined by OPERA. This indicates that the need for H_2 storage in CA2030 depends highly on the policy support for H_2 electrolysis as well as on the end-use sectors in which H_2 is consumed.

[2] Energy storage needs due to extreme weather conditions or policy-strategic considerations have been analysed recently by Berenschot and Kalavasta (2020) by means of the Energy Transition Model (ETM).

Table 1: Summary of storage results calculated by OPERA and COMPETES for CA2030

EV batteries	**Size**	**Volume**	**FCE[a]**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	45	1500	24	10.1	0.5[b]
COMPETES	31	1450[c]	48	1.5	1.5
Total E-storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*	*#*	*%*	*%*
OPERA	64	1946	30	0.05%	1.4%
COMPETES	31	1461	48	0.02%	1.1%
H2 Underground	**Size**	**Volume**	**FCE**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	10	21	2	0.01	1.3
COMPETES	66	900	14	0.16	0.77
Total H_2 storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*		*%*	*%*
OPERA	42	1157	28	2.3%	62.2%
COMPETES	66	900	14	1.0%	13.4%

a) FCE is Full Cycle Equivalent i.e. the ratio between the annual volume stored and the size of the storage medium;
b) Discharge is to vehicles only and not back to the grid (V2G);
c) Including 197 GWh fed back into the grid (V2G).

Storage in the NM2050 scenario
COMPETES and OPERA use the NM2050 scenario developed recently by Berenschot and Kalavasta (2020), and corresponding data obtained from the ETM model as input for the expected energy demand in 2050, although energy supply capacity and production are to some extent endogenously determined. This leads to differences in modelling outcomes, notably of the production of hydrogen and electricity by wind and solar PV.

Compared to the Berenschot and Kalavasta scenario, OPERA foresees similar amounts of domestic electricity supply (400 TWh) and hydrogen production (92 TWh), but less solar PV capacity and production, compensated by mostly offshore wind capacity and production. COMPETES uses the VRE capacities from the Berenschot and Kalavasta scenario as input but foresees a lower domestic electricity demand and lower H_2 production.

Both OPERA and COMPETES foresee a minimal role for Hydrogen-to-Power. This can be considered a direct result of not accounting for uncertainties in supply in these models, as mentioned earlier, which on efficiency grounds avoid deploying the power-hydrogen-power cycle, i.e., the low efficiency renders this option more costly than alternative flexibility options such as demand response or electricity trade. COMPETES optimises the import/export profiles of electricity based on cross-border trade, and these profiles are also adopted within OPERA. COMPETES foresees a much larger net export for NM2050 than Berenschot and Kalavasta.

Table 2 shows a summary of the storage results calculated by OPERA and COMPETES for the NM2050 reference scenario. The main conclusions from our analyses of the reference scenario as well as of some sensitivity cases for NM2050 are outlined below

Table 2: Summary of storage results calculated by OPERA and COMPETES for the NM2050 reference scenario

EV batteries	**Size**	**Volume**	**FCE**	**Max. charge power**	**Max. discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	975	29971	31	24.3	57.5
COMPETES	1037	33033	32	38.4	38.4
Range (minimum-maximum)	969-1037	19854-49569	20-48	24.3-38.4	38.4-57.5
Total E-storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*	*#*	*%*	*%*
OPERA	975	29971	31	0.25%	7.6%
COMPETES	1037	33044	32	0.30%	9.6%
Range (minimum-maximum)	975-2074	31125-65514	29-48	0.25-0.60%	8.0-19.0%
H_2 Underground	**Size**	**Volume**	**FCE**	**Max. charge power**	**Max. discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	2893	17126	6	13.2	21.2
COMPETES	1536	21697	14	4.5	8.6
Range (minimum-maximum)	1268-4280	13611-34391	4-16	3.8-6.7	8.6-23.4
Total H_2 storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*		*%*	*%*
OPERA	2944	26172	9	3.2%	28.6%
COMPETES	1536	21697	14	2.0%	28.7%
Range (minimum-maximum)	1268-4280	18501-40803	8-16	1.6-5.6%	24.0-44.4%

a) These are the minimum and maximum values found in the sensitivity runs of COMPETES and OPERA combined.

Electricity storage by EV batteries

In both models electricity storage is dominated by batteries of electric vehicles (EVs). It is foreseen that by 2050 about 10 million EVs will have about 1000 GWh storage capacity. This capacity is first of all used to store electricity to be used by EVs for mobility services, while the share used for vehicle-to grid (V2G) storage services is often lower. The electricity storage in EVs is characterised by about 30-40 effective charge/discharge cycles per year. A sensitivity case where we excluded V2G in OPERA resulted in more use for other batteries but also for a higher and more continuous H_2 production, with effectively less demand for H_2 storage. Note, however, that – due to a lack of data – OPERA and COMPETES do not sufficiently take into account all costs and possible limitations of EV battery storage transactions, such as the costs of the EV (dis)charging infrastructure or the preferences of EV owners regarding minimum/maximum levels of EV battery charges and V2G discharges.

H_2 underground storage
Our models results show a clear, significant role for large-scale H_2 underground storage, notably in annual volume terms (17-22 TWh). This type of energy storage, however, is not typical seasonal storage – such as the current storage of natural gas for space heating – which has effectively one charge/discharge cycle per year. For the reference scenario NM2050, our models find full cycle equivalents (FCEs) of H_2 underground storage ranging from 6 to 14. This number of full charge/discharge cycles is firstly the result of the large, short-term variability of the residual power load – notably of VRE supply – without a clear seasonal pattern. As noted, this leads to heavy short-term fluctuations of electricity prices and, subsequently to short-term fluctuations in H_2 supply from electrolysis ($P2H_2$) and, therefore, to a need for short-term H_2 storage (and, hence, to a higher FCE of H_2 storage). In addition, the FCE of H_2 storage depends also on the seasonality (and variability) of H_2 demand, with generally a lower FCE in case of a stronger seasonal pattern of H_2 demand. Whereas in COMPETES the H_2 demand profile in NM2050 is assumed to be flat, in OPERA the demand for hydrogen has a limited seasonal pattern largely because the heat demand in NM2050 – already reduced significantly compared to 2020 due to better insulation of buildings – is also met by other energy sources besides hydrogen, such as electricity or geothermal and ambient heat.

As a result of differences in the factors mentioned above (i.e., the seasonality and short-term variability of H_2 demand and supply), the FCE of H_2 storage is higher in COMPETES (14) than in OPERA (6), i.e. the full cycle of H_2 charges/discharges is, on average, shorter in COMPETES (3-4 weeks) than in OPERA (2 months). Consequently, although the volume of H_2 underground storage in NM2050 is substantial according to our models (17-22 TWh, i.e. 20-30% of total H_2 demand), due to the higher FCE – or shorter term cycle – of H_2 underground storage (6-14), the required size of this storage medium is much smaller (1.5-2.9 TWh, i.e. 2-3% of total H_2 demand). This appearance of short-term energy storage needs – and the disappearance of a clear seasonal pattern – is also observed in the recent report by DNV GL (2020): "*The promise of seasonal storage"*.

Hydrogen storage in the transport sector
In OPERA hydrogen storage in the transport sector – by means of H_2 vehicles and H_2 filling stations – plays a major role in NM2050, notably in volume terms. Hydrogen storage in the transport sector, however, refers primarily to hydrogen charged and used for mobility services rather than flexibility services to stabilise the hydrogen balance.

Underground compressed air energy storage
In neither model does there seem to be a role for large-scale electricity storage such as compressed air energy storage (CAES/AA-CAES). Apart from specific modelling characteristics and limitations, the major reason for this finding is that alternative flexibility options are apparently more attractive (cheaper) or, more generally, have a better techno-economic performance to meet the flexibility needs of the Dutch power system. Note, however, that the current study focusses on the flexibility needs due to the variability of the residual power load – notably VRE supply – and did not consider other flexibility needs of the power system.

Cross-border electricity trade
According to COMPETES, cross-border electricity trade is a major flexibility option to meet the variability of VRE, with annual electricity exports of 83 TWh and imports of

40 TWh, resulting in a net export position of about 43 TWh. This requires a substantial cross-border interconnection capacity of approximately 33 GW, larger than the 15 GW envisaged by Berenschot and Kalavasta. A sensitivity case where we excluded all cross-border electricity trade resulted in storage requirements for electricity and hydrogen that are up to 60% larger in volume.

Demand response
In addition, COMPETES shows that there is a large, cost-efficient potential to meet short-term fluctuations in the residual electricity load by means of demand response, in particular of electricity demand for power-to-mobility (EVs), power-to-hydrogen and power-to-heat in both households and industry. The main challenge or uncertainty, however, is to which extent this flexibility potential can be actually realised. Sensitivity cases by COMPETES show that excluding all demand response options (including power-to-hydrogen) results in a significantly higher need for electricity storage volumes, notably by VR batteries (11-13 TWh), but reduces the need for hydrogen storage to zero.

VRE capacities, curtailment, electricity trade and storage
In COMPETES, domestic electricity demand in NM2050 turns out to be relatively low (compared to installed VRE capacities), resulting in a large amount of hours with a large domestic VRE surplus – before curtailment – and low electricity prices. This in turn leads to large net electricity exports by the Netherlands and large amounts of VRE curtailment (as major flexibility options besides demand response). In one of the sensitivity cases, however, a substantial reduction of the (assumed) installed VRE power generation capacities in COMPETES (about 40%) resulted in less VRE curtailment – albeit less than expected (33%) – and, above all, a significant shift from large net electricity exports to large net imports by the Netherlands, but hardly or not to significant changes in storage of electricity or hydrogen.

Limitations
The optimisation models OPERA and COMPETES are based, among others, on the assumption of perfect foresight and, hence, they do not consider uncertainties or risks regarding, for instance, capacity investments or security of energy supply. In addition, these models do hardly or not address other social or behavioural issues such as the social acceptance of energy technology innovations, the time-consuming procedures and long-lasting periods of implementing investments in (cross-border) transmission and distribution networks, or the practical limitations to achieve the estimated potentials of demand response.

In the current study, the analyses by OPERA and COMPETES are primarily focused on the supply of flexibility options – including energy storage – due to the variability of the residual power load (defined as total electricity demand minus electricity supply from VRE sources). This implies that the study does not consider the need for flexibility options (such as electricity storage) due to either the uncertainty ('forecast error') of the residual load – resulting in the need for flexibility on intraday/reserve markets – or the local congestion (overloading) of the electricity distribution network (resulting in local congestion and flexibility markets to deal with these grid overloads). In addition, it does not include the need for electricity storage (or alternative options) to address other power system issues such as inertia, black starts or frequency control. Although the day-ahead or spot market is by far the most important market (in terms of power and trade volumes), the other markets (intraday, reserve) or system functions may offer interesting revenue streams for some types of electricity storage such as (AA)-CAES.

Moreover, the model analyses in the current study are focussed solely on the flexibility (storage) needs during a typical (‘normal’) weather year and do not consider these needs during more extreme weather years. In addition, the present study does not analyse energy storage needs due to political-strategic considerations, for instance to reduce uncertainties and risks of relying on energy imports to ensure security of energy supply. Finally, the model analyses in the present study are focused on the role of electricity and hydrogen storage but do not consider other means of energy storage such as heat storage in industries, households and district heating systems.

Final remark
By specifically including flexibility options such as demand response and electricity trade, this study includes elements that were not explicitly part of the study by Berenschot and Kalavasta (2020). This, and the larger emphasis on minimising social costs, leads to some differences in the envisaged energy system in 2050, including the role of energy storage.

Furthermore, we found that significant differences may arise with respect to the role of hydrogen storage because of a) differences in profiles of primary energy supply used in this study vs. those used in the study by Berenschot and Kalavasta (2020), and b) the model choice of the demand sector in which hydrogen is used, which leads to differences in demand profiles. Next to this, OPERA finds that system flexibility is also coming from synfuel production, which impacts storage needs. Altogether, this reflects that storage needs will be very sensitive to weather-dependent supply profiles, as well as to the level of demand response and other flexibility options, including import and export, that are practically feasible in the system. Given the current state of the art of integrated energy system modelling the true value lies in the identification of trends and order of magnitude assessments for the storage requirements, not for exact storage needs in the year 2050.

Together with the limitations indicated above, these differences offer good topics for further studies (e.g. study on multiple climate/weather years) aiming to develop a sustainable energy system that combines security of supply with cost-effectiveness.

Contents

1 Introduction

Background

The Netherlands is aiming at a more sustainable, low-carbon energy system. For the power system this implies (i) a larger share of electricity from variable renewable energy (VRE), in particular from sun and wind, (ii) a larger share of electricity in total energy use, i.e. a higher rate of ‘electrification’ of the energy system, and – as a result of these two trends – (iii) a higher need for system integration and flexibility – including energy storage – to deal with large fluctuations as well as with large surpluses and shortages of VRE power production in the short, medium and long term.

For the non-power systems, the transition to a low-carbon energy provision implies a switch from ‘grey molecules’ to ‘green molecules’, for instance from natural gas to green gases such as hydrogen produced from renewable, sustainable sources, including the need for storage of these green molecules in a cost-effective way in order to safeguard a sustainable, reliable and affordable energy system.

Objective and scope

In this study, the role of energy storage in the future, low-carbon energy system of the Netherlands is analysed from an integrated, national energy system perspective, including cross-border energy trade relationships with neighbouring countries. Specific focus is paid to large-scale energy storage (LSES) such as compressed air energy storage (CAES) and underground hydrogen storage (UHS). Besides analysing the potential role of LSES, the study considers also other storage technologies – such as batteries or hydrogen storage in cars, filling stations or vessels – as well as other flexibility options such as demand response or cross-border energy trade.

Approach

In order to reach the objective mentioned above, the study defines and uses two reference scenarios, one for 2030 and one for 2050. These scenarios as well as a variety of sensitivity cases for 2050 are analysed by means of two optimisation models, i.e. a European electricity market model (COMPETES) and a national integrated energy system model of the Netherlands (OPERA).

Structure

The structure of this report runs as follows. First, Chapter 2 outlines the approach of the current study, including a brief description of the two models used, the two reference scenarios considered, the major model parameters for these scenarios as well as the major energy storage technologies analysed in this study. Subsequently, Chapter 3 presents and discusses the major results of COMPETES for both the 2030 and 2050 reference scenarios as well as the 2050 sensitivity cases run by this model. Next, Chapter 4 presents and discusses similar results of OPERA. Finally, Chapter 5 provides a comparative summary and discussion of the major modelling results of the current study that pertain to storage.

2 Approach

This chapter provides a brief description of the approach used in the current study, notably regarding the following components:
- The two models used, i.e. COMPETES and OPERA (Section 2.1);
- The two reference scenarios – i.e. one for 2030 and one for 2050 – quantified and analysed by means of these two models (Section 2.2);
- The major model input parameters used for these scenarios (Section 2.3);
- The major storage technologies included in these models and analysed specifically as the focal research topic of the current study (Section 2.4).

2.1 Brief description of the models used

2.1.1 COMPETES

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 within a set of techno-economic specifications regarding power generation units, flexibility options and transmission interconnections across European countries and regions, including EU and national policy targets and restrictions such as reducing greenhouse gas (GHG) emissions.[3]

COMPETES consist of two major modules that can be used to perform hourly simulations for two types of purposes:
- A transmission and generation capacity expansion module in order 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 model covers all EU Member States and some non-EU countries – 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 1). The model runs on an hourly basis, i.e. it optimises the European power system over all 8760 hours per annum.

Over the past two decades, COMPETES has been used for a large variety of assignments and studies on the Dutch and European electricity markets. In addition, it is used and regularly updated as part of the energy modelling framework for the annual Climate and Energy Outlook of the Netherlands (NEV/KEV; see, for instance, PBL et al., 2019).

[3] Over the past two decades, COMPETES was originally developed by ECN Policy Studies – with the support of Prof. B. Hobbs of the Johns Hopkins University in Baltimore (USA) – but since 2018 it is used/developed commonly by the Netherlands Environmental Assessment Agency (PBL) and TNO Energy Transition Studies.

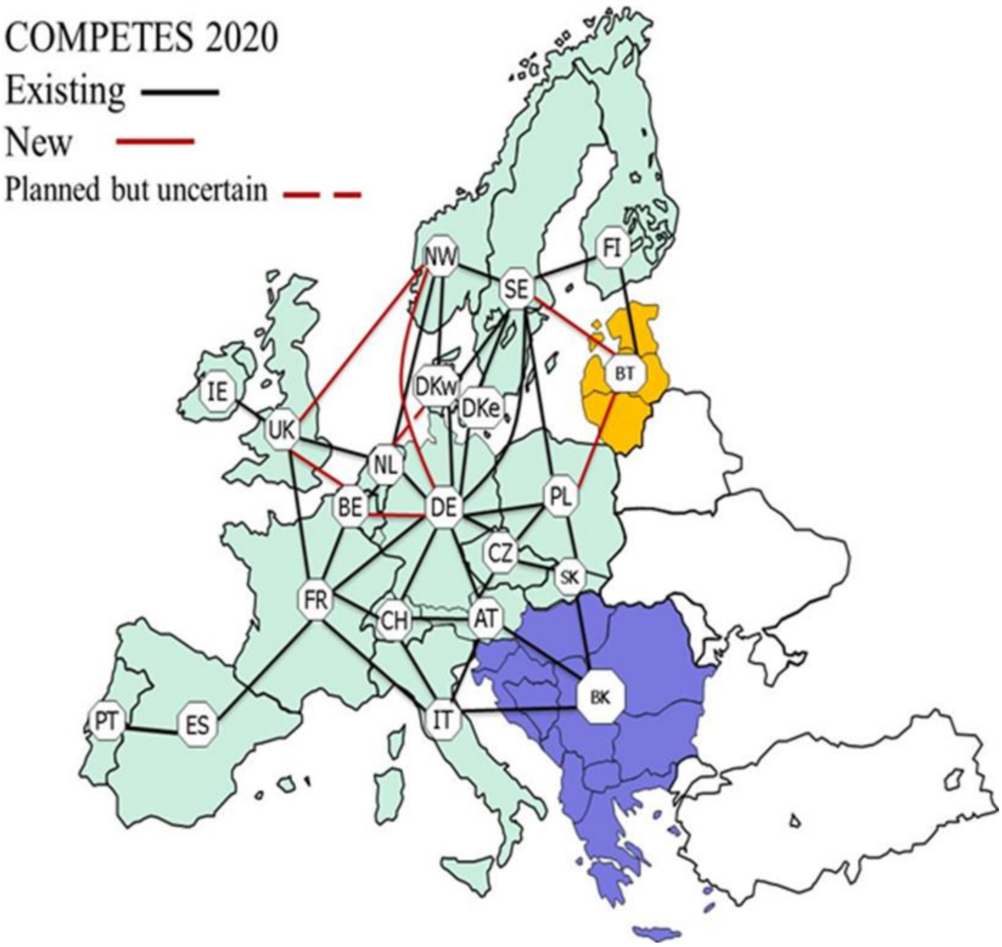

Figure 1: The geographical coverage of the COMPETES model

For each scenario year, the major inputs of COMPETES 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 P2X technologies;
- Power generation technologies, transmission interconnections and flexibility options, including their techno-economic characteristics;
- Hourly profiles of various electricity demand categories and renewable energy (RE) technologies (notably sun, wind and hydro), including the full load hours of these technologies;
- Assumed (policy-driven) installed capacities of RE power generation technologies;
- Expected future fuel and CO_2 prices;
- Policy targets/restrictions, such as meeting certain RE/GHG targets or forbidding the use of certain technologies (for instance, coal, nuclear or CCS).

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

- Flexible power generation:
  - ➢ Conventional: natural gas, coal, nuclear;
  - ➢ Renewable: curtailment of sun/wind;

- Cross-border power trade;
- Storage:
  - Pumped hydro (EU level);
  - Compressed air (CAES/AA-CAES);
  - Batteries (EVs, Li-ion, Pb, VR);
  - Underground storage of power-to-hydrogen ($P2H_2$);
- Demand response:
  - Power-to-Mobility (P2M): electric vehicles (EVs), including grid-to-vehicle (G2V) and vehicle-to-grid (V2G);
  - Power-to-Heat (P2H): industrial (hybrid) boilers and household (all electric) heat pumps;
  - Power-to-Gas (P2G), notably power-to-Hydrogen ($P2H_2$);

On the other hand, for each scenario year and for each European country/region, the major outputs ('results') of COMPETES include:
- Investments and disinvestments ('decommissioning') in conventional power generation and interconnection capacities;
- 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 model, see Sijm et al. (2017b), notably Appendix A. See also Özdemir et al. (2019 and 2020). For a more specific discussion of the 2030 and 2050 reference scenarios quantified and analysed by COMPETES – including in particular the major scenario input parameters used – see Sections 2.2and 2.3. below.

2.1.2 OPERA

OPERA (*Option Portfolio for Emissions Reduction Assessment*) is an integrated optimisation model of the energy system in the Netherlands that covers all GHG sources.[4] It is a bottom-up technology model that determines which configuration and operation of the energy system – combined with other sources of emissions – meet all energy needs and other, environmental requirements of the Dutch society, whether market-driven or policy imposed, at minimal energy system costs. These requirements generally include one or multiple emission targets.

Emissions currently covered in OPERA are the greenhouse gases CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and SF_6 combined as F-gases. In addition to energy related technologies and emission abatement options, the model is capable to include technologies and GHG abatement options that are not energy-related as well. For the choice of technology and abatement options, OPERA draws upon an elaborate database containing data from technology factsheets, as well as data on energy and resource prices, demand

[4] Over the past 10-15 years, OPERA was originally developed by ECN Policy Studies but since 2018 it is used/developed commonly by the Netherlands Environmental Assessment Agency (PBL) and TNO Energy Transition Studies.

for energy services, emission factors of energy carriers, emission constraints and resource availability. Also, energy requirements and emissions from international aviation and navigation are included, as well as emissions and removals by land use, land change and forestry (LULUCF). Note that these latter do not form part of any Dutch emission target yet.

The baseline scenario of OPERA includes the demand for energy services that must be met (for instance, the demand for space heating, lightning, transport, products, etc.). OPERA uses this baseline as a start for the outcomes of alternative (policy) scenarios in terms of additional emission reductions, changes in energy demand and supply, changes in energy system costs, etc. (TNO, 2020).

The baseline scenario takes its technology portfolio from the complete energy balances of the Netherlands in the National Energy Outlook. These energy balances distinguish between energetic energy use, non-energetic use (feedstock in e.g. the petrochemical industry) and other energy conversions (e.g. cokes ovens or refineries).

For each scenario year, the main OPERA outputs cover:
- The demand and supply side of the Dutch energy system, including a variety of energy demand sectors (households, services, transport, agriculture, various industries), energy supply sectors (electricity, gas, heat, hydrogen) as well as energy conversion sectors such as oil refineries or liquid biofuel installations (with or without CCS);
- The energy networks connecting the various parts of the energy system, notably the transmission and distribution networks for electricity, gas, heat and hydrogen.

In addition to providing outputs on energy balances at the national and sectoral level – including energy demand, supply, transport and storage – OPERA delivers also other modelling results such as energy system costs, CO_2 shadow prices and total (GHG) emissions at the national and sectoral level.

Figure 2 provides a schematic illustration of the power system represented in OPERA, including electricity storage and infrastructure. The electricity network is differentiated in three voltage levels (high, medium, low) with on each level the appropriate supply options as well as the main categories of electricity end-users. On the high voltage level, there is the possibility of large-scale energy storage by means of compressed air (CAES), while small scale storage is possible – mainly by means of batteries – at the low and medium voltage levels. These levels are also related to charging stations for electric vehicles (EVs), which enable these vehicles to charge their batteries from the grid (G2V) but also to act as storage facilities by discharging power to the grid (V2G) when electricity prices are relatively high (and, hence, power supply is relatively low).

In addition, Figure 3 provides a schematic illustration of the hydrogen system represented in OPERA, including hydrogen storage and infrastructure. Hydrogen can be supplied by different technologies based on the source such as fossil fuels (gas, coal – both with and without CCS), electricity or biomass. On the other hand, hydrogen may be consumed by means of fuel cells – both stationary and mobile – boilers, gas turbines, etc. or mixed into the natural gas grid in order to supply energy end-users such as industries, households, services, etc.

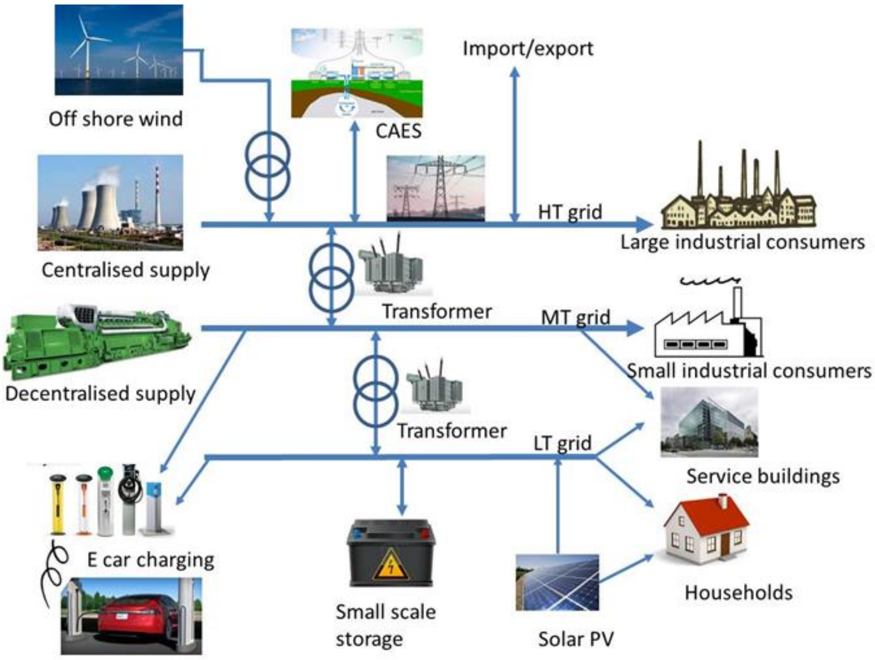

Figure 2: Schematic illustration of the electricity system represented in OPERA, including electricity infrastructure and storage

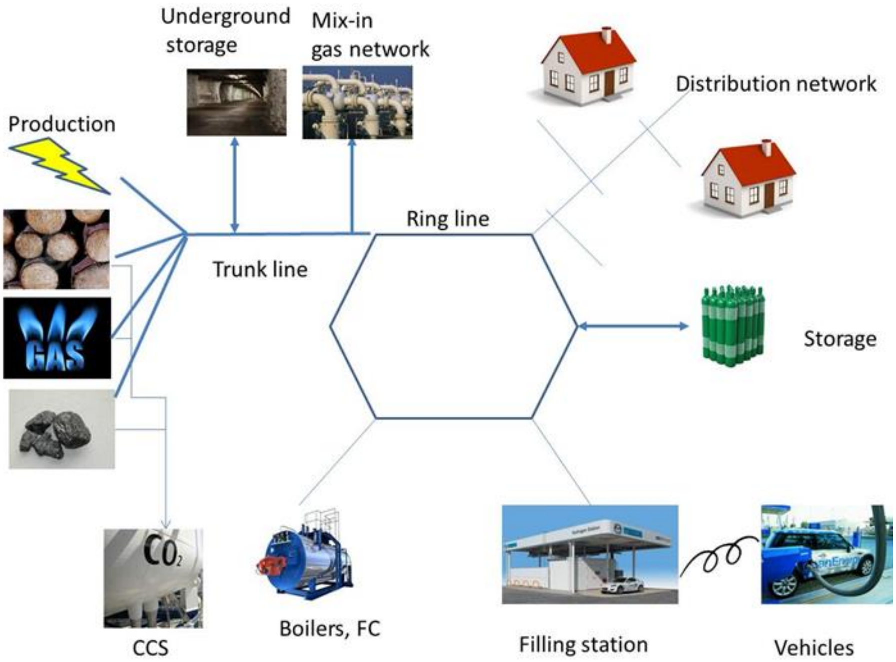

Figure 3: Schematic illustration of the hydrogen system represented in OPERA, including hydrogen infrastructure and storage

The hydrogen network in OPERA is relatively simple, i.e. it consists of a transmission trunk pipeline that feeds the main large-scale industrial demand centres – e.g., Rotterdam – and which on its turn disperses into a medium pressure ‘ring line’ network with pipelines to medium and small-scale end-users, including transport filling stations. In addition to hydrogen storage by these filling stations and hydrogen fuel cell vehicles, in OPERA hydrogen can also be stored underground at large scale

– notably in salt caverns or (potentially) depleted gas fields connected to the hydrogen transmission trunk pipeline – or in vessels linked to the hydrogen ring line network.[5]

OPERA uses a diversified set of energy demand and supply profiles at the national and sectoral level as an input into the model. This means that there are 8760 values per profile input into OPERA. Such a high time resolution with a high level of detail of a large number of technologies and other input variables would lead to an excessive runtime and memory use of the computer. Therefore, OPERA usually decreases the number of time periods used in the optimisation run by grouping similar hours into a limited set of time slices. Due to recent improvements in computer and solver capabilities, however, OPERA is now also able to run and analyse model scenarios on an hourly resolution, for instance on a six, four, two or even one hourly basis (depending on the specific scenario run and level of detail required).

For the current study, we were able – for the first time – to run OPERA on a one hourly basis for the reference scenarios of 2030 and 2050 (see next section). Results from scenario model runs on a single hourly basis are particularly important for studying the energy storage in a system with hourly variations in demand and supply.

For a more detailed description of the OPERA model, see Sijm et al. (2017b), notably Appendix D. See also Ros and Daniëls (2017), Daniëls (2019) and Van Stralen et al. (2020). For a more specific discussion of the 2030 and 2050 reference scenarios quantified and analysed by COMPETES – including in particular the major scenario input parameters used – see Sections 2.2and 2.3. below.

2.1.3 Why use two models for one study?

There are basically two related reasons why we have opted to use two models – COMPETES and OPERA – for this study on energy storage. First, COMPETES and OPERA are two different models with different characteristics, advantages, disadvantages etc. – which, to some extent, complement each other. As said, COMPETES is a European electricity market model with an advanced, detailed modelling of the power system in the Netherlands and other European countries, including interconnections and power trade relations between these countries. Recently, the hydrogen sector has been coupled to the electricity sector ($P2H_2$) but the modelling of the hydrogen system in COMPETES is still in its early stages and under further development.

OPERA, on the other hand, is a national integrated energy system model with an advanced, detailed modelling of all energy demand and supply sectors in the Netherlands, including the demand and supply of hydrogen across a variety of sectors. Compared to COMPETES, however, the modelling of the power system is less detailed in OPERA, for instance, regarding the flexibility characteristics of the

[5] For pragmatic reasons (mainly lack of differentiating data), in both our models (OPERA and COMPETES) we have used the techno-economic parameters of H_2 storage in salt caverns as the proxy (or default option) for H_2 underground storage, while we did not include the alternative option of H_2 storage in depleted gasfields. Despite some techno-economic differences between these two H_2 underground storage options, from a modelling perspective, however, the parameters of H_2 storage in salt caverns are largely similar to H_2 storage in depleted gasfields. Therefore, our reported modelling results regarding H_2 underground storage (notably in Chapters 3, 4 and 5) apply largely for H_2 storage in both salt caverns and depleted gasfields.

power generation units in the Netherlands. In addition, OPERA lacks the interconnections and power trade relations with other European countries. Therefore, in this study, we use the hourly (net) power trade output of COMPETES as input into OPERA. More generally, COMPETES is better equipped to deal with storage – and other, related flexibility – issues of the power system in the Netherlands, connected to other countries, whereas OPERA is better equipped to deal with integrated energy system issues of the Netherlands, including the demand, supply and storage of hydrogen in competition with other energy sources and energy carriers.

In addition, there is another, related reason why we use two models in the current study. As noted, COMPETES and OPERA are different models with a different scope, focus, level of detail, etc. as well as with different characteristics, limits, assumptions, approaches, etc. Differences in modelling outcomes – for instance, on energy storage – do not only depend on (differences in) scenario assumptions but also on (differences in) model characteristics. By using two models in this study, we are able to show the impact of these model characteristics on modelling outcomes regarding energy storage and, to some extent, explain – or at least relate – differences in modelling outcomes to differences in modelling characteristics.

2.2 Reference scenarios 2030 and 2050

As part of the current study, a reference scenario has been defined, quantified and analysed by both COMPETES and OPERA for 2030 and 2050 separately, indicated as the '*Climate Agreement 2030 scenario*' (CA2030) and the '*National Management 2050 scenario*' (NM2050), respectively. The general story line of these two scenarios are outlined briefly in the next two subsections (2.2.1and 2.2.2, respectively), while the major input parameters of these scenarios are discussed in some more detail in section 2.3.

2.2.1 The Climate Agreement 2030 scenario

The Climate Agreement 2030 scenario (CA2030) is based on the national Climate Agreement as presented by the Dutch Government in June 2019 for the period up to 2030 after some intensive discussions and consultations with more than hundred parties ('stakeholders') since early 2018 (for details, see Dutch Government, 2019; and EZK, 2019). The central goal of the Climate Agreement (CA) is to reduce GHG emissions in the Netherlands by 49% in 2030 compared to 1990. This target is differentiated across the five main GHG emitting sectors covered by the CA, i.e. the built environment, industry, mobility, agriculture and electricity generation. For each sector, the CA announces a set of policy measures and instruments to achieve the national GHG mitigation target. For instance, in the electricity sector the main policy instruments to reduce GHG emissions are to forbid the use of coal for power production by 2030 and to stimulate renewable electricity generation (by means of subsidies, etc.). In industry, GHG emissions are reduced by introducing an additional CO_2 levy – besides the EU ETS carbon price – and stimulating both CCS, further industrial electrification as well as the production and use of renewable hydrogen (for further details, see Dutch government, 2019; and EZK, 2019).
The baseline (or background) scenario for CA2030 is the reference scenario of the national Climate and Energy Outlook 2019 (indicated in Dutch as 'KEV2019'). This scenario includes details on (assumed) developments in external factors such as the economy, demography, technology, fuel and CO_2 prices, etc. (for details, see PBL et al., 2019). In addition, it includes national and EU policy measures that have been

either accepted or officially proposed and concretely elaborated up to 1 May 2019. This means that a variety of policy measures announced in the CA of June 2019 have not been included in the reference scenario of the KEV2019. Therefore, as part of defining the CA2030 reference scenario, some policy measures and resulting effects have been added to the KEV2019 reference scenario, notably in terms of stimulating hydrogen electrolysis and other forms of further electrification of energy sectors, including encouraging power-to-mobility (EVs), power-to-heat, etc. (for specific details, see Section 2.3.1).

2.2.2 The National Management 2050 scenario

For 2050, our study is based on the so-called 'National Management 2050 scenario' (NM2050) as recently developed and analysed by Berenschot and Kalavasta (2020) on behalf of the network operators of the Netherlands. This NM2050 scenario is one out of four scenarios explored by their study. These scenarios are characterised by different governance structures, but all take the national Climate Agreement of the Netherlands as the starting point for the development up to 2030 and, subsequently, present four possible future images ('scenarios') of a climate neutral energy system in the Netherlands by 2050.[6] These four scenarios explore four possible corners of the energy playing field in 2050 in order to enable the principal of the study – i.e. the Dutch network operators – to assess the (investment) need for energy system flexibility and infrastructure (including energy storage).

The NM2050 scenario is characterised by a strong governance – i.e. direction, management and control – by the Dutch national administration as well as by a high level of national energy self-sufficiency (i.e. with minimal energy imports). Moreover, it shows a strong further electrification of all energy-use sectors, enabled by a very large installed capacity of solar PV and offshore wind (the largest of all four scenarios). In addition, both industry and freight transport rely on a substantial deployment of domestically produced green hydrogen. Imbalances of the energy system are met by national storage – among others of hydrogen – and feed-back power plants fuelled by green (bio)gas and green hydrogen.

The reason for opting the NM2050 scenario (out of four 2050 climate neutral energy scenarios) is that this scenario is characterised by a high level of electrification of all energy sectors – supported by a high level of variable renewable power generation – as well as by a relatively high level of demand and supply of domestically produced green hydrogen. Therefore, compared to the other three scenarios, the NM2050 scenario is likely to result in a relatively high need for large-scale energy storage at the national level – i.e. the focal point of this study – and, hence, it probably provides a kind of upper bound of this storage need for all 'reasonable', climate-neutral energy scenarios, notably for the need of electricity storage.

On the other hand, as said, the NM2050 is a rather 'extreme' scenario exploring only one of four possible corners of the energy playing field in 2050. Moreover, concerning 2050 there are still many uncertainties regarding fuel and CO_2 prices, the availability and costs of climate neutral technologies, etc. Hence, in addition to the NM2050 reference scenario, we have also explored several sensitivity cases regarding this scenario (see sections 3.2and 4.2).

[6] The other three 2050 scenarios are indicated as '*Regional Management*', '*European CO_2 Management*' and '*International Management*' (for details, see Berenschot and Kalavasta, 2020).

2.3 Major model scenario parameters

2.3.1 Energy demand

Table 3 provides an overview of the main energy demand parameters used in OPERA for the 2030 and 2050 reference scenarios. In OPERA, energy demand is represented via energy services. In most cases, final energy demand is given as an exogenous input expressed in energy terms. In order to allow maximum flexibility to the (optimisation) model, demand for energy services can also be expressed in a unit that best suits the nature of a specific energy service. For instance, the most straightforward determinant of energy demand for road transport is the need for mobility expressed in total amount of kilometres driven yearly. Therefore, the unit 'Billion Vehicle Kilometres' (BVKm) is used for road freight and passenger vehicles instead of the corresponding final electricity and fuel demand in petajoules (PJ). Due to unavailability of input data, the remaining demand for energy services in the transport sector (busses, motorbikes, trains, inland shipping and aviation, which only account for a small fraction of total demand) are grouped together in one single entity, for which the demand is expressed in PJ (Van Stralen et al., 2020).

Table 4 provides the electricity demand parameters used in COMPETES for the Netherlands in CA2030 and NM2050. In this table, electricity demand is distinguished into two main categories:

- *Conventional power demand*. For both CA2030 and NM2050, the conventional electricity demand is fixed at the level obtained from the KEV2019, i.e. almost 117 TWh per annum (PBL, 2019c). This figure assumes that some autonomous growth in conventional power demand is balanced more or less equally by energy efficiency improvements in this demand;
- *Additional power demand*. This is the extra electricity demand due to the (expected) further electrification of the energy system, i.e. the further penetration of the so-called 'Power-to-X' (P2X) technologies such as power-to-heat (P2H), power-to-mobility (P2M), or power-to-gas (P2G), notably power-to-hydrogen (P2H_2). According to the CA2030 scenario, the total additional power demand is expected to amount to about 34 TWh in 2030 and – following the NM2050 scenario – to increase substantially to some 230 TWh in 2050.[7]

More specifically, the additional power demand is distinguished into the following sub-categories (see lower part of Table 4):

- *Baseload power demand by industry.* This demand is assumed to be fixed (i.e. not flexible) at a level of 4.1 TWh in both CA2030 and NM2050.
- Demand for power-to-hydrogen by industry. This demand is assumed to be flexible, i.e. optimised hourly depending on hourly electricity prices, and to increase rapidly from 10 TWh in CA2030 to approximately 113 TWh in NM2050;
- *Power-to-heat by industry*. This demand is assumed to be flexible and to increase substantially from almost 19 TWh in CA2030 to about 71 TWh in NM2050. It should be noted, however, that these figures refer to the *maximum potential* electricity demand by *hybrid* industrial boilers. Therefore, the actual power demand may be lower than these figures, depending on the relative prices of electricity and gas to generate industrial heat;

[7] As explained in the main text below, a part of the additional power demand consists of the (maximum) potential electricity demand for hybrid industrial boilers. Therefore, the actual (additional) power demand (see Section 3.1.2, Figure 9) may be lower than indicated in Table 4, depending on relative prices of electricity and gas to generate industrial heat.

Table 3: OPERA: Energy demand parameters for the Netherlands in CA2030 and NM2050

Main demand parameters	Unit	CA2030	NM2050
Demand for electricity - Chemicals	PJ	40.36	35.00
Demand for heat - Chemicals	PJ	195.24	106.51
Physical demand - Chemicals	Mt HVC	4.11	4.04
Demand for electricity - Iron and steel	PJ	10.10	9.83
Demand for heat - Iron and steel	PJ	28.30	27.83
Physical demand - Iron and steel	Mt steel	7.40	7.20
Demand for electricity - Ammonia	PJ	2.64	1.02
Demand for heat - Ammonia	PJ	21.38	8.28
Physical demand - Ammonia	Mt NH_3	3.30	1.28
Demand for electricity - Refineries	PJ	10.62	3.50
Demand for heat - Refineries	PJ	108.37	37.50
Demand for electricity - Rest industry ETS	PJ	29.06	50.00
Demand for heat - Rest industry ETS	PJ	52.55	10.00
Demand for electricity - Rest industry non-ETS	PJ	40.36	70.00
Demand for heat - Rest industry non-ETS	PJ	58.35	30.00
Demand for electricity - households	PJ	71.36	89.80
Demand for heat - households	PJ	253.97	131.2
Demand for electricity - service sector	PJ	118.34	105.78
Demand for heat - service sector	PJ	94.17	84.62
Demand for mobility – Passenger cars	BVKm	125.37	122.41
Demand for mobility – Light Duty Vehicles (LDVs)	BVKm	20.15	20.68
Demand for mobility – High Duty Vehicles (HDVs)	BVKm	8.03	8.58
Energy fuel - Rest domestic transport	PJ	45.82	0.00
Energy electricity - Rest domestic transport	PJ	8.40	0.00
Energy consumption for international aviation	PJ	308.28	170
Energy consumption for international shipping	PJ	369.85	543
Demand for electricity - Agriculture	PJ	47.77	86.27
Demand for heat - Agriculture	PJ	89.47	62.00
Mobile machinery - Agriculture	PJ	16.80	16.80
Mobile machinery - Industry	PJ	24.63	25.36
Mobile machinery - Service sector	PJ	6.74	7.50

a) Mt = Million tons; PJ = Petajoules; BVKm = Billion Vehicle Kilometres; HVC = High Value Chemicals (such as ethylene, acetylene, propylene, butadiene and benzene;

b) For 2030, all energy demand parameters are exogenous inputs from the KEV2019 (PBL et al., 2019). For 2050, these parameters have been extrapolated based on the KEV2019 values for 2030 and the NM2050 scenario assumptions of Berenschot and Kalavasta (2020).

- *Power-to-heat by households.* This demand – for all electric heat pumps – is assumed to be flexible (to some extent) and to rise significantly from about 0.3 TWh in CA2030 to more than 14 TWh in NM2050;
- *Power-to-mobility*. This demand – by electric vehicles (EVs) – is also assumed to be flexible (to some extent), including both directions, i.e. from grid-to-vehicle (G2V) and from vehicle-to-grid (V2G). The power use of EVs – i.e. excluding V2G – is expected to increase from 1.2 TWh in CA2030 to about 31 TWh in NM2050. In COMPETES, this corresponds to approximately 0.4 mln and 10.4 mln EVs, respectively, using some 3 MWh per EV per annum.[8]

[8] More details on the underlying assumptions and limitations of flexible power demand and, more specifically, the role of demand response in the energy system of the Netherlands, 2030-2050, see Sijm et al. (2020).

For CA2030, the additional power demand figures presented in Table 4 have been obtained from a specific variant of the CA2030 scenario, called the '*CA2030 Up*' scenario variant in which (the upper bound of) some additional power demand – due to the Climate Agreement – in 2030 is assumed up to the conventional demand of the KEV2019 (PBL, 2019c).[9]

Table 4: COMPETES: Electricity demand parameters for the Netherlands in CA2030 and NM2050

Parameter	Unit	CA2030	NM2050
Conventional power demand	TWh	116.9	116.9
Total additional power demand ('electrification')	TWh	34.2	233.1
Total power demand	*TWh*	*151.1*	*350.0*
Specification of additional power demand ('electrification'):			
# Baseload industry (fixed demand)	TWh	4.1	4.1
# Power to Hydrogen (industry, flexible demand)	TWh	10.0	112.8
# Power to Heat (industry, potential hybrid flexible demand)	TWh	18.6	70.8
Total additional power demand by industry	*TWh*	*32.7*	*187.7*
# Power to Heat (household heat pumps, flexible demand)	TWh	0.3	14.3
# Power to Mobility (EVs, flexible demand)	TWh	1.2	31.1
Total additional power demand ('electrification')	*TWh*	*34.2*	*233.1*

Source: PBL (2019c) and Berenschot and Kalavasta (2020).

The only exception regarding additional power demand in CA2030 concerns the demand for power-to-hydrogen ($P2H_2$). In the above-mentioned scenario variant, no additional power demand for hydrogen electrolysis is assumed in CA2030. The Climate Agreement, however, expresses the ambition to establish 3-4 GW of electrolysis capacity. Moreover, at both the national and EU level, there is a strong lobby of H_2 stakeholders to encourage the role of green hydrogen by all kinds of supporting policy measures, even in the short and medium term up to 2030. Therefore, we have assumed a 'modest' electrolysis capacity of 2 GW in CA2030, running at 5000 full load hours and, hence, resulting in an additional power demand for $P2H_2$ of some 10 TWh in CA2030.

For NM2050, the additional power demand figures mentioned in Table 4 have been either derived from or – as far as possible – based on the figures presented in the NM2050 scenario study of Berenschot and Kalavasta (2020) or in the underlying NM2050 model scenario published on the website of the Energy Transition Model (ETM, 2020).

[9] Together with the KEV2019, PBL has published a general, mainly qualitative assessment of the final Climate Agreement of June 2019 (see PBL, 2019a and 2019b). A more detailed, quantitative assessment of this final, full agreement, however, has not been conducted or published by PBL. For the electricity sector, however, PBL has conducted some quantitative assessments by means of the COMPETES model of two scenario variants of the Climate Agreement called '*CA2030 Down*' ("*Onder*") and '*CA2030 Up*' ("*Boven*"), referring to the lower and upper bound of the assumed additional power demand in 2030 (i.e. above the conventional demand assumed in the KEV2019). These assessments have not been officially published by PBL, but TNO has received the COMPETES Excel data file of these assessments.

For the other European countries and regions included in COMPETES similar electricity demand parameters for both CA2030 and NM2050 have been obtained in line with the approach outlined above for the Netherlands (for details and exceptions, see Appendix A, notably Table 36).

2.3.2 Energy supply: sources and technologies

In order to meet the demand for a variety of energy services (in a cost-optimal way), both OPERA and COMPETES include a variety of (competing) primary energy sources and technologies, including energy conversion and end-use technologies, as well as technologies to reduce GHG emissions – in order to meet energy demand in a more sustainable, climate neutral way – and flexibility options such as demand response or storage technologies (in order to meet energy demand in a reliable, balanced way).

The integrated energy system model OPERA contains even more than 500 energy technologies. It is outside the scope of this report to sum them up and present the techno-economic parameters of these technologies that have been used as part of this study. Currently, TNO is updating the technology factsheets of many energy technologies used in OPERA. Factsheets that have been updated and finalised (including external reviews) are publicly available on the TNO website: www.energy.com (TNO, 2020). In addition, industrial process data have been obtained from the MIDDEN project (PBL, 2020).

For the main storage technologies – which are the focal research topic of this study – the techno-economic parameters that have been applied for both models (OPERA and COMPETES) and for both reference scenarios (CA2030 and NM2050) are recorded in Appendix A, notably Table 38. See also Section 2.4 below for a brief description of these technologies.

In OPERA, the installed capacity of energy technologies is usually endogenously optimised by the model. It is, however, also possible to define an (exogenous) input constraint or maximum potential for selected technologies (or even fix the capacity or quantity of these technologies). Table 5 provides an overview of the available capacity of some key (mainly renewable) energy technologies used by OPERA in the current study, including an indication whether this capacity has faced the exogenously set input constraint or has been optimised endogenously by the model.

As mentioned above, the capacity for hydrogen electrolysis in CA2030 is assumed to be 2.0 GWe. Hence this capacity is set exogenously into OPERA. In order to account for the (possible) additional power demand for hydrogen electrolysis – which amounts, potentially, to some 10 TWh in CA2030, assuming about 5000 full load hours (FLHs) for the installed electrolysers, and which was not yet included in the 'KEV2019/CA2030 Up' scenario assessment by PBL – we supposed an additional offshore wind capacity of about 2 GWe, assuming – also – some 5000 FLHs for offshore wind. This 2 GWe of offshore wind is additional to the 11.5 GWe assumed by the 'KEV2019/CA2030 Up' assessment by PBL. Therefore, the total offshore wind capacity assumed in 'our CA2030 scenario' amounts to 13.5 GWe in both OPERA (Table 5) and COMPETES (see Table 7).

