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The role of demand response in the power system of the Netherlands, 2030-2050

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Acknowledgement

In 2017, the (then) Energy research Centre of the Netherlands (ECN) published the major findings of the FLEXNET project on the demand and supply of flexibility by the power system of the Netherlands over the years 2015-2050 (Sijm et al., 2017a, 2017b and 2017c). In 2018, ECN joined forces with TNO and, subsequently, merged into the unit Energy Transition (ET) of TNO.

One of the tools used for the FLEXNET project is the COMPETES model, i.e. a European electricity market optimisation model, including a variety of power generation technologies and flexibility options (on an hourly time resolution). Since the FLEXNET project, i.e. over the last four years, the scenarios and databases of this model have been updated, whereas the flexibility options in this model have been further extended and improved. This applies in particular for the options demand response and energy storage (including both electricity and green hydrogen storage). The role of storage in the energy system of the Netherlands has been analysed as part of an externally funded study, published in 2020 (for details, see Sijm et al., 2020).

The current report presents and discusses the study results on the role of demand response in the power system of the Netherlands (2030-2050). This role is analysed within the context of a European electricity market system, including other, competing flexible options such as cross-border electricity trade, storage, flexible supply and curtailment of power generation from variable renewable energy (VRE), notably sun and wind. Although this report focusses on the role of demand response, to some extent it is also an update and revision of the FLEXNET reports (including additional conceptual, methodological and other improvements).

The study for this report has been conducted largely as part of internal TNO projects funded by the Ministry of Economic Affairs and Climate Policy of the Netherlands (registered at TNO under project numbers 060.33957, 060.38253, 060.42856 and 060.47628/01.04). By means of this report, we – i.e., the authors – would like to thank the Ministry for this support and to show the major methodological improvements as well as the major findings and insights achieved by this study.

Internally, this report has been reviewed by our colleague Bo de Wildt. We would like to thank him for his useful and sharp comments.

Contents

Key messages

The key messages of the current study include:

- There is a large potential for demand response and resulting flexibility offered to the power system in the Netherlands, already in 2030 but notably in 2050, in particular by power-to-hydrogen ($P2H_2$) and power-to-mobility (electric vehicles).

- Demand response (DR) offers a variety of beneficial impacts to the power system – and society at large – such as (i) less dependency on foreign trade for system security and flexibility, (ii) less need for (expensive) interconnection capacity, (iii) less need for (expensive) storage transactions, (iv) less need for curtailment of electricity generation from variable renewable energy (VRE), notably sun and wind, (v) less need for power generation from other, non-VRE sources, such as (green) gas or biomass, which are often more expensive and/or more polluting, (vi) lower average electricity prices, notably for flexible end-users, and – as a result – (vii) lower total power system costs.

- Although VRE producers may benefit from (DR induced) less curtailment of power generation from sun and wind, they may suffer from DR induced lower average electricity prices. To some extent, the balance of these two contrasting impacts of DR on the total generation revenues of VRE producers – and, hence, on the business case of market-based VRE investments – depends on the relationship ('match') between total electricity demand and the supply of electricity from VRE sources. DR can improve (further optimise) this relationship to some extent – and, hence, the business case of merchant VRE investments – notably during hours with a VRE surplus by reducing VRE curtailment and/or raising electricity prices during these hours. However, if there is a fundamental 'mismatch' between electricity demand and VRE supply – in particular a large VRE surplus during a large number of hours, resulting in a poor business case for VRE investments – DR is not able to correct this mismatch in an adequate, sufficient way.

- A key policy implication of this study – and its related companion project deliverable on DR barriers (De Wildt et al., 2022) – is that, in order to realise the potential of DR and its variety of beneficial impacts on the power system, a set of market-design and other policies is required to reduce the barriers to DR and create the appropriate (pre)conditions for DR, including policies (i) to set the right price incentives (and to avoid distorted incentives from grid tariffs and taxation), (ii) to provide access for relevant DR suppliers to relevant electricity markets, (iii) to enable adequate grid and EV charging infrastructures, (iv) to reduce (upfront) financial constraints, and (v) to address awareness, information, data, privacy and other behavioural issues.