In COMPETES, new capacity investments and disinvestments ('decommissioning') are determined exogenously to the model for most renewable power generation technologies (notably sun and wind) as well as for some conventional technologies (for instance, nuclear), while for most other conventional technologies (gas, lignite) and some renewables (biomass, waste) these (dis)investments are optimised endogenously by the model. Several of these endogenous investments, however, are ‘deactivated’ – i.e. not allowed – by the model, for instance because of climate or other policy considerations expressed by European countries or regions.

Table 5: OPERA: Available capacities of energy technologies in CA2030 and NM2050

[GWe]	CA2030	NM2050
Solar - Residential	6.7	12.0
Solar - Services	7.5	17.4
Solar - Large scale utilities	8.9	24.8
Wind - onshore	6.1	20.0
Wind - offshore	13.5	57.8
CCGT - Natural gas	8.4	0.0
CCGT - Hydrogen	0.0	9.1
Electrolysis - $P2H_2$	2.0	31.5

Input constraint (maximum potential)[a]

Endogenous output (result)[b]

a) Capacity has reached the maximum potential set exogenously into OPERA;
b) Capacity has been optimised endogenously by OPERA (within an eventual maximum potential set into the model).

Table 6 presents a summary overview of the power generation technologies covered by COMPETES, including whether capacity investments (and disinvestments) in these technologies are determined endogenously or exogenously by the model (and whether endogenous investments are ‘deactivated’ or not).[10] Subsequently, Table 7 provides the installed capacity parameters for power generation technologies determined exogenously by the model for the Netherlands in CA2030 and NM2050 (while similar parameters for other European countries and regions are presented in Appendix A, Table 37, of this study).

Table 7 shows, for instance, that in COMPETES the installed capacity of offshore wind amounts to 51.5 GW in NM2050 and of solar PV to 106 GW. Note that these figures deviate significantly from the comparable figures for the installed capacities of these technologies determined (endogenously) by OPERA, notably for the installed capacity of solar PV (see Table 5). The reason is that for these technologies (sun/wind), COMPETES determines the installed capacities exogenously – i.e., in this case, closely in line with the installed capacities assumed in the NM2050 scenario developed by Berenschot and Kalavasta (2020) – while OPERA only sets an input constraint (maximum potential) for these technologies and, subsequently, the model determines endogenously the optimal capacity (within the maximum potential). In the case of solar PV, OPERA shows that the optimal capacity in NM2050 (i.e. some 54 GW) is far less than the capacity assumed by Berenschot and Kalavasta (2020) and copied into COMPETES (106 GW). The implications of the differences in input parameters across these models for the resulting energy balances and other modelling results are discussed in Chapter 5 of the current report.

[10] For more techno-economic details on both conventional and renewable power generation technologies included in COMPETES, see Sijm et al., 2017b, notably Appendix A, pp. 193-197.

Table 6: COMPETES: Power generation technologies

Fuel	Technology	Abbreviation	Exoge-nous[a]	Endoge-nous[b]	Deacti-vated[c]
Biomass	Co-firing	Bio-Co		x	x
Biomass	Standalone	Bio-St		x	x
Coal	Pulverized coal	Coal PC	x		
Coal	Integrated gasification combined cycle	Coal IGCC	x		
Coal	Carbon capture and storage	Coal CCS		x	x
Coal	Combined heat and power	Coal CHP	x		
Coke oven gas	Internal combustion	CGas IC	x		
Derived gas	Internal combustion	DGas IC	x		
Derived gas	Combined heat and power	DGas CHP		x	x
Gas	Gas turbine	GT		x	x
Gas	Combined cycle gas turbine	CCGT		x	x
Gas	Combined heat and power	CHP		x	x
Gas	CCGT + Carbon capture and storage	CCS CCGT		x	x
Gas	CHP + Carbon capture and storage	CCS CHP		x	x
Geo	Geothermal power	Geo	x		
Hydro	Conventional - Run-of-River	Hydro RoR	x		
Hydro	Pump storage	HPS		x	x
Hydrogen	Hydrogen	H2		x	
Lignite	Pulverized coal	Lignite PC		x	x
Lignite	Combined heat and power	Lignite CHP		x	x
Nuclear	Nuclear	Nuclear	x		
Oil	Oil	Oil		x	x
RES-E	Other renewable energy sources	Other RES-E		x	x
Solar	Photovoltaic solar power	PV	x		
Solar	Concentrated solar power	CSP	x		
Waste	Standalone	Waste		x	x
Wind	Onshore	Wind onshore	x		
Wind	Offshore	Wind offshore	x		

a) New capacity investments are determined exogenously to the model.
b) New capacity investments are determined endogenously by the model.
c) New capacity investments are not allowed ('deactivated') in 2030 and 2050.

As mentioned, in addition to energy technologies, both OPERA and COMPETES include also a variety of flexibility options. Table 6 presents the parameter values of available capacities of some major flexibility options in COMPETES for CA2030 and NM2050, both including and excluding supply of flexibility by means of demand response.[11] It shows, for instance, that in the scenarios including demand response (DR), the available flexibility capacity of EVs amounts to 1.5 GWe in CA2030, increasing substantially to more than 38 GWe in NM2050 (while it is zero in both scenarios excluding DR). Note, however, that some parameters on available flexibility capacities are set exogenously in COMPETES (notably for most DR options) while other parameters are optimised endogenously by the model (marked grey in Table 8).[12]

[11] For a more detailed analysis and explanation of the role of demand response in these scenarios, see Sijm et al. (2020).

[12] Except for interconnections (cross-border power trade), OPERA includes a comparable – or even wider – set of flexibility options (notably storage technologies) but the capacities of these options are usually determined (optimised) endogenously by the model.

Table 7: COMPETES: Installed power generation capacity parameters for power generation technologies determined exogenously by the model for the Netherlands in CA2030 and NM2050

	Unit	CA2030	NM2050
Coal	GWe	0.0	0.0
Nuclear	GWe	0.5	0.0
Wind onshore	GWe	6.0	20.0
Wind offshore	GWe	13.4	51.5
Solar PV	GWe	25.1	106.0
Other RES-E	GWe	1.6	0.4

Sources: PBL (2019c) and Berenschot and Kalavasta (2020)

Table 8: COMPETES: Available capacity of flexibility options in the Netherlands in CA2030 and NM2050 with and without demand response (DR)

Flexibility option	Unit	CA2030 with DR	CA2030 without DR	NM2050 with DR	NM2050 without DR
Demand response:					
Power-to-Mobility (EVs)	GWe	1.5	0	38.35	0
Power-to-Heat (household heat pumps)	GWe	0.205	0	9.47	0
Power-to-Heat (industrial hybrid boilers)	GWe	2.12	0	8.08	0
Power-to-Hydrogen	GWe	1.38	1.14	19.3	12.7
Storage size					
Li-ion batteries	GWh	0.4	0.4	0.5	0.5
VR batteries	GWh	0	0	0	9
H_2 underground	GWh	66	0	1536	0
Cross-border power trade:					
Interconnections	GWe	11.97	11.97	33.18	46.45

a) Cells marked grey refer to parameters determined endogenously by COMPETES. Other parameters are exogenous inputs into the model;
b) Parameter values for Li-ion batteries refer to the initial capacity available in the baseline scenario (i.e. before new investments/disinvestments are determined by the model). It could invest in additional capacity in both CA2030 and NM2050, but it didn't;
c) Parameter values for VR batteries refer to 100% new capacity investments in CA2030 and NM2050 (i.e. zero initial capacity in the baseline scenario).

Table 8 also shows that the interconnection capacity for cross-border power trade between the Netherlands and its surrounding, connected countries – i.e. Germany, Belgium, Denmark, UK and Norway – is estimated at 12 GW in CA2030 (against about 6 GW in 2015 and approximately 9 GW in 2020). For NM2050, this capacity is estimated at 33 GW in case of including flexibility by means of demand response in the Netherlands and other European countries, and even at 47 GW in case of excluding demand response.

The above-mentioned interconnection capacity figures have been estimated (optimised) by the investment module of COMPETES, including assumptions on (i) the total European electricity demand in 2030 and 2050, (ii) the installed power generation capacities, notably of VRE technologies and the related profiles of these technologies, (iii) the cable distance between the nodes of the interconnected countries concerned (in km), and (iv) the upper values of the costs of the HVDC cables and converter stations.[13]

Note that the estimated (optimised) interconnection capacity in the Netherlands – and other European countries – in 2030 is largely in line with existing, ongoing expansion plans, as laid down in the Ten-Year Network Development Plan of ENTSO-E. On the other hand, the estimated interconnection capacities in NM2050 are optimised model scenario outcomes, which may be questioned whether they will be (full) realised (in time) due to a variety of technical and socio-economic constraints, including time-consuming administrative implementation procedures and social acceptance issues regarding cross-country transmission lines.

2.3.3 Hourly profiles

Both OPERA and COMPETES use a variety of hourly profiles of energy demand and supply as inputs into the models. For the power sector, we basically use the same electricity demand profiles (before demand response) as in the FLEXNET project, while the electricity demand profiles including demand response – i.e. depending on dynamic (optimised) hourly electricity prices – have been regenerated again as endogenous outputs of the CA2030 and NM2050 runs by the models.[14]

For the hourly profiles of power supply from variable renewable energy (VRE) sources, i.e. sun and wind, we basically used the capacity factor profiles as in the FLEXNET project (Sijm et al., 2017a and 2017b). In order to account for the correlations between countries concerning either wind patterns or sun patterns, the same climate year as used for the Netherlands has been taken to represent either hourly wind profiles or hourly sun profiles for the other European countries, i.e. 2012 for wind and 2015 for solar PV.[15]
As part of the current study, however, we have updated the VRE profiles for 2030 and 2050 by means of the expected (higher) full load hours (FLHs) of the VRE technologies in these years (as these technologies are expected to become more efficient and, hence, more productive over these years).

Table 9 shows the full load hours (FLHs) of VRE power generation technologies for the years 2015, 2030 and 2050. It shows, for instance, that the FLHs of solar PV are expected to increase from 840 in 2015 to 924 in 2050 (+10%) and for offshore wind from 3580 to 5411, respectively (+51%).

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[13] More specifically, the unit investment costs of the overlay network are assumed to be 800 €/MWkm for HVDC cables and 96.000 €/MW for HVDC converter stations (expressed in euros of 2010; IRENE-44, 2012; ACER, 2015). For further details on the methodology to estimate additional cross-border transmission investments – and related investment costs – see Sijm, et al, 2017b, notably Section 2.2.1 (pp. 48-49), Appendix A.3 (pp. 195-196), Appendix B.2 (p. 202) and Appendix C.

[14] For an illustration, description and explanation of the electricity demand and supply profiles used in the FLEXNET project, see the report of phase 1 of this project (Sijm et al., 2017a), while the updated, regenerated electricity demand profiles of the CA2030 and NM2050 scenario runs by COMPETES have recently been illustrated, described and explained in Sijm et al. (2020).

[15] Since there is a seasonal correlation between wind and solar – e.g. summer is relatively more sunny and less windy – but not necessarily an hourly correlation, it is acceptable to use wind and solar profiles of two different years to represent a future year (Sijm et al., 2017b).

Table 9: COMPETES and OPERA: Full load hours of VRE power generation technologies in 2015, CA2030 and NM2050

	2015	CA2030	NM2050	Increase 2015-2050 (in %)
Solar PV	840	909	924	10%
Wind onshore	2310	2888	3846	66%
Wind offshore	3580	4454	5411	51%

As an example, Figure 4 shows the resulting hourly profiles of the capacity factor for solar PV and offshore wind over a limited time period in 2050, i.e. during the middle of the year (hours 4200 – 4600), while similar profiles for 2050 as a whole (8760 hours) are presented in Appendix A, Figure 44.[16] In addition Figure 5 below provides the duration curve of the hourly capacity factors for solar PV and wind – both offshore and onshore – in 2050.

The major observations from these three figures include:

- Over the hours 4200 – 4600, i.e. the early summer period, the profile of solar PV has a clear daily pattern (with a peak during the middle of the day), while this pattern is less clear for offshore wind (Figure 4).

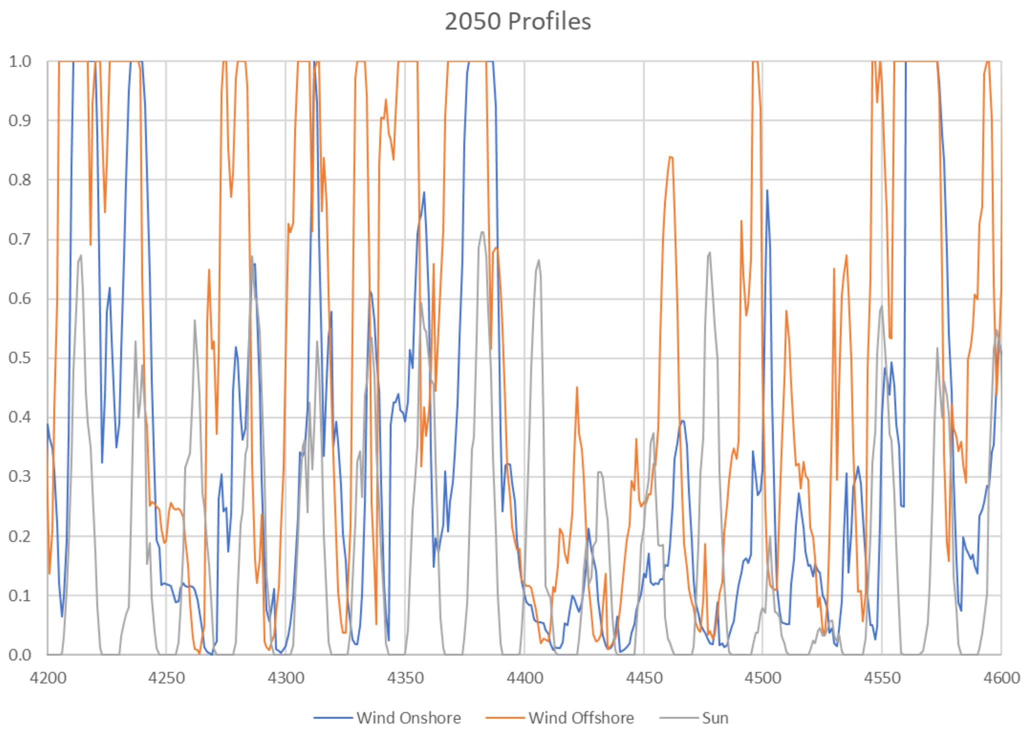


Figure 4:Hourly profiles of the capacity factor for solar PV and offshore wind during the middle of 2050 (hours 4200 – 4600)

[16] Multiplying the hourly capacity factors of VRE generation technologies by means of their installed capacities in a specific year results in the hourly output profiles of these technologies in that year and, by aggregating these hourly outputs, in their total power production in that year.

Therefore, these technologies have a different impact on the need for short-term (hourly/daily) flexibility of the energy system, including storage (as further analysed in Chapter 3);

- Over the year as a whole (8760 hours), the profile of solar PV has a clear seasonal pattern with, on average, relative low output volumes over the months November up to February and significantly higher output volumes over the remaining part of the year, notably over the months May-August. For offshore wind, however, this seasonal pattern is less clear (Appendix A, Figure 44). Therefore, these technologies have a different impact on the need for long-term (large-scale/seasonal) flexibility of the energy system, including storage;
- Over the year as a whole, solar PV never meets, on average, its full hourly capacity factor (1.0) in 2050, while onshore wind produces at full capacity during some 1600 hours and offshore wind even over approximately 3600 hours (Figure 5). Moreover, these wind technologies produce at a lower, but still substantial capacity factor during a large number of additional hours. Overall, there is at least some power production by wind up to 7000-8000 hours, whereas for solar PV this applies for less than 4000 hours (Figure 5). This difference in VRE output performance has also an impact on the need for flexibility of the power system, including storage and back-up generation facilities (as further analysed in Chapter 3).

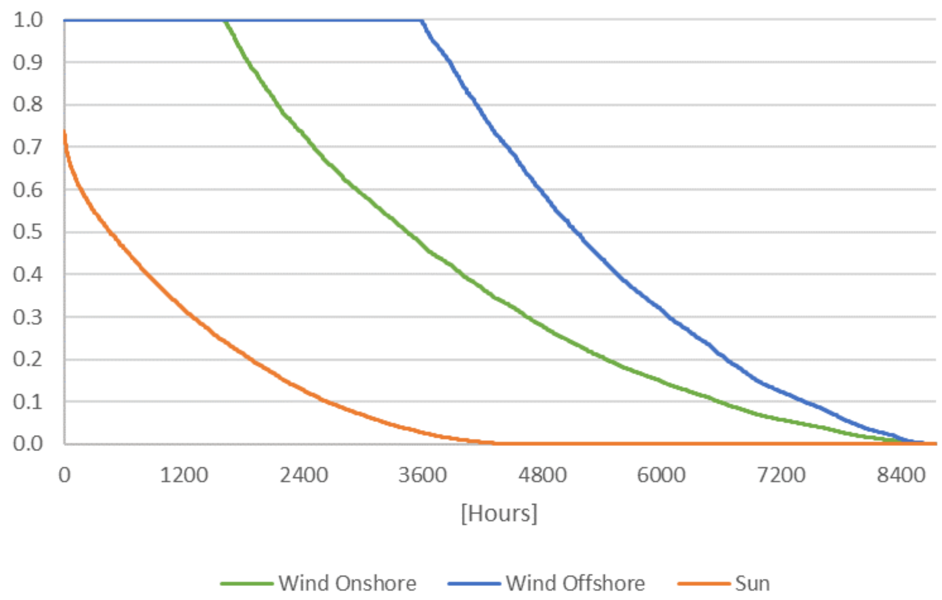


Figure 5: Duration curve of hourly capacity factors for solar PV and wind in 2050

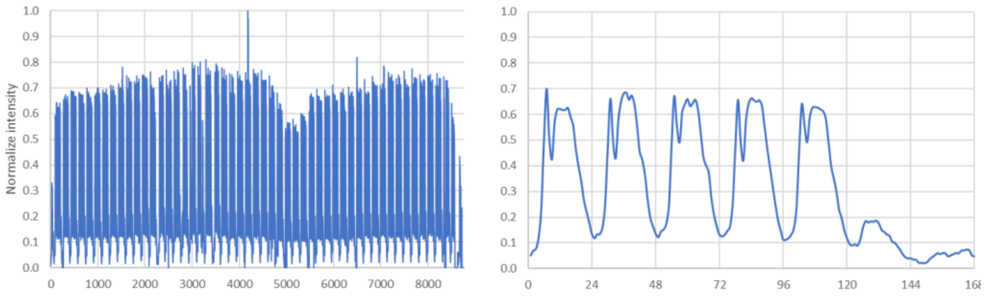
Hydrogen profiles

In OPERA, the demand for hydrogen is distinguished into several H_2 demand categories, in particular H_2 demand by heat boilers in the services sector, H_2 demand by heavy duty vehicles (HDVs) in the transport sector, and H_2 demand for the production of synthetic fuels (Power2Liquids) in industry. Together, these three categories account for approximately 94% of total H_2 demand in the reference scenario of NM2050 analysed in Chapter 4 below.[17]

The demand profile for hydrogen in heavy duty transport is determined by the heavy transport mobility profile and the hydrogen storage size of the vehicle. This profile

[17] See in particular Section 4.1.4, notably Figure 32.

has been determined by means of traffic intensity analysis conducted by TNO's research unit Traffic & Transport. The resulting normalised mobility intensity profile is given in Figure 6 for the entire year and for the first week of February.



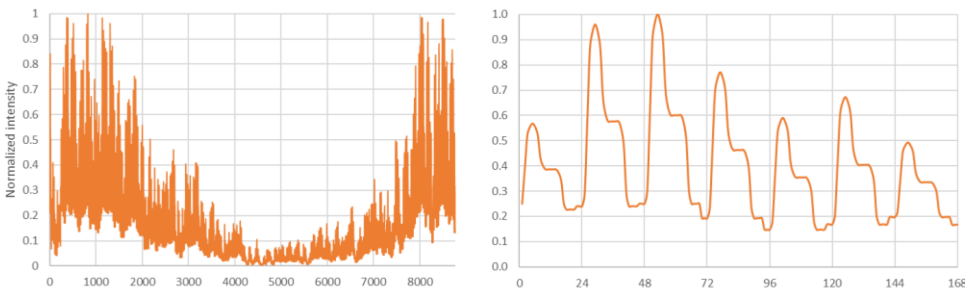
a) The first day in the graphs is a Monday.

Figure 6: Normalized hourly mobility intensity profile for heavy duty transport during an entire year (left) and during the first week of February (right).

The demand profile for synthetic fuels such as kerosene and marine fuels is flat. The production profile - i.e. the H_2 demand profile – for these synthetic fuels, however, is not flat. The reason is that OPERA has the possibility to use a blend of synthetic fuels with fossil fuels and biogenic fuels. The mix of these fuels needs to meet a flat demand profile, but the individual production profiles – including the profile of producing synthetic fuels by means of hydrogen – can be different from that (i.e. not flat). Hence, the H_2 demand profile for producing synthetic fuels is generated endogenously by OPERA.[18]

The demand for hydrogen for heating purposes in the services sector is determined by the heat profile in the services sector, but also by the possibilities to apply demand response. In the current study, the heat demand profile of the services sector is the same profile as developed and used in the Power2Gas study (De Joode et al., 2014).

Figure 7 presents the normalised version of this heat profile for the entire year and for the first week of February. In the graph for the year as whole (left part of Figure 7) a clear seasonal pattern in the heat demand profile of the services sector can be observed. As a result, there is a clear seasonal pattern in the profile of hydrogen demand by the services sector as the need for heat in this sector is mainly met by H_2-fuelled heat boilers (see Section 4.1.6 and Appendix C).



a) The first day in the graphs is a Monday.

Figure 7. Normalized hourly heat demand profile in the services sector for an entire year (left) and for the first week of February (right).

[18] See Section 4.1.6 and Appendix C for an illustration of the H_2 profiles generated by OPERA.

In addition to different H_2 demand categories, OPERA distinguishes also between different H_2 supply options such as steam methane reforming (SMR) or alkaline electrolysis (AEL). The H_2 supply profiles are determined by the H_2 demand profiles of the function it fulfils, the possibilities for demand response and the opportunities for H_2 storage. Hence, these H_2 supply profiles are determined endogenously by OPERA (see Section 4.1.6 and Appendix C).

In COMPETES, the representation of the hydrogen system – and its coupling with the power system – is less detailed and less advanced. More specifically, there is just one, single demand category of hydrogen, which is assumed to have a completely flat demand profile. On the other hand, in the COMPETES model version used for the current study, there is also just one, single hydrogen supply option, i.e. power-to-hydrogen ($P2H_2$). In case of no demand response by $P2H_2$, the hydrogen supply profile is also completely flat, i.e. similar to – and at the same level of – the hydrogen demand profile and, hence there is no need for H_2 storage.

In the case of demand response by $P2H_2$, however, the H_2 supply profile is determined endogenously by COMPETES – i.e. depending on hourly electricity prices – and, hence, there is a need for H_2 storage in order to cover the hourly differences between the flat H_2 demand profile and the flexible, volatile H_2 supply curve (for details and illustrations of the hydrogen profiles in COMPETES, see Section 3.1.6).

2.3.4 Fuel and CO_2 prices

Table 10 provides an overview of the major fuel and CO_2 prices assumed for 2030 and 2050. The CO_2 price refers to the price of an EU ETS emission allowance (per ton of CO_2-equivalent, expressed in euro values of 2020, i.e. at the general consumer price level of 2020). This price is particularly relevant for COMPETES as the GHG mitigation by the power sector across European countries is mainly driven by the price of an EU ETS emission allowance (besides other policy measures – such as subsidies, restrictions or other regulations – affecting investments, disinvestments and operational decisions regarding conventional and renewable power generation technologies). The CO_2 price of an EU ETS allowance is less relevant for OPERA as the mitigation of GHG emissions in this model is primarily driven by the overall GHG reduction target for the Netherlands – see section below – and the resulting (endogenous) CO_2 shadow price to achieve this target.

Table 10: COMPETES and OPERA: Assumed fuel and CO_2 prices in CA2030 and NM2050

	Unit	2030	2050
Biomass Used Cooking Oil (foreign)	€_2020/GJ	17.47	17.47
Wood pellets (foreign)[a]	€_2020/GJ	8.61	9.69
Natural gas	€_2020/GJ	8.09	7.18
Coke oven gas	€_2020/GJ	8.09	7.18
Coal	€_2020/GJ	3.09	2.42
Lignite	€_2020/GJ	1.51	1.18
Oil	€_2020/GJ	15.16	11.45
Uranium	€_2020/GJ	0.84	0.84
CO_2 (EU ETS allowance)	€_2020/ton	48.82	172.29

a) In COMPETES, the price of wood pellets in 2030 is assumed to be subsidised up to the level of the price of coal (i.e. 3.09 €_2020/GJ).

Sources: 2030: PBL et al. (2019), and PBL (2019c); 2050: Berenschot and Kalavasta (2020).

2.3.5 GHG reduction targets

A key driver of the CA2030 and NM2050 scenarios and so, as said, a major input for OPERA in particular, is the overall GHG reduction target for the Netherlands and, hence, the allowed remaining GHG emissions in 2030 and 2050. According to the national Climate Agreement (up to 2030) and the recently effected Dutch Climate Law (up to 2050), this target amounts to 49% in 2030 and 95% in 2050 compared to 1990 emission levels, respectively. As these 1990 levels refer to about 220 MtCO_2-equivalents, these targets translate into a level of remaining GHG emissions of 114 MtCO_2-eq. in 2030 and 11 MtCO_2-eq. in 2050, respectively (Table 11).

Table 11: OPERA: GHG reduction targets for the Netherlands and remaining GHG emissions in 2030 and 2050

Year	GHG reduction with regard to 1990	Remaining GHG emissions [Mt CO_2-eq.]
2030	49%	114
2050	95%	11

These GHG emission targets are less relevant for COMPETES as it focusses on the European power sector rather than on the GHG emissions for the Netherlands as a whole. Moreover, as indicated above, the power production and related GHG emissions in COMPETES are - besides some other policy measures – primarily driven by the emission cap (target) of the EU ETS and the resulting CO_2 price of an emission allowance (which is an input to the model). Therefore, the remaining GHG emissions of the power sector in the Netherlands and other European countries are rather an output than an input of COMPETES.

2.3.6 Comparison of scenario parameters & restrictions for CA2030 and NM2050

For the CA 2030 scenario, both COMPETES and OPERA have used scenario parameters and restrictions that are highly in line with the Climate Agreement of June 2019 and, more specifically, the Climate and Energy Outlook (KEV) of November 2019 (with some small exceptions, as outlined in the sections above). This KEV has been quantified and analysed by, among other models, OPERA and COMPETES. Therefore, there is a close relationship between the inputs and outputs of the KEV2019 and the inputs and outputs of OPERA and COMPETES regarding the CA2030 reference scenario (although this scenario includes some policy measures additional to the KEV2019 – and, hence, some additional power demand – as outlined in the sections above).

Similarly, for 2050, COMPETES has applied scenario parameters and restrictions – both for the Netherlands and other European countries – that, as far as possible, are in line with the NM2050 scenario developed by Berenschot and Kalavasta (2020). This scenario, however, has been quantified and analysed by means of the Energy Transition Model (ETM) developed by Quintel (see ETM, 2020). ETM is a simulation model of the Dutch energy system as a whole, while COMPETES is an optimisation model of the European electricity market (with power trade links across all European countries and regions). Moreover, although some 2050 parameters used by COMPETES are largely in line with the parameters that ETM applied for the NM2050 scenario analysis (notably the parameters on power demand and installed VRE generation capacities in the Netherlands), both models use different hourly energy demand and supply profiles as well as different techno-economic parameters for the technologies and flexibility options included in their models. Therefore, there are large differences between ETM and COMPETES in terms of both modelling approach and inputs, resulting in major differences in modelling outputs.

Although OPERA is a national integrated energy system model – just like ETM – and some major 2050 scenario parameters of OPERA have been aligned, as far as possible, with the NM2050 scenario parameters of ETM/Berenschot and Kalavasta (2020), there are also some major differences between these two models. Firstly, as said, ETM is a simulation model while OPERA – just like COMPETES – is an optimisation model.

Secondly, ETM and OPERA use different hourly energy demand and supply profiles as well as different techno-economic parameters for the technologies and flexibility options included in their models. Thirdly, not all energy demand figures or other NM2050 parameters that are needed for OPERA could be derived from the ETM model website or the scenario study by Berenschot and Kalavasta (2020). And, last but not least, as OPERA is an optimisation model, several parameters – such as energy demand or available capacities of energy resources and generation technologies – are not fixed exogenously (in some cases only a maximum potential or input constraint is defined) but optimised endogenously by the model (for instance, the installed capacity of solar PV, as indicated above). Therefore, there are large differences between ETM and OPERA in terms of both modelling approach and inputs, resulting in major differences in modelling outputs (occasionally even larger than between ETM and COMPETES).

Table 12 provides an overview of the major scenario parameters and restrictions for CA2030 and NM2050 as used by OPERA in this study compared to the values of the NM2050 scenario developed by ETM/Berenschot and Kalavasta (2020).

2.4 Major energy storage technologies

The focus of the current study is the role of large-scale energy storage (LSES) in the Dutch energy system, 2030-2050, in particular of electricity storage by means of compressed air (CAES) and underground storage of hydrogen (either in salt caverns or depleted oil/gas fields). In an integrated energy system, however, these LSES options compete with other storage (and flexibility) options such as electricity storage in batteries or hydrogen storage in vessels, cars or filling stations. Therefore, below we provide a brief, qualitative description of the key storage technologies included in this study, while Table 38 (see Appendix A) presents a more detailed, quantitative overview of the major techno-economic parameters of these technologies used in OPERA/COMPETES.

2.4.1 Compressed air energy storage (CAES)

Compressed air technologies such as diabatic (CAES) and advanced adiabatic (AA-CAES) store energy in the form of compressed air. The air is compressed at pressures of approximately 100 bar and typically stored into salt caverns, but new underground voids are also explored for storage such as depleted gas fields and aquifers (EASE/EERA, 2017). The energy discharge takes place by expansion of the air and using it to drive a gas turbine. This process requires heating of the air.

Table 12: Scenario parameters and restrictions for CA2030 and NM2050 as used by OPERA in this study compared to the NM2050 values of ETM/Berenschot and Kalavasta (2020)

Item	Unit	Parameter values in OPERA		NM2050 values in ETM/BK[a]
		CA2030	NM2050	
Capacity wind offshore	GW	13.5	57.8	51.5
Capacity wind onshore	GW	6.1	20.0	20.0
Capacity Solar PV	GW	28	54.2	106
CO_2 storage capacity CCS	Mt/yr	7.2	25	No restriction[b]
Biomass availability	PJ/yr	230	200	248
Maximum import of natural gas	TWh/yr	No restrictions	0	0
Trade profiles electricity	TWh/yr	Output COMPETES	Output COMPETES	Unclear
Trade hydrogen	TWh/yr	Not allowed	Not allowed	Not allowed
Maximum share district heating for the built environment[d]	-	12%	12%	25%
Passenger cars	-	0.5 Mln EVs	Free[f]	95% EV, 5% H_2
Light duty vehicles (LDVs)	-	10 000 EVs	Free[f]	25% EV, 50% H_2, 25% biofuels
Heavy duty vehicles (HDVs)	-	Zero EVs	Free[f]	
SMR w/o CCS[e]	-	Allowed	Allowed	Allowed
Maximum H_2 admixture % in the methane grid	-	0.1%	15%[c]	Unclear

a) Source: ETM/Berenschot and Kalavasta (2020).
b) Berenschot and Kalavasta (2020) assumes an overall CCS capacity (offshore) of 1700 Mt. In their NM2050 the actual use of CCS amounts to 5.9 Mt in 2050 (implying that, on average, the overall CCS capacity is available for 289 years).
c) Source: New Energy Coalition (2019).
d) The % of final heat demand in the built environment that is provided by district heating on an annual basis.
e) SMR w/o CCS is steam methane reforming without carbon capture and storage.
f) In NM2050, the mix of vehicles is left completely free in OPERA. The resulting (endogenously optimised) mix is: (i) Passenger cars: 97.6% EVs and 2.4% H_2, (ii) Light duty vehicles (LDVs): 100% EVs, (and iii) Heavy duty vehicles (HDVs): 100 H_2.

The source of this heat is what differentiates CAES and AA-CAES. Whereas CAES uses external sources of heat such as natural gas or hydrogen, AA-CAES stores the heat produced during the compression cycle and utilises it to heat the air when the energy is required. The energy density of (AA)CAES is low, i.e. 2-6 kWh/m^3. For CAES there is not a fixed energy/power relation but in the present study we have not optimised the power separately, i.e. we used fixed charge/discharge times (Table 38).

2.4.2 Batteries

Battery technologies such as lithium-ion batteries (Li-ion), lead-acid batteries (PB) and flow-based batteries like the vanadium redox battery (VRB) store energy through electrochemical reactions. Conventional batteries components are a cathode and an anode and an electrolyte as an ionic conductor. PB batteries have a cathode that contains lead dioxide and an anode that contains pure lead, whereas Li-ion uses lithiated metal oxide and carbon material, respectively. While the PB batteries have a lower cost, the Li-ion batteries are becoming more attractive due to their reliability and higher efficiency. Flow batteries, such as VRB, separate the storage and charge/discharge functions. The electroactive materials are stored into two liquid electrolytes of metallic salts (vanadium) rather than in the electrodes as is the case for conventional batteries. The liquid electrolytes are pumped at either side of a core that consists of a positive and a negative electrode separated by an ion-selective membrane (EASE/EERA, 2017). The separate scaling of energy and power rating and can therefore be cost-effective when used for large-scale storage. In this work, however, like for (AA)CAES, the charge and discharge times were kept fixed (Table 38).

2.4.3 Hydrogen storage

Hydrogen – either from electrolysis or any other production source – can be stored by means of a variety of options. In this work storage as compressed hydrogen has been considered only. Large-scale underground hydrogen storage in salt caverns, depleted gasfields or aquifers has low costs and becomes a natural choice for a centralised hydrogen storage hub (Sørensen and Spazzafumo, 2018). Hydrogen can also be compressed and stored in vessels. Typically, these technologies store hydrogen at about 200 bar, i.e. with an energy density in the range of 500 kWh/m^3. The cost of these vessels much larger than those of existing caverns. But both storage technologies need expensive hydrogen compressors, and expanders. In this work we do not differentiate between compressor and expander costs for vessels and caverns. We do, however, optimise the capacities for storage (size), charge and discharge separately. Hydrogen filling stations are an essential part of the fuel cell vehicles (FCV) infrastructure. Filling stations can have different variations on their design, but they require storage vessels, production equipment (optional), compression system and ancillary equipment (EVTC, 2014). Moreover, once the hydrogen goes into the FCV it is commonly stored in compressed hydrogen (up to 700-800 bar) tanks.

2.4.4 Electric vehicles

Batteries of electric vehicles (EVs) provide a specific means to store electricity. While their main function is storage for propulsion of vehicles, there is also the option of feeding electricity back to the grid, i.e. vehicle to grid (V2G). With battery sizes of 100 kWh merging on the market, EVs can by 2050 provide a large storage medium. In this work we have included the V2G option in CA2030 only in COMPETES in NM2050 in both models. The most important assumptions regarding average battery sizes and electricity use by EVs are summarized in Table 13. For discharge for propulsion purposes, driving profiles are used.

Table 13: Average battery size and electricity use of electric vehicles

	CA2030	NM2050	CA2030	NM2050
	Battery capacity		*Electricity use*	
	kWh		MWh/vehicle/yr	
Passenger car - full electric	75	100	3.0	3.1
Passenger car - PI hybrid[a]	75	100	2.5	2.8
LDV - full electric	75	100	6.7	6.7
LDV - PI hybrid[a]	75	100	1.4	1.3

a) These cars also require biofuel or gasoline for propulsion.

Although OPERA and COMPETES have used the same input parameters for average battery size and electricity use, there are some significant differences between these models regarding their approach on EV storage transactions. In OPERA the batteries of all EVs are lumped into one large battery. This battery can be charged at fast-charging filling stations connected to the medium voltage grid or at charging points located in or near homes, or in car parks that are connected to the low voltage grid. When vehicle-to-grid (V2G) is included, the discharge is to the low voltage grid. At present, OPERA does not account for the cost or physical limitations for this charging or discharging capacity, other than the use of the medium and low voltage grid.

Electricity fed to the battery leads to (gross) charging of the battery but, since OPERA assumes one large battery for all EVs, part of this electricity is used for concurrently driving vehicles (following assumed driving profiles). OPERA reports the net charge into the battery as stored electricity. Net battery discharge occurs when OPERA endogenously determines that it is cheaper to discharge the battery rather than use electricity from the grid to meet the demand of driving vehicles, or, in the case of V2G, when discharging the battery is an economically favourable way to meet the electricity demand on the low voltage grid.

Charging and discharging of the battery are optimised for lowest social cost of the energy system, and not to preferences of vehicle users, e.g. regarding buffer volumes, charging times and charging frequency. This means the battery is charged when electricity prices are low, and discharged when they are high. OPERA assumes a storage loss that is a fixed percentage of the state of charge. In the optimisation by OPERA, this assumption disfavours a high state of charge. For the minimum state of charge, OPERA uses the constraint that at each day the state of charge of the battery is such that all demand at that day for driving vehicles can still be met.

In COMPETES, EV batteries can provide two types of flexibility services to the power system, i.e. demand response and electrical storage. For demand response, the EV load – i.e., the amount of electricity demanded and used for driving the EVs (including storage losses) – is divided in two parts, the uncontrollable and the controllable part. For the uncontrollable part (30% of the total EVs in the reference case), the load is just a fixed EV (dumb) charging profile that is directly added to the conventional demand and it does not react to any electricity price. For the controllable part (70% of the total load), the model takes into account (i) availability, i.e. when the vehicles are parked and connected to the electric system, (ii) energy demand, i.e. what amount of energy is needed, and (iii) deadline, i.e. the energy demand must be supplied before departure. During the time where EVs are connected to the grid, the EVs must charge at least their required energy demand before departure. EVs can shift their consumption within this time window to take advantage of the lowest electricity prices during this time window. The shift between the fixed (dumb) and the flexible (smart, dynamic) charging profile is indicated as demand response of EV batteries by means of grid-to-vehicle (G2V) transactions.

In addition, EV batteries can also act as electrical storage by means of vehicle-to-grid (V2G) transactions, where EVs can charge (during low prices) when being connected to the electric system and discharge, i.e. provide energy back (during high prices), if there is enough energy in the batteries for the next trip before departure. Although the initial costs of the EV batteries and the EV charging infrastructure are not covered by COMPETES when analysing EV flexibility services for the power system (as these costs are assumed to be made primarily for mobility purposes in the transport system), the model makes sure that the degradation of the EV batteries are recovered when using V2G storage transactions.

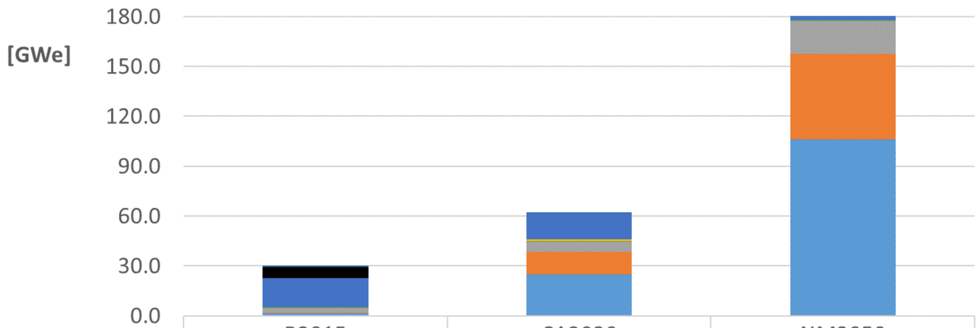
3 Results from COMPETES

This chapter presents and discusses the major results of the study obtained by means of the COMPETES model. First of all, Section 3.1 discusses the results regarding the reference scenarios CA2030 and NM2050. Subsequently, Section 3.2 briefly defines the sensitivity cases conducted by COMPETES for NM2050 and presents the major findings of these cases.

3.1 COMPETES: Reference scenarios CA2030 and NM2050

3.1.1 Installed power generation and interconnection capacities

As outlined in the previous chapter, by means of the COMPETES investment module and the CA2030 and NM2050 parameters on (i) power demand across European countries and regions, (ii) exogenous investments and installed capacities of some (mainly renewable) power generation technologies, (iii) techno-economic characteristics of all power generation, interconnection and flexibility options, and (iv) expected fuel and CO_2 prices, the model optimises (activated) endogenous investments and installed capacities of the other (mainly conventional) power generation technologies as well as of the transmission interconnections and flexibility options in CA2030 and NM2050.



	R2015	CA2030	NM2050
Nuclear	0.5	0.5	0.0
Coal	6.6	0.0	0.0
Gas	17.8	15.5	3.5
Other RES-E	0.1	1.1	0.3
Biomass	0.5	0.5	0.1
Wind Onshore	2.6	6.0	20.0
Wind Offshore	0.4	13.4	51.5
Solar PV	1.5	25.1	106.0

a) R2015 is the reference scenario of 2015 as used in the FLEXNET project (see Sijm et al., 2017a and 2017b).
b) Gas in this report refers to natural gas (unless indicated otherwise).

Figure 8: COMPETES: Installed capacities of power generation technologies in R2015, CA2030 and NM2050

Figure 8 presents the resulting installed capacities of the major power generation technologies in the Netherlands in CA2030 and NM2050, whereas Table 37 in Appendix B provides similar data on installed power generation capacities in other

EU countries and regions.[19] For comparative reasons, Figure 8 presents also the installed capacities of the reference scenario for 2015 ('*R2015*') as used in the FLEXNET project (Sijm et al., 2017a and 2017b). It shows, for instance, that the installed capacities of conventional power generation (coal, gas, nuclear) decreases significantly over the years 2015-2050, whereas they increase substantially for the variable renewable energy (VRE) technologies, in particular for solar PV and offshore wind.[20]

In addition, as explained in Section 2.3.2, COMPETES determines the (optimal) interconnection capacity for cross-border trade between the Netherlands and other EU countries. For the Netherlands, the total interconnection capacity with neighbouring countries amounted to about 6 GW in 2015, while it is estimated at 12 GW in CA2030 and 33-47 GW in NM2050 depending on whether supply of flexibility due to demand response in the Netherlands and other European countries is included (33 GW) or excluded (47 GW; see Table 8 in Section 2.3.2)

3.1.2 *Electricity balance: power demand and supply*

Once the installed capacities of both the power generation technologies, the transmission interconnections and the flexibility options have been determined, the unit and economic dispatch module of COMPETES optimises the hourly electricity production in each European country and region, including the power trade (imports, exports) across these countries and regions. Figure 9 presents the resulting electricity balances (power demand and supply) of the Netherlands in R2015, CA2030 and NM2050. It shows, for instance, that – due to the (assumed) further electrification of the Dutch energy system – total domestic power demand, i.e. excluding exports, increases from about 113 TWh in R2015 to almost 136 TWh in CA2030 and even to nearly 346 TWh in NM2050 (see Figure 9 and Table 14).[21]

The lower part of Figure 9 illustrates that the increasing domestic power demand is met by rising domestic power supply from VRE sources, notably offshore wind and solar PV. More specifically, the output from these resources – including onshore wind – increases from less than 9 TWh in R2015 to approximately 100 TWh in CA2030 and to more than 380 TWh in NM2050. As a percentage of total domestic power production, the share of total VRE output amounts to 9%, 56% and 98%, respectively. Actually, in both CA2030 and NM2050 – due to the assumed electricity demand and the installed VRE capacities – the Netherlands faces a net domestic electricity production surplus (or net foreign power trade surplus) whereas in R2015 it still had a domestic electricity output deficit (or net foreign power trade deficit). More specifically, in R2015 the Netherlands realised, on balance, a net power import position of almost 17 TWh while in both CA2030 and NM2050 it is expected to have net exports of about 42-43 TWh (Table 14).[22]

[19] Although COMPETES delivers results for both the Netherlands and other European countries and regions, in the main text of this study we will present and discuss only results regarding the Netherlands (unless stated otherwise).

[20] Note that of the technologies presented in Figure 8, coal with CCS and gas (excluding CHP) are the only technologies for which new investments are activated and determined endogenously by COMPETES for both CA2030 and NM2050. New investments in other technologies presented in Figure 8 are either deactivated ('not allowed') or determined exogenously by the model (for details, see Section 2.3.2, notably Table 6).

[21] Note that the domestic demand figures presented in Figure 9 have been set exogenously into COMPETES (see Section 2.3.1, in particular Table 4).

[22] Note that the VRE supply data in Figure 9 refer to VRE output *after* VRE curtailment. In NM2050, however, a major part of offshore wind output is curtailed (for details, see Table 15 and the related main text below).

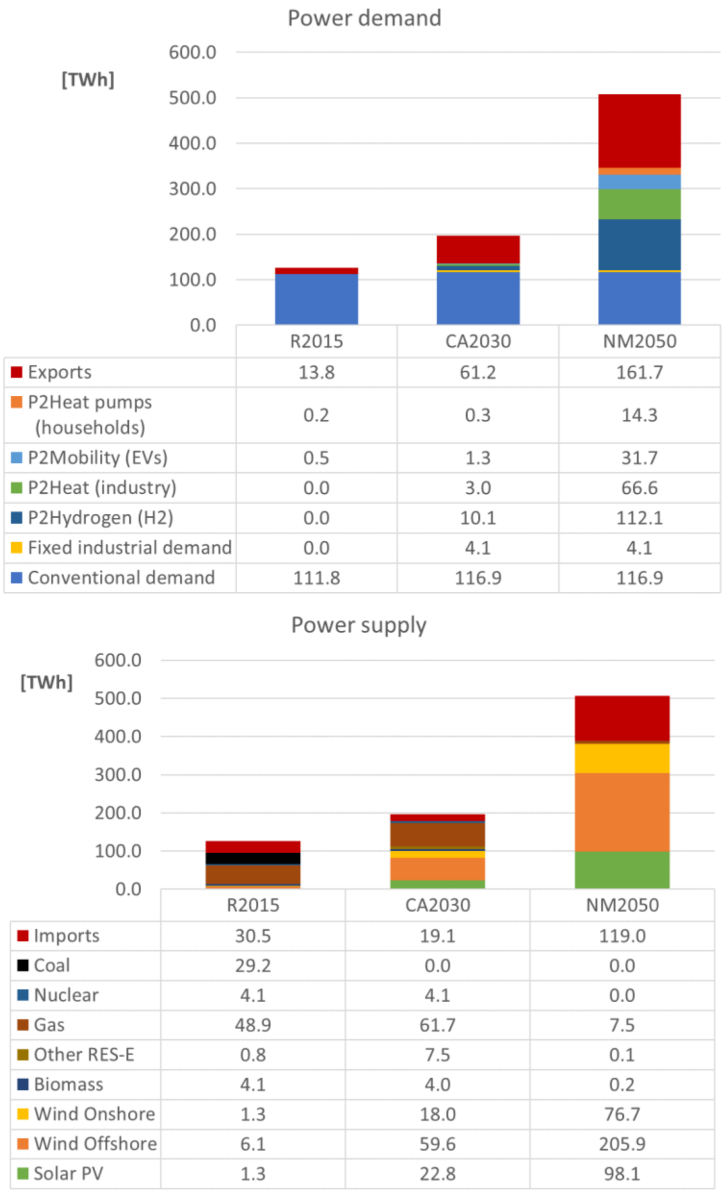


Figure 9: COMPETES: Power demand and supply in R2015, CA2030 and NM2050

Table 14: COMPETES: Aggregated electricity balances in R2015, CA2030 and NM2050

[TWh]	R2015	CA2030	NM2050
Domestic power demand	112.5	135.7	345.7
Domestic power supply	95.8	177.8	388.5
Domestic power production deficit[a]	+16.7	-42.1	-42.8
Power imports	30.5	19.1	119.0
Power exports	13.8	61.2	161.7
Foreign power trade deficit[b]	+16.7	-42.1	-42.8

a) A minus ('-') indicates a domestic power production surplus, whereas a plus ('+') indicates a domestic power output deficit;
b) A minus ('-') indicates net power exports ('trade surplus'), whereas a plus ('+') indicates net power imports ('trade deficit').

3.1.3 *The variability of the residual load*

In the electricity sector, the variability of the residual load is the main source (or 'cause') of the need for flexibility of the power system.[23] The concept '*residual load'* is defined as the difference between domestic power demand minus domestic power supply from VRE resources (before any VRE curtailment). Figure 10 illustrates the hourly residual load for the year as a whole (8760 hours) in CA2030 and NM2050. It shows that the hourly residual load varies both rapidly and widely in CA2030 – i.e. between +22 and -17 GW per hour – and even much stronger in NM2050, i.e. between +53 and -112 GW (see also Figure 11). In addition to the hourly variation of the residual load, Figure 10 also seems to indicate some seasonal pattern in the residual load, at least in CA2030 – in the sense that the residual load is, on average, a bit lower in the summer than in the winter – although this pattern is less clear in NM2050.[24] This means that, notably in NM2050, flexibility options such as cross-border electricity trade, demand response and storage predominantly have to deal with large, short-term (hourly, daily) fluctuations in the residual power load but hardly or not with a longer-term, seasonal variation in this load

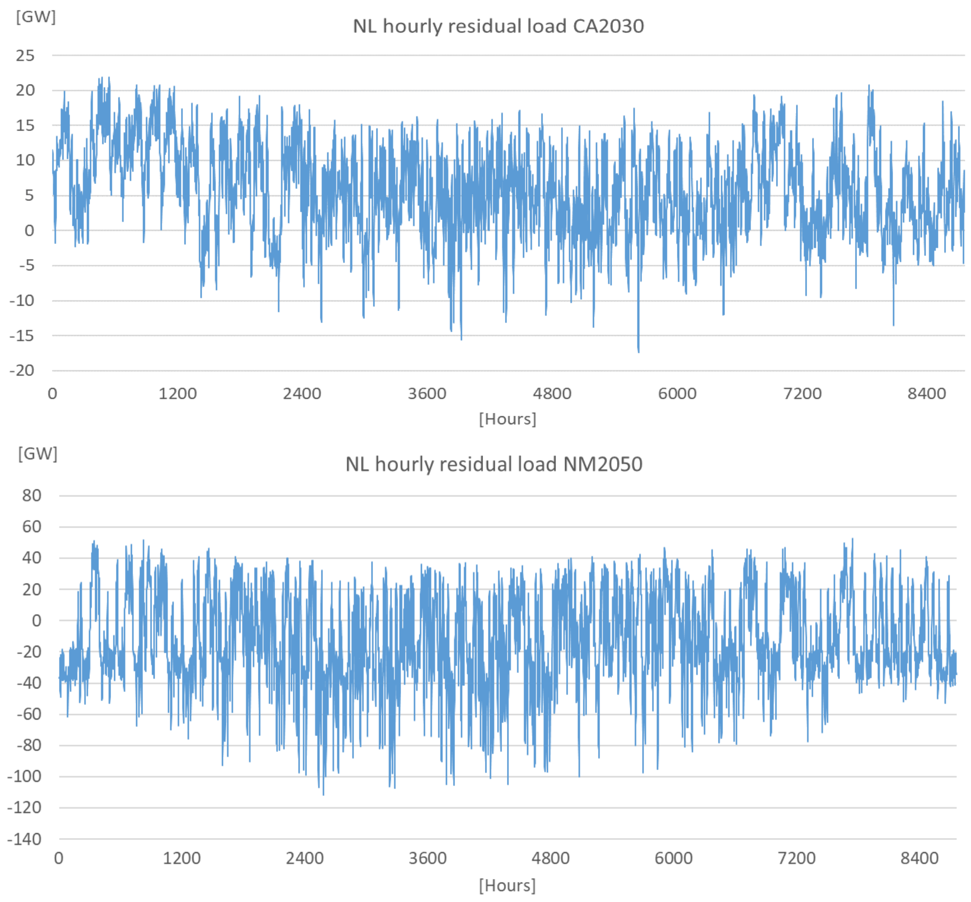


Figure 10: COMPETES: Residual load – Hourly resolution in CA2030 and NM2050

[23] The other major sources ('causes') are *the uncertainty of the residual load* – largely due to the lower predictability ('forecast error') of VRE output generation – and *the overloading ('congestion') of the power grid* (Sijm et al., 2017a).

[24] See also Appendix B, in particular Figure 45, Figure 46 and Figure 47, which show the residual load on both a daily and weekly (average) resolution and as a moving average of hourly residual load over 50 and 150 windows.

By ranking the hourly residual loads over a year from high to low, Figure 11 provides the duration curve of these loads in CA2030 and NM2050. In addition to confirming the wide spread of the hourly residual load observed above, it also shows that these loads are negative during a large number of hours during the year, i.e. about 1800 hours in CA2030 and more than 5600 hours in NM2050. This large number of hours with a negative residual load results primarily from the assumed scenario parameters on electricity demand, installed VRE capacities and the full load hours of the installed VRE technologies.

A negative residual load implies that the domestic power supply from VRE resources is larger than the domestic power demand, i.e. there is a domestic surplus of electricity production. This raises the question how this negative residual load – or domestic VRE generation surplus – can be addressed. One option is foreign power trade (i.e. electricity exports) but there are other options such as storage, VRE curtailment or demand response (i.e. shifting electricity demand from VRE deficit to surplus hours).

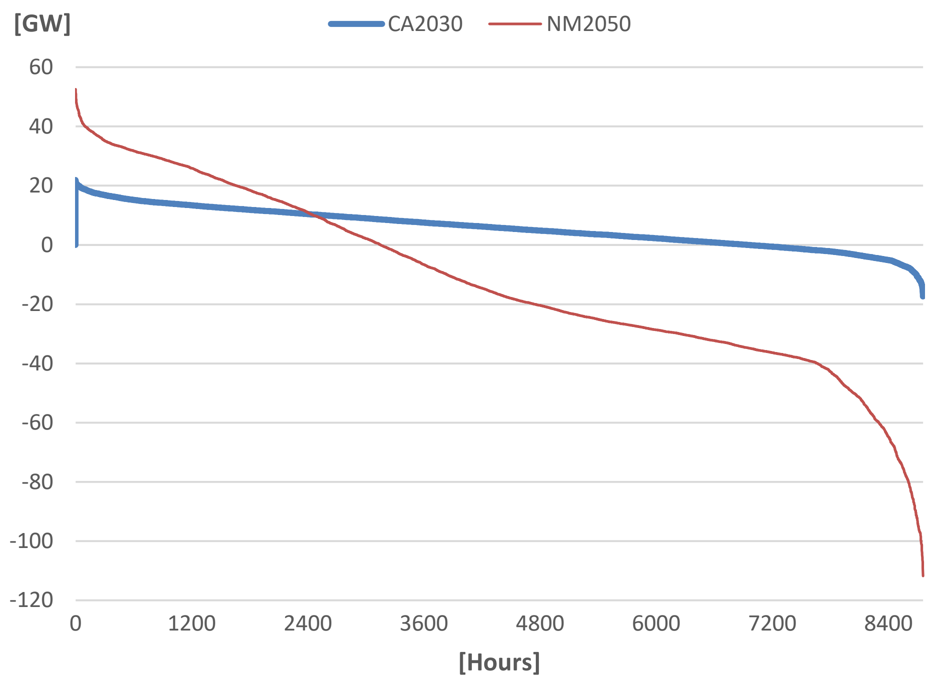


Figure 11: COMPETES: Duration curve of the residual load in CA2030 and NM2050

On the other hand, in a situation where total domestic power supply is dominated by VRE electricity generation – such as in NM2050 where the share of VRE in total power output amounts to 98% - a similar question arises, i.e. how can a positive residual load (or domestic VRE generation deficit) be addressed, in particular when this residual load is substantial, for instance 10 GW or more (see Figure 11, notably the left part of the residual load duration curve of NM2050). One option is, once again, foreign trade (i.e., in this case, electricity imports) but there are again other options such as back-up dispatchable power generation, demand response or (discharge from) electricity storage.

Note that the duration curves presented in Figure 11 refer to the residual load *before* VRE curtailment (and before the deployment of any other flexibility option such as cross-border power trade, demand response or energy storage). While VRE curtailment is still negligibly small in CA2030, it is rather substantial in NM2050. More specifically, Table 15 shows that in NM2050 about 73 TWh of VRE output generation is curtailed, i.e. 16% of total VRE supply before curtailment. As the operational (marginal) costs of offshore wind are slightly higher in COMPETES than of offshore wind or solar PV, COMPETES prefers to curtail offshore wind as the first option. Consequently, in COMPETES almost all VRE curtailment in NM2050 is assigned to offshore wind (i.e. 72.8 TWh out of 73 TWh). In addition, a small amount of VRE curtailment is assigned to onshore wind (0.2 TWh), notably in those hours of the year in which VRE curtailment of offshore wind is not sufficient to meet the total need for VRE curtailment.

Table 15: COMPETES: Curtailment of VRE power generation in NM2050

	Unit	Solar PV	Wind onshore	Wind offshore	Total
VRE supply before curtailment (b.c.)	TWh	97.9	76.9	278.7	453.7
VRE curtailment	TWh	0.0	0.2	72.8	73.0
VRE supply after curtailment	TWh	97.9	76.7	205.9	380.7
VRE curtailment as % of VRE supply b.c.	%	0.0%	0.3%	26.1%	16.1%

3.1.4 *Flexibility options to deal with the variability of the residual power load*

In order to get a better view of the role of flexibility options, including storage, in addressing the variability of the residual power load – notably during the 'more extreme' peak and off-peak load hours – the upper part Figure 12 presents the contribution of the main flexibility options to deal with the (positive) residual load during the first 100 ('peak') hours of the residual load duration curve in NM2050, while the lower part illustrates how these options address the (negative) residual load during the last 100 ('off-peak) hours of this curve.

Figure 12 shows that during the first 100 (peak) hours the residual load is largely met by cross-border trade (i.e. net electricity imports) and demand response (i.e. shifting electricity demand from (peak) hours with a high electricity price to (off-peak) hours with a low electricity price. In the current version of COMPETES we distinguish between three categories of demand response ('flexible electricity demand'):[25]

- *Power-to-Mobility* (P2M), where demand response refers to the difference between so-called 'dumb' versus 'smart' charging of EVs (see Section 2.4.4);
- *Power-to-Hydrogen* (P2H$_2$), where the production of hydrogen by means of electrolysis is shifted from hours with high electricity prices to hours with low electricity prices (see Section 3.1.6 below);
- *Power-to-Heat* (P2H), including demand response by (i) all electric heat pumps in households, and (ii) hybrid boilers in industry.

In addition, Figure 12 shows that a minor part of the residual load (RL) during the first 100 hours of the RL duration curve is met by electricity storage (discharge) and by dispatchable ('flexible') power generation, i.e. from (natural) gas and so-called 'other renewable energy sources' (RES-E) besides VRE (sun/wind) such as biomass or

[25] See also Section 2.3.1, notably Table 4, as well as Sijm et al. (2020).

hydro power. Storage refers predominantly to electricity storage by means of EV batteries, notably V2G transactions (as further discussed in Section 3.1.5 below). Note, however, that although Figure 12 indicates that the role of storage in addressing peak residual loads is, on average, relatively modes, it is quite significant during certain peak hours, running up to some 10-15 GW of storage discharges (against a residual load of 40-50 GW).

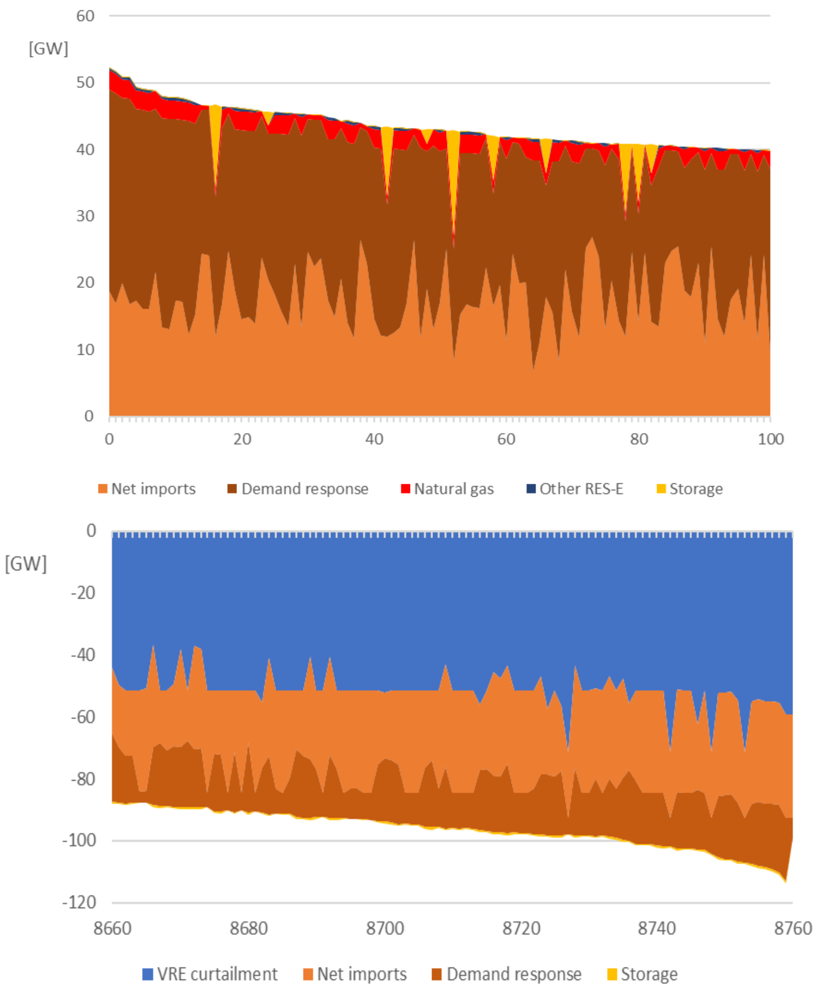
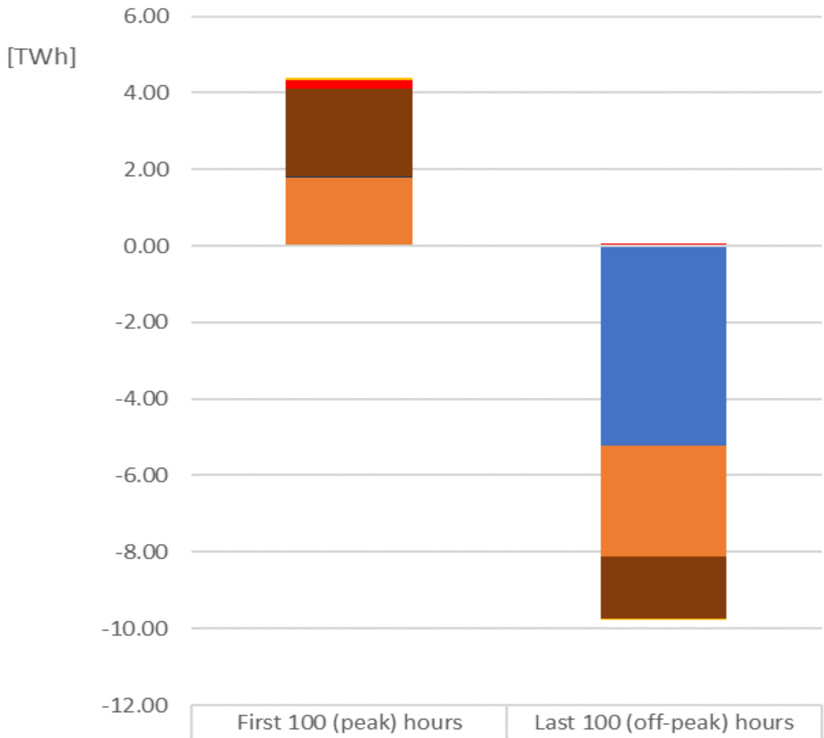


Figure 12: COMPETES: Flexibility options during the first 100 ('peak') and last 100 ('off-peak') hours of the residual load duration curve in NM2050

The lower part of Figure 12 shows that during the last 100 (off-peak) hours of the RL duration curve, the (large) negative residual loads – or VRE surpluses – are primarily addressed by VRE curtailment, demand response and cross-border power trade (i.e., in this case, net electricity exports. The role of storage – predominantly storage charge by EV batteries for V2G transactions – is hardly visible in Figure 12, but it makes an almost constant – albeit small – contribution (<0.9 GW) in addressing large negative residual loads (90-110 GW) during the last 100 hours of the RL duration curve.[26]

[26] The almost constant (but small) contribution of storage during the off-peak hours is most likely due to the assumptions on the V2G storage transactions made in this study (for details, see Section 3.1.5 below). In practice, V2G charges may be more volatile (and, hence, more substantial during certain off-peak hours), similar to V2G discharges presented in Figure 12.

By aggregating the electricity volumes of the residual load (RL) and the main flexibility options over the first 100 hours as well as, separately, the last 100 hours of the RL duration curve, Figure 13 shows the contribution (role) of these options in meeting the RL over these hours in NM2050. Over the first 100 (peak) hours, the aggregated RL (VRE shortage) amounts to about 4.4 TWh. This load is met primarily by demand response (53% of the aggregated RL), followed by net imports (40%) and natural gas-fired power generation (5%). The contribution of storage (discharge) – predominantly V2G by EV batteries – amounts to 0.07 TWh, i.e. about 2% of the aggregated RL over the 100 peak hours considered.



	First 100 (peak) hours	Last 100 (off-peak) hours
Storage	0.07	-0.05
Natural gas	0.20	0.07
Demand response	2.32	-1.61
Other RES-E	0.03	0.00
Net imports	1.78	-2.92
VRE curtailment	0.00	-5.20

a) A negative figure for net imports implies actually net exports;
b) A small part of gas-fired power generation refers to 'must-run CHP', which also produces during hours with a negative residual load, thereby enhancing the VRE surplus (i.e. with 0.07 TWh) over the last 100 hours of the residual load duration curve.

Figure 13: COMPETES: Contribution of flexibility options in meeting the aggregated residual load during the first 100 (peak) and last 100 ('off-peak') hours of the residual load duration curve in NM2050

Over the last 100 (off-peak) hours, the aggregated (negative) RL – i.e. VRE surplus – amount to about 9.7 TWh. This surplus is addressed primarily by VRE curtailment (54% of the VRE surplus), followed by net exports (30%) and demand response (17%). The contribution of storage charge – by EV batteries for V2G transactions – amount to 0.05 TWh, i.e. less than 1% of the aggregated RL over the 100 off-peak hours considered.

Finally, Figure 14 presents the duration curve of the main flexibility options in NM2050 over this scenario year as a whole. Put simply, the surface below these curves but above the X-axis (upper left part of the graph) represents the energy volume of these flexibility options to address positive residual load (VRE shortages) by enhancing electricity supply or reducing demand, whereas the surface above these curves but below the X-axis (bottom right part of the graph) represents the energy volumes of the flexibility options dealing with negative residual loads (VRE surpluses) by enhancing electricity demand or reducing supply). The height of the duration curves indicates the hourly capacities used by the respective flexibility options to meet these energy volume transactions (where Table 16 provides the maximum values of these capacities).

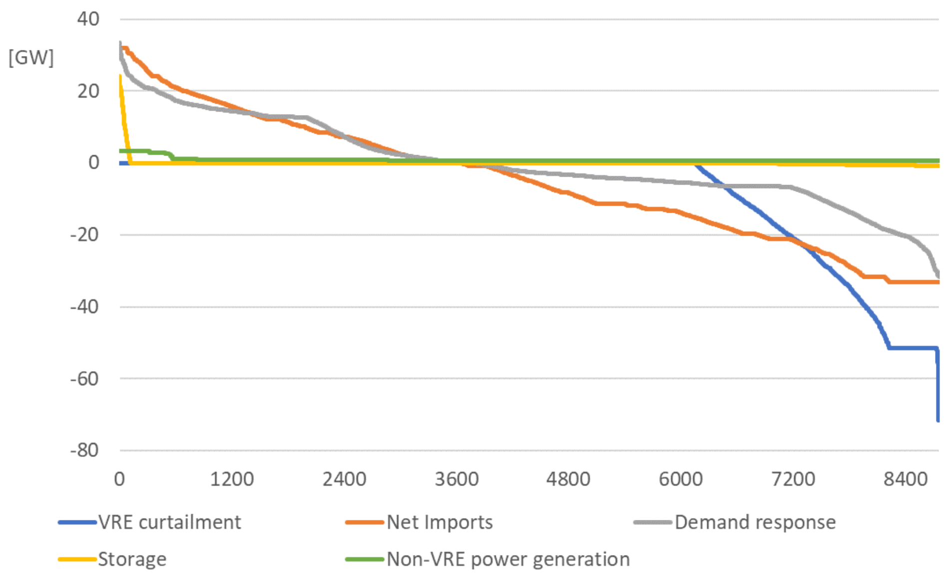


Figure 14: COMPETES: Load duration curves of flexibility options in NM2050

Figure 14 shows, for instance, that in NM2050 the Netherlands relies on net imports to meet its domestic RL over some 3600 hours of the year, whereas it relies on net exports – largely to deal with its VRE surpluses – over the remaining 5000 hours of the year. However, whereas the maximum interconnection capacity (about 33 GW) is used for electricity exports during a substantial number of hours over the year (about 430 hours), the maximum interconnection capacity used actually for electricity imports is slightly lower (about 32 GW) and applies only for about 80 hours (see also Table 16).

Table 16: COMPETES: Capacities of flexibility options in NM2050 during hours with a VRE shortage and hours with a VRE surplus

[GW]	VRE shortage: Enhancing electricity supply/reducing demand	VRE surplus: Enhancing electricity demand/reducing supply
VRE curtailment	0	71.5
Net imports	32	33.2
Demand response	33.4	31.6
Storage	24.1	0.9
Power generation	3.3	-0.7

Figure 14 also shows, among others, that storage discharge as a flexibility option applies only for a limited number of hours in NM2050 (about 120 hours). As noted, however, in some of these hours its contribution to deal with VRE shortages is quite substantial, running up to a maximum of 24 GW per hour (Table 16). On the other hand, storage charge applies for a large number of hours in NM2050 – actually the remaining 8550 hours of the year – but the volumes involved are very small, i.e. close to zero in most cases and only between 0.5 GW and 0.9 GW during some 1000 hours of the year. Apart from assumptions regarding the availabilities and costs of other, competing flexibility options, these storage outcomes are largely due to the assumptions made regarding storage by means of EV batteries, which will be further discussed in the next section.

3.1.5 Electricity storage

Table 17 provides a summary overview of the main electricity storage results by COMPETES for the two reference scenarios (CA2030 and NM2050). It shows that the total electricity storage *size* – or required storage capacity in energy terms – is estimated at 31 GWh in CA2030 and 1037 GWh in NM2050, i.e. 0.02% and 0.3% of total domestic electricity demand in these scenario years, respectively. In addition, it indicates that the total annual storage volume – i.e. the total annual volume of hourly electricity charges – amounts to 1.5 TWh in CA2030 and almost 33 TWh in NM2050, i.e. about 1.0% and 9.5% of total domestic electricity demand, respectively. The rapid increase in both electricity storage size and volume between CA2030 and NM2050 is predominantly due to the rapid increase in the number of electric vehicles (EVs) between these years, including some increase in the average storage size of the batteries of these EVs (for details, see below, notably Table 18).

Table 17: COMPETES: Summary overview of electricity storage in CA2030 and NM2050

CA2030	**Size**	**Volume**	**FCE**	**Charge**	**Discharge**
E-Storage option	GWh	GWh	#	MW	MW
EV batteries	30.50	1450	48	1505	1505
Li-ion batteries	0.04	3.38	85	40	40
Total E-storage	30.54	1453	48		
As % of total E-demand	0.02%	1.0%			
NM2050	**Size**	**Volume**	**FCE**	**Charge**	**Discharge**
E-Storage option	GWh	GWh	#	MW	MW
EV batteries	1037	32967	32	38357	38357
Li-ion batteries	0.05	10.51	210	50	50
Total E-storage	1037	32978	32		
As % of total E-demand	0.30%	9.5%			

a) *Size* refers to the storage capacity (in energy terms) estimated by the model to be required to meet storage needs over a year;
b) *Volume* refers to the total amount of hourly charges over a year (in energy terms);
c) *Full cycle equivalent* (FCE) is defined as storage volume divided by storage size (in number of full charge/discharge cycles);
d) *Charge/discharge* refers to the charge/discharge capacity of the total storage size (in capacity terms).

The fact that in both scenario years the electricity storage volume is much higher than the electricity storage size indicates that electricity storage is characterised by a high full cycle equivalent (FCE), defined simply as storage volume divided by storage size.

More specifically, the FCE of total electricity storage amounts to 48 in CA2030 and 32 in NM2050 (i.e., 'on average' for all the electricity storage options involved).

More specifically, Table 17 shows that in both CA2030 and NM2050 electricity storage is almost fully dominated by a single storage option, i.e. batteries of electric vehicles (EVs). In addition, there is a tiny role for stationary Li-ion batteries in both scenario years, but no role for other types of direct electricity storage (apart from converting electricity into hydrogen, which can be stored and, in principle, reconverted into electricity again). These issues are further specified and discussed in the subsections below (including Section 3.1.6 on hydrogen storage).

Electricity storage by EV batteries
Based on the methodology regarding electricity storage by EV batteries (as explained in Section 2.4.4), these batteries turn out to be the dominant, almost sole electricity storage option in COMPETES in both CA2030 and NM2050 (and also – more significantly in terms of power system flexibility provided – one of the main demand response options in NM2050, besides demand response by P2H in households and $P2H_2$ in the energy sector).[27] For instance, Table 17 that in NM2050 out of a total annual volume of electricity storage of 32,978 GWh almost 100% (32,967) is covered by EV batteries.

Table 18 provides some more detail on electricity storage volumes in both scenario years by splitting these volumes in two parts:

- *The G2V part*, i.e. the part of the total annual EV battery charges – including storage losses – that is used by EVs for mobility purposes ('driving'). This part represents the actual electricity demand by EVs (including demand response from hours with relatively high electricity prices to hours with relatively low electricity prices);
- The *V2G part,* i.e. the part of the total annual EV battery charges – including storage losses – that is fed back by EVs to the grid in order to stabilise the power system, notably by means of EV battery charges during hours with relatively low electricity prices and EV battery discharge to the grid during hours when electricity prices are relatively high. This part represents the actual or 'real' electricity storage by EV batteries for power system balancing purposes.

Table 18 indicates that in NM2050 the main part of total EV battery charges (96%, i.e. 31.7 TWh) is used for mobility purposes, i.e. G2V transactions – including demand response – for EV driving, while only a small part (4%, i.e. 1.2 TWh) is used for 'real' electrical storage purposes, i.e. for V2G transactions to balance the power system.

Figure 15 shows the hourly profile of the V2G transactions in NM2050. As COMPETES does not distinguish hourly EV battery charges into charges for G2V versus V2G transactions, we have assumed – probably less realistically – that, in each hour, the V2G charge represents 4% of the total hourly EV battery charge (i.e. the average share of V2G transactions in total annual EV battery charges, as indicated in Table 17 and discussed above).

[27] For details on the role of demand response by EV batteries and other P2X technologies, see Sijm et al. (2020).

Table 18: COMPETES: Electricity use and storage by EVs (passenger cars) in CA2030 and NM2050

	G2V (including losses	V2G (including losses)	Total annual storage volume	Total storage size	FCE
	[GWh]	[GWh]	[GWh]	[GWh]	[#]
CA2030	1253	197	1450	30.5	48
NM2050	31731	1237	32967	1036.6	32
As % of total domestic power demand					
CA2030	0.8%	0.2%	1.0%	0.02%	
NM2050	9.2%	0.4%	9.6%	0.3%	

a) In COMPETES, EVs refer to EV passenger cars only (and not to other EVs such as electric buses, trucks, etc.);
b) The storage capacity of a single passenger EV is assumed to be 75 kWh in CA2030 and 100 kWh in NM2050;
c) The average electricity use of a single passenger EV for driving about 12-15.000 kms per year is assumed to be about 3 MWh per annum in both CA2030 and NM2050;
d) The number of passenger EVs amounts to approximately 0.41 mln in NM2030 and 10.4 mln in NM2050.

On the other hand, COMPETES optimises V2G discharges and, hence, the profile of these discharges can be obtained directly from the model. The resulting V2G charge and discharge profiles, as presented in Figure 15, can be re-ordered into a duration curve of V2G transactions, showing a similar pattern as the duration curve of the total storage transactions presented and discussed in Section 2.1.4 above (see particularly Figure 14). This is not surprising since, as noted above, EV storage – even if restricted to V2G transactions – is the dominant part of total electricity storage in NM2050.

More specifically, Figure 15 illustrates that, due to the assumption outlined above, V2G storage charges show a rather regular, continuous pattern while its (average) size is relatively small (with a maximum charge capacity of about 1 GW). On the other hand, V2G storage discharges show a rather irregular pattern, with high peaks of these discharges – up to 25 GW – during a limited number of hours over the year. This suggests that V2G discharges play a crucial role in meeting residual power load during these (VRE shortage) hours, similar to the observations made in Section 3.1.4 above (notably Figure 12). Strikingly, Figure 15 shows that these incidental, high peak storage discharges occur particularly in the winter months (January-March) but hardly or not in summer months (July-September).

Finally, Figure 16 presents the state of charge (SOC) of electricity storage by EV batteries of passenger cars in both CA2030 and NM2050, including both G2V and V2G storage transactions. As COMPETES is lacking data on the electricity discharge pattern for the EV fleet as a whole, however, the SOC in Figure 16 refers to the storage size of the amount of EVs that is assumed to be connected to the grid at a specific time and that are willing to provide flexibility services (G2V/V2G). Moreover, only 70% of the storage size of these EVs can be used for flexibility purposes since it is assumed to be the 'available controllable part' of the EV battery size (for further details, see Section 2.4.4).

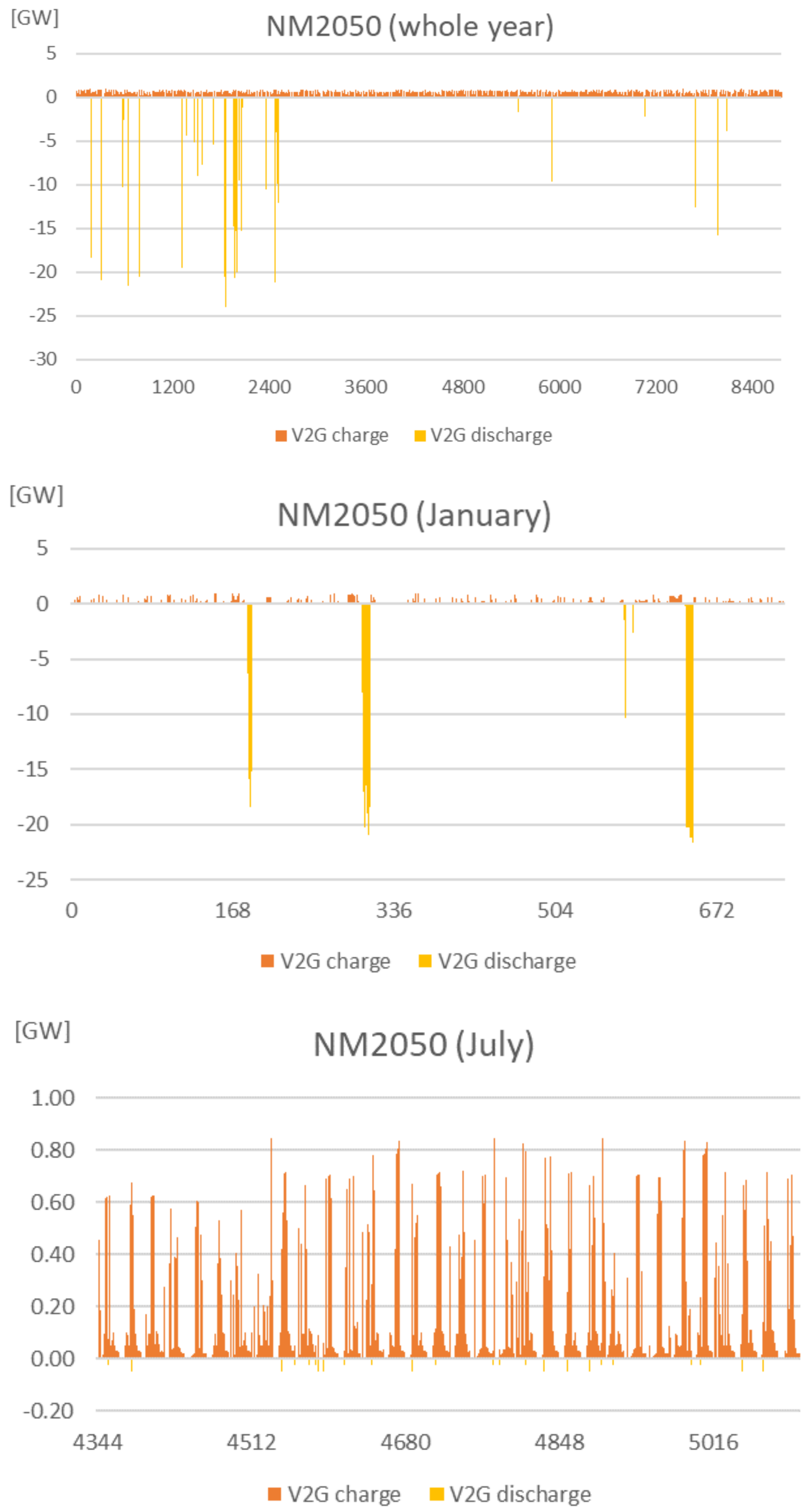
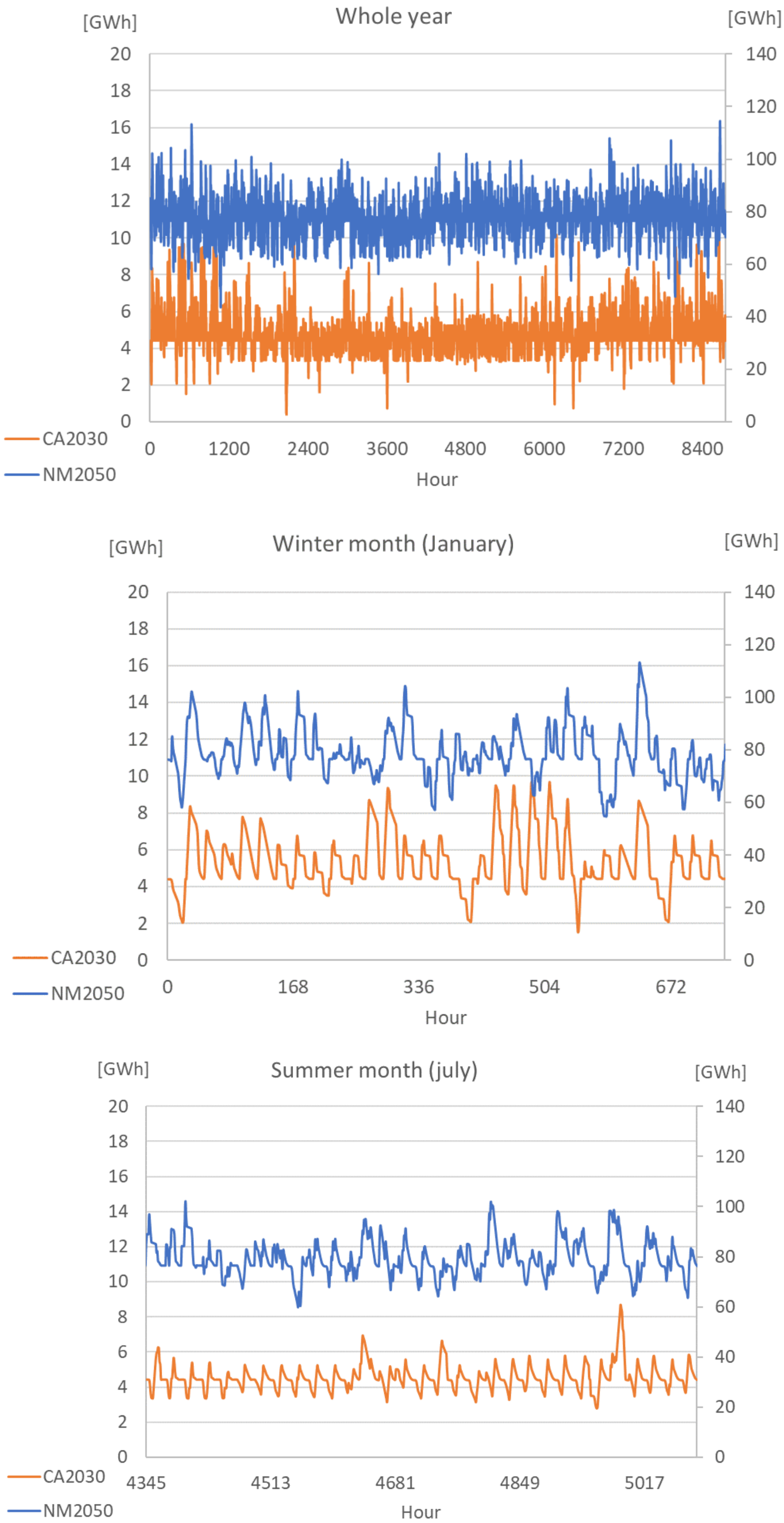


Figure 15: COMPETES: Vehicle-to-grid (V2G) storage transactions in NM2050



a) Left Y-axis refers to CA2030; right Y-axis refers to NM2050.

Figure 16: COMPETES: State of charge of electricity storage by EV batteries in NM2050

Electricity storage by stationary Li-ion batteries
Table 17 above shows that, compared to EV batteries, stationary Li-ion batteries play a tiny role in electricity storage in both CA2030 and NM2050.In particular, the storage size of Li-ion batteries increases from 40 MWh in CA2030 to 50 MWh in NM2050, while the storage volume of these batteries rises from 3.4 GWh to almost 11 GWh, respectively, resulting in a full cycle equivalent of 85 and 210, respectively. [28]

Figure 17 presents the state of charge (SOC) of electricity storage by Li-ion batteries both for the year as a whole as well as, more detailed, for a winter month (January) and a summer month (July). A striking feature of this figure is that the number of (short-run) storage cycles of Li-ion batteries appears to be significantly higher in a summer month (July) than in a winter month (January), which suggests that this number of cycles depends on the variability of power generation from solar PV.

Electricity storage by other options
Apart from EV and (stationary) Li-ion batteries, the COMPETES model runs for the reference scenarios CA2030 and NM2050 did not result in any capacity investments or operational transactions by other electricity storage options (although the model allowed capacity investments – and resulting operational transactions – by these other options). Besides other batteries (e.g., Pb or VR), this applies also for the two large-scale electricity storage technologies included in the model, i.e. CAES and AA-CAES. Apart from specific modelling characteristics and limitations, the major reason for this finding is that alternative flexibility options are apparently more attractive (cheaper) or, more generally, have a better techno-economic performance to meet the flexibility needs of the Dutch power system. Note, however, that the current study focuses on the flexibility needs due to the variability of the residual power load – notably VRE supply – and did not consider additional ancillary services and other flexibility needs of the power system.

Main observations and qualifications on electricity storage
As noted above, besides electricity storage by EV batteries for mobility ('driving') purposes (including demand response), according to the model results of COMPETES the role of other electricity storage options for power system balancing purposes (including V2G storage transactions) is generally limited in both CA2030 and NM2050. Basically, there are three major reasons for this finding. Firstly, as noted in Section 4.1.3 (notably Figure 10), the variability of the residual power load in CA2030 and NM2050 is primarily characterised by large, short-term fluctuations (hourly, daily) but hardly or not by a clear, long-term seasonal pattern.

Secondly, in COMPETES these short-term fluctuations in the residual load are largely met by relatively cheap, short-term flexibility options such as cross-border electricity trade, VRE curtailment and demand response, including demand response – and resulting storage implications – by electric vehicles and power-to-hydrogen (P2H_2). Consequently, the volatility (margin) of electricity prices is reduced substantially and there is hardly any room – or further need – for more expensive flexibility options such as flexible, hydrogen-fired power generation plants or single-purpose, large-scale energy storage technologies (e.g., CAES).

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[28] The storage size values of Li-ion batteries refer to the initial values available in the baseline scenario of the investment module of COMPETES, i.e. before new, additional investments or disinvestments are determined by the model. The module could invest in additional storage size investments in both CA2030 and NM2050, but it didn't.

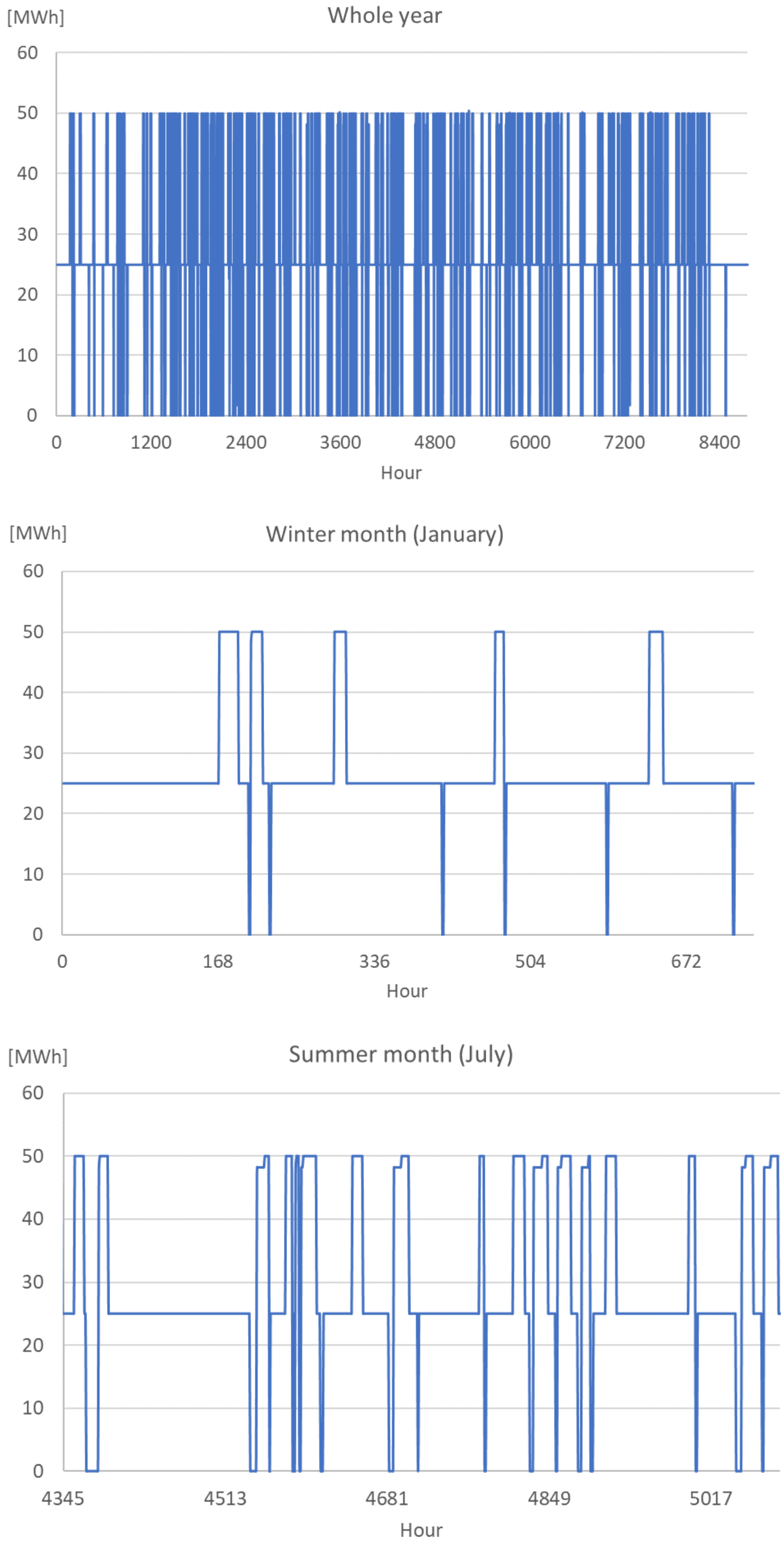


Figure 17: COMPETES: State of charge of electricity storage by Li-ion batteries in NM2050

Thirdly, in CA2030 and, notably, in NM2050 a large number of EVs is expected to be available – i.e. about 0.5 million and 10 million, respectively – with an (assumed) average EV battery storage size of 75 kWh and 100 kWh, respectively. For typical mobility purposes, this average battery size is relatively large ('over-dimensioned') and, hence, there is room to serve other purposes, notably system flexibility purposes by means of demand response (G2V) and, in particular, V2G storage transactions.

Although COMPETES ensures that the degradation costs of the EV batteries are recovered when applying V2G transactions, it does not include the initial costs of the EV batteries and the EV (dis)charging infrastructure (as these costs are assumed to be made primarily for mobility purposes in the transport system rather than for balancing purposes in the power system). Hence, the costs of V2G storage transactions are relatively low and even zero in the case of G2V demand response transactions, whereas both transaction can benefit from the margin between hours with high electricity prices and hours with low electricity prices. Therefore, although both G2V and V2G transactions are subject to some optimising restrictions in COMPETES – e.g., a part of all EVs is actually connected to the grid for a limited number of hours; storage charging conditions for EV driving purposes have to be met, etc. – there is, in principle, a large potential for both V2G storage transactions and, notably, G2V demand response transactions.

Some additional qualifications, however, can be added to the COMPETES model findings and observations made above regarding the role of electricity storage in the energy system of the Netherlands. Firstly, these findings result primarily from the general character and specific underlying assumptions of the COMPETES model. As noted, COMPETES is an optimisation model of the European electricity market, i.e. it seeks to meet European power demand at minimum social costs within a set of techno-economic specifications of power generation units, flexibility options and transmission interconnections across European countries and regions, including policy targets and restrictions – such as GHG limitations – of these countries and regions. As such, the model generates results for a cost-optimal solution, e.g. where to invest or how to allocate scarce resources in a social cost-effective way (see Chapter 5, Section 5.3, for a further discussion of these 'optimisation' results).

Moreover, although COMPETES includes the investment costs of interconnections between European countries, it does not consider social acceptance or other complicated, time-consuming implementation issues regarding these investments. In addition, as noted, COMPETES identifies a relatively large – and relatively cheap – potential of demand response as a flexibility option (within some specific techno-economic restrictions) but it does not consider to which extent this potential is, in practice, realistic and can be actually achieved. Sensitivity cases, however, show that changes in the underlying model assumptions can have a significant impact on the energy storage results by COMPETES (see Section 3.2 below).

Finally, the analysis in the sections above is primarily focused on the demand and supply of flexibility options – including energy storage – due to the variability of the residual power load (defined as total electricity demand minus electricity supply from VRE sources). This implies that the study does not consider the need for flexibility options (such as electricity storage) due to either the uncertainty ('forecast error') of the residual load – resulting in the need for flexibility on intraday/reserve markets – or the local congestion (overloading) of the electricity distribution network (resulting in local congestion and flexibility markets to deal with these grid overloads). In addition, it does not include the need for electricity storage (or alternative options) to address other power system issues such as inertia, black starts or frequency control. Although the day-ahead or spot market is by far the most important market (in terms of power and trade volumes), the other markets (intraday, reserve) or system functions may offer interesting revenue streams for some types of electricity storage such as (AA)-CAES.

3.1.6 Hydrogen storage

While the modelling of the European power system in COMPETES is rather detailed and well advanced, the modelling of the coupling with the hydrogen system is less advanced and still under development. More specifically, the total annual domestic demand for hydrogen is given outside the model, while the hourly profile of hydrogen demand is assumed to be completely flat (at the level of the total annual hydrogen demand divided by 8760, i.e. the number of hours in the year).