Summary

Background
The Netherlands is aiming at a climate-neutral energy system in 2050. For the power system this implies (i) a larger share of electricity from variable renewable energy (VRE), notably sun and wind, (ii) a larger share of electricity in total energy use due to the further penetration of so-called 'power-to-X' (P2X) technologies such as power-to-heat (P2H), power-to-hydrogen ($P2H_2$) or power-to-mobility (P2M), and – as a result of these two combined trends – (iii) a higher need for system integration and flexibility to deal cost-effectively with large fluctuations as well as with large surpluses and shortages of VRE power production in the short, medium and long term.

More specifically, low-carbon power systems with a relatively high share of VRE sources in total domestic electricity demand, such as the foreseen Dutch power system in 2030 and beyond, are usually characterised by two related issues regarding the so-called '*residual load*' (RL) of the system, where residual load – or '*residual demand*' – is defined as the difference between total electricity demand and the supply of electricity from VRE sources. These issues – or 'challenges' – include:

- The incidence of, on the one hand, a large number of hours with a (relatively large) *positive* RL – i.e., hours with a '*VRE shortage*', usually characterised by high electricity prices – and, on the other hand, a large number of hours with a (relatively large) *negative* RL – i.e., hours with a '*VRE surplus'*, usually characterised by (very) low (or even negative) electricity prices. Hours with a VRE shortage raise the question how this shortage can be met, notably in a carbon-free and cost-effective way. On the other hand, hours with a VRE surplus raise the question how this surplus can be used in an optimal way or, put differently, how low (negative) electricity prices can be avoided and increased to higher (positive) levels in order to improve the business case of market-based investments in VRE technologies.
- The high and increasing *variability* of the RL. The variability of the RL is the main source ('cause') of the need for flexibility ('*ramping'*) by the power system. This raises the question how this high and increasing need for flexibility can be met in a reliable and cost-effective way, notably in a power system where the conventional supply of flexibility – i.e., by means of flexible fossil-fuel plants – is diminishing (or even disappearing).

Demand response is one of the options to deal with these two related issues. Firstly (to address the first RL issue), by increasing electricity demand in hours with a negative RL (VRE surplus) and decreasing electricity demand in hours with a positive RL (VRE shortage). Secondly (to address the second RL issue), by changing ('*differentiating'*) the level of DR either *upwards*, thereby offering upward flexibility ('*ramping'*) to the power system, or *downwards*, thereby offering downward flexibility. In the current study, DR – in both the 'absolute' and 'differential' way – is offered by four P2X technologies (also called '*flexible load options*' or simply '*DR options*'):

- *Power-to hydrogen* ($P2H_2$);
- *Power-to-heat in industry* (P2H-i), notably hybrid (electricity/gas) boilers to generate industrial heat;
- *Power-to-heat in households* (P2H-h), in particular all-electric heat pumps for household space heating and hot water purposes;
- *Power-to-mobility* (P2M), especially passenger electric vehicles (EVs).

Besides DR, other major categories of flexible options to deal with the two RL issues outlined above, and included in the current study, refer to:

- *Non-VRE generation*, i.e. power generation from both flexible and less flexible sources, excluding sun and wind, such as (green) gas, biomass, hydro or nuclear;
- *VRE curtailment,* i.e. curtailment of power generation from VRE sources;
- *Trade,* i.e. exports/imports of electricity to/from other countries;
- *Storage,* i.e. charges/discharges of electricity by means of storage technologies such as batteries or compressed air energy storage (CAES).

Objective and scope

The overall objective of the current study is to analyse the role of demand response in the power system of the Netherlands over the years 2030-2050. The *role* of demand response (DR) refers both to the *potential* (size) of DR in these years as well as to the *impact* of this potential on the performance of the power system in the Netherlands. In order to deal with the two related issues regarding the residual load of the power system, the role of demand response is analysed within the context of a European electricity market system, including other, competing flexible options such as trade or storage.

Approach

To reach the objective mentioned above, the study defines and uses two reference scenarios, one for 2030 and one for 2050, both with and without DR. 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 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 relatively high level of national energy self-sufficiency. 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.

The reference scenarios for 2030 and 2050, as well as some sensitivity cases for 2050, are analysed by means of COMPETES, i.e. a European electricity market optimisation model – based on an hourly time resolution – which includes both a variety of power generation technologies, flexible P2X/DR technologies and other, competing flexible options such as trade or storage.