On the other hand, there is only one supply option to meet this demand, i.e. domestic production of hydrogen by means of electrolysis ($P2H_2$) without foreign trade of hydrogen. In case of no demand response by $P2H_2$, the installed capacity of hydrogen electrolysis is optimised at the level of hourly hydrogen demand and, as a result, the hourly profile of hydrogen supply is completely flat (at the same level of the hydrogen demand profile). Consequently, as hourly hydrogen supply is always equal to hourly hydrogen demand, there is no need for hydrogen storage in this case.

In the case of demand response by $P2H_2$, however, the capacity of hydrogen electrolysis is enlarged and optimised in order to benefit from the variability of hourly electricity prices over the year, i.e. producing more hydrogen when electricity prices are low and less – or even zero – when prices are high. As a result, the hourly profile of hydrogen supply is determined by the model – within the maximum capacity constraint of electrolysis – and fluctuates heavily depending on the volatility of the hourly electricity prices. Consequently, as hourly hydrogen supply deviates from hourly hydrogen demand, there is a need for hydrogen storage in this case.

Figure 18 presents the hourly profiles of H_2 demand, supply and storage in CA2030, while Figure 19 provides similar profiles in NM2050. While the upper part of these figures shows the H_2 profiles for the year as a whole, the middle and lower part illustrate the profiles for a specific month, i.e. a winter month (January) and a summer month (July), respectively. The respective hydrogen demand, supply and storage profiles of NM2050 are basically the same as the profiles of CA2030. The main difference of the profiles between these scenario years refers to their *level*, which is primarily determined by the level of hydrogen demand in these years.

In COMPETES, the annual demand for hydrogen from electrolysis amounts to 6.7 TWh (24 PJ) in CA2030 and to 76 TWh (272 PJ) in NM2050. For CA2030, the demand for hydrogen is derived from the (assumed) additional power demand for hydrogen electrolysis of 10 TWh (see Section 2.3.1, notably Table 4). For NM2050, the demand for hydrogen (272 PJ) is obtained from the NM2050 scenario of Berenschot and Kalavasta (2020), which assumes a domestic hydrogen production/consumption of 335 PJ, including 63 PJ hydrogen for power production. As the dispatch of power production is optimised endogenously by COMPETES this amount of 63 PJ has been (initially) subtracted from the total hydrogen demand of

335 PJ, resulting in a remaining (initial) hydrogen demand of 272 PJ. Since power generation from hydrogen turned out to be not competitive in NM2050 – and, hence, no additional hydrogen demand due to producing electricity – the final hydrogen demand in NM2050 remained 272 PJ.[29]

An annual hydrogen demand of 6.7 TWh in CA2030 and 76 TWh in NM2050 translates in an hourly hydrogen demand of 0.77 GWh and 8.5 GWh, respectively. As the demand profile for hydrogen in COMPETES is assumed to be completely flat this implies a H_2 demand profile at a fixed level of 0.77 GW in CA2030 and of 8.5 GW in NM2050 (see the straight blue line in Figure 18 and Figure 19, respectively.

As outlined above, in case of no demand response by $P2H_2$, the capacity of hydrogen electrolysis and the supply curve of hydrogen are fixed at the same level as the H_2 demand profile and, consequently, there is no need for H_2 storage. In case of demand response by $P2H_2$, however, the capacity of hydrogen electrolysis is enlarged and optimised in order to benefit from hourly price differences, while the profile of hourly hydrogen production depends on the hourly electricity price level.

Figure 18 presents the resulting hourly profile of H_2 supply in CA2030 (in orange), while a similar profile in NM2050 is provided in Figure 19. These figures indicate that the optimised capacity of hydrogen electrolysis is enhanced from 0.77 GW to 0.93 GW in CA2030 and from 8.5 GW to 12.9 GW in NM2050. In addition, they show that the hourly supply of hydrogen fluctuates between these maximum capacity levels and zero. As the hourly H_2 supply deviates significantly from the hourly H_2 demand over a large number of hours over the year, there is a significant need for H_2 storage – either charge or discharge – as shown by the H_2 storage profiles in Figure 18 and Figure 19.

Figure 20 presents the resulting state of charge (SOC) of H_2 underground storage in CA2030 and NM2050 – assuming that H_2 is stored in salt caverns – while Table 19 provides a summary overview of some indicators for this type of storage in these scenario years. For underground H_2 storage in salt caverns, the required (available) storage size amounts to 66 GWh (0.24 PJ) in CA2030 and 1536 GWh (5.5 PJ) in NM2050, while the annual storage volume amounts to 900 GWh (3.2 PJ) and 22 TWh (78 PJ), respectively. This results in a full cycle equivalent (FCE) of 14 in both scenario years. This seems to indicate that underground H_2 storage in salt caverns is used primarily to meet storage needs over a 'medium-term' period of 3-5 weeks (see also Figure 18 and Figure 19 showing the volatility of the SOC of H_2 underground storage both for the year as a whole as well as for a winter month and a summer month).

To summarise, according to the COMPETES model scenario runs, the required (available) size of H_2 underground storage increases from 0.24 PJ in CA2030 to 5.5 PJ in NM2050 – i.e. 1% and 2%, respectively, of total domestic H_2 demand in these years – while the total annual volume of H_2 underground storage increases similarly from 3.2. PJ to 78 PJ, respectively, i.e. approximately 13% and 29% of total domestic H_2 demand in CA2030 and NM2050, respectively (Table 19). Overall, these are relatively high figures regarding H_2 underground storage in these years.

[29] In sensitivity case 1B (see Section 3.2), however, there was some power generation from hydrogen in NM2050, i.e. 7.2 TWh, resulting in an additional demand for hydrogen of 12 TWh (i.e. 43.2 PJ), assuming an efficiency of 0.6 for this hydrogen-to-power technology in NM2050.

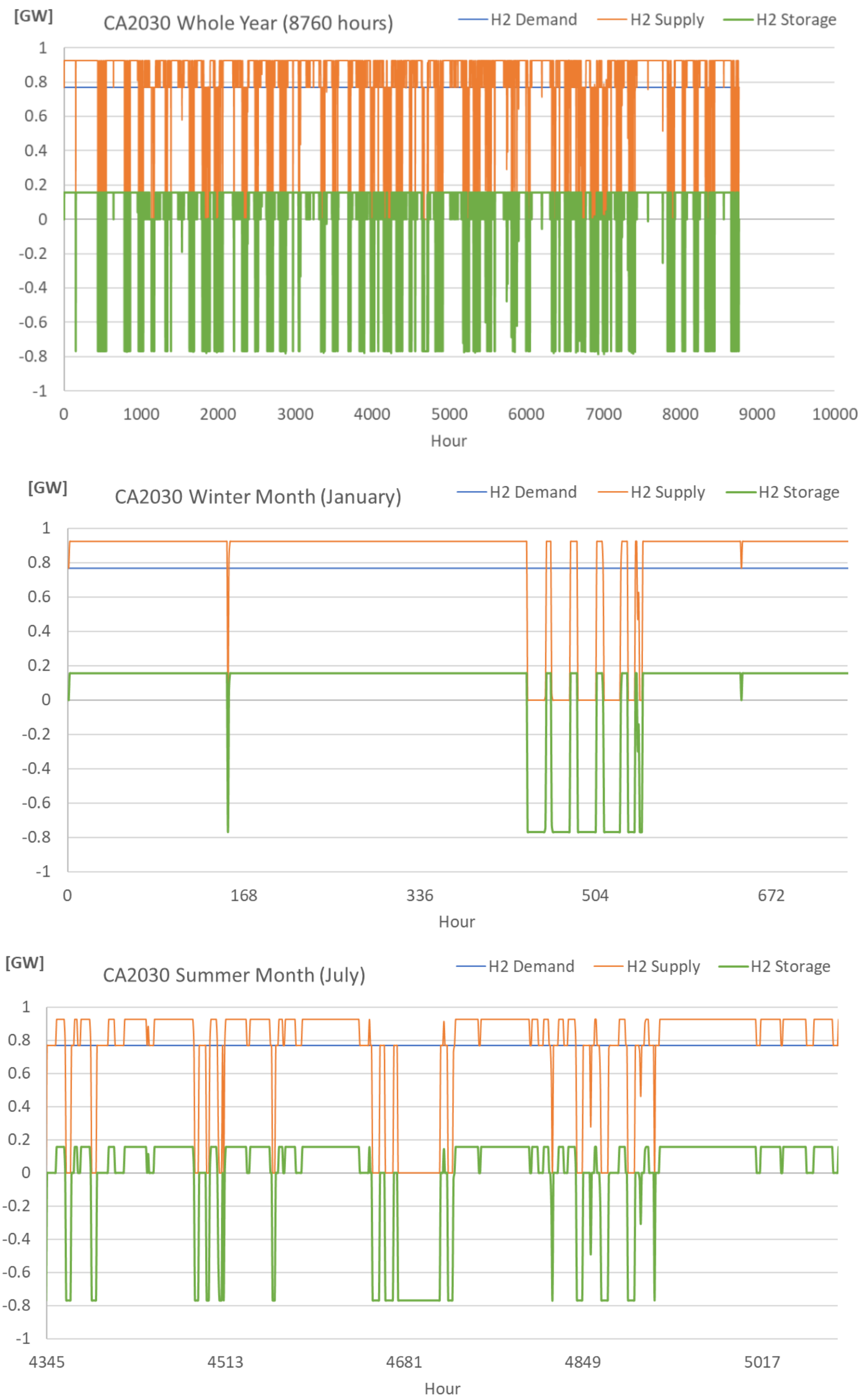


Figure 18: COMPETES: Hourly profiles of H_2 demand, supply and storage in CA2030

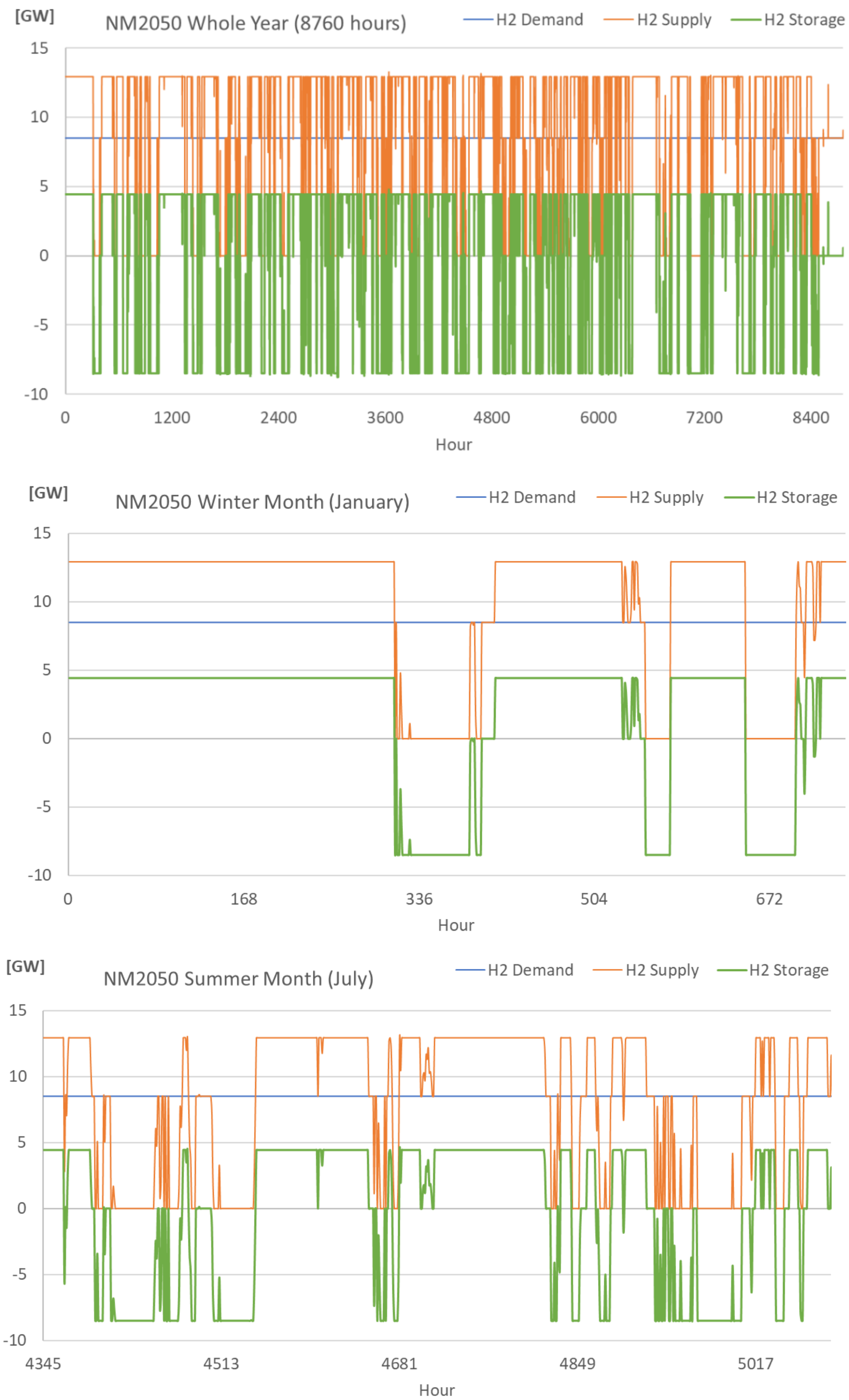
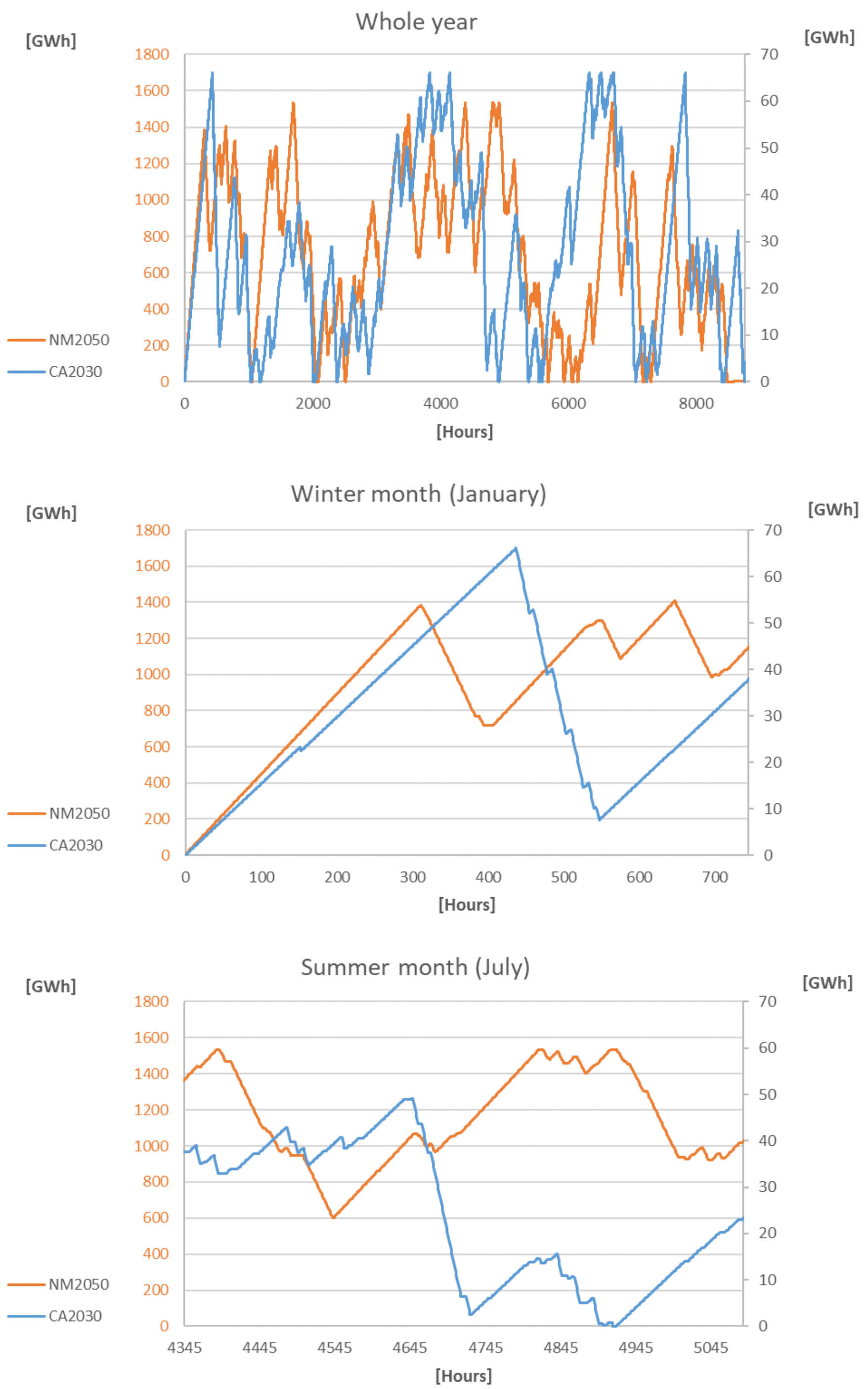


Figure 19: COMPETES: Hourly profiles of H_2 demand, supply and storage in NM2050



a) Injection of 1400 GWh H_2-equivalent over a period of 300 hours, i.e. 4.7 GW/h. This requires 4-6 wells assuming single well (9⅝ inch tubing) injection rates of 0.8-1.2 GW/h (265k-400k Nm^3/hr LHV; 6.5-9.5 million Nm^3/day).

b) Withdrawal of 1500 GWh of H_2 over a period of 100 hours, i.e. 15 GW/h. This requires 9-13 wells assuming single well (9⅝ inch tubing) withdrawal rates of 1.2-1.8 GW/h (400k-600k Nm^3/hr LHV; 9.5-14 million Nm^3/day).

Figure 20: COMPETES: State of charge of H_2 underground storage in salt caverns in CA2030 and NM2050

Table 19: COMPETES: H_2 underground storage in salt caverns in CA2030 and NM2050

	Size	Volume	FCE	Charge	Discharge
	GWh	GWh	#	MW	MW
CA2030	66	900	14	156	765
NM2050	1536	21697	14	4505	8631
As % of total domestic H_2 demand					
CA2030	1.0%	13.4%			
NM2050	2.0%	28.7%			

a) A storage size of 1536 GWh requires 7-13 caverns, assuming typical single-cavern capacities of 125 GWh (LHV) (500k m^3 geometric volume) to 250 GWh (LHV) (1 million m^3 geometric volume).

Some qualifications, however, can be added to these figures presented in Table 19. Firstly, the figures regarding hydrogen storage are based on a relatively simple modelling approach and underlying assumptions, notably regarding the competitiveness and, hence, the demand for hydrogen electrolysis in CA2030. In particular, hydrogen storage in the current version of COMPETES results solely from the assumption of demand response by power-to-hydrogen ($P2H_2$). Due to lack of data, however, some related costs – notably the 'ramping' costs of fluctuating hydrogen electrolysis, including start-up and cycling costs – are not yet included in the model analysis. Hence, the flexibility of $P2H_2$ is likely overestimated and, therefore, the resulting need for H_2 storage as well.

Moreover, for CA2030, the level of demand for hydrogen electrolysis – i.e. about 10 TWh of electricity to produce 6.7 TWh of hydrogen – is determined (assumed) exogenously into COMPETES. Without appropriate public support, however, hydrogen electrolysis is likely not competitive in CA2030 and, hence, the level of demand for hydrogen electrolysis and, so, the supply of 'green' hydrogen and the resulting need for hydrogen storage is likely overestimated in CA2030 (depending on the level of public support for hydrogen electrolysis for that year (see also the analysis of hydrogen storage needs in CA2030 by means of the OPERA model in Section 4.1). Therefore, the figures on hydrogen storage resulting from COMPETES have to be treated with due care.

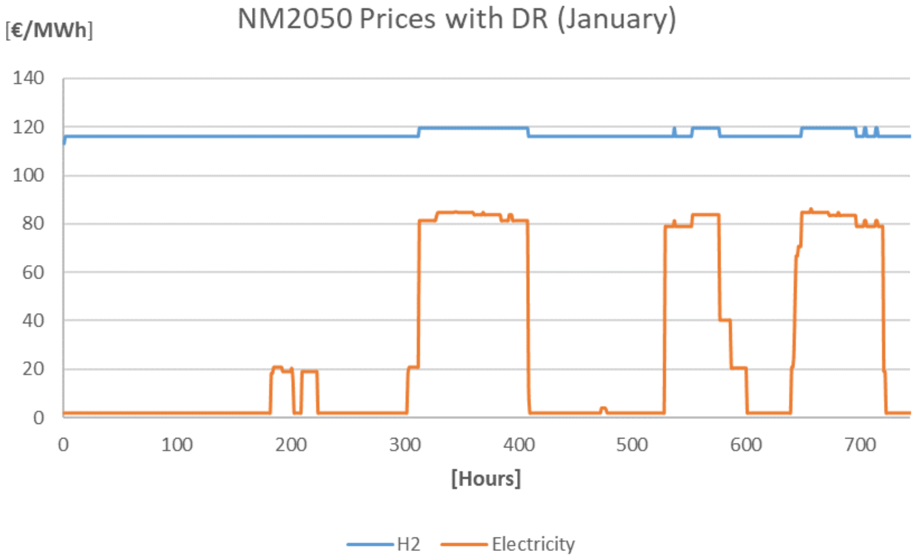
3.1.7 *Link between energy storage and energy prices*

Flexibility options such as demand response and energy storage have an impact on the volatility of energy prices. In general, the deployment of these options reduces the volatility of these prices, i.e. the duration curve of these prices becomes flatter.

In addition, there are other impacts of flexibility options on energy prices. For instance, the storage of hydrogen from electrolysis has an impact on the price of hydrogen and its link with the price of electricity. This is illustrated in Figure 21 and Figure 22 showing (the linkage between) these prices in NM2050 with and without demand response (DR).

As explained in the previous section, in the NM2050 case without DR, there is no storage of hydrogen resulting in the COMPETES model. In that case, the prices of hydrogen show a clear, direct relationship with the prices of electricity as the H_2 prices are solely determined by the electricity prices and the $P2H_2$ efficiency rate of 0.67, i.e. the pure correlation effect (see lower parts of Figure 21 and Figure 22). In the case with DR, however, there is storage of hydrogen. In that case, the prices of hydrogen are not only determined by the electricity prices (and the fixed $P2H_2$ efficiency rate) but also by the storage cost of hydrogen (including storage losses). In this case, the correlation between hydrogen and electricity prices is less clear (see upper part of Figure 21 and Figure 22).

Note that in Figure 22 electricity prices in NM2050 are relatively low during a large number of hours over the year. This applies in particular for the case of electricity prices without demand response. In this case, electricity prices vary between €2/MWh and €4/MWh over some 5000 hours per annum, whereas the average electricity price over the year as a whole amounts to approximately €15/MWh.



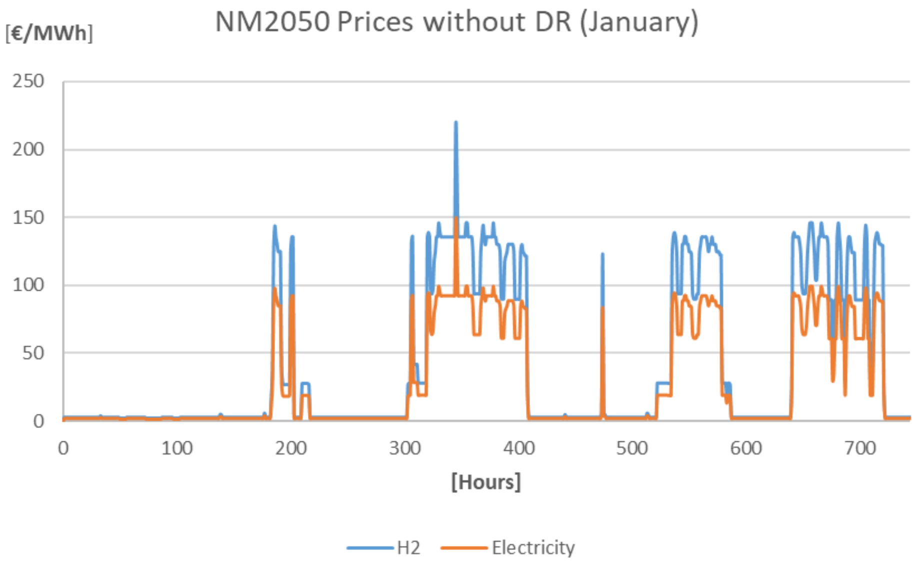


Figure 21: COMPETES: Hourly electricity and hydrogen prices in NM2050 (with and without demand response)

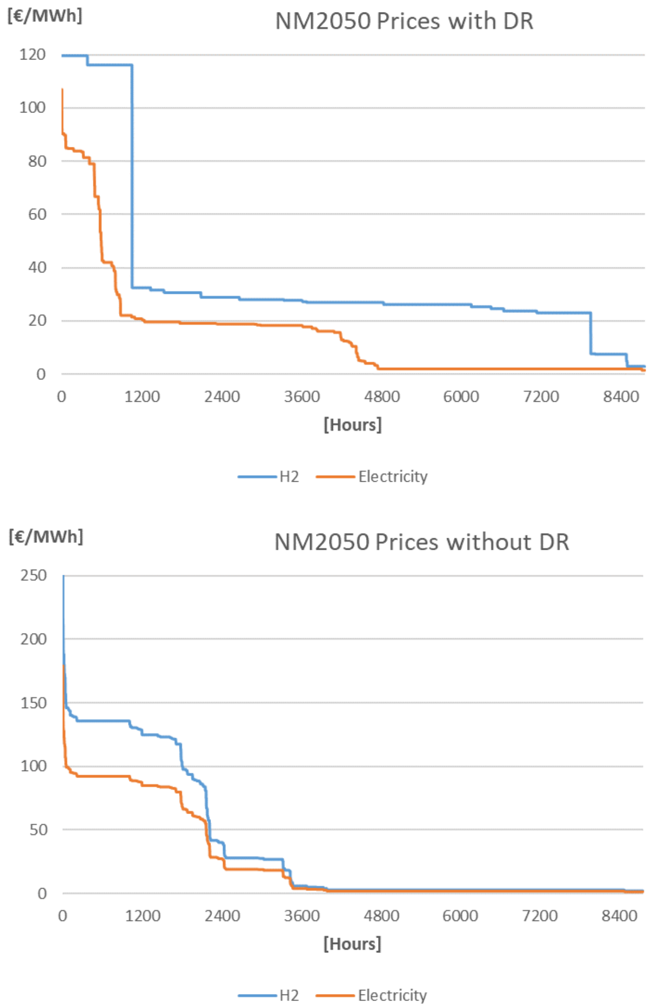


Figure 22: COMPETES: Duration curve of hourly electricity and hydrogen prices in NM2050 (with and without demand response)

Also in the case of demand response, however, electricity prices are relatively low during a large number of hours over the year. In this case, electricity prices vary between €2/MWh and €4/MWh over some 4000 hours per annum, whereas the average electricity price over the year as a whole amounts to approximately €26/MWh (see also Section 3.2.4 below).

These low electricity prices are due to the underlying assumptions of the NM2050 scenario, as developed by Berenschot and Kalavasta and copied exogenously into COMPETES. This applies in particular for the (assumed) capacities of VRE power generation, especially of solar PV as well as the assumed level of total electricity demand. As discussed further in Chapter 5, the assumed installed capacity of solar PV in NM2050 is most likely too high from a social optimal (cost minimisation) point of view. The (too) large installed capacity of solar PV – and of VRE power generation in general – results in a large VRE surplus (negative residual load) and, hence, in relatively low electricity prices during a large number of hours over the year as a whole, despite the fact that during (a part of) the year (a part of) the VRE surplus has been addressed by flexibility options such as VRE curtailment, demand response and/or electricity storage.

3.1.8 Summary and conclusion

Table 20 provides a summary overview of the energy storage options identified by COMPETES to play a role in CA2030 and NM2050. Some major observations from this table and from the COMPETES model analysis outlined in the previous sections include;

- The role of electricity storage in CA2030 and NM2050 is primarily dominated by batteries of passenger EVs. This role, however, refers largely to electricity charged and used by passenger EVs for mobility services, while the share charged and used for flexibility services – including G2V demand response and V2G storage services – is substantially lower;
- There seems to be no role for large-scale electricity storage such as compressed air energy storage (CAES/AA-CAES) in both CA2030 and NM2050;
- On the other hand, there seems to be a significant role for large-scale energy storage by means of H_2 underground storage, i.e. an estimated storage volume of approximately 3 PJ in CA2030, increasing to 78 PJ in NM2050. As a percentage of annual domestic hydrogen demand, this amounts to about 13% and 29%, respectively.

Table 20: COMPETES: Summary overview of energy storage in CA2030 and NM2050

CA2030	**Size**	**Volume**	**FCE**	**Charge**	**Discharge**
E-Storage option	GWh	GWh	#	MW	MW
EV batteries	30.50	1450	48	1505	1505
Li-ion batteries	0.04	3.38	85	40	40
Total E-storage	30.54	1453	48		
As % of total E-demand	0.02%	1.0%			
CA2030	**Size**	**Volume**	**FCE**	**Charge**	**Discharge**
H_2 Storage option	GWh	GWh	#	MW	MW
Underground	66.08	900	14	156	765
As % of total H_2 demand	0.99%	13.4%			
NM2050	**Size**	**Volume**	**FCE**	**Charge**	**Discharge**
E-Storage option	GWh	GWh	#	MW	MW
EV batteries	1037	32967	32	38357	38357
Li-ion batteries	0.05	10.51	210	50	50
Total E-storage	1037	32978	32		
As % of total E-demand	0.30%	9.5%			
NM2050	**Size**	**Volume**	**FCE**	**Charge**	**Discharge**
H_2 Storage option	GWh	GWh	#	MW	MW
Underground	1536	21697	14	4505	8631
As % of total H_2 demand	2.03%	28.7%			

Some major qualifications, however, can be added to the observations made above. Firstly, the results outlined above depend to some extent on the underlying scenario assumptions and specific input parameters made. This applies in particular for the assumed installed capacity of solar PV in NM2050 as developed by Berenschot and Kalavasta (2020) and copied exogenously into COMPETES. As noted (and further discussed in Chapters 4 and 5), this assumed capacity is most likely too high from a social optimal (cost minimisation) point of view. The (too) large installed capacity of solar PV – and of VRE power generation in general – results in a large VRE surplus (negative residual load) and, hence, in relatively low electricity prices during a large number of hours over the year as a whole, despite the fact that during (a part of) the year (a part of) the VRE surplus has been addressed by flexibility options such as VRE curtailment, demand response and/or electricity storage.

Secondly, the analysis is largely focussed on the role of electricity storage to meet the need for flexibility due to the variability of the residual load on the spot power market. Although this is one of the key electricity markets, the possible role of electricity storage to meet the need for flexibility due to other reasons (uncertainty of the residual load; congestion of the grid) or other system needs (inertia, black start, frequency control) is ignored.

Thirdly, while the modelling of the European power system in COMPETES is rather detailed and well advanced, the modelling of the coupling with the hydrogen system is still less advanced and under development. For instance, at present the need for hydrogen storage is based solely on the assumed flexibility (demand responsiveness) of $P2H_2$ but some relevant costs – notably the 'ramping' costs of fluctuating hydrogen electrolysis – are still lacking. As a result, the need for hydrogen storage is likely overestimated.

Finally, for CA2030, the level of demand for hydrogen electrolysis is assumed outside the model. Without appropriate public support, however, hydrogen electrolysis is likely not competitive in CA2030 and, hence, the level of demand for hydrogen electrolysis and the resulting need for hydrogen in CA2030 may be overestimated. Or, to put it slightly different, the need for hydrogen storage in 2030 seems to depend highly on the public support for hydrogen electrolysis and other types of hydrogen demand and supply.

3.2 COMPETES: Sensitivity cases NM2050

Overall, we have conducted nine sensitivity cases for NM2050 by means of the COMPETES model. These cases include:

1. *Limit cross border power trade in NM2050*:
   - A. Limit the 2050 interconnection capacities to the levels of 2030 (i.e. no new capacity investments in cross-border interconnections beyond 2030);
   - B. Limit the (Dutch) interconnection capacity in 2050 to zero (i.e. no cross-border power trade/flexibility in 2050);
   - C. Limit the (Dutch) interconnection capacity in 2050 to zero and exclude all demand response (DR) options in 2050;

2. *Reduce the investment (CAPEX) and fixed operational (FXOPEX) costs of storage options in COMPETES by 50% in NM2050:*
   - A. Reduce the CAPEX and FXOPEX of all CAES and battery storage options – excluding EV batteries – by 50% in 2050;
   - B. Reduce the CAPEX and FXOPEX costs of all hydrogen storage options by 50% in 2050;

3. *Exclude demand response (DR) options in NM2050*:
   A. Exclude all DR options in 2050, including DR by power-to-hydrogen (i.e. no H_2 storage).
   B. Exclude all DR options in 2050, except DR by power-to-hydrogen (i.e. enabling H_2 storage).

4. *Adjust/reduce the assumed installed capacities of VRE power technologies:*
   A. Adjust the assumed capacities of solar PV and offshore wind in COMPETES to the capacities optimised by OPERA (see Chapters 2 and 4), i.e. for solar PV from 106 GW to 54.2 GW and for offshore wind from 51.5 GW to 57.8 GW in NM2050.
   B. Reduce the assumed capacities of solar PV and offshore wind in COMPETES substantially, i.e. for solar PV from 106 GW to 40 GW and for offshore wind from 51.5 GW to 45 GW in NM2050.

The results of these sensitivity cases are presented and discussed below. Case 2A (i.e. reducing the CAPEX and FXOPEX of all CAES and battery storage options in COMPETES by 50%), however, turned out to have no impact at all, i.e. it did not result in any new, additional investments in these storage options and, so, in any additional storage or other activities. Therefore, the results of this sensitivity case are similar to the modelling outcomes of the reference scenario of NM2050. Hence, we have not recorded case 2A separately in the tables and figures below but merged it together with the reference scenario of NM2050 (indicated by REF/2A).

3.2.1 Storage results

Figure 23 presents the energy storage results of the sensitivity cases versus the reference scenario of NM2050 for the two main storage options identified by COMPETES – i.e. EV batteries and H_2 underground storage – while Table 21 provides the specific data of these results, including also two other storage options, i.e. Li-ion batteries and Vanadium Redox (VR) flow batteries. The major observations regarding these results include:

- The storage size of EV batteries remains the same over all cases. This is not surprising as the number of passenger EVs is the same across all cases (about 10.4 mln.) while the storage size per EV is assumed outside the model (at 100 kWh);
- The size of H_2 underground storage, however, varies significantly across most cases. Whereas this size is zero in the two cases without DR (1C and 3A), it rises substantially from 1.5 TWh in NM2050 REF to 3.0 TWh in 1A (no new investments in interconnection beyond 2030) and even to 4.3 TWh in 1B (no power trade at all). The reason for this increase is that in these cases the restriction or even nullification of foreign power trade leads to a higher volatility of domestic electricity prices. This provides an incentive for more demand response by $P2H_2$ and, therefore, a higher need for H_2 storage;
- For the same reason, the storage volume increases for both EVs – notably V2G transactions – and H_2 underground storage in cases 1A and 1B;
- Because of the changes mentioned above, the full cycle equivalent (FCE) increases substantially for EV batteries in cases 1A and 1B, whereas it decreases significantly for H_2 underground storage in these cases as the size of this storage option increases much faster than its storage volume;
- While the role of Li-ion batteries is rather small in the reference scenario of NM2050, it increases slightly in 1C, 3A and 3B (no demand response);

- In addition, whereas VR batteries play no role in NM2050 REF, they become somewhat more important in cases 1C and 3A (no DR). Striking is the high FCE of this storage technology in these cases, indicating that it is primarily used for short-term storage transactions on the power market.

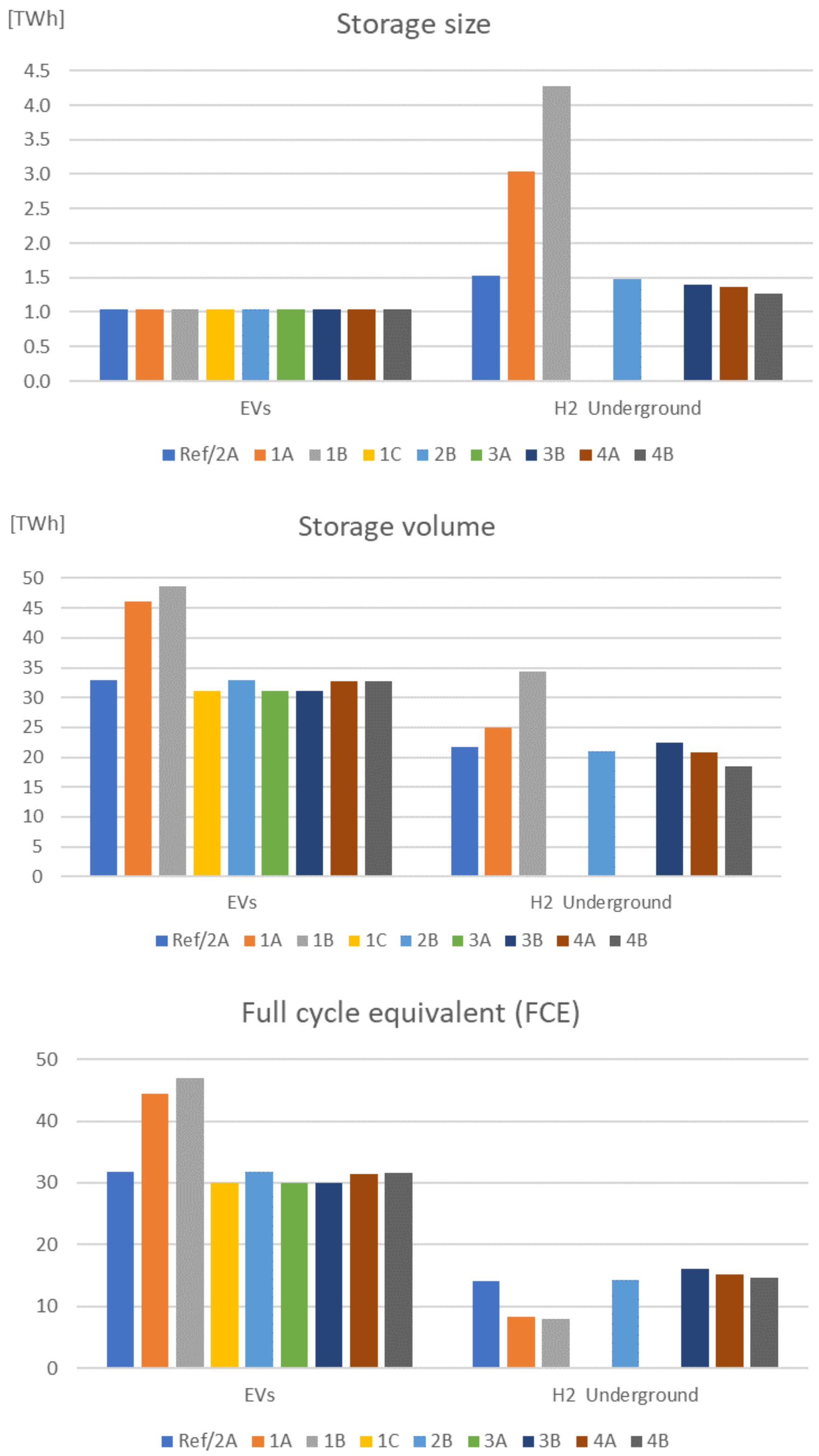


Figure 23: COMPETES: Storage results – Comparison of NM2050 ref. scenario and sensitivity cases

Table 21: COMPETES: Storage results – Comparison of NM2050 ref. scenario and sensitivity cases

Storage option/-parameter	Unit	REF/-2A	Sensitivity cases 1A	1B	1C	2B	3A	3B	4A	4B
EV batteries										
Size	GWh	1037	1037	1037	1037	1037	1037	1037	1037	1037
Volume	GWh	33033	46758	49569	31101	32961	32961	31100	32665	32757
FCE	#	32	45	48	30	32	32	30	32	32
(Dis)charge	MW	38357	38357	38357	38357	38357	38357	38357	38357	38357
H_2 Underground										
Size	GWh	1536	3033	4280	0	1474	0	1392	1370	1268
Volume	GWh	21697	24995	34319	0	21044	0	22450	20778	18501
FCE	#	14	8	8	0	14	0	16	15	15
Charge	MW	4505	5406	6698	0	4601	0	4633	4275	3845
Discharge	MW	8631	8632	23404	0	10392	0	8631	8631	8631
VR batteries										
Size	GWh				10.87	0.0018	9			
Volume	GWh				12727	1.32	11338			
FCE	#				1171	752	1256			
(Dis)charge	MW				10879	2	9031			
Li-ion batteries										
Size	GWh	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Volume	GWh	10.51	13.96	10.55	17.24	10.56	18.18	25.1	9.09	8.48
FCE	#	210	279	211	345	211	364	502	181	170
(Dis)charge	MW	50	50	50	50	50	50	50	50	50

3.2.2 VRE capacities

In the reference scenario NM2050, the assumed capacities of VRE power generation technologies have been set exogenously by COMPETES at the same level as assumed in the NM2050 scenario of Berenschot and Kalavasta (2020) and as used in the Energy Transition Model (ETM) to calculate this scenario (see Chapter 2, notably Section 2.3.2). On the other hand, the total domestic electricity demand in COMPETES is substantially lower than in the ETM, i.e., 346 TWh and 406 TWh, respectively (see Chapter 5, in particular Section 5.2.1).

In COMPETES this imbalance between VRE supply and domestic electricity demand results in a large amount of hours with a (large) VRE surplus and, consequently, to large volumes of (net) electricity exports and VRE curtailment. Therefore, we have run two sensitivity cases regarding the assumed VRE capacities in COMPETES. In particular, these cases include:

- Case 4A: in this case the assumed capacities of solar PV and offshore wind in COMPETES have been adjusted to the capacities optimised by OPERA (see Chapters 2 and 4), i.e. for solar PV from 106 GW to 54.2 GW and for offshore wind from 51.5 GW to 57.8 GW in NM2050;
- Case 4B: in this case the assumed capacities of solar PV and offshore wind has been reduced substantially, i.e. for solar PV from 106 GW to 40 GW and for offshore wind from 51.5 GW to 45 GW in NM2050. Overall the total VRE capacity (including onshore wind) decreases from 178 GW in the reference case of NM2050 to 105 GW in case 4B (i.e., by approximately 40%).

Table 22 provides a summary overview of the main relevant inputs and outputs of COMPETES in the reference case of NM2050 versus the sensitivity cases 4A and 4B. For each case, the main observations from this table are briefly discussed below.

Table 22: COMPETES: Key inputs and outputs of the reference scenario and two sensitivity cases of NM2050

Installed capacities	**Unit**	**NM2050**	**Case 4A**	**Case 5B**
Solar PV	GWe	106.0	54.2	40.0
Offshore wind	GWe	51.5	57.8	45.0
Onshore wind	GWe	20.0	20.0	20.0
Hydrogen2Power	GWe	0.0	0.0	0.0
Power2Hydrogen	GWe	19.3	19.0	18.3
Energy balances				
Total hydrogen demand/supply	*TWh*	*76.6*	*76.6*	*76.6*
Total electricity demand	*TWh*	*345.7*	345.8	345.1
Power supply:				
Solar PV	TWh	98.1	50.2	37.0
Offshore wind	TWh	205.9	233.6	195.1
Onshore wind	TWh	76.7	76.9	76.9
Other/conventional	TWh	7.8	7.6	7.8
Total domestic production	TWh	388.5	368.3	316.9
Net electricity imports/exports	TWh	-42.8	-22.5	28.2
Total domestic electricity supply	*TWh*	*345.7*	*345.8*	*345.1*
VRE curtailment				
Solar PV	TWh	0.0	0.0	0.0
Offshore wind	TWh	72.7	79.2	48.3
Onshore wind	TWh	0.2	0.0	0.0
Energy storage volumes				
Total electricity storage	TWh	33.0	32.7	32.8
Total hydrogen storage	TWh	21.7	20.8	18.5
Energy storage volumes as % of total demand				
Electricity storage	%	9.6	9.4%	9.5%
Hydrogen storage	%	28.7	27.1%	24.2%

Case 4A: Adjusting assumed VRE capacities to the level optimised by OPERA
This case results in a significant increase in electricity output from offshore wind, both before and after curtailment by approximately 26 TWh and 20 TWh, respectively (so, more curtailment of electricity output from offshore wind). Electricity output from solar PV, however, decreases substantially by almost 50% from 98 TWh in the reference case to 50 TWH in case 4A. Overall, total domestic electricity production declines by some 20 TWh (from 388 TWh to 368 TWh), leading to a similar decline in total annual net exports (from 43 TWh to 23 TWh). As already indicated above, total VRE curtailment (almost solely offshore wind output) increases from 73 TWh to 79 TWh. Overall, however, there is hardly any change in total annual volumes of electricity and hydrogen storage (see Table 22 and, for further details – including other storage results of case 4A - Table 21 in the previous Section 3.2.1).

Case 4B: Reducing substantially the installed VRE capacities in COMPETES
Case 4B results in a drastic reduction of power generation from solar PV (from 98 TWh to 37 TWh) and a relatively small reduction from offshore wind (after curtailment) from 206 TWh to 196 TWh. The curtailment of offshore wind declines significantly – although less than expected – from 73 TWh in the reference case of NM2050 to 48 TWh in case 4B (i.e. by about 33%, compared to a reduction of total VRE capacity by approximately 40%).

A striking result of case 4B is that, due to the reduction of total domestic electricity production from 389 TWh (in the reference case) to 317 TWh (in case 4B), the electricity trade position of the Netherlands shifts from large net electricity *exports* in the reference case (43 TWh) to large net *imports* in case 4B (28 TWh). Another striking result is that, overall, the annual volumes of energy storage hardly change and even decline slightly in the case of hydrogen storage (see Table 22 and, for further details – including other storage results of case 4B - Table 21 in the previous Section 3.2.1).

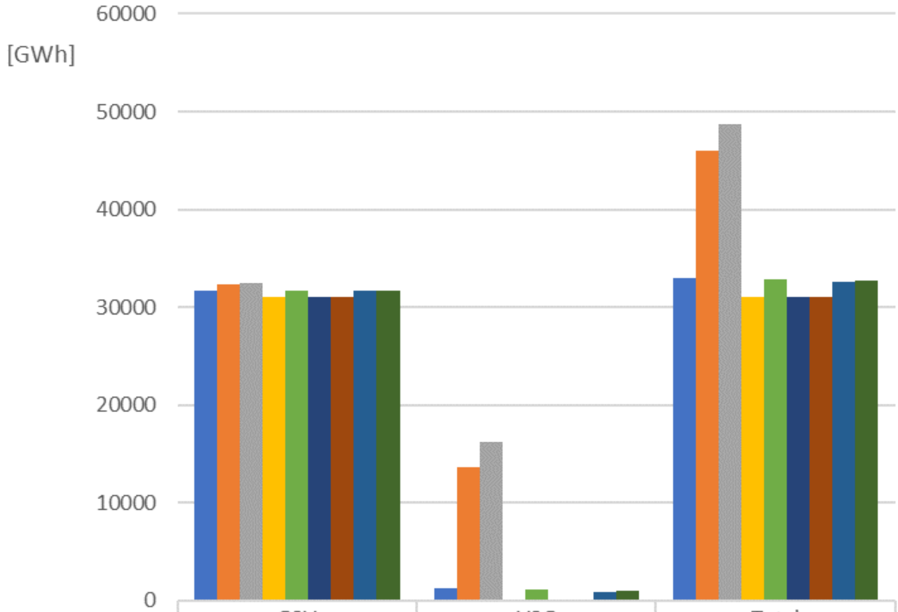
A likely reason (to be further explored) for the latter result on energy storage is that due to the drastic reduction of VRE capacity and VRE electricity output, the demand for flexibility by the power system declines accordingly, which is met by less flexibility offered by VRE curtailment and, to a lesser extent, by means of demand response and electricity trade but, overall, does not lead to a significant change in the need for electricity storage.[30]

The modest decline in hydrogen storage in case 4B (about 15% compared to the reference case of NM2050) is likely due to the lower volatility in electricity prices – resulting from less electricity output from VRE resources – and, hence, to less demand response by $P2H_2$, which results in less variability in hydrogen supply and, therefore, in less need for hydrogen storage.

3.2.3 Total storage and electricity use by passenger EVs

Figure 24 presents the results of the sensitivity runs regarding total electricity use and storage by passenger EVs. More interestingly, it provides a distinction of this total use and storage between G2V and V2G transactions. Whereas the total annual power use for G2V – i.e. predominantly mobility transactions – remains basically the same, the electricity use for V2G (flexibility/storage transactions) increases significantly from 1.3 TWh in the reference scenario of NM2050 to 14.4 TWh in 1A (limiting foreign power trade) and even to 17 TWh in 1B (no power trade). In the case without demand response (1C, 3A and 3B), however, there are no V2G or flexible G2V transactions at all.

[30] Note that the shift from large net annual exports to large net annual imports does not necessarily imply that the flexibility potential of cross-border trade changes (let alone declines) as the interconnection capacity for variations in hourly electricity trade does not change.



	G2V	V2G	Total
REF/2A	31731	1237	32967
1A	32384	13655	46039
1B	32518	16198	48717
1C	31101	0	31101
2B	31727	1171	32899
3A	31101	0	31101
3B	31101	0	31101
4A	31716	950	32665
4B	31720	1036	32757

Figure 24: COMPETES: Total electricity use and storage by passenger EVs – Comparison of NM2050 reference scenario and sensitivity cases

3.2.4 Electricity and hydrogen prices

Figure 25 presents the results of the sensitivity cases regarding electricity and hydrogen prices. It shows that, compared to the reference case, the average electricity price increases steadily when cross border power trade is steadily reduced (from 1A to 1C) or when all DR options are excluded. Both the average electricity and hydrogen price become highest in case 1C (no power trade and no DR, i.e. the supply of flexibility options is significantly reduced).

In addition, Figure 26 presents the duration curves of hourly electricity prices for both the sensitivity cases and the reference scenario of NM2050. It indicates that the volatility of the electricity price is highest in 1B (no trade), 1C (no power trade and no DR) and 3A (no DR).

3.2.5 Power system costs

Table 23 presents the results of the sensitivity cases regarding total power system costs in the Netherlands. It shows that these costs are higher in almost all sensitivity cases (except 2A and 2B) compared to the reference scenario of NM2050. These costs increase most (+212%) in case 1C (no trade and no DR).

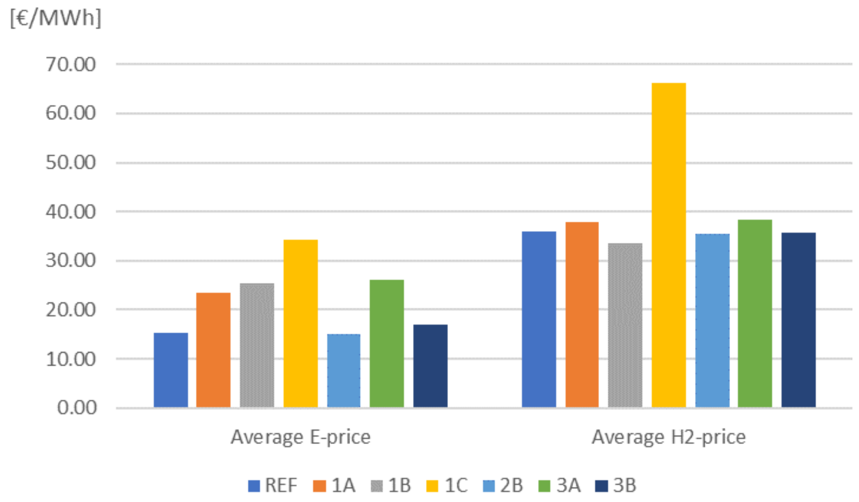


Figure 25: COMPETES: Electricity and hydrogen prices – Comparison of NM2050 reference scenario and sensitivity cases

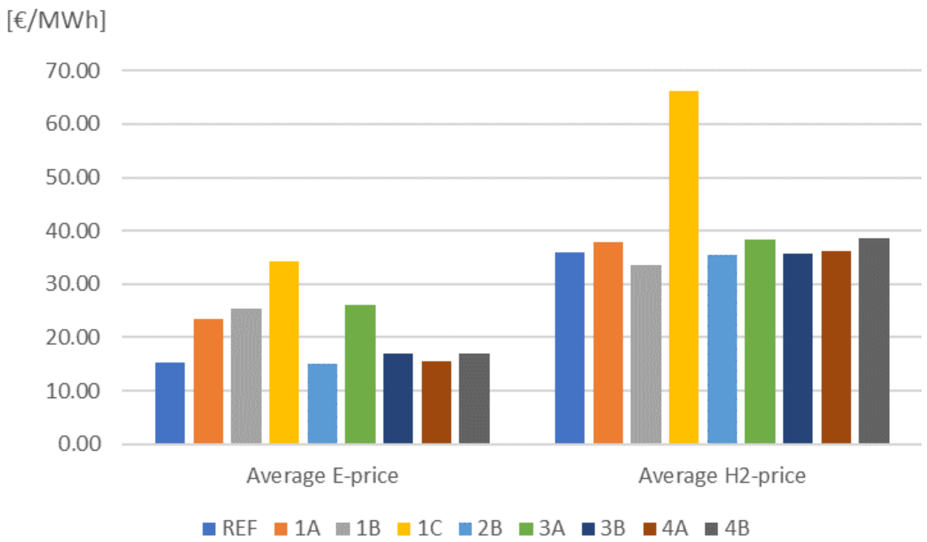


Figure 26: COMPETES: Duration curves of hourly electricity prices – Comparison of NM2050 reference scenario and sensitivity cases

Table 23: COMPETES:NL power system costs – Comparison of NM2050 reference scenario and sensitivity cases

	Unit	REF/-2A	Sensitivity cases							
			1A	1B	1C	2B	3A	3B	4A	4B
Total costs	Billion €	2.5	2.8	3.6	7.8	2.5	3.3	3.3	2.7	2.6
Δ Total costs[a]	Billion €		0.3	1.1	5.3	0.0	0.8	0.8	0.2	0.1
Δ Total costs[a]	%		13	42	212	0.0	32	32	9.9	5.1

a) Change in total costs compared to the NM2050 reference scenario.

3.2.6 Conclusion

The sensitivity cases conducted by COMPETES show that limiting cross-border power trade in NM2050 and excluding (all) demand response options have the highest impact on storage results and other system performance indicators such as electricity prices or power system costs. Limiting cross-border trade results in higher storage use, in particular of H_2 underground storage and EV batteries (i.e. notably V2G transactions). No demand response results in higher electricity storage, in particular of VR and Li-ion batteries, but leads to zero H_2 underground storage in COMPETES, assuming an hourly H_2 demand profile that is completely flat. Remarkably, sensitivity cases in which the investment and fixed operational costs of storage options are reduced by 50% in the COMPETES model have hardly or no impact on the storage outcomes or other system performance indicators of this study.

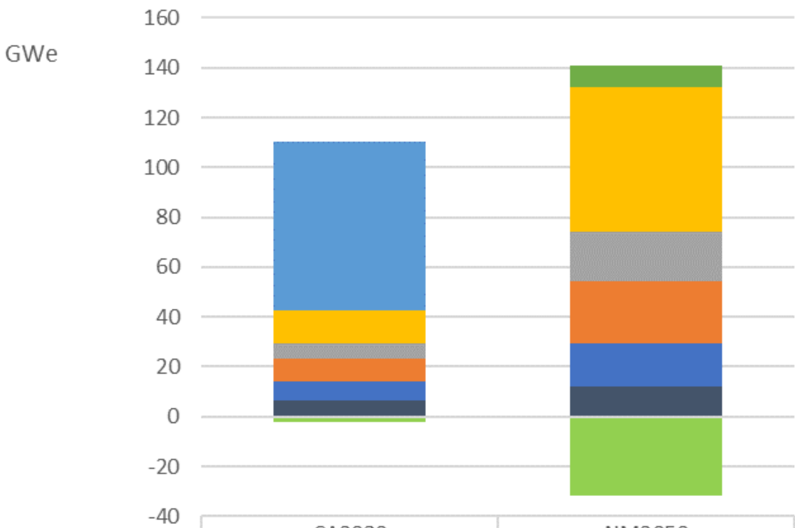
4 Results from OPERA

This chapter presents and discusses the major results of the study obtained by means of the OPERA model. Section 4.1 discusses the results regarding the reference scenarios CA2030 and NM2050. Subsequently, Section 4.2 briefly defines the sensitivity cases conducted by OPERA for NM2050 and presents the major findings of these cases.

4.1 OPERA: Reference scenarios CA2030 and NM2050

4.1.1 Installed capacities of major energy technologies

Figure 27 presents the installed capacities of some key technologies in the field of electricity and hydrogen production as used by OPERA in the reference scenario of CA2030 and NM2050. As explained in Chapter 2, for some technologies the available capacities have been optimised endogenously by OPERA, whereas for other technologies the installed capacities have reached the maximum potential set exogenously into the model (see Section 2.3.2, notably Table 5).



	CA2030	NM2050
CCGT - Hydrogen	0.0	9.1
CCGT - Natural gas	67.8	0.0
Wind - Offshore	13.5	57.8
Wind - Onshore	6.1	20.0
Solar - Large scale utilities	8.9	24.8
Solar - Services	7.5	17.4
Solar - Residential	6.7	12.0
H2 Electrolysis	-2.0	-31.5

a) As H_2 electrolysis is using electricity rather than producing electricity, we have indicated the installed capacity of H_2 electrolysis in terms of electricity input (GWe) but with a negative sign.

Figure 27: OPERA: Installed capacities of major (renewable) energy technologies in CA2030 and NM2050

As a result, the installed capacity for certain technologies used by OPERA may deviate significantly from those assumed by COMPETES or by the ETM model to calculate the NM2050 scenario developed by Berenschot and Kalavasta (2020). For instance, for NM2050 both ETM and COMPETES have set the installed capacity of solar PV exogenously at 106 GWe, whereas OPERA has optimised the total capacity of solar PV at 54.2 GWe, and deploys more offshore wind.[31] Consequences of these different approaches will be discusses in Chapter 5.

Figure 27 shows that, at contrast with CA2030, in NM2050 most of the installed capacity is for VRE sources. The installed *input* capacity of hydrogen electrolysis in OPERA increases from the exogenously imposed 2.0 GW electricity (GWe) in CA2030 to an endogenously determined 31.5 GWe in NM2050. Moreover, in NM2050 there is, according to OPERA, an installed *output* capacity of 9.1 GWe for a CCGT installation fuelled by hydrogen.[32]

4.1.2 Primary and final energy use

Figure 28 presents the mix of total *primary* energy use in CA2030 and NM2050, both excluding and including international bunker fuels. In addition, Figure 29 provides the mix of *final* energy consumption by three end-user sectors – i.e. the built environment, agriculture and transport – while Figure 30 shows the mix of final energy use by industry, excluding and including bunker fuels, in these scenario years.[33]

In brief, some of the major observations from these figures include:

- As expected, following current trends, the role of conventional fuels (oil, gas, coal) declines significantly between CA2030 and NM2050, whereas the role of solar PV and, notably, wind energy increases substantially over these years (Figure 28);
- The use of (primary) biofuels increases rapidly from 10 PJ in CA2030 to 546 PJ in NM2050, mainly to provide international bunker fuels such as heavy fuel oil (HFO) and kerosene (see Figure 28 and Figure 30);
- The use of electricity increases significantly between CA2030 and NM2050 in all energy end-use sectors, notably in agriculture, transport and industry, but far less in the built environment (Figure 29 and Figure 30);
- The use of hydrogen is almost zero in most end-use sectors in CA2030 but increases rapidly toward NM2050 in both the built environment (94 PJ), transport (112 PJ) and international bunker fuels (106 PJ). While the use of hydrogen increases also in industry, this sector is, on balance, a net producer of hydrogen, rising from 7 PJ hydrogen output in CA2030 to 216 PJ in NM2050 (Figure 29 and Figure 30). As a result, not all hydrogen produced and used in industry – e.g., in NH_3 synthesis – is included in Figure 30. The hydrogen balance will be discussed further in section 4.1.4;
- In all sectors (except transport where it does not play a role) there is a significant increase in the use of ambient heat in NM2050 compared to CA2030.

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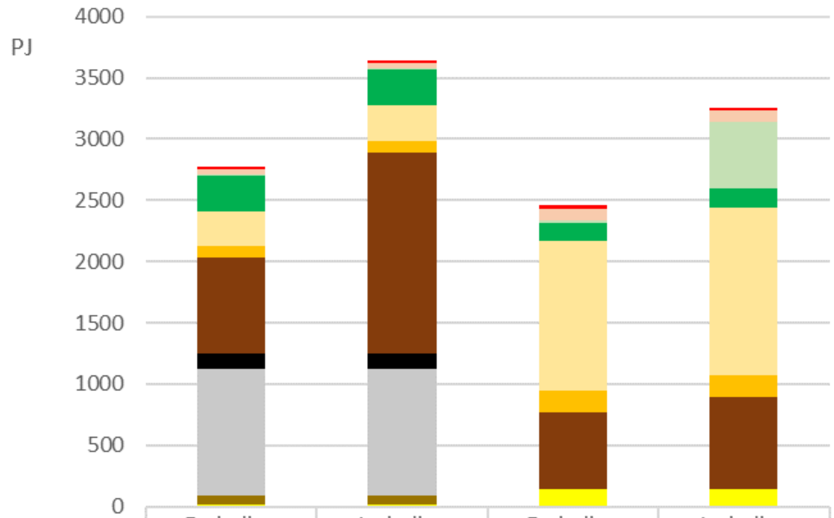
31 See, in particular, Section 2.3.2 (Table 5 and Table 7), Section 2.3.6 (Table 12), Section 3.11 (Figure 8) and the current Section 4.1.1 (Figure 27).

32 Note that of all the numbers on installed capacity mentioned in the main text above only the capacity of hydrogen in CA2030 (2.0 GWe) has been set exogenously into the model, while all other capacities have been optimised endogenously by OPERA (see Section 2.3.2, Table 5).

33 See Appendix D (Figure 55 and Figure 56) for Sankey diagrams of the Dutch energy system in CA2030 and NM2050 according to OPERA, including the flows and conversions from primary to final energy use as well as the storage of some energy carriers, notably electricity and hydrogen.



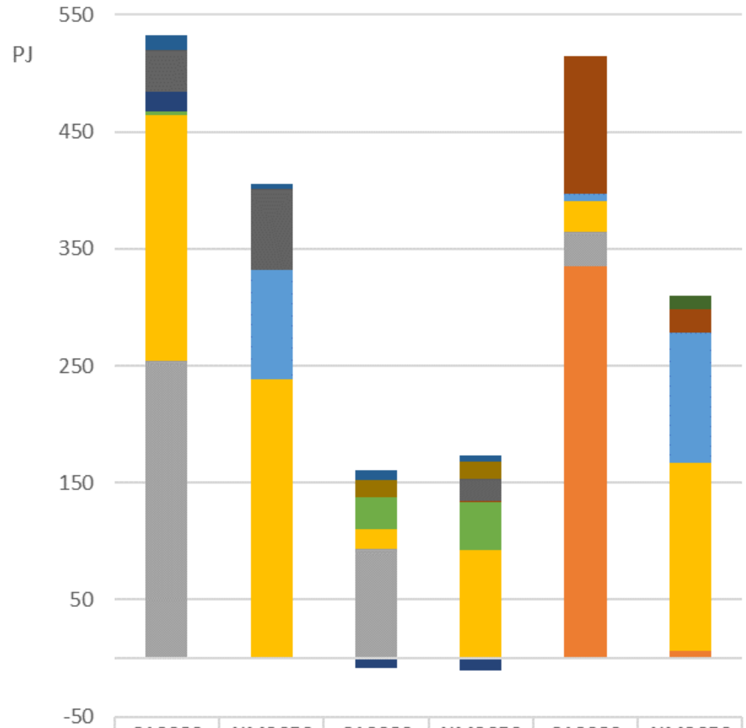
	CA2030		NM2050	
	Excluding bunker fuels	Including bunker fuels	Excluding bunker fuels	Including bunker fuels
Geothermic heat	20.8	20.8	26.9	26.9
Ambient heat	43.8	43.8	92.6	92.6
Biofuels	10.0	10.0	22.8	546.0
Biomass	293.2	293.2	152.9	155.1
Wind	283.5	287.2	1218.6	1364.1
Solar PV	93.6	93.6	180.0	180.0
Oil	784.6	1639.8	620.6	750.1
Coal	126.3	126.3	0.4	0.4
Natural gas	1033.8	1039.8	0.0	0.0
Other	72.9	72.9	2.2	2.2
Electricity import	14.8	14.8	142.7	142.7

Figure 28: OPERA: Mix of total primary energy use in CA2030 and NM2050

4.1.3 Electricity balance: power demand and supply

Figure 31 presents the electricity balance in CA2030 and NM2050. As OPERA is lacking adequate power trade relationships with foreign countries, we have used the hourly profiles of net power trade from COMPETES and have added these profiles to the hourly profiles of domestic demand/supply resulting from OPERA. Consequently, the *net* power trade figures of OPERA are similar to those of COMPETES (compare Table 24 with Table 14 in Section 3.1.2).

OPERA defines and uses slightly different electricity demand/supply categories than COMPETES. More importantly, whereas the level of power demand by the different demand categories (conventional, EVs, heat pumps, other additional demand) is assumed exogenously in COMPETES, it is – to some extent – optimised endogenously by OPERA (i.e. within the limits and other characteristics set by the definition of the reference scenarios of CA2030 and NM2050). This explains the major differences between the electricity balance of OPERA versus COMPETES (compare with Figure 9 in Section 3.1.2).

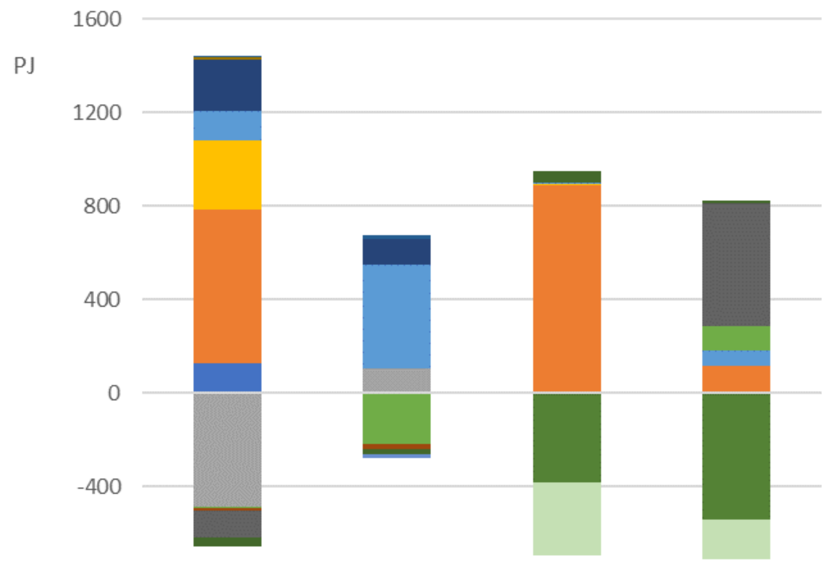


	Built environment		Agriculture		Transport	
	CA2030	NM2050	CA2030	NM2050	CA2030	NM2050
Synthetic fuels	0.0	0.0	0.0	0.0	0.0	12.5
Heat	13.4	4.6	8.6	5.5	0.0	0.0
Geothermic heat	0.0	0.0	14.9	14.9	0.0	0.0
Ambient heat	34.8	69.2	0.0	18.9	0.0	0.0
Biofuels	0.0	0.0	0.0	0.2	118.2	19.2
Biogas	17.5	0.1	-8.8	-10.7	0.0	0.0
Biomass	2.8	0.0	27.8	41.8	0.0	0.0
Hydrogen	0.5	93.7	0.0	0.0	5.9	112.0
Electricity	209.9	237.5	16.5	91.9	26.0	159.9
Natural gas	254.0	0.0	93.3	0.0	30.0	0.0
Oil products	0.0	0.4	0.2	0.1	334.9	6.7
Coal	0.0	0.0	0.0	0.0	0.0	0.0

a) A negative sign refers to energy output production (rather than final energy use).

Figure 29: OPERA: Mix of final energy use by the built environment, agriculture and transport in CA2030 and NM2050

The total domestic power demand in OPERA is higher than in COMPETES, i.e. 395 TWh vs 346 TWh. In COMPETES the level of conventional power demand in NM2050 is assumed to be fixed for both CA2030 and NM2050 at the level obtained from the KEV2019, i.e. almost 117 TWh per annum (see Section 2.3.1). On the other hand, in OPERA it is determined endogenously that conventional power demand increases slowly to 125 TWh in CA2030 and to 140 TWh in NM2050. In addition, in COMPETES, the total additional power demand for P2Heat (industry) and P2Hydrogen is assumed to be almost 179 TWh in NM2050. OPERA on the other hand deploys P2Heat only in the built environment but has a larger P2Hydrogen demand, a substantial P2L contribution and about 29 TWh for the ULCOLYSIS process for steel production, which is part of other additional demand in Figure 31.



	Industry excl bunkers		Bunkers	
	CA2030	NM2050	CA2030	NM2050
Kerosine			-310.8	-170.0
HFO			-384.3	-543.0
Synthetic fuels	0.0	-17.4		
Heat	-37.2	-21.8	48.3	7.7
Geothermic heat	5.9	12.0		
Ambient heat	9.0	4.5		
Biofuels	-118.1	0.0	0.0	526.0
Biogas	-8.7	-24.2		1.6
Biomass	222.6	109.6		
Hydrogen	-6.6	-216.4		106.3
Electricity	126.3	443.5	4.7	63.0
Natural gas	292.0	0.0	7.7	
Oil products	-486.3	99.0		
Oil crude	661.7	4.5	889.0	117.6
Coal	126.1	0.1		

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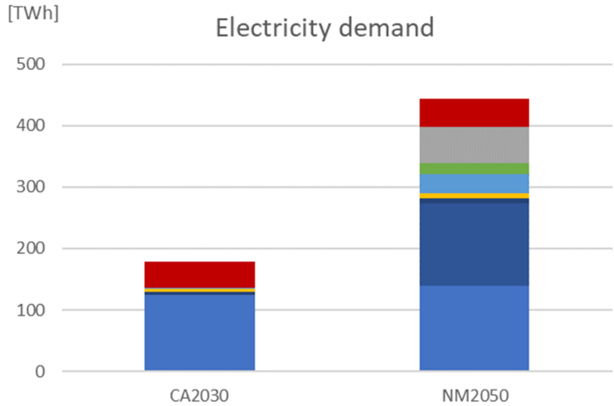
a) A negative sign refers to energy output production (rather than final energy use).

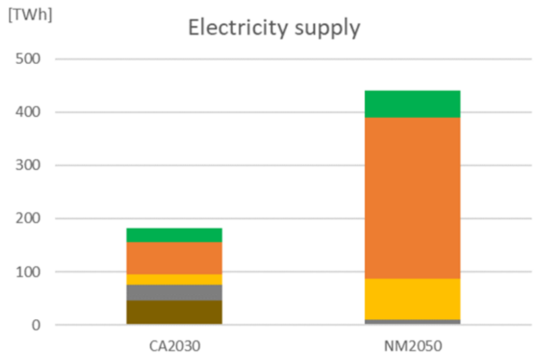
Figure 30: OPERA: Mix of final energy use by industry (excluding bunker fuels) and bunker fuels in CA2030 and NM2050

As mentioned above, in OPERA net electricity exports in NM2050 are fixed at the level of COMPETES (i.e. 42.8 TWh). Consequently, the difference between total domestic supply and demand of electricity is the same in OPERA and COMPETES but OPERA foresees a total higher electricity supply (i.e. 438 TWh versus 389 TWh; see Table 24 versus Table 14).

There are also some significant differences in the *mix* of power supply in NM2050 (see the lower parts of Figure 31 and Figure 9, respectively). In particular, the electricity output from offshore wind in NM2050 is substantially higher in OPERA than in COMPETES (i.e. 298 vs 206 TWh), whereas the power production from solar



	CA2030	NM2050
Net export	42.0	42.8
Other additional demand	1.4	59.5
P2L	0.0	17.3
Electric vehicles	1.7	32.2
P2 Heat (electric boilers HH)	6.8	4.5
Heat pumps HH	4.2	7.7
P2H2	0.2	134.4
Conventional demand	125.0	139.3



	CA2030	NM2050
Conventional (CCGT)	46.8	0.8
Conventional (other)	28.9	10.0
Wind onshore	19.7	76.4
Wind offshore	60.0	302.5
Solar PV	26.0	50.0

Figure 31: OPERA: Balance of electricity demand and supply in CA2030 and NM2050

Table 24: OPERA: Aggregated electricity balances in CA2030 and NM2050

[TWh]	CA2030	NM2050
Domestic power demand	139.4	394.9
Domestic power supply	181.3	437.7
Domestic power production deficit[a]	-42.1	-42.8
Net electricity imports/Foreign power trade deficit[b]	-42.1	-42.8

a) A minus ('-') indicates a domestic power production surplus;

b) A minus ('-') indicates net power exports ('trade surplus').

PV is significantly lower (50 vs 98 TWh). As the full load hours of the VRE technologies in NM2050 are assumed to be the same in both models, the differences in power production per VRE technology are solely due to the assumed versus optimised installed capacities of these technologies in COMPETES and OPERA, respectively.[34]

In addition, in COMPETES there is still some power generation from natural gas in NM2050 (7.5 TWh) – but none in OPERA – while in OPERA there is some electricity production from hydrogen (10 TWh), but none in COMPETES.[35]

4.1.4 Hydrogen balance: H_2 demand and supply

Whereas the hydrogen balance in COMPETES is rather simple, it is more differentiated in OPERA. More specifically, in the COMPETES model version used for the current study, there is just one category of domestic hydrogen demand, which is assumed to be met by just one single domestic hydrogen supply option, i.e. alkaline electrolysis (AEL), with no cross-border hydrogen trade.[36] Moreover, total domestic hydrogen demand is assumed exogenously in COMPETES at 6.7 TWh (14 PJ) in CA2030 and 76 TWh (272 PJ) in NM2050 (see Section 3.1.7).

In OPERA, on the other hand, the demand for hydrogen is more differentiated across a variety of demand categories (see upper part of Figure 32). This domestic hydrogen demand can be met by a variety of domestic hydrogen supply options, including – among others – alkaline electrolysis (AEL) and steam methane reforming (SMR, with or without CCS) but excluding foreign hydrogen trade options (see lower part of Figure 32). Moreover, hydrogen demand and supply are – to some extent – optimised endogenously by OPERA, i.e. within the limits and other characteristics set by the definition of the reference scenarios for CA2030 and NM2050. As a result, total domestic hydrogen demand/supply amounts to approximately 1.9 TWh (6.7 PJ) in CA2030 and to 91.4 TWh (329 PJ) in NM2050.[37] For CA2030, the total hydrogen demand/supply is significantly lower in OPERA than in COMPETES, whereas it is substantially higher in NM2050.

The upper part of Figure 32 shows that in NM2050 about 94% of total hydrogen demand is borne by three major demand categories, i.e. heavy duty vehicles (HDVs), the production of synthetic fuels (P2Liquids) and heat boilers in the services sector.[38] The lower part of Figure 32 illustrates that hydrogen supply of 6.7 PJ in CA2030 comes predominantly (91%) from one production technology (SMR, without CCS) while the remaining part (9%) is borne by AEL. In NM2050, on the other hand, the highly increased supply of hydrogen (329 PJ) comes solely from one production

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[34] Note, however, that the share of total VRE output in total domestic power supply in NM2050 is similar in both models (i.e. about 98%), whereas there is a slight difference in CA2030 (i.e. 56% in COMPETES vs 58% in OPERA).

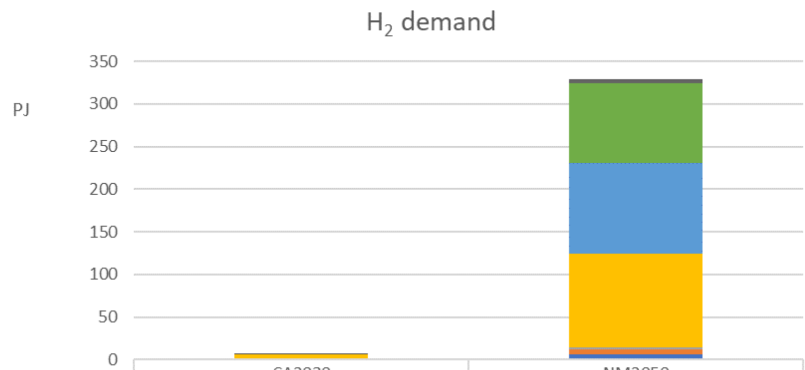
[35] As noted, however, in COMPETES there is some power output from hydrogen in NM2050 sensitivity case 1B (7.2 TWh; see Section 3.1.7, footnote 29).

[36] In an updated version of COMPETES (under development), the model includes also another hydrogen supply option (SMR) as well as the opportunity of foreign hydrogen trade.

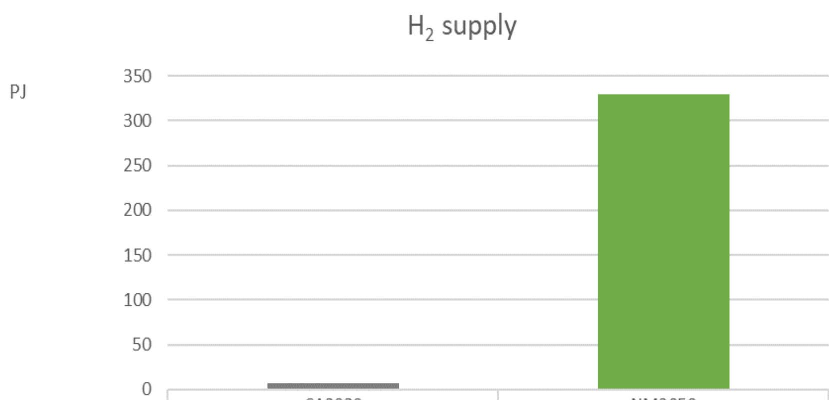
[37] As noted before, however, not all hydrogen produced and used in industry – for instance, in ammonia synthesis – is included in the hydrogen balance presented in Figure 32. Therefore, the total (gross) hydrogen production and use are actually higher than the total (net) hydrogen supply and demand indicated in this figure.

[38] The built environment consists of two main subsectors, i.e. households and the services sector. The latter subsector consists, in turn, mainly of (offices and other buildings of) government services, trade services and other services.

source, i.e. AEL. Some of the hydrogen in the energy system is not explicitly visible in OPERA as this hydrogen is part of integral technologies considered. For CA2030 this amounts to 162 PJ, i.e. 70.4 PJ in ammonia synthesis, 18.7 PJ in production of synthetic fuels, 55.0 PJ in refineries and 18.0 PJ for methanol production to be used in synthesis of High Value Chemicals. In NM2050 there is 49.3 PJ additional hydrogen: 27.3 PJ in ammonia production, 4.3 PJ in refineries and 17.7 PJ for methanol production.



	CA2030	NM2050
CCGT - Hydrogen	0.0	4.7
Chemicals	0.0	0.0
Heat boilers - Other	0.2	0.2
Heat boilers - Services	0.4	93.7
Synthetic fuels (Power2Liquids)	0.0	106.3
High Duty Vehicles (HDVs)	3.9	109.9
Passenger cars	2.1	2.1
Transport loss	0.1	6.0
Admixture	0.0	6.3



	CA2030	NM2050
Steam Methane Reforming (SMR)	6.1	0.0
Alkaline Electrolysis (AEL)	0.6	329.2

Figure 32: OPERA: Balance of hydrogen demand and supply in CA2030 and NM2050

4.1.5 Storage and variability of electricity demand and supply

Using all input parameters (regarding energy demand, energy technologies, normalised hourly profiles, etc.) OPERA optimises the required (available) capacities and hourly dispatch of energy technologies, including the required size and volume transactions of energy storage options, with the restriction that cross-border electricity trade profiles are obtained from COMPETES.

The normalised hourly profiles of electricity demand and (VRE) supply in OPERA are mostly similar to those in COMPETES (as illustrated and discussed in Section 2.3.3 and, more extensively, in Sijm et al., 2017a and 2017b). However, as the nominal electricity demand levels and installed capacities of VRE power generation technologies in OPERA are (slightly) different from those in COMPETES – notably in NM2050 – the resulting nominal ('real') hourly profiles of electricity demand and (VRE) power supply in OPERA are (slightly) different from those in COMPETES (in particular in NM2050).

Figure 33 and Figure 34 show the resulting nominal (cumulative) hourly profiles of electricity demand and (VRE) supply in OPERA in CA2030 and NM2050, respectively. Some major observations from these figures include:

- The hourly profiles of electricity demand show a clear hourly and daily pattern (i.e. a high variability with peaks early in the morning and early in the evening) whereas the seasonal pattern of these profiles is less clear, with the major exception of the profile of electricity demand by household heat pumps (i.e. a strong seasonal pattern with high demand in the winter and low demand in the summer);
- The hourly profiles of VRE power generation are highly variable. For solar PV, these profiles show a strong daily and seasonal pattern (with high peaks in summertime around the middle of the day), whereas for wind these patterns are less clear (or even largely absent);
- In NM2050, the peaks in cumulative electricity demand/supply profiles are, on average, about 2.5 times higher than in CA2030;
- In CA2030, the hourly profile of the residual load (not shown in Figure 33) is still dominated in most hours by the demand side of the electricity balance in the sense that VRE power supply is generally lower than total electricity demand and that the resulting positive residual load ('VRE shortage') is met by additional ('flexible') supply options such as power generation from gas, electricity imports or storage (discharge). During some hours in CA2030, however, there is already a negative residual load ('VRE surplus'), which – besides switching off power generation from gas – is met by additional ('flexible') demand options such as electricity exports or storage (charge). This is, for instance, the case during the first week of July in CA2030 (see bottom part of Figure 33);
- In NM2050, however, the hourly profile of the residual load (not shown in Figure 34) is dominated in most hours by the supply side of the electricity balance in the sense that VRE power supply is generally higher than total electricity demand and that the resulting negative residual load ('VRE surplus') is met by flexibility options such as power trade (i.e. electricity exports), storage (i.e. charging batteries) and demand response (i.e. shifting electricity demand from VRE shortage hours to VRE surplus hours). On the other hand, during several hours of the NM2050 there is still a (substantial) VRE shortage, which is met by similar (but 'opposite') flexibility options such as electricity imports, storage discharge and shifting electricity demand to VRE surplus hours. Both cases can be clearly observed from the bottom part of Figure 34, showing the hourly electricity profiles during the first week of July in NM2050.

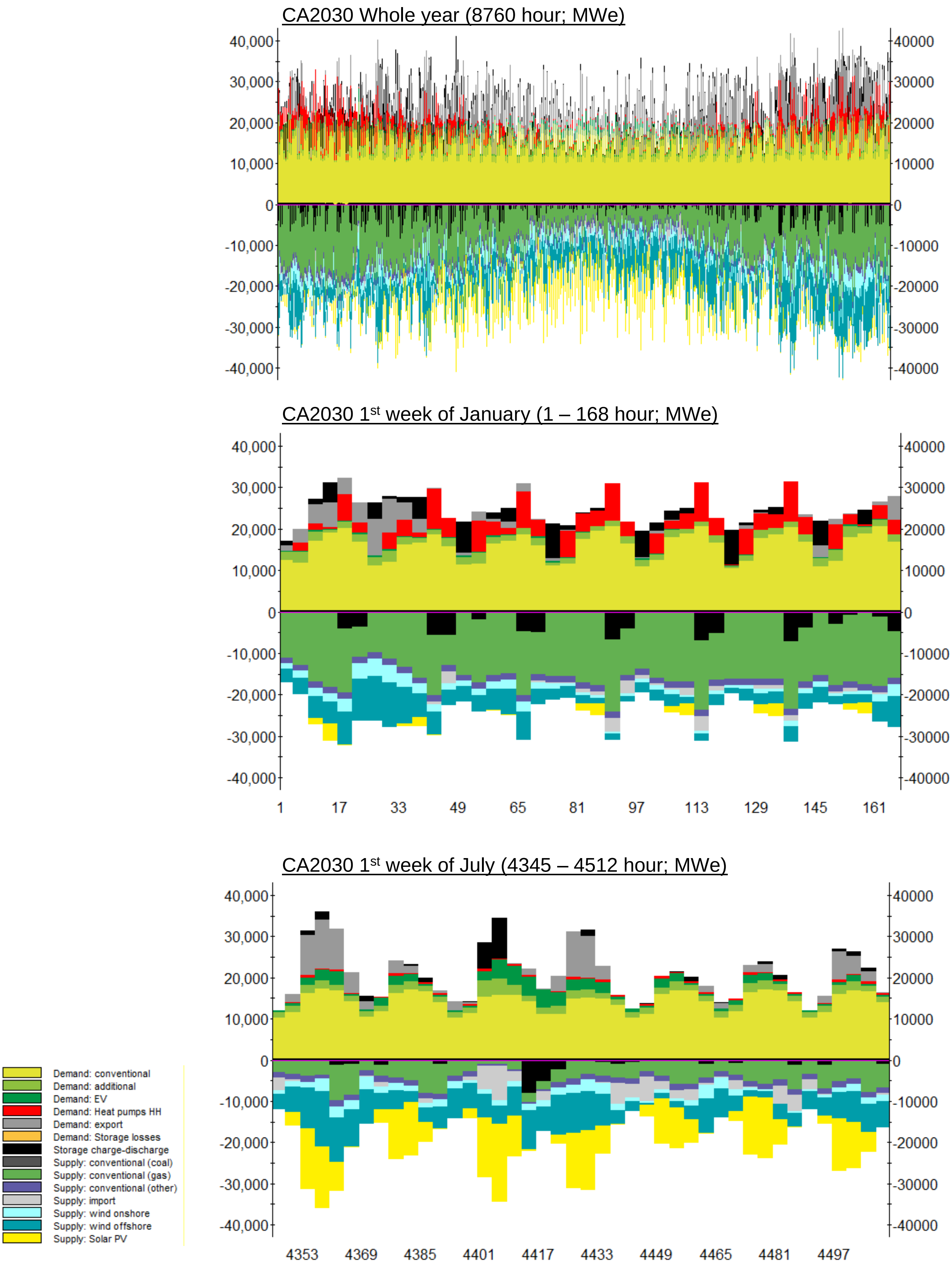


Figure 33: OPERA: Hourly electricity profiles in CA2030

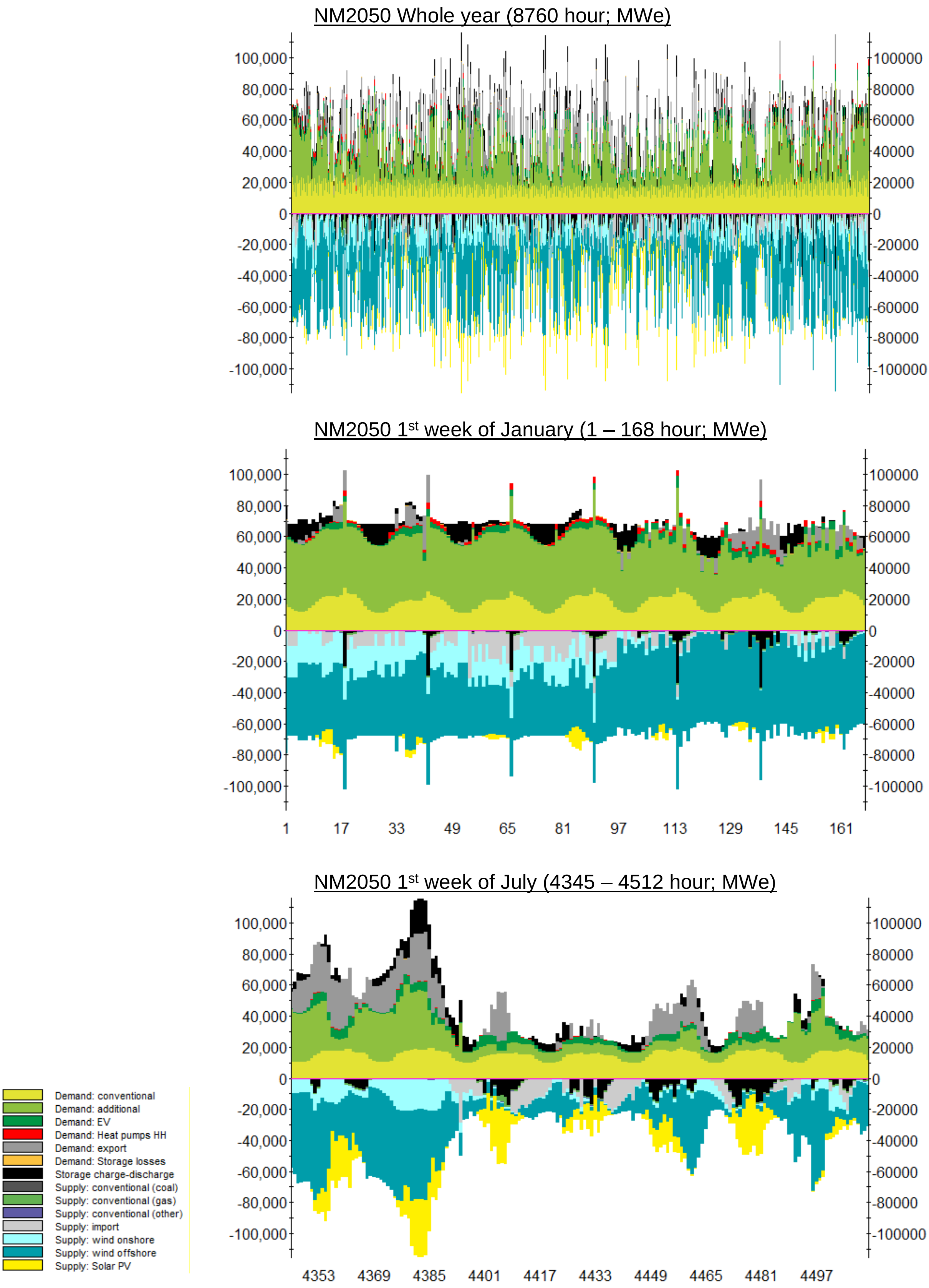


Figure 34: OPERA: Hourly electricity profiles in NM2050

Table 25 shows the contribution of flexibility technologies as electrolysis, storage, power trade, VRE curtailment and dispatchable power generation (CCGT-H2) that OPERA calculates for CA2030 and NM2050. We distinguish contributions to the annual energy volume and to the deployed maximal power during the year. Storage options have both supply (discharge) and demand (charge) power. Size refers to the capacity of the storage medium.

In CA2030 (exogenously set) electricity export has a very large volume contribution. Storage in EV batteries is the next largest flexibility option, but it should be noted that all energy is used to drive cars and is not fed back to the grid as V2G is excluded in CA2030. The demand capacity for EV batteries of 10 GW is determined both by the driving profiles of the electric cars and the surplus of VRE. There is a limited need for battery storage, mostly VRB. In this study we have assumed for VRB a ratio of five for discharge/charge times[39]. This pattern of slow charge versus fast discharge and a relatively low number of FCE fits the demand/supply requirements well in CA2030. Other battery types with different discharge/charge dynamics (and higher FCE) play a minor role. As OPERA optimises the VRE deployment, curtailment is minimal. The 2 GW electrolysis capacity is not much used, as demand for hydrogen is met by SMR (see Figure 32). Hydrogen to power is not deployed in CA2030.

In 2050 NM a large part of the 437.7 TWh electricity production is used for electrolysis. An almost negligible part of this hydrogen is reconverted to electricity (CCGT-H2), mostly to provide additional capacity of 9 GW at times when there is no or hardly any VRE power generation, hardly or no electricity import and discharge of stored electricity is insufficient. Most of the flexibility in the electricity supply is provided by import and export, with capacities in the order of 30 GW. Electricity storage is exclusively in EV batteries. In NM2050 the storage size available in about 10 M vehicles with an average battery size of 100 kWh is so large that this can provide for the whole electricity storage need, without additional batteries. Of the net 30.0 TWh storage in EV batteries, only 13.3 TWh is fed back to the grid. The remaining 17.7 TWh of the stored electricity is used to fulfil the transport activity demand of 32.2 TWh. The difference between 32.2 and 17.7 TWh is energy charged to batteries compensated by simultaneous discharge by driving cars. Note, however that we have not included explicit costs for charging and discharging, nor for battery size. The charge and discharge capacities associated with EV batteries are quite large and are mostly determined by the excess and shortage in VRE supply versus the demand. Figure 35 shows the SOC of the EV batteries. Noticeable is a large peak in winter indicating that the EV battery has a role in seasonal electricity storage. Finally, VRE curtailment is quite minor according to OPERA, which endogenously calculates solar PV and wind capacities.

There is no electricity storage in large-scale storage options such as CAES or AA-CAES (i.e. similar to the findings by COMPETES on electricity storage discussed in Section 3.1), but this may be related to the chosen fixed charge/discharge times[40]. We will discuss this in section 5.2.2.

[39] The ratio of discharge/charge capacity is smaller than five as the charge capacity includes charge/discharge losses.

[40] For CA2030 and NM2050, OPERA showed some storage outcomes for CAES and AA-CAES but the numbers are so negligibly small – for instance, less than 1 GWh storage volume per annum – that they are regarded as ‘modelling noise’ and, therefore, not included in Table 25.

Table 25: OPERA: Summary overview of flexible electricity supply and demand in CA2030 and NM2050

CA2030	Volume	Supply[b] capacity	Demand[b] capacity	Size	FCE
OPTION	**TWh**	**GW**	**GW**	**GWh**	**#**
EV batteries	1.08	0.5	10.1	44.9	24
VR batteries	0.37	5.0	1.4	25.0	15
Other batteries	0.08	0.5	0.4	1.3	61
CCGT-H2	0	0	n.a.		
Import[c]	4.1	8.6	n.a.		
Export[c]	46.1	n.a.	12.0		
Electrolysis	0.20	n.a.	2.0		
Curtailment	0.1				
NM2050	**Volume**	**Supply[b] capacity**	**Demand[b] capacity**	**Size**	**FCE**
OPTION	**TWh**	**GW**	**GW**	**GWh**	**#**
EV batteries[a]	30.0 (13.3)	57.5	24.3	974.5	31
CCGT-H2	0.8	9.1	n.a.		
Import[c]	39.6	31.1	n.a.		
Export[c]	82.5	n.a.	32.2		
Electrolysis	134.4	n.a.	31.5		
Curtailment	0.1				

a) The total electricity demand for EV is 32.2 TWh, with 8.2 GW maximum deployed power. The value between parenthesis is the electricity fed back to the grid (V2G).
b) For storage options the discharge capacity is the supply capacity and the charge capacity is the demand capacity.
c) In OPERA the total import(export) is the sum of import(export) in all hours where there is net import(export). In COMPETES the import(export) is the sum of gross import(export) of all hours, leading to larger volumes.

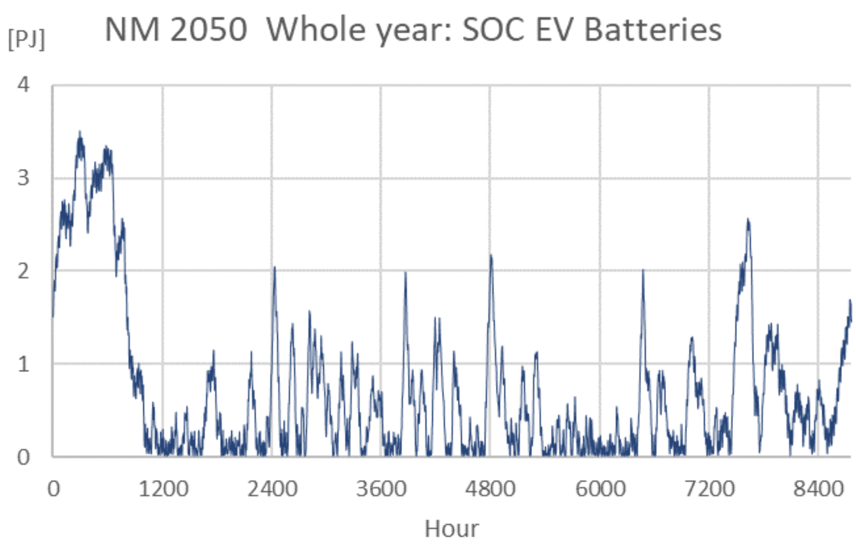


Figure 35: OPERA: State of charge of the EV batteries in NM2050

4.1.6 Storage and variability of hydrogen demand and supply

Chapter 2 has explained OPERA's approach regarding its use of (normalised) hourly profiles for the main categories of hydrogen demand and supply (see Section 2.3.3). Figure 36 shows the resulting hydrogen profiles in NM2050 by means of *stacked columns* – for the year of NM2050 as a whole as well as for both a winter month (January) and a summer month (July). In addition, Appendix C provides line graphs of hourly profiles of some major, individual hydrogen demand and supply categories as well as the resulting hourly profile of H_2 storage charges and discharges during NM2050 (see Figure 50 up to Figure 54).