Part I: The potential of demand response

Definition of key concepts

Part I analyses the potential (size) of DR by the four selected P2X technologies – both individually and added together – in CA2030 and NM2050. This analysis is based on the definition and application of the following three related concepts:

- *Electricity demand ('load'),* i.e. the (hourly/annual) electricity use by a technology or set of technologies – or even by the power system as a whole – in a certain scenario year.
- *Demand response (DR),* i.e. either *load switching* (between certain hours, notably from hours with relatively high electricity prices to hours with relatively low prices) or *load curtailment* (at certain hours, in particular at hours with relatively high

electricity prices). In this study, demand response is defined and measured as the difference (Δ) between electricity demand in the (scenario) case with DR, i.e. demand responds to changes in electricity prices, and electricity demand in the (same) case without DR, i.e. demand is not responsive to changes in electricity prices. If this difference is positive, it is called *upward* DR, and *downward* DR if the difference is negative.

- *Flexibility by DR,* i.e. the flexibility offered to the power system by one or more demand-responsive technologies. In this study, flexibility by DR is defined and measured as the difference (Δ) between DR at a certain hour t and DR at the previous hour t-1 (t = 1,….., 8760). If this difference is positive, it is called *upward* flexibility (by DR) and *downward* flexibility if the difference is negative.

Major results of part I

The main findings of part I of the study are summarised in the following three tables:

- Table 1 presents major results on the total annual electricity demand by the four selected technologies in CA2030 and NM2050, both with and without DR;
- Table 2 summarises major results on total annual DR potentials, including both potentials of total annual upward and downward DR as well as potentials of total annual upward and downward flexibility by DR;
- Table 3 provides some comparative results on both total (annual) and average (hourly) electricity demand and DR potentials by the four selected P2X technologies added together (as a single option) in CA2030 and NM2050.

The main findings and observations from the three tables mentioned above include:

➢ In CA2030, the *electricity demand* by the four selected flexible load options is significantly lower in the case with DR (almost 15 TWh) than without DR (about 30 TWh). This is mainly due to the large downward DR (almost 16 TWh) by power-to-heat in industry (P2H-i), resulting from the fact that in the case without DR this load curtailing technology, i.e. an E-boiler, is assumed to be the default technology to generate industrial heat during all hours of the year, whereas in the CA2030 case with DR a gas boiler turns out to be the dominant, competitive technology during most hours of the year (about 7400) in which electricity prices are relatively high (compared to gas). Consequently, in CA2030, the share of P2H-i in total electricity demand by all four flexible load options amounts to 62% in the case without DR (and to 33% for $P2H_2$), whereas it drops to 21% in the case with DR (and rises to 69% for $P2H_2$).

➢ In NM2050, on the contrary, the difference in total *electricity demand* by the four DR options in the cases with and without DR is rather low in both absolute and relative terms, i.e. 225 TWh versus 227 TWh, respectively (Table 1). In addition to the higher energy storage losses for power-to-heat in households (P2H-h) and power-to-mobility (P2M, i.e. passenger EVs), this difference is, on balance, largely due to the relatively small downward DR by P2H-i (about 4 TWh), resulting from the fact that in the case without DR this technology is assumed to be the default technology to produce industrial heat, while in the case with DR it turns out to be indeed the dominant, competitive technology during most hours of the year (more than 8200). Hence, (downward) DR occurs only during a small number of hours over the year (less than 600). As a percentage of total electricity demand by all flexible P2X technologies, the share of P2H-i remains rather stable in NM2050 with and without DR, i.e. about 30% (while for $P2H_2$ this share amounts to approximately 50%).

Table 1: Total annual electricity demand by the four selected P2X technologies in CA2030 and NM2050 with and without demand response (DR versus NoDR)

	In absolute volumes [TWh][a]					As % of all DR options			
	CA2030		NM2050			CA2030		NM2050	
	NoDR	DR	NoDR	DR		NoDR	DR	NoDR	DR
$P2H_2$	10.0	10.1	111.1	112.1		33%	69%	49%	50%
P2H-i	18.6	3.0	70.8	66.6		62%	21%	31%	30%
P2H-h	0.3	0.3	14.3	14.3		1%	2%	6%	6%
P2M (EVs)	1.2	1.3	31.1	31.7		4%	9%	14%	14%
All options	30.2	14.7	227.3	224.7		100%	100%	100%	100%

a) In the case of load curtailing technologies (i.e., P2H-i), the difference between total annual electricity demand with and without DR is due to the load curtailment (downward DR). In the case of load shifting technologies ($P2H_2$, P2H-h and P2M), this difference is due to higher energy storage losses – hydrogen/electricity – in the scenario with DR and, hence, the resulting higher electricity needs to cover these losses.