In brief, the major observations from the above-mentioned figures include:

- In NM2050, the demand for hydrogen – apart from H_2 storage charges – is dominated by the profiles of three demand categories, i.e. the hydrogen demand by (i) heat boilers in the services sector, (ii) heavy duty vehicles (HDVs) in the transport sector, and (iii) the production of synthetic fuels (P2Liquids) in industry (see the area above the X-axis in Figure 36). Together, these three categories account for approximately 94% of total hydrogen demand in NM2050 (Figure 32);
- The hourly profile of H_2 demand by heat boilers in the services sector shows a clear, strong seasonal pattern. More specifically, during the winter period the demand for hydrogen by the services sector – mainly for heating offices and other service buildings – is, on average, relatively high but fluctuates heavily over the day with a peak during the early hours of a working day. During the summer period, however, this demand – including the need for hot tap water – is substantially lower and rather stable (see Appendix C, Figure 50);
- The hourly profile of H_2 demand by HDVs in the transport sector has a clear daily and weekly pattern throughout most of the year in the sense that the demand for H_2 is highest during the working hours of the working days of the week and much lower during the other hours of the week (see Appendix C, Figure 51);
- The hourly profile of H_2 demand for synthetic fuels is rather erratic, but fluctuates heavily, as the price of these fuels depends strongly on the price of hydrogen. The profiles therefore largely follow the hydrogen supply profiles (see also Appendix C, Figure 52 and Figure 53);
- In NM2050, the supply of hydrogen – apart from H_2 storage discharges – is dominated by the profile of one single supply option, i.e. H_2 production by means of alkaline electrolysis (AEL; see the area below the X-axis in Figure 36). This option accounts even for 100% of total hydrogen supply in NM2050 (Figure 32);
- The hourly profile of H_2 supply by AEL is rather erratic, but fluctuates heavily, as the production of hydrogen by means of electrolysis ($P2H_2$) is responsive to – and, hence, depends largely on – the price of electricity, which is also rather erratic and volatile, depending largely on the supply of VRE power generation (see also Appendix C, Figure 53);
- The difference between the hourly profiles of aggregated H_2 demand and supply results in the hourly profile of H_2 storage, including hourly charges and discharges of hydrogen (see Figure 36, as well as Appendix C, Figure 54). These figures show that the hourly profile of H_2 storage fluctuates heavily but does not show a clear daily, weekly or seasonal pattern.

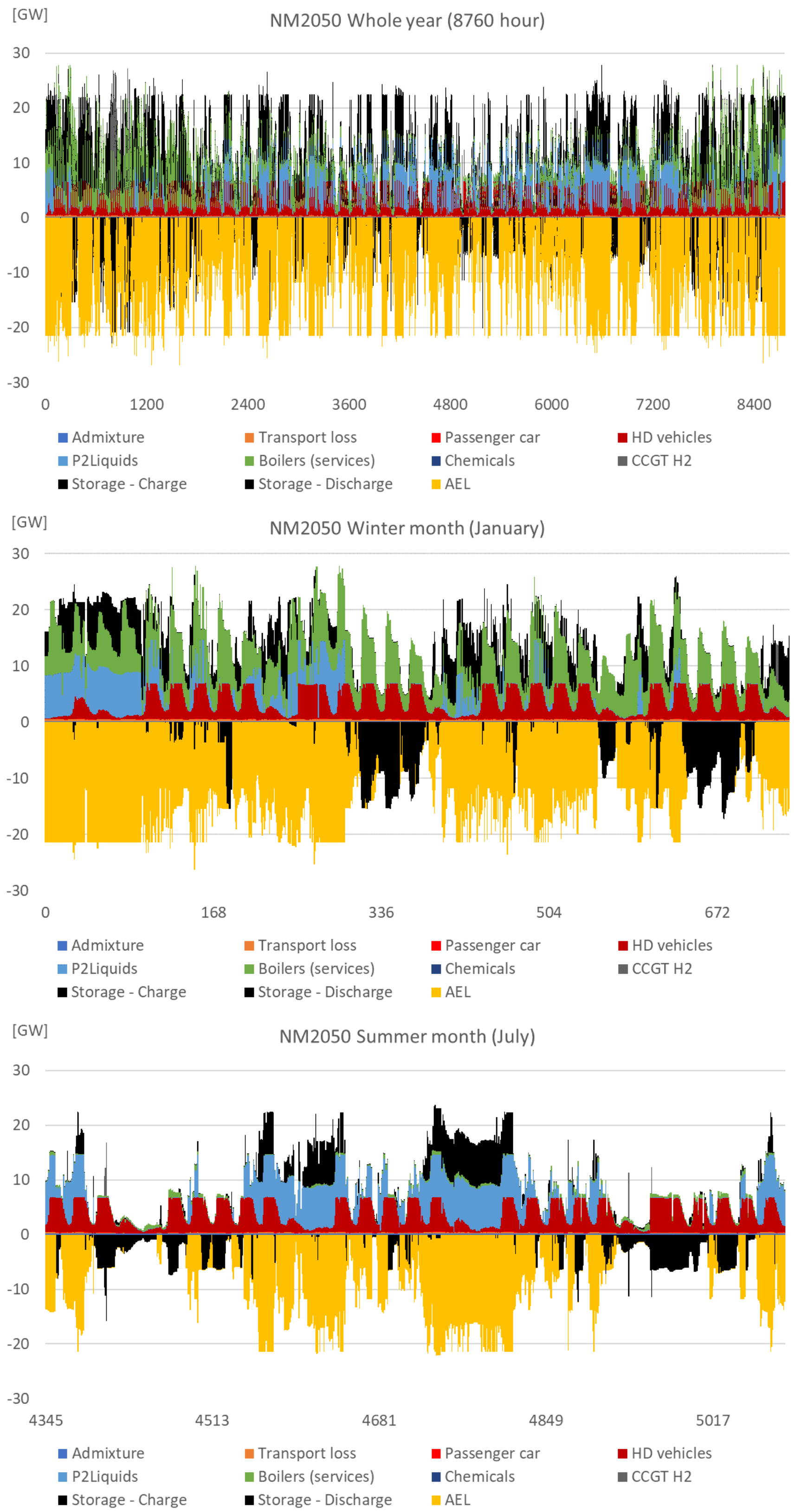


Figure 36: OPERA: Cumulative hourly profiles (stacked columns) of different categories of H_2 demand, supply and storage in NM2050

The annual volumes and deployed power of the most important hydrogen options are summarised in Table 26. In CA2030 most of the produced hydrogen is used in transport. This is also the sector where the largest amount of hydrogen is stored, but this is only used for mobility services. Although the volumes of hydrogen stored in vessels and underground is small, these storage options have large discharge power, required to meet the high power demand of boilers in the built environment. The preference of vessels over underground storage in CA2030 is due to the slow charging, determined by the SMR supply capacity, and the fast discharge to serve boilers in the built environment. As vessels are placed in the regional (''ring line") network, the discharge can take place entirely on the regional network. In CA2030 the optimised capacity of the H_2 pipeline is much lower than that of the (total) regional network. Using the underground storage would require that the pipeline capacity would have to be increased to the same level as the regional network, leading to higher costs.

Table 26: OPERA: Summary overview of hydrogen supply and demand in CA2030 and NM2050.

CA2030	Volume	Supply[b] capacity	Demand[b] capacity	Size	FCE
H_2 option	**TWh**	**GW**	**GW**	**GWh**	**#**
Underground storage	0.02	1.3	0.01	10.2	2
Storage in vessels	0.13	9.7	0.2	9.6	13
Storage in vehicles	0.66	0.4	0.7	21.5	31
Storage in filling stations	0.35	0.7	0.4	0.7	478
SMR	1.70	0.2	n.a.		
Electrolysis	0.17	1.3	n.a.		
Boilers	0.18	n.a.	10.8		
Transport	1.66	n.a.	0.4		
NM2050	**Volume**	**Supply[b] capacity**	**Demand[b] capacity**	**Size**	**FCE**
H_2 option	**TWh**	**GW**	**GW**	**GWh**	**#**
Underground storage	17.1	21.2	7.9	2893	6
Storage in vehicles	7.54	6.3	5.4	46	164
Storage in filling stations	1.51	5.4	5.4	5.4	278
Electrolysis	91.5	21.4	n.a.		
Boilers	26.1	n.a.	14.9		
P2L	29.5	n.a.	7.7		
Transport	30.6	n.a.	6.3		
CCGT-H2	1.3	n.a.	15.1		

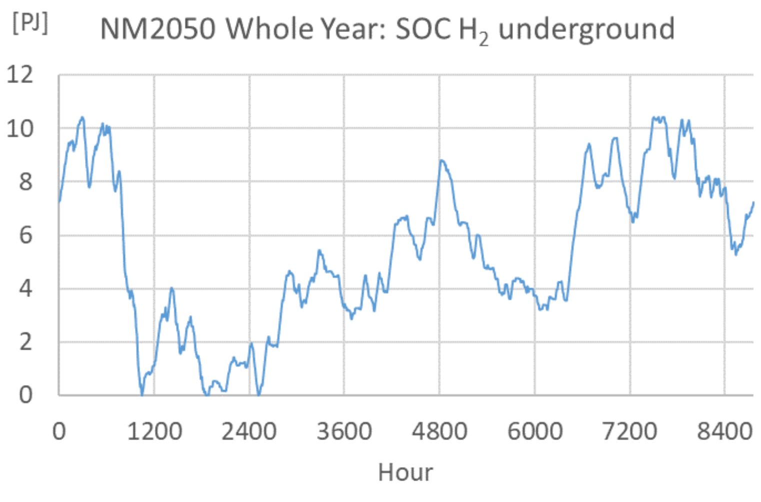
a) A storage size of 2893 GWh requires 12-24 caverns, assuming typical single-cavern capacities of 125 GWh (LHV) (500k m^3 geometric volume) to 250 GWh (LHV) (1 million m^3 geometric volume).

b) For storage options the discharge capacity is the supply capacity and the charge capacity is the demand capacity.

In NM2050 H_2 storage has a substantial role, although most of the hydrogen is directly used by transport, boilers and P2L. According to Figure 36 the P2L process is mostly active when H_2 is being produced. The electrolysis and P2L operate at 49% and 44% of their maximum annual capacity, respectively. For transport, 9 TWh per year is stored. The remaining H_2 storage is underground and amounts to approximately 17 TWh (62 PJ). Due to the variations of supply of VRE there are several periods of charge and discharge over the year, resulting in a required size of H_2 underground storage of 2.9 TWh (10 PJ), with an FCE of about 6. Noticeably, the H_2 storage needs a large discharge capacity of 21.2 GW, to fulfil the demand of particularly boilers and CCGT when H_2 production is not possible due to insufficient VRE supply (see also Figure 36, results for winter month). Notice, that demand for H_2 by CCGT is quite small in annual volume but large in demand capacity**.** At contrast with CA2030, in NM2050 H_2 storage in vessels is not selected since in NM2050 the optimised capacity of the pipeline is already high, at 21.2 GW in agreement with electrolysis capacity. Apparently, in NM2050 this capacity is high enough to meet the peaks in H_2 demand by the built environment. Therefore the underground storage on the pipeline suffices and no further storage in more expensive vessels is required.

Figure 37 shows the resulting state of charge (SOC) of H_2 underground storage in NM2050 – for the year while Figure 38 presents the SOC of hydrogen storage in the transport sector by means of H_2 vehicles and H_2 filling stations.[41] These figures clearly illustrate the difference in volatility and 'time pattern' of the respective storage options over the year (as also indicated by their FCE in Table 26).

For instance, in the transport sector, the volatility of the SOC of hydrogen storage is rather high – i.e. fluctuating heavily between the minimum and maximum size of the respective storage options (Figure 38). This results in a relatively high FCE and indicates that H_2 storage in the transport sector meets predominantly short-term storage needs (i.e. over one or two days).



a) Injection of 4.5 PJ (1250 GWh) H_2-equivalent over a period of 200 hours, i.e. 6.3 GW/h. This requires 6-8 wells assuming single well (9⅝ inch tubing) injection rates of 0.8-1.2 GW/h (265k-400k Nm^3/hr LHV; 6.5-9.5 million Nm^3/day)
b) Withdrawal of 8.1 PJ (2250 GWh) of H_2 over a period of 200 hours, i.e. 11.25 GW/h. This requires 7-10 wells assuming single well (9⅝ inch tubing) withdrawal rates of 1.2-1.8 GW/h (400k-600k Nm^3/hr LHV; 9.5-14 million Nm^3/day).

Figure 37: OPERA: State of charge of H_2 underground storage in NM2050

[41] Note that the top (maximum) of the SOC graphs in Figure 37 and Figure 38 represents the required (available) size of the respective H_2 storage options in NM2050 as determined by OPERA and recorded in Table 26.

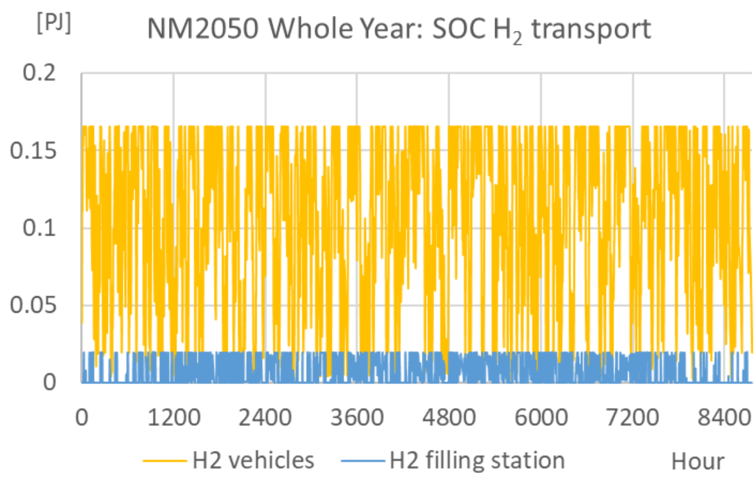


Figure 38: OPERA: State of charge of storage by H_2 transport in NM2050

Figure 37 shows that the actual size of H_2 underground storage is, on average, gradually charged up to its full (maximum available) size of 10.4 PJ in the months October-January – as well as, to some extent, during the period April-June – and that it is, on average, gradually discharged up to its minimum size level of 0 PJ in the months February-March, as well as, to some extent, during the period July-September. Overall, this results in a relatively low FCE for H_2 underground storage in NM2050 (i.e. 6) and indicates that this storage option meets largely longer-term (seasonal) storage needs.

4.1.7 Summary and conclusion

Table 27 provides a summary overview of the energy storage options identified by OPERA to play a role in CA2030 and NM2050. Some major observations from this table and from the OPERA model analysis outlined in the previous sections include:

- Overall, the total annual volume of electricity storage amounts to 1.5 TWh in CA2030 and almost 30 TWh in NM2050. As a percentage of total electricity domestic demand in these scenario years, this corresponds to 1.1% and 7.6%, respectively;
- The role of electricity storage in CA2030 and NM2050 is primarily dominated by batteries of EVs, notably by passenger EVs and in NM2050, to some extent, also by electric light duty vehicles (E-LDVs). As indicated above, this storage is mostly for electricity used by EVs for mobility services, including G2V demand response. The storage used for V2G is about 13 TWh in NM2050 and excluded in CA2030;
- In addition to EV batteries, there is some role of electricity storage by VR batteries and other batteries (NiCd, Pb) in CA2030. In NM2050 the large size of the total of EV batteries is sufficient for all e-storage needs. Hence no contribution is found from other electrochemical storage or from large-scale electricity storage such as compressed air energy storage (CAES/AA-CAES);
- Electricity storage is characterised by high discharge power and much lower charge power capacity. In addition to price considerations, these power characteristics determine the selection of batteries deployed by OPERA. Note, that so far, we have used fixed charge/discharge times for electrical storage and have not separately optimised the charge/discharge power capacities of batteries. Such optimisation may enhance the deployment of VRB or CAES/AA-CAES;

Table 27: OPERA: Summary overview of energy storage in CA2030 and NM2050

CA2030	**Size**	**Volume**	**FCE**	**Charge capacity**	**Discharge capacity**
E-Storage option	*GWh*	*TWh*	*#*	*GW*	*GW*
EV batteries	44.9	1.08	24	10.1	0.5
VR batteries	25.0	0.37	15	1.4	5.0
Other batteries	1.3	0.08	61	0.4	0.5
Total E-storage	71.2	1.53			
As % of total E-demand	0.05%	1.1%			
CA2030	**Size**	**Volume**	**FCE**	**Charge capacity**	**Discharge capacity**
H_2 Storage option	*GWh*	*TWh*	*#*	*GW*	*GW*
Underground storage	10.2	0.02	2	0.01	1.3
Storage in vessels	9.6	0.13	13	0.2	9.7
Storage in vehicles	21.5	0.66	31	0.7	0.4
Storage in filling stations	0.7	0.35	478	0.4	0.7
Total H_2 storage	42.0	1.16			
As % of total H_2 demand	2.3%	62.2%			
NM2050	**Size**	**Volume**	**FCE**	**Charge capacity**	**Discharge capacity**
E-Storage option	*GWh*	*TWh*	*#*	*GW*	*GW*
EV batteries	974.5	30.0	31	24.3	57.5
As % of total E-demand	0.25%	7.6%			
NM2050	**Size**	**Volume**	**FCE**	**Charge capacity**	**Discharge capacity**
H_2 Storage option	*GWh*	*TWh*	*#*	*GW*	*GW*
Underground	2893	17.1	6	13.2	21.2
Vehicles	46	7.5	164	5.4	6.3
Filling stations	5.4	1.5	278	5.4	5.4
Total H_2 storage	2944	26.2		2	9
As % of total H_2 demand	3.2%	28.6%			

- There seems to be a significant role for large-scale energy storage by means of H_2 underground storage (in salt caverns), notably in NM2050. Whereas the size and volume of H_2 underground storage is relatively small in CA2030 (i.e. about 10 GWh and 21 GWh, respectively), they are far more important in NM2050 (i.e. approximately 2.9 TWh and 17 TWh, respectively);
- Similarly to electricity storage, the storage of hydrogen in caverns and vessels is characterised by high discharge power capacities. This is mostly required to meet peaks in heating demand and, notably in NM2050, for demand by CCGT-H_2 (Table 26);
- In addition, hydrogen storage in the transport sector – by means of H_2 vehicles and H_2 filling stations – plays a major role in the hydrogen balance of CA2030 and NM2050, notably in volume terms. More specifically, the volume of hydrogen

storage in the transport sector amounts to 1 TWh in CA2030 and 9 TWh in NM2050. As a percentage of total hydrogen demand in these scenario years, this corresponds to 53% and 7.7%, respectively. Hydrogen storage in the transport sector, however, refers primarily to hydrogen charged and used for mobility services rather than flexibility services to stabilise the hydrogen balance;

- Overall, the total volume of H_2 storage by all options recorded in Table 27 amounts to 4.2 PJ in CA2030 and 94 PJ in NM2050, i.e. 62% and 29% of the total hydrogen demand in these scenario years, respectively.

A major qualification of the observations outlined above is that the analysis of the role of electricity storage is focussed on the need for flexibility due to the variability of the residual load on the spot power market. Although this is one of the key electricity markets, the possible role of electricity storage to meet the need for flexibility due to other reasons (uncertainty of the residual load; congestion of the grid) or other system needs (inertia, black start, frequency control) is ignored.

Another qualification (regarding H_2 storage) is that the total hydrogen balance in CA2030 and NM2050 does not include all hydrogen produced and used in industry (e.g. in ammonia synthesis). As a result, total hydrogen demand is relatively low, notably in CA2030 when hydrogen demand and storage are largely dominated by the transport sector, with large storage volumes for mobility services by H_2 vehicles and filling stations. Consequently, the volume of hydrogen storage is relatively high in CA2030, in particular as a % of total hydrogen demand.

4.2 OPERA: Sensitivity cases NM2050

Overall, we have conducted seven sensitivity cases for NM2050 by means of the OPERA model (Table 28). To some extent, OPERA has carried out similar sensitivity cases as COMPETES, designated as cases 1A, 2A and 2B.[42] OPERA has also conducted some new, additional cases designated as cases 3A, 4A, 5A and 5B. The reference scenario NM2050 is designated as REF. In two sensitivity cases we exclude a major electricity flexibility option found for the reference case, i.e. electricity flows across the border (1A) and V2G (3A). In all cases (except 1A) the import/export profile was not adapted, i.e. the same as in the reference case.

Table 28: OPERA: NM2050 Sensitivity cases conducted by OPERA

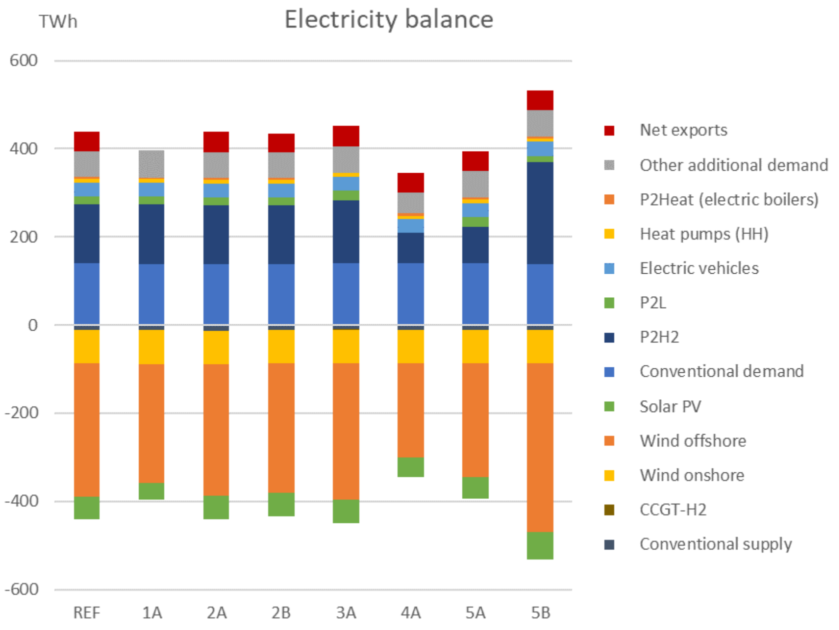
Case	Short description
REF	Reference scenario 2050
1A	No cross-border electricity trade flows
2A	Reduce CAPEX and FXOPEX costs of all E-storage options by 50% (excl. EVs)
2B	Reduce CAPEX and FXOPEX costs of all H_2 storage options by 50%
3A	Exclude V2G
4A	Allow imports of biomass (up to 200 PJ)
5A	Allow hydrogen trade with flat profile at low price (1.5 €/kg)
5B	Allow hydrogen trade with flat profile at high price (3 €/kg)

[42] Note that case 1A (no power trade) is designated as case 1B in COMPETES (see Section 3.2). The designation 2A and 2B refers to similar sensitivity cases in both models.

The results regarding energy storage are presented and discussed in Section 4.2.4, but first we show and discuss the results regarding the underlying determinants of energy storage, i.e. the electricity balance (Section 4.2.1), the hydrogen balance (Section 4.2.2) as well as the implications of the changes in hydrogen and electricity demand for the installed capacities of some major energy technologies (Section 4.2.3).

4.2.1 Electricity balance

Figure 39 shows the implications of the sensitivity cases for the electricity balance in NM2050, while Table 40 in Appendix C provides the underlying data, including the changes in the main demand and supply categories of the electricity balance in these cases. In brief, the major changes and implications of the sensitivity cases conducted by OPERA for the electricity balance in NM2050 include:



a) For the underlying data, see Table 40 in Appendix C.

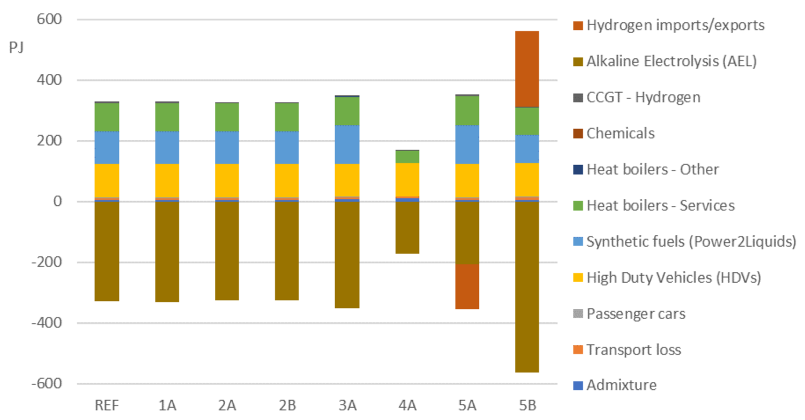
Figure 39: OPERA: Electricity balance – Comparison of NM2050 ref. scenario and sensitivity cases

- In some sensitivity cases, the implications for the electricity balance are relatively small. This applies for cases 2A (half E-storage costs), and 2B (half H_2 storage costs).
- When cross-border trade is excluded (1A), the absence of net export (-42.8 TWh) reduces the need for offshore wind (-32 TWh) and solar PV (-13 TWh);
- In the case without V2G (3A) the electricity balance increases by 11 TWh, due to enhanced hydrogen production (P2H2). Another noticeable effect is that no electric boilers are deployed;
- The additional import of biomass (4A) reduces the need for VRE, mostly because less hydrogen is produced. As also shown in the next section, the H_2 demand for heating is greatly reduced and the H_2 demand by P2L vanishes;
- In case 5A (allow H_2 trade; low H_2 price) power demand for the domestic production of hydrogen by AEL is reduced substantially by 50 TWh. As a result, domestic power production is reduced accordingly, in particular from offshore

wind (by 45 TWh).[43] On the other hand, in case 5B (allow H_2 trade; high H_2 price) power demand for the production (and export) of hydrogen by AEL is increased substantially by 95 TWh. Consequently, domestic power supply is increased accordingly, notably from offshore wind (+80 TWh) and solar PV (+13 TWh; for further details, see Appendix C, Table 42).

4.2.2 Hydrogen balance

Figure 40 shows the implications of the sensitivity cases for the hydrogen balance in NM2050, while Table 41 in Appendix C provides the underlying data, including the changes in the main demand and supply categories of the hydrogen balance in these cases. In brief, the major changes and implications of the sensitivity cases conducted by OPERA for the hydrogen balance in NM2050 include:



a) For the underlying data, see Table 41 in Appendix C.

Figure 40: OPERA: Hydrogen balance – Comparison of NM2050 ref. scenario and sensitivity cases

- In some sensitivity cases, the implications for the hydrogen balance are relatively small. This applies in particular for cases 1A (no power trade), 2A (half E-storage costs), 2B (half H_2 storage costs);
- In the case of no V2G (3A), there is a slight additional use of hydrogen for passenger cars and boilers, but the most significant effect is the increase of P2L (synthetic fuels) demand. The larger, and more continuous, H_2 production in this case, makes the production synthetic fuels economically preferred at more hours in the year;
- When biomass import up to 200 PJ is allowed (4A), the use of hydrogen by heat boilers in the services sector as well as for the production of synthetic fuels in industry is, to some extent, replaced by imported biomass. As a result, the domestic H_2 demand as well as the domestic production of hydrogen by means of AEL ($P2H_2$) declines by almost 50% from 329 PJ in the reference case of NM2050 to 171 PJ in case 4A;
- Domestic production of hydrogen by AEL is also highly affected in cases 5A and 5B, although in opposite ways. In case 5A (allow H_2 trade; low H_2 price) domestic H_2 production is replaced by cheaper H_2 imports (amounting to almost 150 PJ), whereas in case 5B (allow H_2 trade; high H_2 price) domestic output of hydrogen increases significantly due to the opportunity of profitable exports (up to the limit

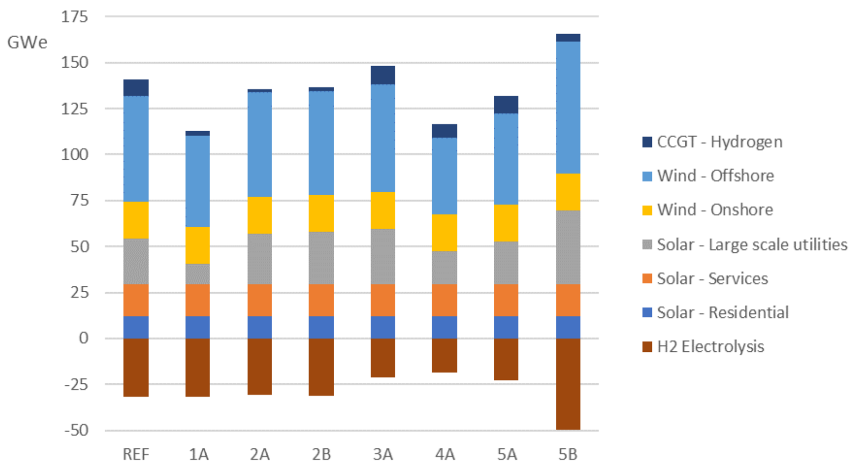
[43] Note that in cases 2A up to 5B, net power trade in OPERA is fixed at the level of the reference case of NM2050. Therefore, changes in domestic power demand have to be met accordingly by similar changes in domestic power supply.

set by OPERA, i.e. 250 PJ). On the other hand, cases 5A and 5B also have some impact on the domestic H_2 demand, notably to produce synthetic fuels, as these fuels compete with other fuels while the price of synthetic fuels depends highly on the price of hydrogen. So, the H_2 demand by synthetic fuels, increases by 22 PJ in case 5A (low H_2 price) and decreases by 15 PJ in case 5B (high H_2 price)

4.2.3 Installed capacity of major energy technologies

Figure 41 shows the implications of the sensitivity cases – notably the changes in energy demand discussed in the previous two sections – for the installed capacities of some major energy technologies in NM2050, while Table 42 in Appendix C provides the underlying data, including the changes in these capacities. In brief, the major changes and implications of the sensitivity cases conducted by OPERA for the installed capacities of some major energy technologies in NM2050 include:

- For some technologies, the changes in installed capacities are zero in all sensitivity cases. This applies for onshore wind and solar PV in the residential (household) and services sector. This results simply from the fact that the installed capacities of these technologies have either been fixed at a certain level or reached their input constraint (maximum potential) set by the model;
- For the other technologies included in Figure 41, most cases show significant changes in installed capacities. This applies in particular for offshore wind and large-scale solar PV in the utility sector as well for both power2hydrogen (H_2 electrolysis) and hydrogen2power (CCGT-H_2); for details, see Appendix C, Table 42);
- In general, the changes in installed capacities of the technologies mentioned above are in line with the changes in the energy balances discussed in the previous two sections, in particular with the changes in electricity/hydrogen demand and the resulting, required changes in electricity/hydrogen supply given the (maximum) capacities set exogenously by OPERA (see Appendix C, Table 40,Table 41 and Table 42). A notable exception is case 3A (no V2G) where the installed electrolysis capacity is reduced whereas the H_2 production is increases, i.e. the fraction of the utilised electrolysis capacity increases from 49% in the reference case to over 81% in the case of no V2G.



a) For the underlying data, see Table 42 in Appendix C.

Figure 41: OPERA: Installed capacity of energy technologies– comparison of NM2050 reference scenario and sensitivity cases

4.2.4 Storage results

Based on the changes in the energy balances and installed capacities discussed in the previous sections, Figure 42 and Figure 43 present the energy storage results of the sensitivity cases versus the reference scenario of NM2050 for the main electricity and hydrogen storage options identified by OPERA, while Table 29 and Table 30 provide the specific, underlying data of these results. The major observations regarding these storage results include:

- The storage *size* of EV batteries remains similar over all cases. This is not surprising as the number of EVs is similar across all cases (about 9.7 mln), while the storage size per EV is assumed outside the model (at 100 kWh);
- The exclusion of V2G (3A) significantly deceases the electricity storage *volume* (and consequently FCE) but introduces the need for VR batteries. These partly replace the V2G function of the electric vehicles, but not completely. This leads to several minor shifts in electricity demand for EV, but also for P2L and boilers. The VR batteries are typically used for medium-term storage, i.e. in the order of one week. In section 4.1.5 a high discharging power was found for EV batteries with V2G functionality (57 GW). The discharging and charging power capacity of VR in case 3A was 15.8 and 4.2 GW, respectively. The reduced discharging power induces shifts in electricity use described in section 4.2.1. As pointed out before, the (dis)charging time of VR batteries was assumed fixed in this study.
- The storage *volume* of EV batteries is significantly higher in cases 1A (no power trade) and 4A (allow biomass imports). The reason is that in case 1A the nullification of cross-border power trade leads to a higher volatility of domestic electricity prices. This provides an incentive for more demand response by EV batteries – notably for V2G transactions – and, therefore, a higher volume of storage transactions (and hence FCE). In case 4A (allow biomass imports) the domestic demand/supply of hydrogen is replaced by biomass imports. As a result, there is less demand response by $P2H_2$, which leads to a higher volatility of domestic electricity prices and, consequently, more demand response by EV batteries. Actually, in case 4A the demand response by $P2H_2$ is, to some extent, replaced by the demand response by P2Mobility (EV batteries). These are also cases where VRB plays a small, additional role. Also, reduction of VRB cost increases their role (case 2A);
- In all cases the largest volumes of H_2 are stored underground with some substantial and striking differences in storage volume. Interestingly, an increase in volume does not always correlate with an increase in size, i.e. there is also a variation in FCE;
- The storage size and volume of H_2 filling stations is relatively small but rather stable across all cases considered whereas the storage size and volume of H_2 vehicles is slightly bigger and a bit more volatile across all cases;
- Without cross-border power trade (case 1A) there is a higher volatility of domestic electricity prices. This is an incentive to increase the (short-term) flexibility of hydrogen production, which – in turn – increases the need for short-term H_2 storage transactions. As a result, the storages volumes and, notably, the FCEs (‘volatility’) of the storage options involved – in particular H_2 underground – increase;

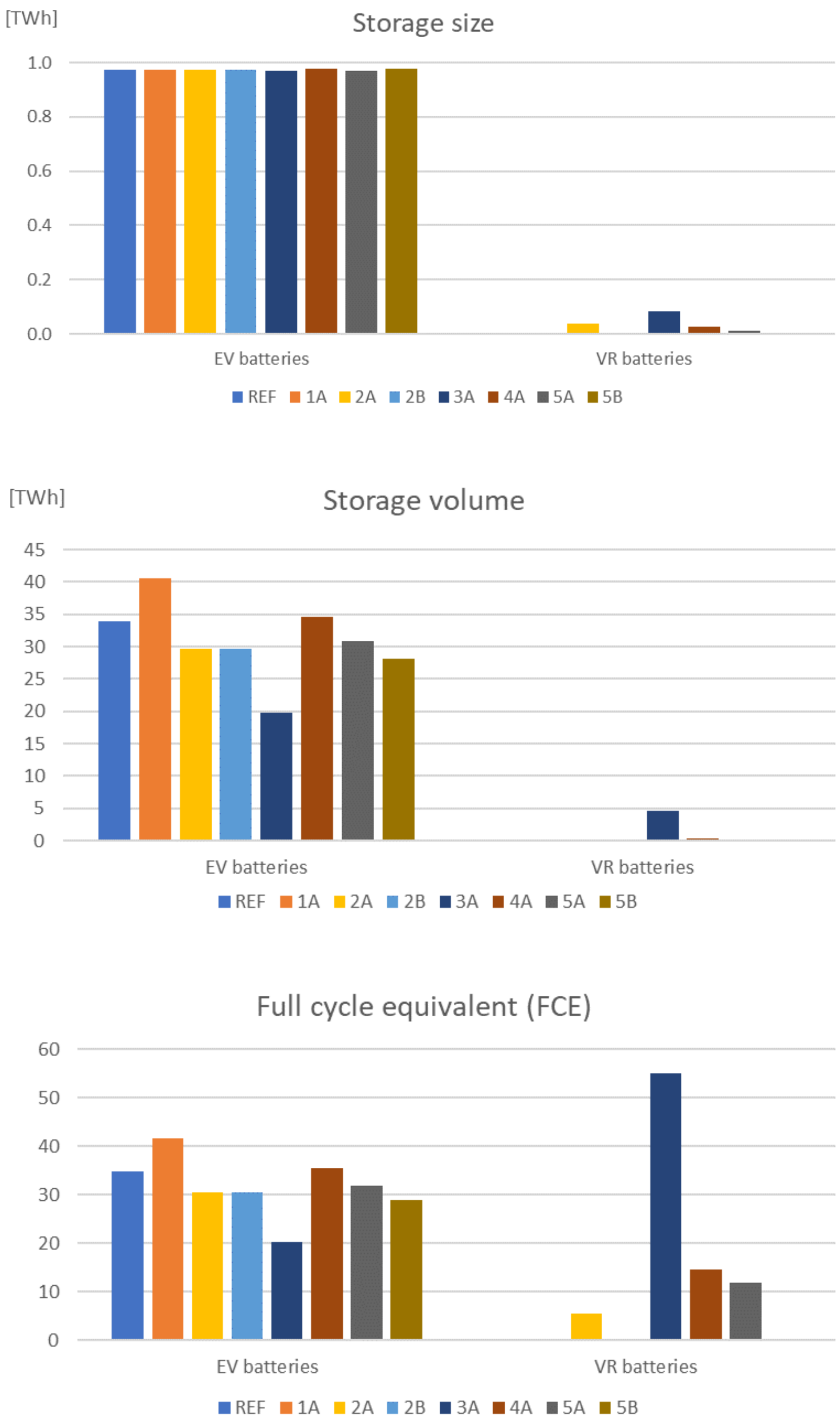


Figure 42: OPERA: Electricity storage results – Comparison of NM2050 reference scenario and sensitivity cases

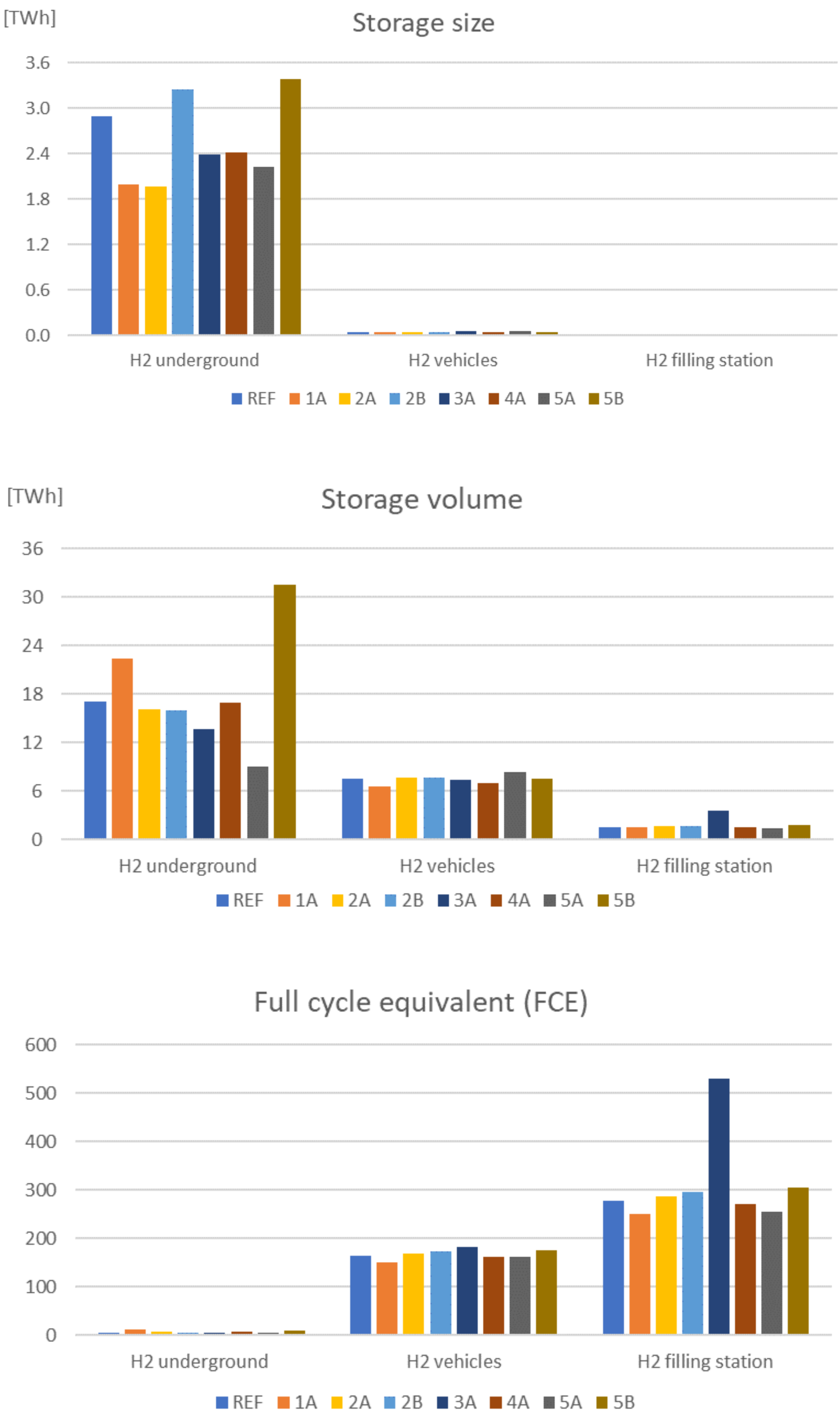


Figure 43: OPERA: Hydrogen storage results – Comparison of NM2050 reference scenario and sensitivity cases

Table 29: OPERA: Electricity storage results – Comparison of NM2050 reference scenario and sensitivity cases

Storage option/ parameter	**Unit**	**REF**	Sensitivity cases						
			1A	2A	2B	3A	4A	5A	5B
EV batteries									
Size	GWh	975	976	975	975	969	976	972	976
Volume	GWh	29971	40604	29610	29660	19854	34588	30853	28211
FCE	#	31	42	30	30	20	35	32	29
VR batteries									
Size	GWh			38		83	26	11	
Volume	GWh			212		4533	374	133	
FCE	#			6		55	15	12	

- Only in the case without V2G (3A) a significant increase of H_2 storage in vehicles and transport is found, because of the slightly higher share of H_2 fuelled vehicles. This results in a reduction of underground storage;
- As may be expected, allowing H_2 trade has a large effect on H_2 storage. When H_2 prices are low (5A), large H_2 imports and the resulting lower domestic supply of hydrogen result in a lower domestic H_2 underground storage size and volume is due, while in case 5B (high H_2 price) the opposite applies.
- Reduction of cost of H_2 storage has a minor effect only on H_2 storage (case 2A);

Table 30: OPERA: Hydrogen storage results – Comparison of NM2050 reference scenario and sensitivity cases

Storage option/ parameter	**Unit**	**REF**	Sensitivity cases						
			1A	2A	2B	3A	4A	5A	5B
H_2 underground									
Size	GWh	2893	1991	1963	3251	2382	2423	2229	3381
Volume	GWh	17126	22347	16094	15986	13611	16860	9049	31503
FCE	#	6	11	8	5	6	7	4	9
H_2 vehicles									
Size	GWh	46.0	43.7	44.9	44.2	57.6	42.9	51.9	43.0
Volume	GWh	7539	6515	7585	7617	10551	6991	8346	7576
FCE	#	164	149	169	172	183	163	161	176
H_2 filling stations									
Size	GWh	5.4	5.9	5.6	5.5	6.7	5.4	5.6	5.6
Volume	GWh	1508	1482	1613	1638	3537	1455	1411	1724
FCE	#	277	251	287	297	530	272	254	305

4.2.5 Conclusions

- Omitting the largest flexibility option deployed in the reference case, i.e. cross border trade of electricity, does not lead to large changes in the electricity and hydrogen balances, apart from the avoided electricity production used to meet the export need. On the other hand, the stored volumes of hydrogen and, specifically, electricity increase substantially. Remarkably, at the same time the

size of the storage medium does not increase (electricity) or even decreases (hydrogen), i.e. there is an increase in charge/discharge cycles;
- When V2G, the other large flexibility option, is excluded, the electricity balance increases by 11 TWh due to a slightly larger amount of hydrogen that is produced to meet flexibility requirements. The storage requirements for hydrogen are reduced, both in size and volume. The main cause is that the electrolysis production is now at 81% of the maximum annual capacity versus 49% in the reference case. The stored volume of electricity is also reduced, with VR batteries providing flexible storage with about 55 charge/discharge cycles per year;
- Allowing up to 200 PJ of biomass to be imported reduces, as expected, the electricity balance and, even more, the hydrogen balance, but does not lead to reductions in electricity or hydrogen storage requirements;
- Size and volume of storage are quite insensitive to cost reductions of storage technologies of 50%;
- Allowing H_2 trade across the border can substantially change the production, storage size, and storage volume, depending on the price set for H_2.

5 Comparison and discussion of modelling results

This chapter compares the study results for energy storage obtained by OPERA and COMPETES and discusses the link between these results and the major modelling inputs and outputs of these models. Furthermore, for NM2050 we also include inputs and outputs from the Energy Transition Model (ETM) used to analyse the NM2050 scenario developed by Berenschot and Kalavasta (2020). The chapter ends with a reflection on the storage modelling results in order to put these results in an appropriate perspective.

5.1 Storage results for CA2030

5.1.1 Comparison of electricity storage results

Table 31 presents a summary of the electricity storage results by OPERA and COMPETES in CA2030. It shows that in both models –particularly in COMPETES – storage by means of EV batteries is the main electricity storage option in CA2030. The total storage size of all EV batteries, however, is about 50% higher in OPERA than in COMPETES, i.e. 45 GWh vs 31 GWh, respectively. As the (assumed) average battery size per EV is similar in both models (75 kWh), this difference in total EV storage size is solely due to the total number of EVs operating in these models, i.e. about 0.6 million in OPERA and approximately 0.4 million in COMPETES.

In Table 31, the annual volume of electricity stored by EV batteries looks quite similar in OPERA and COMPETES – i.e. 1500 GWh and 1450 GWh, respectively – but actually these figures hide some major differences. In OPERA, storage volume of EV batteries in CA2030 refers only to *net* EV battery storage, i.e. gross battery charges (during a certain hour) for EV driving *minus* electricity used 'instantaneously' by EV driving (i.e., during the same hour), while – at least in CA2030 – EV charges for V2G transactions are not included in the model. In COMPETES, on the other hand, storage volume of EV batteries refers to both (i) gross hourly battery charges for EV driving, and (ii) EV battery charges for V2G transactions. Out of the total annual storage volume of 1450 GWh in COMPETES, about 1253 GWh is used for EV driving (including storage losses) while 197 GWh is fed back to the grid (G2V).

The above-mentioned differences in storage volumes between OPERA and COMPETES explain largely the differences in the full cycle equivalent (FCE) of EV batteries between these models, i.e. 24 and 48, respectively. Correcting for these differences would increase the storage volume in OPERA and/or decrease the storage volume in COMPETES, thereby reducing the difference in FCE between these models – or making them even largely similar (see also Section 5.2.2 below).

In CA2030, electricity storage in COMPETES is dominated by EV batteries, while there is only a tiny role for stationary Li-ion batteries and no role for other batteries or large-scale storage technologies such as (AA)-CAES. In OPERA, however, there is a significant role for other batteries in CA2030, notably for stationary Vanadium Redox (VR) batteries as a flexibility option to balance the power system. This role of VR batteries – or difference between OPERA and COMPETES – is explained by the dual fact that in CA2030 OPERA (i) does not include V2G transactions as a flexibility option, and (ii) hardly relies on flexible power-to-hydrogen production and H_2 storage as an alternative flexibility option to the power system (see next section below).

Table 31: OPERA vs COMPETES: Comparison of electricity storage results in CA2030

EV batteries	**Size**	**Volume**	**FCE[a]**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	45	1500[b]	24	10.1	0.5[c]
COMPETES	31	1450[d]	48	1.5	1.5
Other E-storage	**Size**	**Volume**	**FCE**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA[e]	26.39	446	17	1.4	5.0
COMPETES[f]	0.04	3	85	0.04	0.04
Total E-storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*	*#*	*%*	*%*
OPERA	64	1946	30	0.05%	1.4%
COMPETES	31	1461	48	0.02%	1.1%

a) FCE is Full Cycle Equivalent, i.e. the ratio between the annual volume stored and the size of the storage medium;
b) In CA2030, storage volume in OPERA refers only to net EV battery storage, i.e. gross battery charges (during a certain hour) for EV driving minus electricity used instantaneously by EV driving (during that same hour), while excluding EV charges for V2G transactions;
c) Discharge is to vehicles only and not back to the grid (V2G);
d) EV battery storage in COMPETES refers to (i) gross battery charges for EV driving, and (ii) EV battery charges for V2G transactions. Out of 1450 GWh total storage volume, 1253 GWh is used for EV driving (including storage losses), while 197 GWh is fed back to the grid (V2G);
e) Mainly stationary Vanadium Redox (VR) batteries;
f) Only stationary Li-ion batteries.

5.1.2 Comparison of hydrogen storage results

Table 32 presents a comparative summary of the main hydrogen storage results by OPERA and COMPETES in CA2030. Although overall the need for hydrogen storage is still relatively modest in CA2030 – and largely similar in both models – Table 32 shows some interesting differences in modelling results across the various H_2 storage options between OPERA and COMPETES. For instance, the need for underground hydrogen storage (UHS) is substantially higher in COMPETES than in OPERA. More specifically, the required size of UHS in CA2030 is estimated at 10 GWh by OPERA and 66 GWh by COMPETES, while the total volume of H_2 to be stored underground on an annual basis is estimated at 21 GWh and 900 GWh, respectively, resulting in a full cycle equivalent (FCE) of underground H_2 storage of 2 and 14, respectively.

The differences in H_2 storage results in CA2030 are due to a mix of differences in modelling characteristics and scenario assumptions between OPERA and COMPETES, resulting in a different role for hydrogen (storage) in CA2030 between these models.

Firstly, following the ambitions of the Climate Agreement of June 2019, a modest additional 2 GW of electrolysis capacity has been assumed in both models. COMPETES assumes a correspondingly (policy-supported) high demand for H_2 from domestic electrolysis of 24 PJ (6.7 TWh) whereas OPERA determines endogenously that the (market-based) demand for H_2 in CA2030 is much lower (6.7 PJ) and is predominantly met by hydrogen produced from natural gas by means of Steam

Methane Reforming (SMR, without CCS).[44] Hydrogen supply from electrolysis (P2H_2), however, is highly variable as it is highly responsive to fluctuations in electricity prices – resulting in a relatively higher need for (short-term) H_2 storage – while SMR is hardly or not responsive to fluctuations in electricity prices and, hence, requires less H_2 storage.[45] This indicates that the need for H_2 storage in CA2030 depends on the policy support of H_2 demand from electrolysis.

Secondly, COMPETES does not differentiate total H2 demand into specific use functions or categories – e.g., heating by industries – and assumes that the hourly profile of total hydrogen demand is completely flat. OPERA, on the other hand, differentiates total H2 demand into some specific use functions in different sectors, which each having its own specific demand profile, varying from completely flat to highly variable (in the short run) with or without a clear seasonal pattern. As a result, the total (aggregated) H_2 demand profile in OPERA has a rather mixed character.

Finally, COMPETES includes only one hydrogen storage option (i.e., underground storage), whereas OPERA models also a variety of other options, including storage by H_2 vehicles, filling stations and vessels. Hence, in COMPETES the H_2 storage need in CA2030 is covered only by underground storage, whereas in OPERA it is met by a variety of H_2 storage options, depending on the techno-economic characteristics of these options to meet the balance in variations of H_2 demand and supply for specific use functions.

Table 32: OPERA vs COMPETES: Comparison of hydrogen storage results in CA2030

H_2 Underground	**Size**	**Volume**	**FCE**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	10	21	2	0.01	1.3
COMPETES	66	900	14	0.16	0.77
Other H_2 storage	**Size**	**Volume**	**FCE**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA[a]	32	1135	36	1.3	10.8
COMPETES	n.a.	n.a.	n.a.	n.a.	n.a.
Total H_2 storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*	*#*	*%*	*%*
OPERA	42	1157	28	2.3%	62.2%
COMPETES	66	900	14	1.0%	13.4%

a) Hydrogen storage in H2 vehicles, filling stations and vessels;

[44] Note, that in OPERA the H_2 demand of 6.7 PJ is new demand for mobility (high-duty vehicles) and for heating in the built environment, which is on top of 162 PJ of H_2 demand that is part of conventional industrial processes such as oil-refining and ammonia production. This conventional (internal) industrial demand and supply of hydrogen has not been included in the energy balance and storage assessment of the current study.

[45] Moreover, as H_2 production is predominantly met by SMR, it means that the energy storage requirement is moved from H_2 to the SMR feedstock, i.e. natural gas.

Actually, in CA2030 the role of the other H_2 storage options in OPERA is much larger than the role of H_2 underground storage. While the size and annual volume of H_2 underground storage in OPERA amount to 10 GWh and 21 GWh in CA2030, respectively, for the other H_2 storage options – notably H_2 vehicles and filling stations – they amount to 32 GWh and 1135 GWh, respectively (Table 32).

As there are no other H_2 storage options in COMPETES, the differences in H_2 storage results between OPERA and COMPETES in CA2030 are smaller in terms of total H_2 storage than of H_2 underground storage alone. Actually, in CA2030 the annual volume of H_2 underground storage is about 45 times larger in COMPETES than in OPERA (i.e. 900 GWh vs 21 GWh) while the volume of all H_2 storage options is approximately 22% smaller (i.e. 900 GWh vs 1157 GWh, respectively; see Table 32).

In CA2030, demand and supply of hydrogen in OPERA are, as said, relatively low, while it is largely stored in H_2 vehicles and H_2 filling stations for transport purposes and, to some extent, in vessels for other end functions, e.g. meeting seasonal (peak) demands in space heating by H_2 boilers in the services sector. In COMPETES, on the other hand, demand and supply of hydrogen in CA2030 are relatively much higher (compared to OPERA), while it is used for – but stored relatively less – for a variety of (unspecified) end functions. As a result, in CA2030 the total annual volume of H_2 storage as a % of total H_2 demand is rather high in OPERA (62%) while it is substantially lower in COMPETES (13%; see Table 32).

5.2 Storage results for NM2050

5.2.1 Comparison of major model inputs and outputs in NM2050

Before comparing the storage results of OPERA and COMPETES for NM2050, we will first compare the major inputs and outputs of these models. Table 33 presents a comparison of the major modelling inputs and outputs of the reference scenario NM2050 analysed in the current study by means of OPERA and COMPETES as well as of the NM2050 scenario developed by Berenschot and Kalavasta (2020) and analysed by the ETM model (see Chapter 2, notably Sections 2.2. and 2.3). The latter are included in the last column of Table 33, designated as ETM/BK.

As far as possible, COMPETES has used the same NM2050 parameters as ETM/BK. This applies in particular for the parameters on the installed capacities of VRE power generation, but not for the installed capacities of Power2Hydrogen and Hydrogen2Power, as these are determined endogenously by COMPETES. Therefore, it does also not apply for the electricity and hydrogen demand by these technologies. Consequently, there may be significant differences in total electricity and hydrogen demand between COMPETES and ETM/BK.

In addition, there may be differences between COMPETES and ETM/BK regarding the full load hours of VRE technologies, their hourly profiles and techno-economic characteristics or the output curtailment of these technologies. More specifically, the ETM/BK model assumed 3000 and 4500 full load hours for wind onshore and offshore, respectively, much lower than assumed by COMPETES (i.e., 3846 and 5411 hours, respectively). Moreover, there is a difference in modelling approach, i.e. COMPETES is an (European electricity market) optimisation model whereas ETM is a (national integrated energy system) simulation model. So, there may be significant differences in modelling inputs and outputs between COMPETES and ETM/BK.

Table 33: Comparison of modelling inputs and outputs of the reference scenario NM2050

	Unit	OPERA	COMPETES	ETM/BK[a]
Installed capacities				
Solar PV	GWe	54.2	106.0	106.0
Offshore wind	GWe	57.8	51.5	51.5
Onshore wind	GWe	20.0	20.0	20.0
Hydrogen2Power	GWe	9.1	0.0	39.0
Power2Hydrogen	GWe	31.5	19.3	45.0
Energy balances				
Total domestic H_2 demand/supply	TWh	91.5	76.6	93.1
Total domestic electricity demand	*TWh*	*396.9*	*345.7*	*406.0*
Power supply:				
Solar PV	TWh	50.0	98.1	93.0
Offshore wind	TWh	302.5	205.9	232.0
Onshore wind	TWh	76.4	76.7	60.0
Hydrogen2Power	TWh	0.8	0.0	11.0
Other/conventional	TWh	10.0	7.8	3.0
Total domestic production	*TWh*	*437.7*	*388.5*	*399.0*
Net electricity export	TWh	42.8	42.8	--0.4
Total domestic electricity supply	*TWh*	*396.9*	*345.7*	*406.0*
VRE curtailment				
Solar PV	TWh	0.0	0.0	n.a.[b]
Offshore wind	TWh	10.3	72.8	n.a.
Onshore wind	TWh	0.5	0.2	n.a.
VRE curtailment as a % of total VRE production				
Solar PV	%	0.1%	0.0%	3%
Offshore wind	%	3.3%	26.1%	
Onshore wind	%	0.7%	0.3%	
Energy storage volume				
Total electricity storage volume	TWh	30.0	33.0	17.2[c]
Total hydrogen storage volume	TWh	26.2	21.7	57.1[d]
Energy storage as % of total demand				
Electricity storage	%	7.6	9.6	4.2%
Hydrogen storage	%	28.6	28.7	17.2%

a) ETM inputs and outputs for NM2050 as developed by Berenschot and Kalavasta (2020);
b) n.a. = not available;
c) The ETM website reports 61.71 PJ EV battery storage (ETM, 2020);
d) Data from the ETM website. The storage size is 16 TWh (ETM,2020).

Box 1: Simulation and optimisation models

An integrated energy system model may follow (i) an optimisation approach, in which the primary aim is to determine economically optimal investment decisions endogenously, or (ii) a simulation approach, in which the decisions on system configuration are taken exogenously (Lund et al., 2017). The main difference between the two methodologies is that the optimisation model 'endogenously' provides an optimal state of the energy system – in terms of minimizing costs or maximizing (social) returns (welfare) – within certain technical, socioeconomic or policy constraints, while the simulation model takes the state of the energy system exogenously from the user in order to 'calculate' the energy balance.

From a computational perspective, optimisation models (e.g. OPERA) are usually heavier because the model has to determine all endogenous decision variables, while, simulation models (e.g. ETM) do not require notable computational capacity as the decision variables are determined by the user and the model just calculates the energy balance. In this regard, these simulation models are sometimes called 'energy calculators' (Fattahi et al., 2020; Pfenniger et al., 2014).

Simulation models are well-suited to investigate the effect of short-term changes to the system, such as the implementation of a specific technology, or to carry out what-if analyses. At given conditions (input data), results of a simulation model are, e.g., total energy use, total GHG emissions or total energy system costs. In particular, simulation models can in detail describe the dynamics of the system, and some allow a stochastic approach.

Optimisation models are usually preferred for making long-term strategic choices, notably on investments in energy technologies and infrastructure at minimum total system costs. Sensitivity or what-if analyses can be made by modifying the model constraints or input parameters. For energy system modelling, the recent trend has been towards a larger share of optimisation models (Hall et al., 2016; Lopion et al., 2016).

COMPETES and OPERA are optimisation models, whereas ETM is a simulation model. Berenschot and Kalavasta (2020) use ETM to describe the operation of the energy system in four different scenarios. COMPETES and OPERA base their model constraints and input parameters on one these scenarios (NM2050), notably that energy demand, and in the case of COMPETES also the installed VRE capacities, are in line with that scenario. Within this set of constraints and parameters – and with their own modelling approach – COMPETES and OPERA then optimise the mix and deployment of technologies at minimal social cost. The resulting mix may differ from the choices made by Berenschot and Kalavasta (2020) and, hence, for the inputs and outputs of ETM.

The above-mentioned differences between COMPETES and ETM/BK apply also between OPERA and ETM/BK. Although both models are integrated energy system models of the Netherlands, OPERA is an optimisation model (similar to COMPETES) whereas ETM is, as said, a simulation model (see Box 1). While OPERA has set several input parameters in line with the general characteristics and limits of the NM2050 scenario defined and developed by ETM/BK, given its character as an optimisation model several other parameters have been determined endogenously by the model – e.g., some parameters on energy demand or, more specifically, on the installed capacities of offshore wind and solar PV – in order to achieve an energy system outcome that is (more) optimal from a social cost perspective.

Table 33 shows that the installed capacities of the key VRE technologies (solar PV, offshore and onshore wind) in COMPETES have been set exactly in line with ETM/BK. However, due to the higher full load hours of these technologies in COMPETES (compared to ETM/BK) this results in a higher electricity output generation in COMPETES (before any VRE curtailment). Moreover, total domestic electricity demand in NM2050 is significantly lower in COMPETES than in ETM/BK, not only because there turns out to be no need for Hydrogen-to-Power in COMPETES – and, hence, less demand for Power-to-Hydrogen – but also because conventional electricity demand as well as electricity demand for hybrid Power-to-Heat in industry are lower in COMPETES than in ETM/BK. As a result, COMPETES foresees a large number of hours with a (large) VRE surplus in the reference scenario NM2050, resulting in large amounts of VRE curtailment, net electricity exports and demand response (as analysed in Chapter 3).

On the other hand, within the overall characteristics and limits of the NM2050 scenario, OPERA has determined endogenously an installed capacity for offshore wind that is significantly higher than in COMPETES/ETM (about 58 vs 52 GWe) and substantially lower for solar PV (54 vs 106 GWe, respectively). The output of electricity from offshore wind in OPERA is almost 100 TWh higher than in COMPETES and 70 TWh higher than in ETM/BK, while the electricity generation from solar PV is significantly lower by 48 TWh and 43 TWh, respectively.

The installed capacities of Power2Hydrogen have been optimised by OPERA as well as by COMPETES and turn out to be lower than the capacities set by ETM/BK (Table 33). When comparing to the total hydrogen demand/supply, this implies that $P2H_2$ runs at 49% of its maximum capacity in OPERA, at 67% in COMPETES but only at 35% according to ETM/BK. The total hydrogen demand/supply in OPERA is in line with ETM/BK for NM2050 (approximately 92-93 TWh) but it is significantly lower in COMPETES (77 TWh). The lower amount in COMPETES results from a significant lower demand for hydrogen – i.e. zero – to produce power, notably compared to ETM/BK.

The above-mentioned similarity in total hydrogen demand between OPERA and ETM/BK does not imply, however, that H_2 use is the same in these models. Where both models see a high use of hydrogen for synthetic fuels, OPERA foresees a high use by high-duty H_2 vehicles and as well for space heating in the services sector by means of H_2 boilers (Figure 32). ETM/BK deploys hydrogen mostly for heating in industry, to a lesser extent for mobility and, as mentioned, electricity generation. The optimisation by OPERA results in a large share in biomass for heating in industry whereas ETM/BK foresees biomass use particularly in mobility in the form of biofuels.

The total domestic electricity demand in OPERA is also more or less in line with ETM/BK (about 400 TWh) but – as explained above – significantly lower in COMPETES. On the other hand, COMPETES determines, on balance, a significant additional foreign electricity demand (i.e. net power exports) of almost 43 TWh in NM2050, while ETM/BK records net electricity imports of some 7 TWh. As OPERA takes the hourly net export profile of COMPETES as input into the model, the total domestic power production required to meet total domestic electricity demand, including net exports, is substantially higher in OPERA (440 TWh) than in ETM/BK (399 TWh) or in COMPETES (389 TWh).

The overall, relatively large VRE installed capacities and the overall, relatively low total electricity demand – including net exports – in COMPETES result in a relatively large amount of VRE output curtailment in this model. As the operational costs of offshore wind are slightly higher in COMPETES than of onshore wind or solar PV, COMPETES prefers to curtail offshore wind as a first option. Overall, as a result, almost 73 TWh of offshore wind is curtailed in COMPETES in NM2050, i.e. approximately 26% of total (uncurtailed) power output from offshore wind.

Finally, at the bottom lines of Table 33, the outcomes of OPERA and COMPETES regarding energy storage are summarised and, as far as available, compared with energy storage results recorded by ETM/BK. This will be further discussed in sections 5.2.2 and 5.2.3 below.

5.2.2 Comparison of electricity storage results

Table 34 presents a comparative summary of the main electricity storage results of OPERA and COMPETES for the reference scenario of NM2050. Apart from a tiny role for stationary Li-ion batteries in COMPETES, it shows that in both models electricity storage in NM2050 is fully dominated by a single option, i.e. EV battery storage. More specifically, it indicates that the total storage size of all EV batteries in NM2050 is relatively large and more or less similar in both models, i.e. approximately 1 TWh. This total storage size results from the average storage size per EV assumed exactly similar in both models (i.e., 100 kWh in NM2050) while the total number of EVs in NM2050 is more or less similar in these models (i.e., about 10 million EVs).

In addition, Table 34 indicates that the total annual storage volume of all EV batteries in NM2050 is largely similar in both models (30-33 TWh). As mentioned in Section 5.1.1, however, this aggregated figure hides some major differences between OPERA and COMPETES, although – in contrast to CA2030 – in NM2050 OPERA also includes V2G transactions as a flexibility (storage) option, similar to COMPETES. Nevertheless, in NM2050 there are still major differences between OPERA and COMPETES regarding their approach on EV battery storage transactions, notably on V2G transactions as well as regarding the calculation and reporting of gross versus net charging for EV driving. More specifically, COMPETES records *gross* battery charges for EV driving while OPERA records *net* EV battery charges, i.e. *gross* battery charges (during a certain hour) for EV driving minus instantaneous electricity used instantaneously for EV driving (during the same hour). In addition, overall COMPETES is more restrictive regarding V2G transactions than OPERA, resulting in a higher amount of V2G in OPERA than in COMPETES.[46]

For NM2050, Table 34 records a total annual storage volume of EV batteries amounting to approximately 33 TWh in COMPETES and 30 TWh in OPERA. Out of the 33 TWh EV battery storage volume in COMPETES, almost 31.8 TWh refers to gross battery charges for EV driving (including storage losses), while 1.2 TWh is fed back to the grid (V2G). In OPERA, on the other hand, out of 30 TWh EV battery storage volume, approximately 16.7 refers to net battery charges for EV driving (including storage losses), while the amount of V2G transactions is estimated at 13.3 TWh.[47] As noted, the (large) difference is V2G transactions between OPERA and

[46] For further details on the major differences between OPERA and COMPETES regarding their approach on EV battery storage transactions, see Chapter 2, Section 2.4.4.

[47] The gross battery charges for EV driving (including storage losses) in OPERA, however, are largely similar to these charges in COMPETES, i.e. approximately 34 TWh and 32 TWh in NM2050, respectively.

Table 34: OPERA vs COMPETES: Comparison of electricity storage results in NM2050

EV batteries	Size	Volume	FCE	Charge p.	Discharge p.
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	975	29971[a]	31	24.3	57.5
COMPETES	1037	32967[b]	32	38.4	38.4
Other E-storage	**Size**	**Volume**	**FCE**	**Charge p.**	**Discharge p.**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA[c]	n.a.	n.a.	n.a.	n.a.	n.a.
COMPETES[d]	0.05	10.5	210	0.05	0.05
Total E-storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*	*#*	*%*	*%*
OPERA	975	29971	31	0.25%	7.6%
COMPETES	1037	33044	32	0.30%	9.6%

a) In NM2050, storage volume in OPERA refers to both (i) net EV battery storage, i.e. gross battery charges (during a certain hour) for EV driving minus electricity used instantaneously by EV driving (during the same hour), and (ii) EV battery charges for V2G transactions. Out of the net 30 TWh storage volume, 16.7 TWh is used for non-instantaneous EV driving, while 13.3 TWh is fed back to the grid (V2G);
b) EV battery storage in COMPETES refers to (i) gross battery charges for EV driving, and (ii) EV battery charges for V2G transactions. Out of the gross 33 TWh storage volume, 31.8 TWh is used for EV driving, while the remaining 1.2 TWh is fed back to the grid (V2G);
c) n.a. = not applicable (i.e. no other electricity storage options);
d) Only stationary Li-ion batteries.

COMPETES is due to the different modelling assumptions regarding the opportunities and limits of V2G transactions (i.e., more restrictive in COMPETES). This is also shown by the charge and discharge power capacities of both models where OPERA foresees a very high discharge capacity (58 GW), which is somewhat artificial since no explicit discharging cost were assumed. In NM2050, other technologies besides EV batteries hardly play any role in electricity storage. For OPERA this changes when V2G is excluded (in one of the sensitivity cases of NM2050). Excluding V2G transactions results in a partial replacement of these storage transactions by VR batteries, with a more modest discharging power of 16 GW (see section 4.2.4).

The electricity storage results of OPERA and COMPETES for NM2050 do not show deployment of (AA)-CAES. As explained, the absence of explicit cost for V2G makes V2G the cheapest technology for electricity storage. When V2G is excluded, stationary VRB is the option preferred by OPERA, when using the techno-economic parameters of Table 38. However, these parameters include for both (AA)-CAES and Vanadium Redox (VR) batteries fixed charging and discharging times, which makes the (dis-)charge power directly proportional to the electricity storage size. In practice, for large scale technologies such as (AA)-CAES and VRB this so-called power-to-electricity ratio can be optimised for the energy system in which they operate. Including this optimisation (with explicit costs for charging, discharging and storage medium) into OPERA and COMPETES may result in a larger deployment of CAES. The present data assume a longer discharge time for CAES than for VRB, i.e. a lower power to electricity ratio whereas the energy system seems to favour high (discharge) power to electricity ratios, as shown by the high discharge powers found for the V2G discharge (Table 34).[48]

[48] Note that for hydrogen storage separate optimisation of (dis)-charge power and storage size of each storage option was already implemented.

The ETM/BK study is not very explicit on electrochemical storage. The report by Berenschot & Kalavasta (2020) mentions 17 GW battery discharge power in NM2050 and 62 PJ (17 TWh) total storage in EV. These numbers are not very dissimilar to what OPERA calculates in the case without V2G (Section 4.2.4).

Overall, according to Table 34, in both OPERA and COMPETES electricity storage represents more than 50% of the total energy storage (i.e. including both electricity and hydrogen storage). The finding that electricity storage, characterized by daily-weekly charges and discharges is a major storage option in 2050 is also corroborated by a recent study by DNV GL (2020), called '*The promise of seasonal storage*'.

5.2.3 Comparison of hydrogen storage results

Table 35 presents a comparative summary of the main hydrogen storage results of OPERA and COMPETES in NM2050. In both models, underground storage is the main H_2 storage option in NM2050. The size of H_2 underground storage in NM2050, however, is substantially higher in OPERA than in COMPETES (about 2.9 TWh vs 1.5 TWh), whereas the annual volume of H_2 underground storage is significantly lower (about 17 TWh vs 22 TWh, respectively), resulting in a much higher FCE of H_2 underground storage in COMPETES (14) than in OPERA (6).

The main reason for the above-mentioned differences in model outcomes regarding H_2 underground storage in NM2050 is that in COMPETES hydrogen supply is highly responsive to short-term fluctuations in electricity prices, while the H_2 demand profile is assumed to be completely flat. Consequently, there is a high need for short-term H_2 storage transactions to balance supply and demand on a short-term (daily) basis. In OPERA, H_2 demand and supply profiles are more differentiated and more complex. As a result, the H_2 storage profile is also more differentiated and complex, expressing the need for not just daily but also longer-term storage e.g. to meet intra- and inter-seasonal heat demand in the services sector by means of H_2 boilers.

Table 35: OPERA vs COMPETES: Comparison of hydrogen storage results in NM2050

H_2 Underground	**Size**	**Volume**	**FCE**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA	2893	17126	6	13.2	21.2
COMPETES	1536	21697	14	4.5	8.6
Other H_2 storage	**Size**	**Volume**	**FCE**	**Charge power**	**Discharge power**
	GWh	*GWh*	*#*	*GW*	*GW*
OPERA[a]	51	9047	176	10.8	11.7
COMPETES[b]	n.a.	n.a.	n.a.	n.a.	n.a.
Total H_2 storage	**Size**	**Volume**	**FCE**	**Size/ Demand**	**Volume/ Demand**
	GWh	*GWh*	*#*	*%*	*%*
OPERA	2944	26172	9	3.2%	28.6%
COMPETES	1536	21697	14	2.0%	28.7%

a) Hydrogen storage by H_2 vehicles and filling stations;

b) n.a. = not applicable (i.e. no other H_2 storage options).

While the role of other H_2 storage options in NM2050 – notably H_2 vehicles and filling station – is not included in COMPETES, it is substantial in OPERA in absolute terms (9 TWh) although – compared to CA2030 or to H_2 underground storage in NM2050 – it is less significant in relative terms. Nevertheless, due to the volume of these other H_2 storage options, the total volume of all H_2 storage options in NM2050 is significantly higher in OPERA than in COMPETES. As total H_2 demand in NM2050, however, is also comparatively higher in OPERA than in COMPETES, the total annual volume of H_2 storage as a % of total H_2 demand in NM2050 is more or less similar in both models, i.e. 28.6% and 28.7%, respectively (Table 35).

The ETM/BK study foresees a H_2 storage need of 57.1 TWh (total annual volume of H_2 stored) with a storage size of 16 TWh which is higher than values found in the present study using the models OPERA and COMPETES. A detailed comparison with the ETM is beyond the scope of this project, but analysis has indicated that a different wind energy supply profile (year 2015 for ETM vs. year 2012 for OPERA & COMPETES) and the different composition of the hydrogen demand can account for the difference. In OPERA, hydrogen-fired boilers are used to fulfil the (additional) heat demand (space heating) of the built environment in winter, and this hydrogen is produced through electrolysis with surplus electricity from wind during the same period. Together with flexible synfuel production this improves the match between H_2 demand and supply, leading to a low(er) volume of underground H_2 storage, i.e., 19% of the annual production. In the ETM, combined cycle gas turbine (CCGT) power plants are deployed to provide electricity at periods of VRE shortage. This means H_2 demand and production are out of phase, leading to a high volume of H_2 storage, i.e. 57% of the annual production. Based on available data it is not possible to say if this CCGT deployment, which is minimal in OPERA and absent in COMPETES, is enforced by the ETM electricity supply profile only, or also by limitations of flexibility (other than H_2 production) in the ETM. In all models the stored volume is larger than the storage size, i.e. the H_2 underground storage has a more short-term character rather than strictly seasonal. This results in a full cycle equivalent of 3.6 in the ETM model, about 6 in OPERA and even of 14 in COMPETES (Table 35).[49]

5.3 Reflection on the energy storage modelling results

The presented study is one of the first to use an (integrated) energy system optimization modelling approach with a time resolution of one hour to analyse the future role of energy storage in a more climate-neutral Dutch energy system. We have used two well-established optimization models for this purpose, i.e. OPERA and COMPETES, that are designed to meet energy demand and related policy targets – such as reducing GHG emissions – in a cost-optimal way, i.e., at the lowest social cost, making use of hourly energy demand, supply and storage profiles. Both models have their own specific characteristics, underlying input assumptions and limitations, and had to be further developed and updated for the purpose of this study. Although the study offers some interesting (new) insights – notably on energy storage – it also has its limitations which indicate the need for further research on the role of energy storage in the future, more climate-neutral energy system in the Netherlands.

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[49] The need for shorter term energy storage in future, more climate-neutral energy systems is corroborated in the recent study 'The promise of seasonal storage' (DNV GL), which also indicates that the increasing penetration of VRE technologies will lead to shorter effective storage times.

The major advantage of optimisation models such as OPERA or COMPETES is that they generate quantitative results on the mix of investments in energy technologies and the allocation of deployment of these technologies in order to achieve energy demand and related policy targets at the lowest social costs. As such, they offer insights to policy makers and other energy system stakeholders (industries, households, system operators, etc.) regarding decision-making on energy investments and allocating scarce energy (technology) resources in a social cost-effective way.
On the other hand, the current versions of OPERA and COMPETES are based, among others, on the assumption of perfect foresight and, hence, they do not consider uncertainties or risks regarding, for instance, capacity investments or security of energy supply. In addition, these models do hardly or not address other social or behavioural issues such as the social acceptance of energy technology innovations (although, to some extent, these issues are or could be included in the models). Simulation models such as the Energy Transition Model (ETM), however, may be better able to address these issues – for instance, by assuming/simulating the (large-scale) deployment of energy storage or back-up 'green' power generation technologies to safeguard domestic security of energy supply – although these models tend to ignore the optimal social costs of such a deployment (see Box 1).

In the current study, the analyses by OPERA and COMPETES are primarily focused on the supply of flexibility options – including energy storage – due to the variability of the residual power load (defined as total electricity demand minus electricity supply from VRE sources). This implies that the study does not consider the need for flexibility options (such as electricity storage) due to either the uncertainty ('forecast error') of the residual load – resulting in the need for flexibility on intraday/reserve markets – or the local congestion (overloading) of the electricity distribution network (resulting in local congestion and flexibility markets to deal with these grid overloads). In addition, it does not include the need for electricity storage (or alternative options) to address other power system issues such as inertia, black starts or frequency control. Although the day-ahead or spot market is by far the most important market (in terms of power and trade volumes), the other markets (intraday, reserve) or system functions may offer interesting revenue streams for some types of electricity storage such as (AA)-CAES.

Moreover, the model analyses in the current study are focussed solely on the flexibility (storage) needs during a typical ('normal') weather year and do not consider these needs during more extreme weather years. In addition, the present study does not analyse energy storage needs due to political-strategic considerations, for instance to reduce uncertainties and risks of relying on energy imports to ensure security of energy supply. Finally, the model analyses in the present study are focussed on the role of electricity and hydrogen storage but do not include or consider other means of energy storage such as heat storage in industries, households and district heating systems.

A major basic finding in the current study is that the variability of the residual power load in CA2030 and NM2050 is primarily characterised by large short-term fluctuations (hourly, daily) but hardly or not by a clear long-term (seasonal) pattern. In our models, notably in COMPETES, these short-term fluctuations are met by relatively cheap, short-term flexibility options such as cross-border electricity trade and demand response (i.e. shifting electricity demand from hours with high to low electricity prices). Consequently, the volatility (margin) of electricity prices is reduced substantially and there is less room – or further need – for more expensive flexibility options such as carbon-free (e.g., 'green hydrogen') back-up power generation installations – which run only for a limited amount of hours per year – or single-purpose, large-scale (seasonal) storage of electricity.

Some specific findings of the current study concern the role of EV battery storage in the future energy system of the Netherlands. In 2030, this role is most likely still limited – as the expected number of electric vehicles (EVs) is still limited – but by 2050 EV battery storage can play a dominant role in energy storage. Assuming an average battery size of 100 kWh per EV, the expected number of 10 million EVs in 2050 offers a large-scale – and relatively cheap – potential for energy storage (and demand response), as indicated in the present study.

According to both OPERA and COMPETES, in the reference scenario NM2050 EV battery storage accounts for more than 50% of the total annually stored energy volume (and even up to 100% of the electrochemical storage volume). Depending on the specific modelling assumptions and restrictions, the main part of this storage is used for EV driving ('mobility') purposes while the other part is used for flexibility purposes – i.e., to balance the power system – by means of V2G storage transactions (i.e., by feeding EV battery charges back to the grid). Including the option of V2G may even avoid the need for other electrochemical storage technologies, while excluding – or limiting – this option enhances the need for other flexibility options such as storage by means of stationary VR batteries.
It has to be noted, however, that – due to a lack of data – the current study does not sufficiently take into account all costs and possible limitations of EV battery storage transactions, such as the costs of the EV (dis)charging infrastructure or the preferences of EV owners regarding minimum/maximum levels of EV battery charges and V2G discharges. In addition, little is still known about how many EVs in future years (2030, 2050) will or can be actually connected to the grid for how many hours (during which parts of the day) in order to enable these EVs to deliver flexibility services to the power system such as (G2V) demand response or (V2G) storage transactions. Therefore, our current results on these services may be too optimistic and, hence, call for further research on the potential and optimal deployment of EV battery storage.
Other major findings of the current study refer to large-scale hydrogen storage, notably underground storage in caverns or depleted gas fields. In CA2030, the need for H_2 underground storage is still limited, but varies heavily between our models, depending on the (assumed) policy support for hydrogen electrolysis (as $P2H_2$ is quite responsive to fluctuating electricity prices and, hence, requires quite some H_2 storage).

In NM2050, on the other hand, our models results show a clear, significant role for large-scale H_2 underground storage, notably in annual volume terms (17-22 TWh). This type of energy storage, however, is not typical seasonal storage – such as the current storage of natural gas for space heating – which has effectively one charge/discharge cycle per year. For the reference scenario NM2050, our models find full cycle equivalents (FCEs) of H_2 underground storage ranging from 6 to 14. This number of full charge/discharge cycles is firstly the result of the large, short-term variability of the residual power load – notably of VRE supply – without a clear seasonal pattern. As noted, this leads to heavy short-term fluctuations of electricity prices and, subsequently to short-term fluctuations in H_2 supply from electrolysis (P2H_2) and, therefore, to a need for short-term H_2 storage (and, hence, to a higher FCE of H_2 storage). In addition, the FCE of H_2 storage depends also on the seasonality (and variability) of H_2 demand, with generally a lower FCE in case of a stronger seasonal pattern of H_2 demand. Whereas in COMPETES the H_2 demand profile in NM2050 is assumed to be flat, in OPERA the demand for hydrogen has a limited seasonal pattern largely because the heat demand in NM2050 – already reduced significantly compared to 2020 due to better insulation of buildings – is also met by other energy sources besides hydrogen, such as electricity or geothermal and ambient heat.

As a result of differences in the factors mentioned above (i.e., the seasonality and short-term variability of H_2 demand and supply), the FCE of H_2 storage is higher in COMPETES (14) than in OPERA (6), i.e. the full cycle of H_2 charges/discharges is, on average, shorter in COMPETES (3-4 weeks) than in OPERA (2 months). Consequently, although the volume of H_2 underground storage in NM2050 is substantial according to our models (17-22 TWh, i.e. 20-30% of total H_2 demand), due to the higher FCE – or shorter term cycle – of H_2 underground storage (6-14), the required size of this storage medium is much smaller (1.5-2.9 TWh, i.e. 2-3% of total H_2 demand). This appearance of short-term energy storage needs – and the disappearance of a clear seasonal pattern – is also observed in the recent report by DNV GL (2020): "*The promise of seasonal storage"*.

Although the model optimization findings mentioned above provide some interesting insights and relevant directions towards a future, climate-neutral and cost-effective energy system, some major qualifications, however, can be added to these findings.

Firstly, in order to realise the estimated, full potential of flexibility by means of cross-border electricity trade substantial investments have to be made in expanding current transmission and interconnections capacities across European countries in general and between the Netherlands and its surrounding countries in particular. Although our European electricity market model COMPETES includes the (investment) costs of power transmission lines and interconnection transformers between European countries, it does not consider social acceptance or other complicated, long-lasting implementation issues regarding these investments. In addition, although COMPETES optimises hourly power supply across European countries in a 'normal' weather year – including the use of (pumped hydro) storage and acknowledging the correlation of VRE supply profiles between neighbouring countries – it does not address, as said, extreme weather years, (other) uncertainties or risks regarding security of energy supply or, more specifically, the political issue whether and to which extent a country such as the Netherlands would like to rely on cross-border electricity trade to guarantee its security of electricity supply or, put differently, the flexibility of its power system.

Secondly, as mentioned above, our model findings indicate that, potentially, there is a large supply of flexibility by means of electricity demand response (DR), notably by electric vehicles (EVs) and power-to-X (P2X) technologies such as power-to-hydrogen (P2H_2) or hybrid power-to-heat (P2H) technologies in industries. Although our estimates of these DR potentials include major relevant costs and specific (time) restrictions regarding different types of demand response, due to lack of data or other modelling limitations, these estimates often ignore other relevant costs or DR

restrictions, including social or behavioural considerations such as specific preferences by EV owners, households, industries, etc.
For instance, our models account for the additional investment (and storage) costs due to demand response by $P2H_2$ – or other P2X technologies – but they do not adequately include the ‘ramping’ costs due to a more flexible, strongly fluctuating production level of $P2H_2$ (such as higher efficiency losses, additional degradation costs of process installations or higher grid connection costs). Moreover, some industries are stuck to long-term (‘sunk’) capacity investments or, for a variety of reasons, prefer a flat, stable production process rather than a flexible, highly fluctuating process. Due to these and other shortcomings, the actual potentials of demand response may be overestimated and, therefore, the need for other flexibility options – including energy storage – underestimated.

Thirdly, the modelling outcomes on energy storage – and other variables – depend not only on the general characteristics and limitations of the optimization models, OPERA and COMPETES, but also on the specific input parameters and underlying (policy) assumptions of the reference scenarios used in the current study. This applies not only for the reference scenario of CA2030 but, in particular, for NM2050 (as the uncertainties of this long-term scenario are much higher than of CA2030). The reference scenario of NM2050 is characterised by a high degree of electrification and, above all, high installed capacities of VRE power generation, notably offshore wind and solar PV. In addition, in COMPETES domestic electricity demand in NM2050 turns out to be relatively low (compared to installed VRE capacities), resulting in a large amount of hours with a large domestic VRE surplus – before curtailment – and low electricity prices. This in turn leads to large net electricity exports by the Netherlands and large amounts of VRE curtailment (as major flexibility options besides demand response).

A variety of NM2050 sensitivity cases conducted in the present study shows, however, that changing one of the modelling characteristics, assumptions or specific input parameters has a significant impact on energy storage results in some cases, while in other cases this impact is relatively limited or even nearly absent. For instance, excluding flexibility options such as demand response or energy cross-border trade has a significant impact on underground H_2 storage and/or electricity storage, notably on storage by VR batteries or Vehicle-to-Grid (V2G) storage transactions by means of EV batteries. On the other hand, a substantial reduction of the (assumed) installed VRE power generation capacities in COMPETES (about 40%) resulted in less VRE curtailment – albeit less than expected (33%) – and, above all, a significant shift from large net electricity exports to large net imports by the Netherlands, but hardly or not to significant changes in storage of electricity or hydrogen.

Finally, in this study an existing scenario was used as a starting point for detailed analysis on the role of storage. Within the limitations and constraints set by the storyline of that scenario the most cost optimal solution has been assessed using OPERA and COMPETES. This does not entail that the scenario assessed is the most cost effective scenario for the Netherlands and that the results should be interpreted as the cost effective role of energy storage in the Netherlands. Many more scenario configurations and constraints are possible and require further investigation to come to more robust estimates for the role of energy storage in the Netherlands.

5.4 Suggestions for follow-up research

The findings and insights of the current study as well as, in particular, its major limitations and shortcomings provide indications and suggestions for follow-up research on the role of (large-scale) energy storage in the future, climate-neutral energy system of the Netherlands. In brief, from an energy system modelling perspective, these suggestions include:

- Further research on the actual potential of demand response – notably on the short-term price responsiveness of electricity demand by EVs and P2X technologies, including all relevant costs and limitations involved – and its impact on the need for other, competing flexibility options such as energy storage;
- Further research on the actual potential and role of energy storage by means of EV batteries – notably on V2G storage transactions, including all relevant costs and limitations involved – and its impact on energy storage options;
- Further research on energy storage needs due to (i) the uncertainty of the residual power load (notably due to the forecast error of VRE supply), and (ii) the incidence of (local) network constraints (congestion) as well as on energy storage needs to address other power system issues such as inertia, black starts or frequency control (besides energy storage needs due to the variability of the residual load), including the opportunities and limitations to combine these different system needs and functions into multi-purpose energy storage options in order to improve the business case of these options and, hence, optimise their role in the energy system;
- Further research on energy storage needs during extreme weather years or situations, such as a *Dunkelflaute* (within an international, European context);
- Further research on the role of other types of energy storage, notably heat storage, including its impact on the role of electricity/hydrogen storage as analysed in the current study;
- Further research on energy storage needs due to political-strategic considerations – e.g., reducing uncertainties of relying on energy imports – or other security of energy supply considerations (e.g., enhancing system redundancy), as well as research on how to best include these considerations in optimisation models such as OPERA and COMPETES;

  Further research on the future role of storage in the energy system of the Netherlands with different, alternative scenario configurations and transition paths up to 2050.

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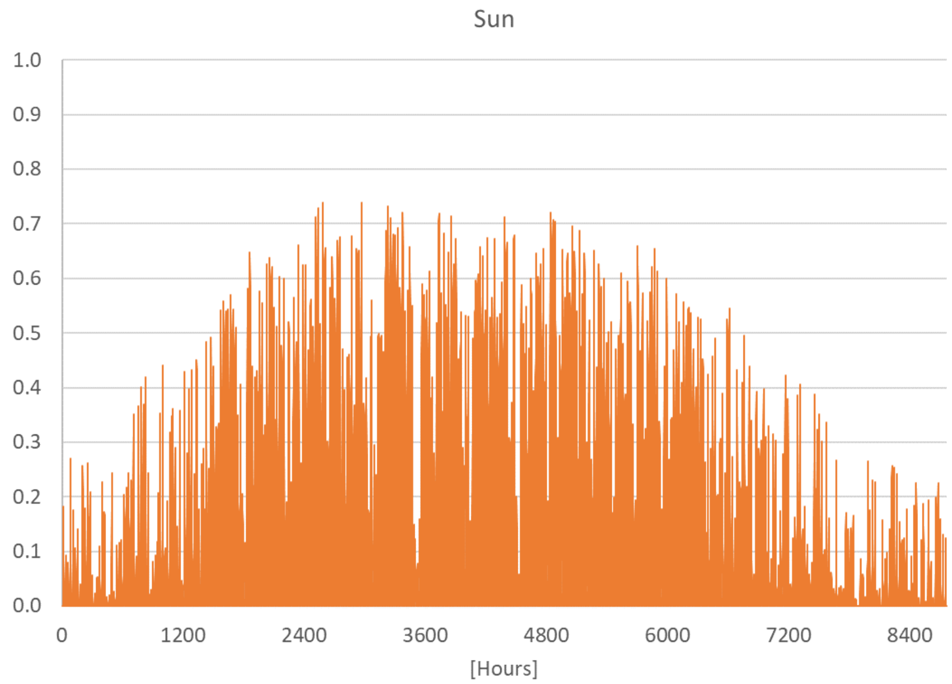
A Additional tables and figures of Chapter 2 (modelling inputs)



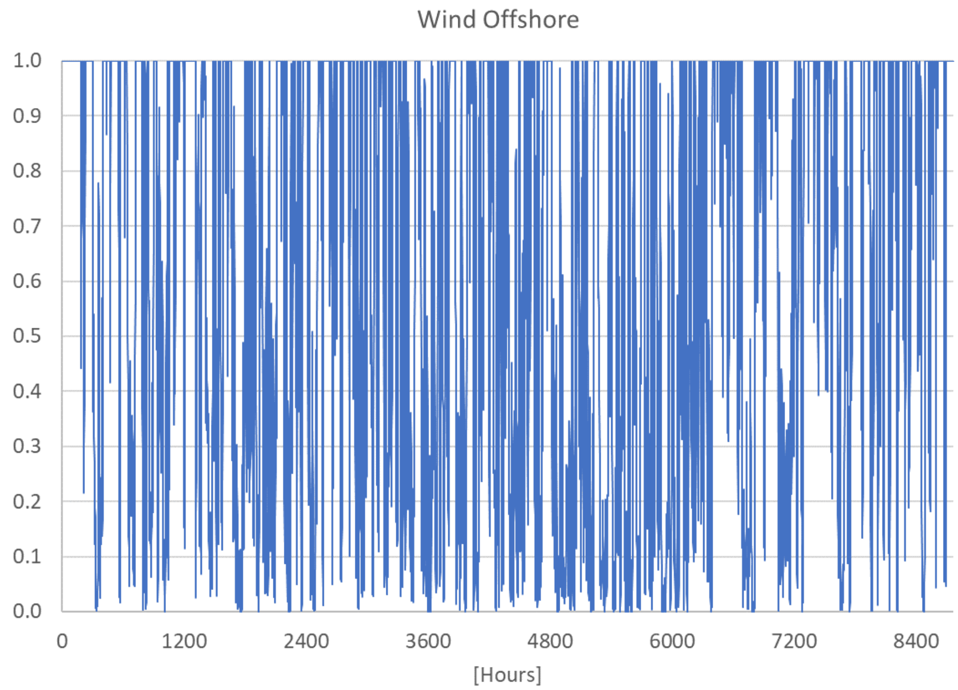


Figure 44: COMPETES and OPERA: Hourly profiles of the capacity factor for solar PV and offshore wind during the whole year 2050 (8760 hours)

Table 36: COMPETES: Electricity demand parameters for European countries and regions in CA2030 and NM2050

CA2030 [in TWh]	Conventional demand	Additional demand			Total additional demand	Total power demand
		Mobility (EVs)	Households (P2H)	Industry (P2H2)		
Netherlands	116.9	1.2	0.3	10.1	11.6	128.5
Germany	541.1	1.5	6.4	26.8	34.7	575.8
Belgium	85.6	0.2	1.5	6.1	7.8	93.5
UK	300.8	2.8	7.3	20.6	30.7	331.5
Norway	140.0	0.5	2.0	13.4	15.9	155.9
Denmark	41.4	0.1	1.0	4.7	5.8	47.2
France	444.5	2.2	10.6	24.0	36.8	481.3
Other EU+	1650.6	6.3	15.1	78.2	99.5	1750.2
Total EU+	3321.0	14.8	44.2	183.9	242.9	3563.9

NM2050 [in TWh]	Conventional demand	Additional demand			Total additional demand	Total power demand
		Mobility (EVs)	Households (P2H)	Industry (P2H2)		
Netherlands	116.9	31.1	14.3	111.0	156.4	273.3
Germany	541.1	180.8	20.2	297.2	498.3	1039.4
Belgium	85.6	15.8	2.5	67.9	86.2	171.8
UK	300.8	212.7	27.3	228.8	468.8	769.6
Norway	140.0	29.0	1.6	148.8	179.3	319.3
Denmark	41.4	13.4	3.2	52.0	68.6	110.0
France	444.5	181.2	34.9	266.7	482.7	927.2
Other EU+	1650.6	621.0	39.1	585.6	1245.6	2896.3
Total EU+	3321.0	1284.9	143.1	1758.0	3185.9	6506.9

a) For the Netherlands, we have also assumed some additional power demand for (i) baseload industry, and (ii) potential power demand by industrial hybrid boilers (for details see Section 2.2, notably Table 4, and Section 3.1, Figure 9). Since we did not have comparable data on these two additional demand categories for the other countries, we did not include them in the tables above.

Sources: Conventional demand: PBL (2019c); Number of EVs and HPs: ENTSO-E (2018); Demand for hydrogen: Blanco et al. (2018).