- *Total annual (upwards + downwards) DR* by all four flexible load options aggregated individually amounts to 20 TWh in CA2030, while it is more than five times higher in NM2050, i.e. about 105 TWh (almost half of the total flexible load by these options in NM2050; see Table 1 and Table 2). As a percentage of this total annual DR, the share of P2H-i in CA2030 amounts to 77% (as downward DR is offered in a large number of hours), while for the other three flexible load options – $P2H_2$, P2M and P2H-h – the shares amount to 13%, 9% and 1%, respectively. In NM2050, however, the share of P2H-i drops to 4% (as downward DR by this load curtailing technology is provided only during a relatively small number of hours), while for the other three flexible technologies the comparative shares – and, even more significantly, the underlying absolute amounts of DR – increase substantially to 61%, 33% and 3%, respectively.

- The total annual (upward + downward) *flexibility* by all four DR options aggregated together, however, is significantly lower than the total annual DR by the options individually, notably in CA2030, but still it amounts to almost 3 TWh in CA2030 and even to 45 TWh in NM2050 (Table 2). As a percentage of this total annual supply of flexibility by DR, the share of P2H-i amounts to 24% in CA2030 but drops to 1% in NM2050, while for P2M it increases significantly from 43% to 72%, respectively.

- The main reason why the share of P2H-i in total annual *flexibility* by all DR options aggregated individually is relatively low in NM2050 (1%) is that the number of hours in which the industrial heat technology switches between gas and electricity – and, hence, offers either upward or downward flexibility – is rather low, i.e. about 40 hours in this scenario year, as industrial heat is generated by either a gas boiler or – predominantly – an E-boiler during a large number of consecutive hours at the same capacity level (8.1 GW). On the other hand, the main reason why the comparative rate for P2M is relatively high (79%) is that this load shifting technology supplies flexibility during almost every hour of the year, while over a large number of hours the amount of upward or downward flexibility is quite substantial, ranging between 5 and 25 GW in absolute terms.

Table 2: Total annual DR potentials by the selected P2X technologies in CA2030 and NM2050

	In absolute volumes [TWh][a]					**As % of all options individually**			
	Total demand response (DR)		**Total flexibility by DR**			**Total demand response (DR)**		**Total flexibility by DR**	
	CA'30	**NM'50**	**CA'30**	**NM'50**		**CA'30**	**NM'50**	**CA'30**	**NM'50**
$P2H_2$	2.7	63.8	0.8	8.7		13%	61%	27%	19%
P2H-i	15.6	4.2	0.7	0.3		77%	4%	24%	1%
P2H-h	0.2	2.9	0.2	3.6		1%	3%	6%	8%
P2M (EVs)	1.9	34.5	1.2	32.4		9%	33%	43%	72%
All options:									
- individually	20.3	105.4	2.8	44.9		100%	100%	100%	100%
- together	16.7	78.9	2.6	40.2		82%	75%	94%	90%

a) Total annual DR potentials refer to both potentials of total annual upward and downward DR as well as potentials of total annual upward and downward flexibility by DR, expressed in absolute volumes, i.e. in positive (+) energy terms only and, hence, added up accordingly.

- Note that in all cases considered in Table 2, the total annual potentials of both demand response (DR) and flexibility by DR are generally significantly lower for the four P2X technologies added together (as a single, flexible option) than the sum of the DR potentials by the options aggregated individually. For instance, in NM2050, the total annual DR by all four options summed up individually amounts to 105 TWh, whereas it is approximately 25% lower – i.e., about 79 TWh – for the four technologies aggregated together as a single option. The reason is that, in the case of DR and flexibility by DR – as part of the system optimisation process - the values of these variables in a certain hour often show opposite signs (both positive and negative) for the technologies individually, i.e. DR/flexibility by one or more of the technologies is moving upwards while simultaneously (in the same hour) it is moving downwards for one of more other technologies. As a result, the total annual sum of the parts (i.e. the technologies considered individually) is usually higher than the sum of the whole (i.e. the technologies added together as a single, flexible option).

- Dividing the total annual volumes of electricity demand and DR potentials by the number of hours in a year leads to comparative, average (hourly) values of these variables (expressed in GW/#h). Table 3 shows that, as a result, in CA2030 these values for all DR options added together amount to about 3.4 GW/#h for the average flexible load by these options (without DR), 1.9 GW/#h for the average DR, and 0.3 GW/#h for the average flexibility by DR. Expressed as a percentage of the average total domestic load without DR (including both fixed and flexible load by all domestic sectors and technologies), these average values correspond to 20%, 11% and 2%, respectively.

- Finally, in NM2050, however, both the total (annual) and average (hourly) figures on electricity demand and DR potentials by the four P2X technologies added together are substantially (5 to 15 times) higher than in CA2030. For instance, for this group of technologies, the average flexible load in NM2050 (without DR) amounts to almost 26 GW/#h, the average DR to 9 GW/#h, and the average flexibility by DR to 4.6 GW/#h. Expressed as a percentage of the average total domestic load, these values correspond to 65%, 23% and 12%, respectively.

Table 3: Comparative data on total (annual) and average (hourly) electricity demand and DR potentials by all four flexible load options added together in CA2030 and NM2050

	Total (per annum; in TWh)		Average (per hour; in GW/#h)	
	CA2030	**NM2050**	**CA2030**	**NM2050**
Total domestic load (before DR)[a]	151.2	348.3	17.3	39.8
Flexible load (before DR)[b]	30.2	227.3	3.4	25.9
Demand response (DR)[b]	16.7	78.9	1.9	9.0
Flexibility by DR[b]	2.6	40.2	0.3	4.6
As % of total/average domestic load (before DR)				
Flexible load (before DR)	20%	65%	20%	65%
Demand response (DR)	11%	23%	11%	23%
Flexibility by DR	2%	12%	2%	12%
As % of flexible load (before DR)				
Demand response (DR)	55%	35%	55%	35%
Flexibility by DR	9%	18%	9%	18%
As % of demand response				
Flexibility by DR	16%	51%	16%	51%

a) By all domestic (NL) sectors and all electricity demand technologies added together.

b) By the four selected, flexible P2X ('DR') technologies added together (as a single option).

Discussion of part I

The current study shows that there is a large potential for demand response – and the resulting flexibility by DR – in the power system of the Netherlands. This applies already for the scenario year CA2030 but in particular for the scenario year NM2050, when, e.g., the total annual potential of flexibility offered by DR amounts to about 40 TWh, i.e. more than 15 times higher than in CA2030 (2.6 TWh). Some qualifications, however, can be added to the assessment of these DR potentials.

On the one hand, there are some arguments that the DR potentials assessed in this study may be underestimated. Firstly, in this study, power demand assumptions for the Netherlands in 2030 are based on the policy targets and assumptions of the Dutch Climate Agreement of 2019, resulting in a total electricity demand of approximately 150 TWh in 2030. Based on the more recent EU's Fit-for-55 policy package, however, current (2022) power demand assumptions for the Netherlands are usually much higher, running up to about 200 TWh in 2030. A higher electricity demand in 2030 (or, similarly, in 2050) implies that the potential for demand response is also higher.

Secondly, the current study is focussed on DR by four specific P2X technologies in certain sectors. Although the electricity demand by these technologies is substantial, notably in NM2050 (i.e., almost 230 TWh or about 65% of total domestic power load in NM2050), there may be other technologies or sectors that may be able to provide a significant additional amount of DR in NM2050 (or maybe even in CA2030) such as power-to-heat in the non-household, residential sector (services, offices, etc.) or by power-to-mobility by non-passenger EVs.

Thirdly, the current study – and the underlying COMPETES model – does not include explicit heat storage technologies (although it does include implicit thermal energy storage by – well insulated – homes heated by all-electric, household heat pumps). By 2030 and, notably, 2050, however, there may be some competitive thermal energy storage options available that could be mixed with P2H technologies, both in the industrial and residential sectors (see Maruf et al., 2021, and references cited there). If so, the DR potentials of the technologies concerned would increase accordingly.