Table 37: COMPETES: Installed power generation capacities of European countries and regions in CA2030 and NM2050

CA2030 [in GWe]	Solar PV	Onshore Wind	Offshore Wind	Hydro	Other RES-E	Coal/ Lignite	Nuclear	Gas	Oil	Total
Netherlands	25.1	6.0	13.4	0.04	1.6	0.0	0.5	15.5	0.0	62.1
Germany	66.5	58.7	23.1	14.1	6.7	18.6	0.0	26.3	0.0	214.0
Belgium	5.1	3.3	4.1	1.4	1.7	0.0	0.0	2.3	0.0	17.9
UK	24.5	16.1	30.0	1.7	8.1	0.0	5.7	8.7	0.2	95.0
Norway	0.4	4.0	3.7	35.8	0.1	0.0	0.0	0.0	0.0	44.0
Denmark	2.9	5.6	4.2	0.0	1.9	0.4	0.0	0.4	0.0	15.5
France	31.4	36.3	18.7	27.1	3.6	0.0	37.6	5.8	1.0	161.5
Other EU+	98.8	114.9	24.3	149.5	27.6	28.9	36.4	38.5	0.0	518.9
Total EU+	254.7	245.0	121.6	229.7	51.3	47.9	80.3	91.0	1.2	1128.9

NM2050 [in GWe]	Solar PV	Onshore Wind	Offshore Wind	Hydro	Other RES-E	Coal/ Lignite	Nuclear	Gas	Oil	Total
Netherlands	106.0	20.0	51.5	0.0	0.4	0.0	0.0	3.5	0.0	177.9
Germany	134.0	258.9	99.5	8.0	31.4	24.0	0.0	33.8	1.2	590.7
Belgium	8.3	12.9	16.2	0.7	9.2	0.0	0.0	5.1	0.0	52.4
UK	27.4	12.2	60.0	8.6	18.6	0.0	14.1	26.5	0.6	168.1
Norway	0.0	12.9	63.9	45.4	0.0	0.0	0.0	1.0	0.0	123.2
Denmark	4.7	36.4	50.1	0.0	1.7	0.4	0.0	7.6	1.6	102.5
France	88.0	158.1	86.4	20.4	31.3	1.7	55.0	9.3	1.2	451.4
Other EU+	913.9	550.4	124.1	196.8	251.9	34.6	47.2	110.1	3.1	2232.0
Total EU+	1282.2	1061.7	551.8	279.9	344.5	60.7	116.4	193.4	7.8	3901.8

a) Note that for some power generation technologies, new capacity investments are endogenously determined by the model, i.e. these investments are endogenous outputs rather than exogenous inputs. This applies in particular for biomass, coal with CCS, gas, hydro pumped storage, hydrogen, lignite, oil and waste (for details, see Table 6 in Section 2.3.2).

Sources: CA2030: PBL (2019c); NM2050: the 2050 installed capacity was increased proportionally to the increase of electricity demand in NM2050 (see Table 36) with regard to the electricity demand in the alternative scenario for 2050 (A2050) of the FLEXNET project (Sijm et al, 2017a and 2017b).

Table 38: COMPETES and OPERA: Techno-economic parameters of energy storage technologies in 2030 and 2050

Parameter	Unit	CAES		AA-CAES		VRB batteries	
		2030	2050	2030	2050	2030	2050
Investment cost	M€/PJ	23148	20833	72222	66667	19444	15556
Fixed operational cost	M€/PJ/yr	301	271	944	889	556	444
Variable cost	M€/PJ	0.56	0.56	0.56	0.56	0.11	0.09
Energy input/output	MWh/MWh	1.9	1.9	1.55	1.55	1.38	1.38
Charge time	h	8	8	10	10	25	25
Discharge time	h	12	12	5	5	5	5
Lifetime	yr	50	50	40	40	12.5	12.5
Self-discharge	%/h	0	0	0	0	0	0
Maximum capacity	GWh	11.52[a]	11.52[a]	1.4	1.4	No limit	No limit
Minimum capacity	GWh	3.84	3.84	0.7	0.7	0	0
CO_2 emissions	kg/MWh	210	210	0	0	0	0

Parameter	Unit	Li-ion batteries		Pb batteries		H_2 underground	
		2030	2050	2030	2050	2030	2050
Investment cost	M€/PJ	69722	68611	20556	18333	33.3	33.3
Fixed operational cost	M€/PJ/yr	976	961	288	257	0.8	0.8
Variable cost	M€/PJ	0.35	0.26	0.96	0.85	0	0
Energy input/output	MWh/MWh	1.08	1.08	1.33	1.33	1	1
Charge time	h	1	1	5	5	N/A	N/A
Discharge time	h	4	4	10	10	N/A	N/A
Lifetime	yr	10	10	12.5	12.5	50	50
Self-discharge	%/h	0.05	0.05	0.003	0.003	0	0
Maximum capacity	GWh	No limit	No limit	No limit	No limit	No limit	No limit
Minimum capacity	GWh	40[b]	50[b]	0	0	0	0
CO_2 emissions	kg/MWh	0	0	0	0	0	0

Parameter	Unit	H_2 filling station		H_2 vehicles		H_2 vessels	
		2030	2050	2030	2050	2030	2050
Investment cost	M€/PJ	18180	18180	N/A[c]	N/A	4166.67	4166.67
Fixed operational cost	M€/PJ/yr	181	181	N/A	N/A	41.67	41.67
Variable cost	M€/PJ	0	0	N/A	N/A	0.00	0.00
Energy input/output	MWh/MWh	1	1	1	1	1.03	1.03
Lifetime	yr	20	20	10	10	20	20
Self-discharge	%/h			0	0	0	0
Maximum capacity	GWh	No limit	No limit	N/A[e]	N/A[e]		
Minimum capacity	GWh	0	0	N/A	N/A		
CO_2 emissions	kg/MWh	0	0	0	0	0	0

Parameter	Unit	H_2 compression[f]		H_2decompression[f]			
		2030	2050	2030	2050		
Investment cost	M€/GW	45	4.5	N/A[c]	N/A		
Fixed operational cost	M€/GW/yr	3.6	0.18	N/A	N/A		
Variable cost	M€/PJ	0	0	N/A	N/A		

a) Limit for OPERA but none in COMPETES.
b) For COMPETES we assumed this initial capacity in the baseline scenario, but not for OPERA (where the initial 'green field' capacity is zero).
c) OPERA includes the entire costs of the H2 vehicle; the costs of H2 storage are not separately specified.
d) Depends on driving profile.
e) Depends on the number of H2 vehicles which is an outcome of OPERA. The model assumes per vehicle a storage capacity of 200 kWh per vehicle.
f) Same compression and decompression for storage underground and in vessels

Sources:

- *CAES*: Huang et al. (2017), Réveillère and Londe (2017), ESTMAP (2016), HyUnder (2014), KEMA (n.d.), IRENA (2017), US DoE (2019), EERA (2013), Corre Energy (2019);
- *AA-CAES:* Huang et al. (2017), HyUnder (2014), EASE (2020);
- *VR, Li*-ion and Pb batteries: TNO (2020);
- *H_2 Underground*: HyUnder (2014), FCH-JU (2017);
- *H_2 filling stations, vehicles and cylindrical/spherical vessels*: OPERA model.

B Additional tables and figures of Chapter 3 (COMPETES modelling outputs)

Figure 45: COMPETES: Residual load – Daily (average) resolution in CA2030 and NM2050

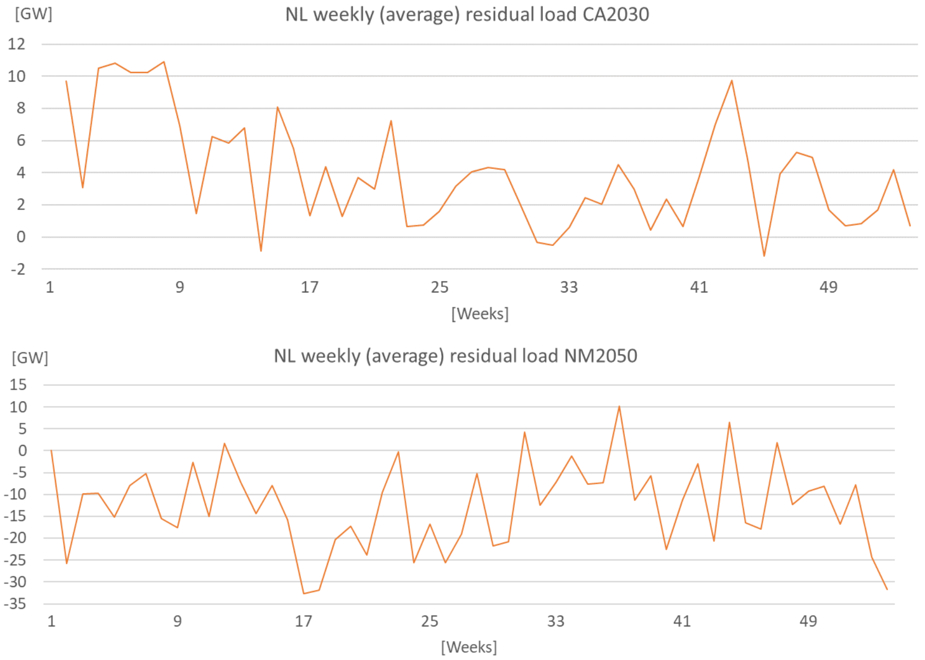


Figure 46: COMPETES: Residual load – Weekly (average) resolution in CA2030 and NM2050

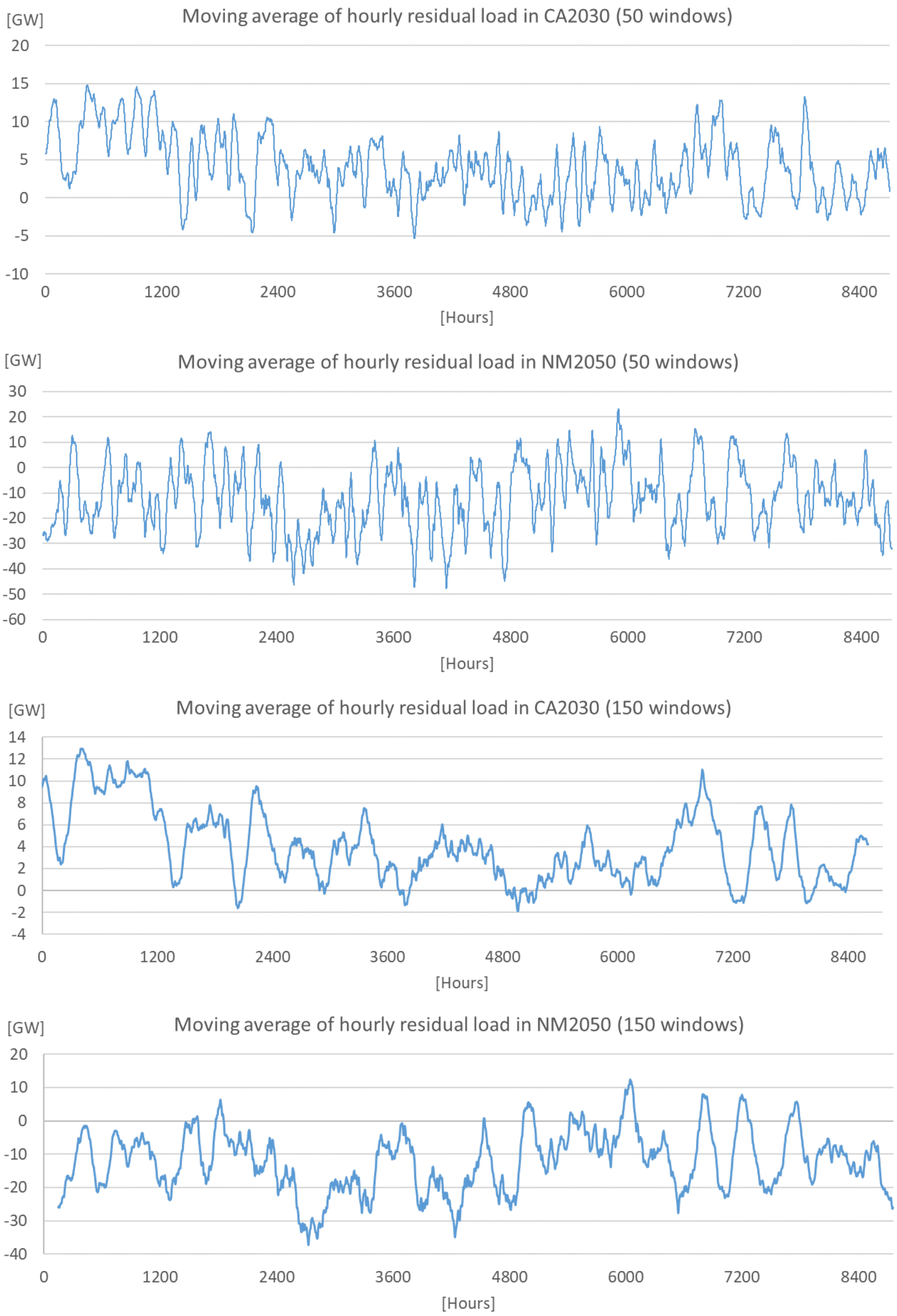
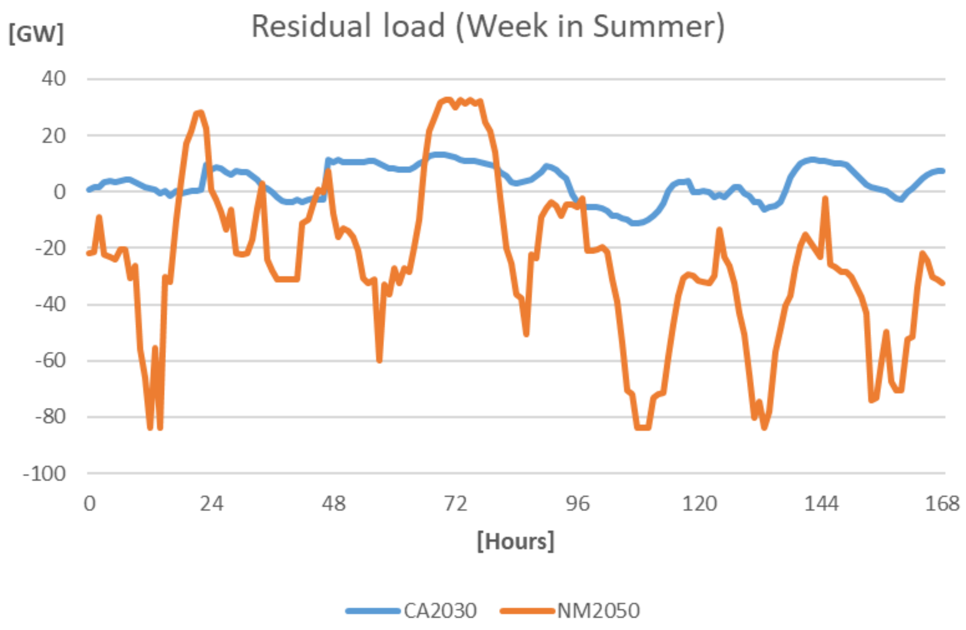


Figure 47: COMPETES: Moving average of hourly residual load over 50 and 150 windows in CA2030 and NM2050



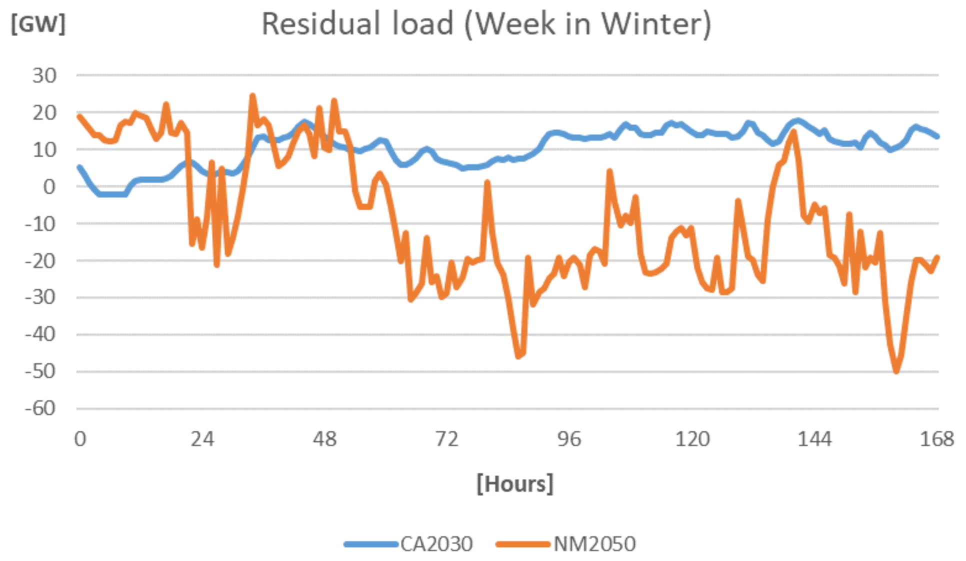


Figure 48: COMPETES: Hourly residual load during a summer and winter week in CA2030 and NM2050

Table 39: COMPETES: Maximum hourly ramps during a summer and winter week in CA2030 and NM2050

Week	Year	Maximum hourly ramp [GW]
Winter	2030	2.9
	2050	26
Summer	2030	14.1
	2050	53.8

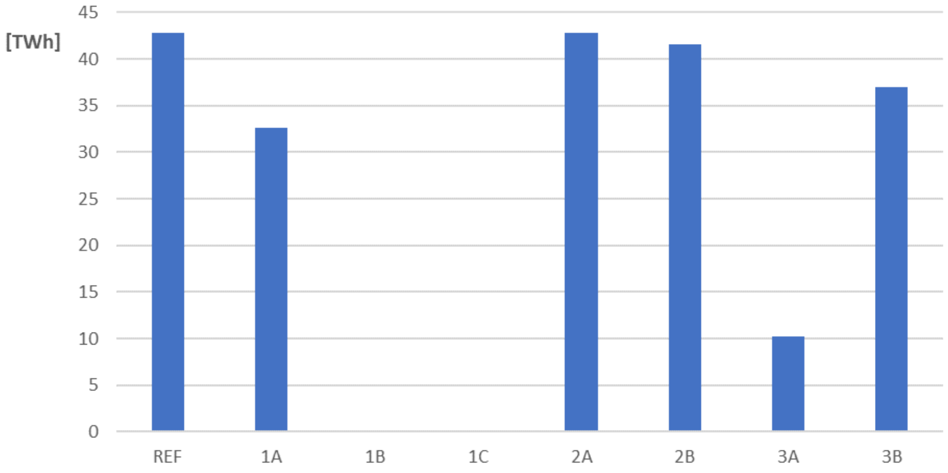


Figure 49: COMPETES: Net annual electricity trade– Comparison of NM2050 reference scenario and sensitivity cases

C Additional tables and figures of Chapter 4 (OPERA modelling outputs)

Table 40: OPERA: Electricity balance –NM2050 reference scenario and sensitivity cases

[TWh]	REF	1A	2A	2B	3A	4A	5A	5B
Power demand								
Conventional demand	139.3	139.0	139.1	139.0	139.7	139.3	139.4	138.8
P2Hydrogen	134.4	134.9	132.8	133.1	144.1	69.9	84.4	229.8
Heat pumps (households)	7.7	7.9	7.9	7.9	7.9	6.8	7.8	7.9
P2Heat (electric boilers)	4.5	3.8	4.3	4.2	0.0	5.3	4.4	4.2
Electric vehicles (EVs)	32.2	32.3	32.2	32.3	31.9	32.3	32.1	32.3
P2Liquids	17.3	17.3	17.3	17.3	20.9	0.0	20.9	14.9
Other additional demand	59.5	60.5	59.4	59.2	61.8	47.1	59.7	58.9
Net exports	42.8	0.0	42.8	41.6	42.8	42.8	42.8	42.8
Power supply								
CCGT - Hydrogen	0.8	0.8	0.2	0.3	0.5	0.5	0.9	0.3
Conventional supply	10.0	10.0	12.3	9.9	9.8	10.9	10.0	11.2
Wind onshore	76.4	77.1	76.5	75.6	76.5	76.2	76.6	75.7
Wind offshore	302.5	270.3	298.4	295.1	309.5	214.0	257.2	382.3
Solar PV	50.0	37.4	52.6	53.5	54.6	44.0	48.8	63.4

Table 41: OPERA: Hydrogen balance–NM2050 reference scenario and sensitivity cases

[PJ]	REF	1A	2A	2B	3A	4A	5A	5B
H_2 demand								
Admixture	6.3	6.3	6.3	6.3	7.7	12.2	6.3	6.4
Transport loss	6.0	6.2	5.9	5.9	6.1	3.8	5.9	8.8
Passenger cars	2.1	2.0	2.0	2.0	2.6	1.9	2.4	1.9
High Duty Vehicles	109.9	109.9	109.9	109.9	108.4	109.9	109.9	109.9
Synthetic fuels (P2L)	106.3	106.2	106.2	106.2	127.3	0.0	128.7	91.5
Heat boilers - Services	93.7	93.4	93.5	93.4	93.4	38.5	93.8	92.5
Heat boilers - Other	0.2	1.5	0.0	0.3	1.7	0.6	0.3	0.0
Chemicals	0.0	0.1	0.0	0.0	0.4	1.6	0.0	0.0
CCGT - Hydrogen	4.7	4.7	1.4	1.9	3.2	2.7	5.6	1.7
H_2 supply								
Alkaline Electrolysis	329.2	330.3	325.2	325.8	350.8	171.3	206.7	562.8
H_2 imports/exports[a]	0.0	0.0	0.0	0.0	0.0	0.0	146.2	-250.0

a) A negative sign means hydrogen exports.

Table 42: OPERA: Installed capacities of major energy technologies – Comparison of NM2050 reference scenario and sensitivity cases

[GWe]	REF	1A	2A	2B	3A	4A	5A	5B
Solar - Residential	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Solar - Services	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Solar - Large scale utilities	24.8	11.1	27.6	28.6	30.0	18.2	23.4	40.0
Wind - Onshore	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Wind - Offshore	57.8	49.8	56.9	56.6	58.6	41.7	49.4	72.0
CCGT - Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT - Hydrogen	9.1	2.5	1.5	2.0	10.4	7.4	9.5	4.4
H_2 Electrolysis	31.5	31.8	30.7	31.0	20.9	18.4	22.8	49.4
Changes in installed capacity compared to the reference case								
[GWe]	**REF**	**1A**	**2A**	**2B**	**3A**	**4A**	**5A**	**5B**
Solar - Residential		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar - Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar - Large scale utilities		-13.7	2.9	3.8	5.2	-6.6	-1.4	15.3
Wind - Onshore		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind - Offshore		-8.0	-0.9	-1.2	0.8	-16.1	-8.5	14.2
CCGT - Natural Gas		0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT - Hydrogen		-6.5	-7.6	-7.1	1.3	-1.7	0.5	-4.6
H_2 Electrolysis		0.3	-0.8	-0.5	-10.6	-13.1	-8.7	17.9

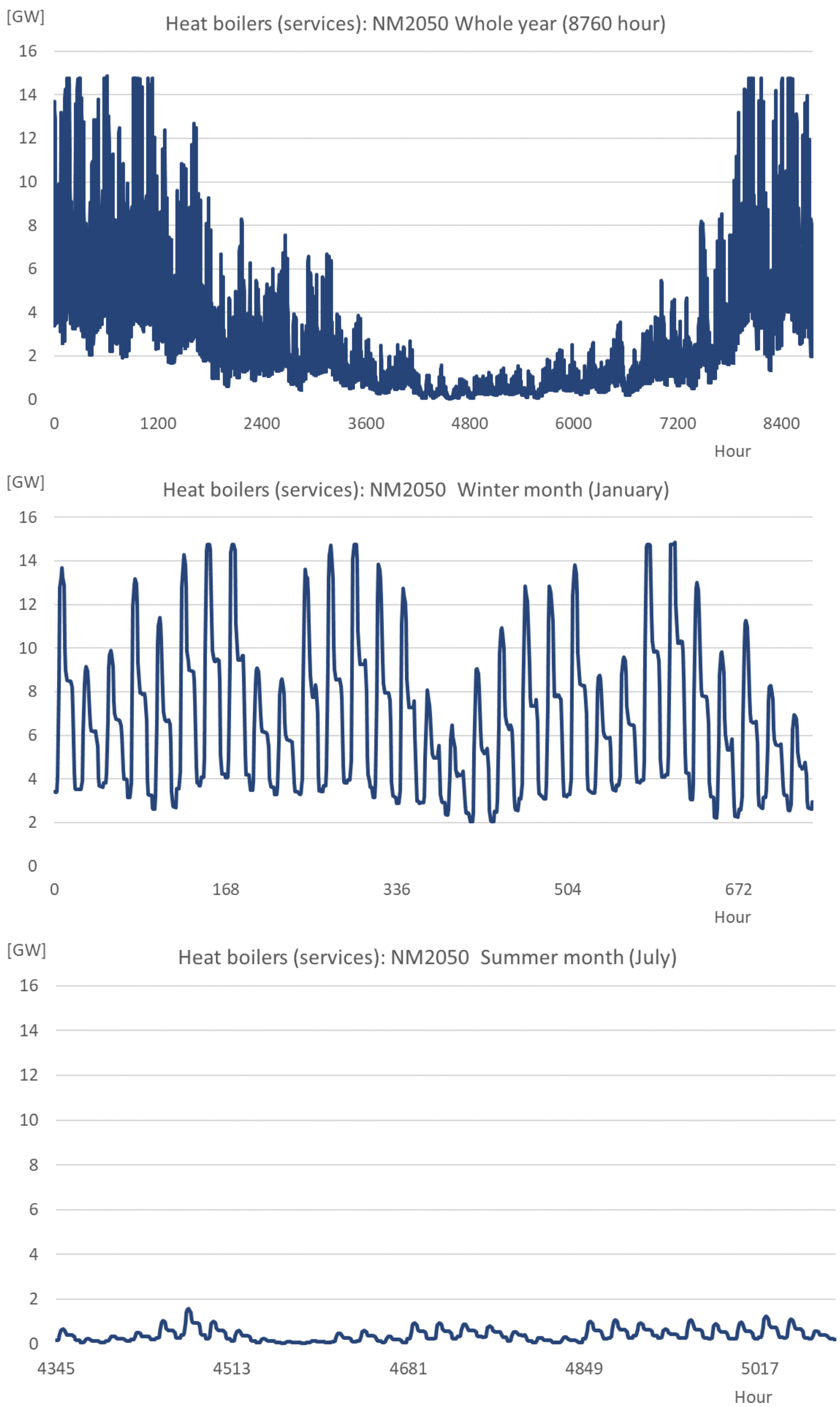


Figure 50: OPERA: Hourly profiles of H_2 demand by heat boilers (services sector) in NM2050

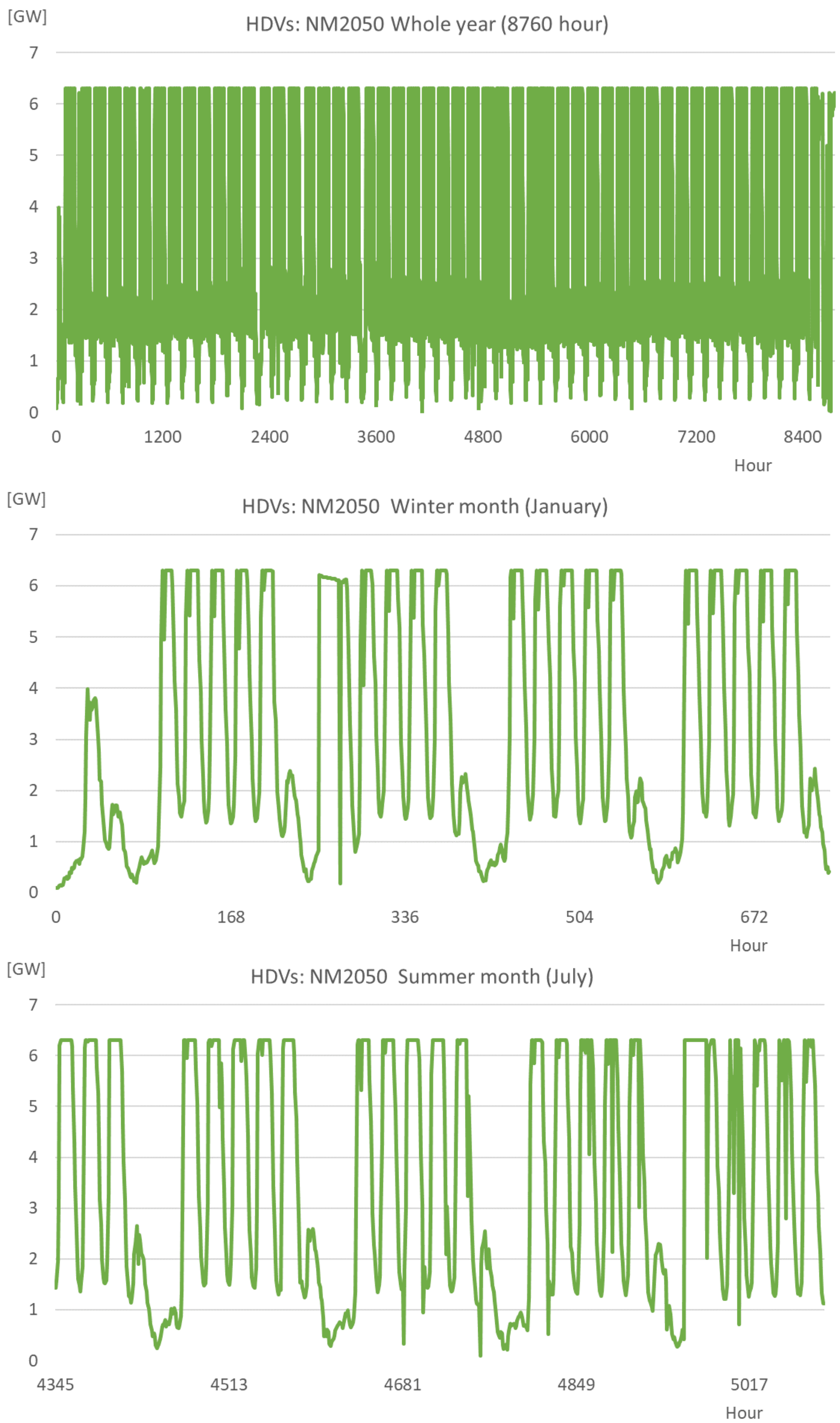


Figure 51: OPERA: Hourly profiles of H_2 demand by Heavy Duty Vehicles (HDVs) in NM2050

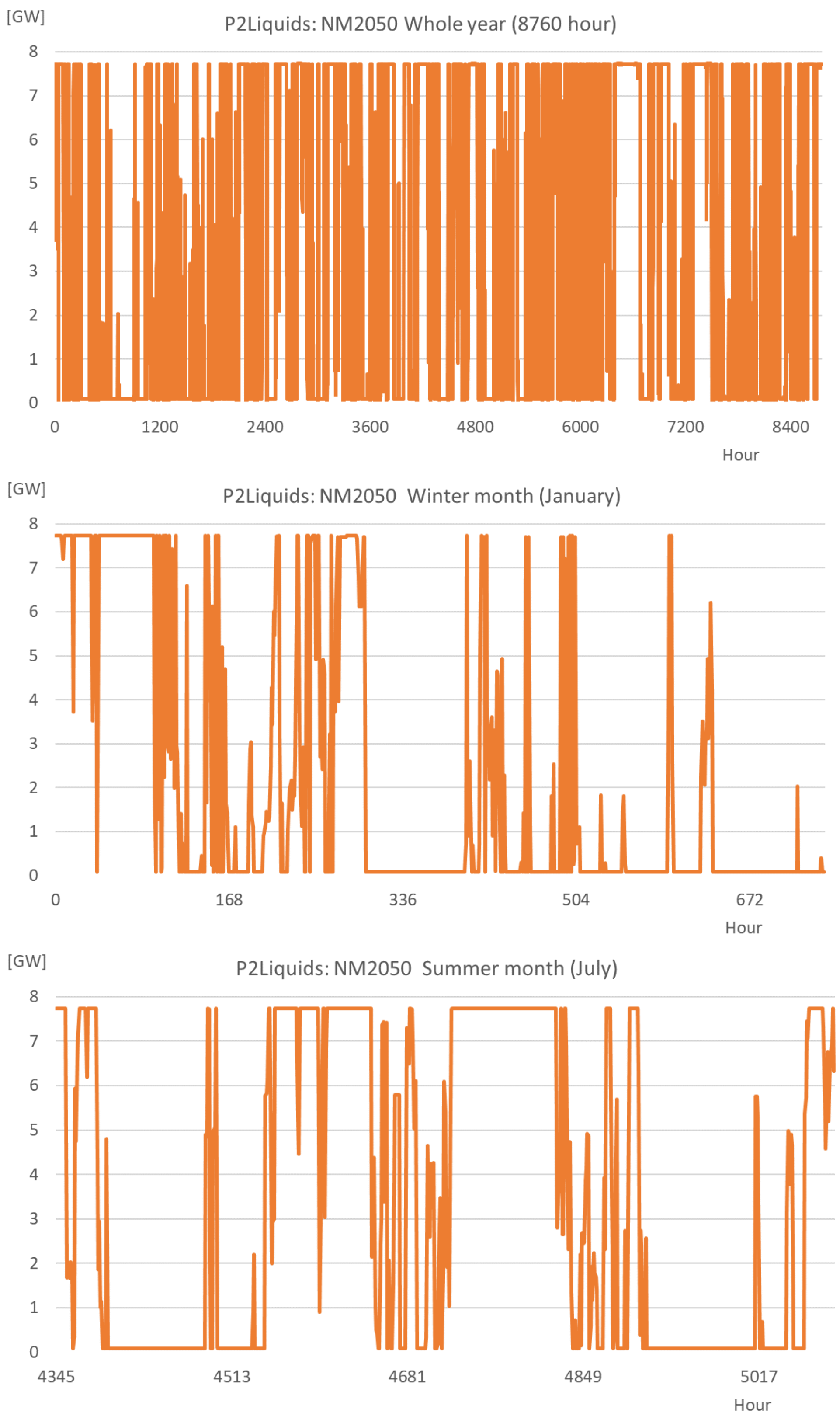


Figure 52: OPERA: Hourly profiles of H_2 demand by Power2Liquids in NM2050

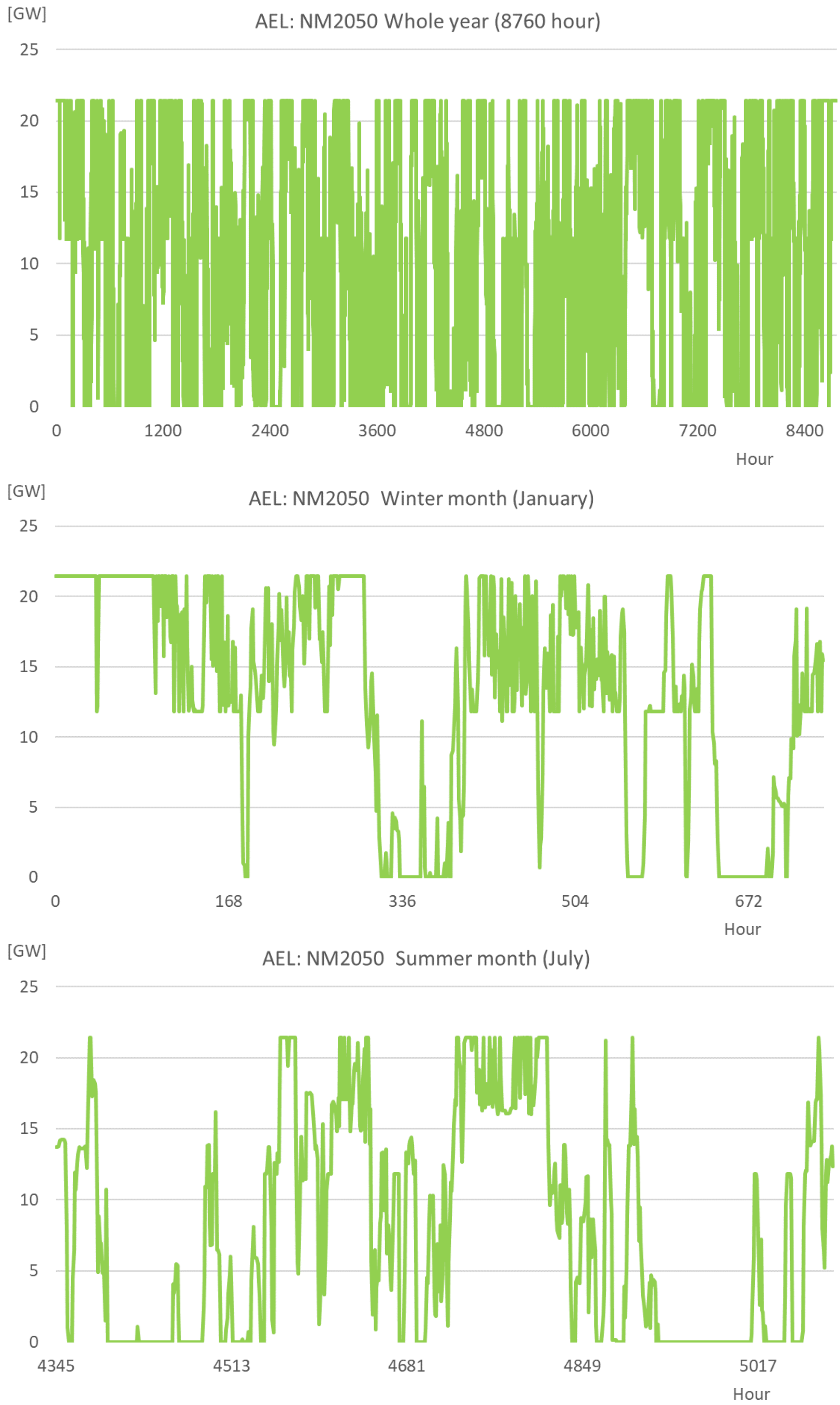


Figure 53: OPERA: Hourly profiles of H_2 supply from alkaline electrolysis (AEL) in NM2050

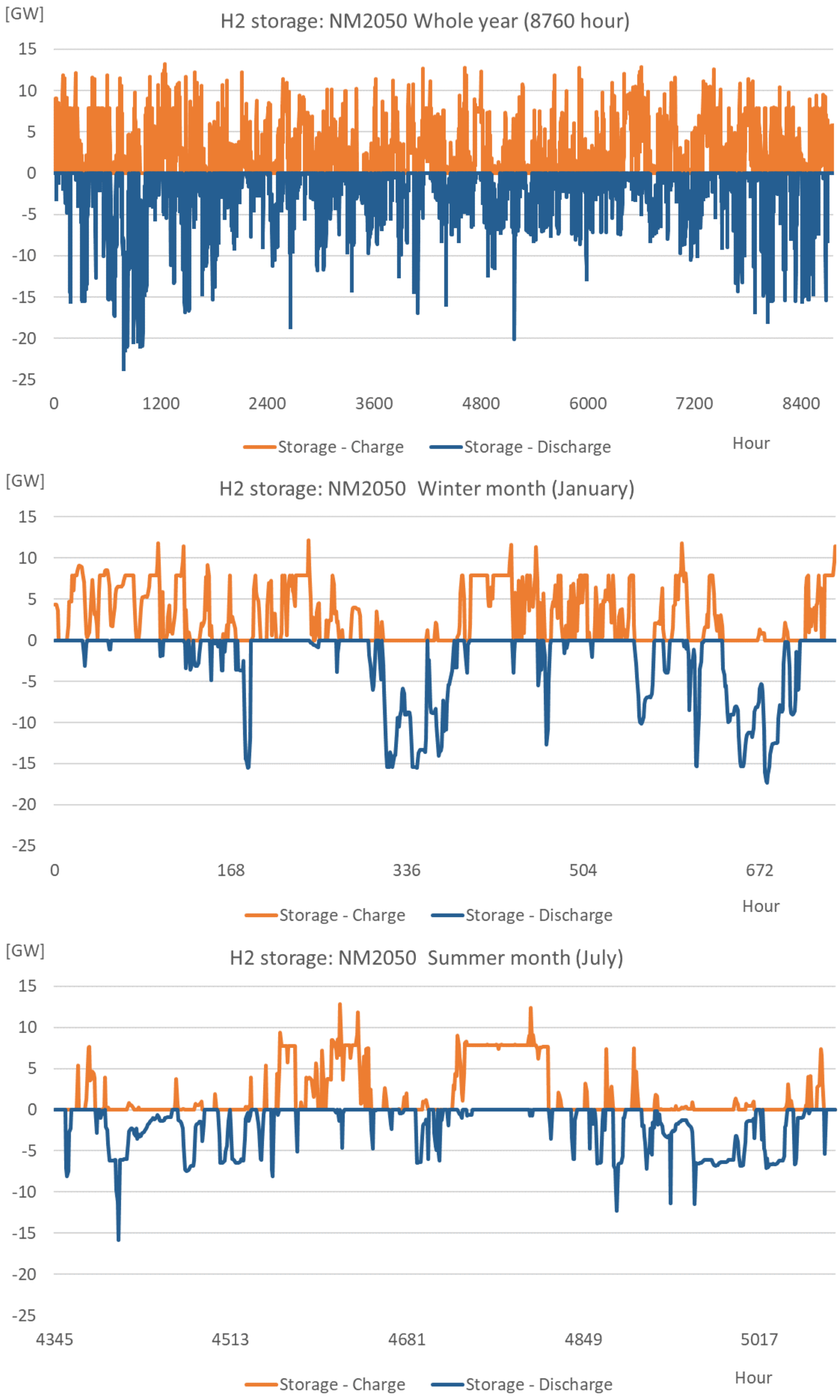


Figure 54: OPERA: Hourly profiles of H_2 storage in NM2050

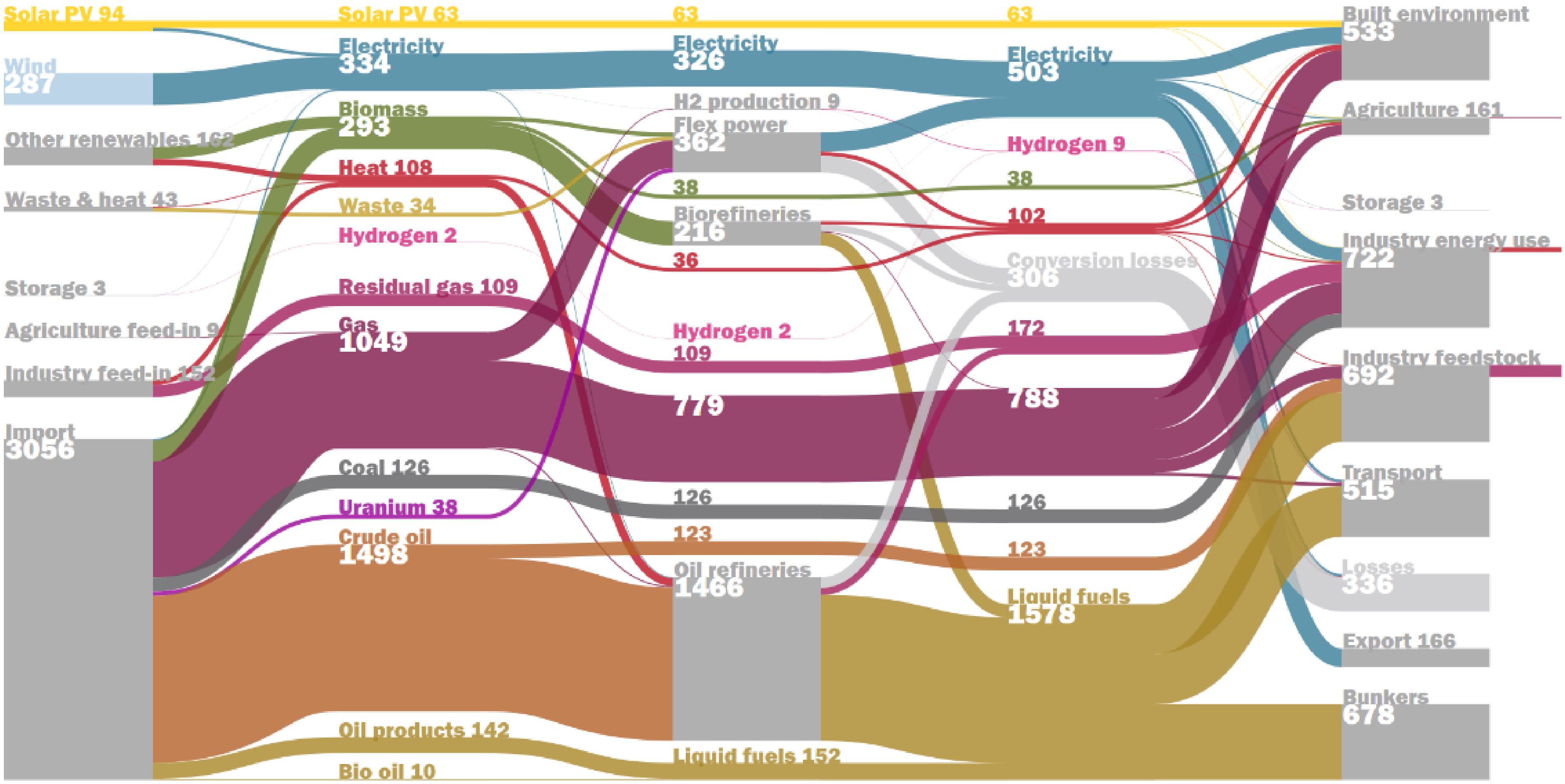


Figure 55: OPERA: Sankey diagram of the energy system in the Netherlands in CA2030

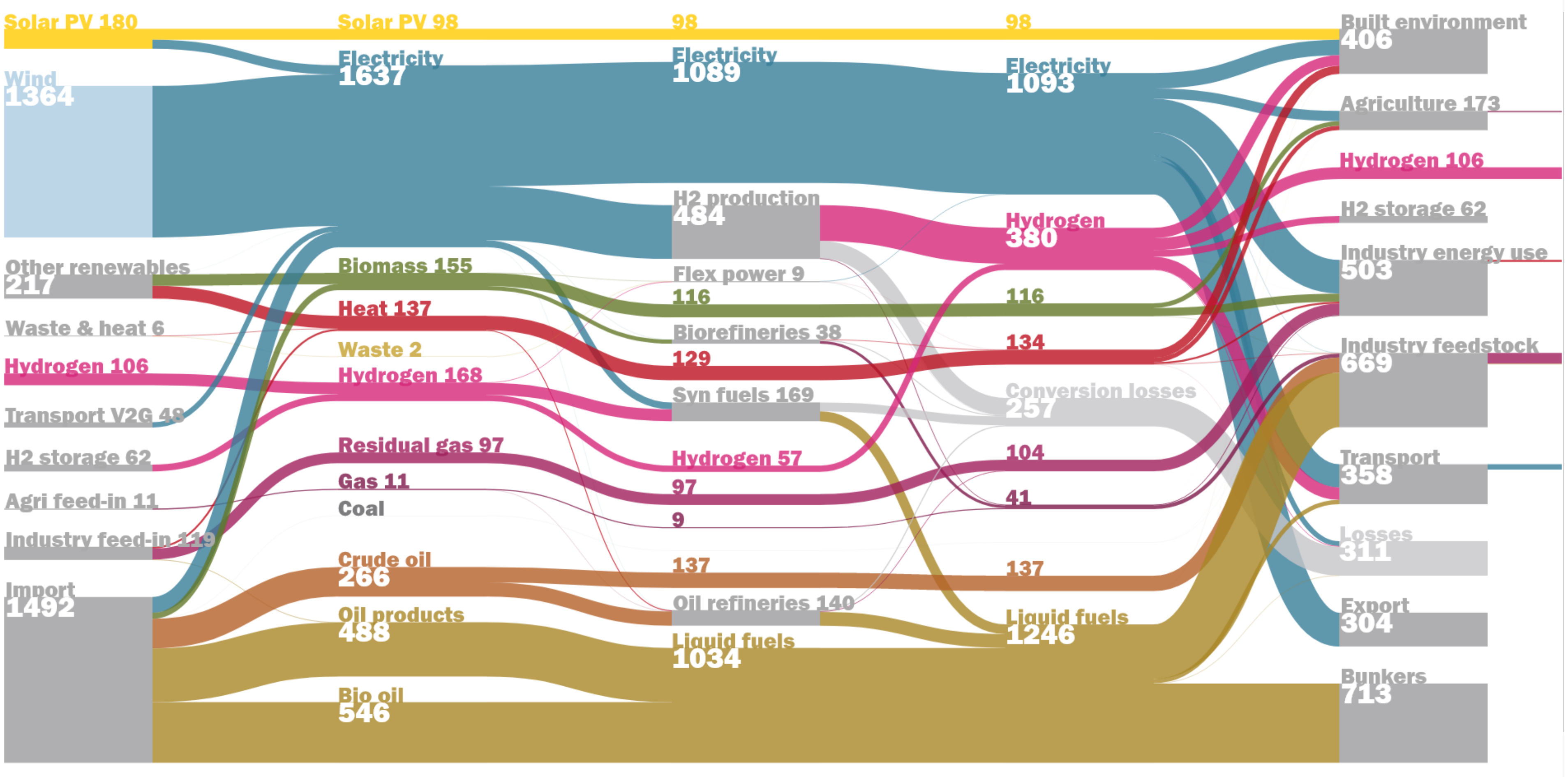


Figure 56: OPERA: Sankey diagram of the energy system in the Netherlands in NM2050