Fourthly, the current study is focussed on analysing the potential of DR to meet the flexibility needs of the power system due to the hourly variability of the residual load (notably on the day-ahead market). It does not cover, however, the need for flexibility due to other reasons – such as congestion of the power grid or uncertainty of the residual load due to, for instance, difficulties and resulting errors to forecast the short-term electricity demand or the availability of sun and wind – or on other electricity markets such as the intraday market or the markets for electricity balancing and (other) ancillary services (Sijm et al., 2017b and 2021). Although the day-ahead market is – and likely remains – by far the most important electricity market for offering DR potentials to address the variability of the residual load up to 2050 in both energy volume and monetary terms, providing DR potentials for these alternative purposes or markets may become (more) attractive and, hence, (more) significant over the coming decades.

Finally, the current study is primarily focussed on *implicit* DR, i.e. DR incentivised by time-varying prices to which end-users respond. In some case, however, additional potential of DR may be offered by *explicit* DR, i.e. DR incentivised by an explicit contract where end-users promise to respond to a signal or instruction to adjust the load, and to which they receive a reward or some compensation in return. For instance, in this study DR by power-to-heat in industry (P2H-i) assumes implicit DR, which implies that offering flexibility by this technology is restricted to the (limited) number of hours in which the relative electricity/gas price incentive changes effectively for all P2H-i end-users simultaneously and, hence, in which the full demand for industrial heat by all end-users switches simultaneously from electricity to gas (or vice versa). Explicit DR offers the opportunity to differentiate the signal and related reward incentive across different P2H-i end-users over a larger number of hours in a year, which may result in a higher potential of DR and flexibility provided by these end-users.

On the other hand, there are also arguments that the DR potentials assessed in this study may be (seriously) overestimated. Firstly, as already indicated above, the assessment of the DR potential for the load curtailing technology power-to heat in industry (P2H-i) assumes that an E-boiler is the default technology to meet the flat demand for industrial heat in the case without DR (over all hours of the year). For NM2050, this assumption makes sense as an E-boiler turns out to be the dominant, competitive technology to produce industrial heat during almost all hours of the year (8200). For CA2030, however, this assumption may be questioned as a gas boiler turns out to be the dominant, competitive technology over most hours of the year (7400). As a result, the assumption concerned leads to a high (over) estimation of the total (annual) and average (hourly) DR by P2H-i in CA2030. Surprisingly, however, this assumption does not lead to an over- or underestimation of the total or average flexibility offered by this technology as it neither changes the number of hours in which the industrial heat technology switches between gas and electricity nor the flat amount of DR during each of these hours.

Secondly (and likely most importantly), this study – and the underlying COMPETES model in particular – has included a variety of constraints to DR by the four selected P2X technologies. These constraints refer to the controllability and availability of these technologies (including the willingness and ability to provide DR), the investment costs of expanding $P2H_2$ capacity (in order to become more demand-responsive), the variable costs of hybrid heat technologies in industry, the specific (minimum) charging requirements of EVs, the specific saturation and load recovery constraints of flexible heat pumps in households, etc. (Morales-España et al., 2022).

In a companion project deliverable to this study, however, we have analysed a large variety of (other) constraints – called 'barriers' – to demand response in general and to DR by the four P2X technologies of the current study in particular (De Wildt et al., 2022). Apart from barriers to the further (future) electrification of the energy system in general and the further penetration of these technologies in particular, the barriers to demand response include, among others, lack of required preconditions for DR (e.g., proper price incentives; no distorted incentives from grid tariffs and taxation; adequate grid capacity; lack of awareness, data or other information; accurate measurement and enforcement of DR), financial (upfront investment) constraints, system or people's inertia, and all kinds of behavioural constraints such as consumer values, preferences, privacy issues, etc. (for details, see De Wildt et al., 2022). The incidence of these barriers to DR can substantially reduce (the realisation of) the potential DR as assessed in the current study.

Finally, it has to remarked that the (over- or under)assessment of the future DR potentials depends also on the specific characteristics and specifications of the model used and of the model scenarios in particular. For instance, these potentials do not only depend on the way the flexible P2X technologies – and other technologies/flexible options – are modelled and optimised, but also on the (assumed or obtained) hourly profiles of these technologies or on the (assumed) future electrification of the energy system and the further penetration of the selected P2X technologies in particular.

Part II: The impact of demand response

Part II of the study analyses the impact of DR on the power system of the Netherlands in the scenario years CA2030 and NM2050. This analysis is conducted at three related levels:

- The impact of DR on the *electricity balance*, i.e. on the major components of (total) electricity demand and supply, including the impact of DR on related variables such as electricity prices, VRE supply revenues and total system costs;
- The impact of DR on the so-called '*residual load balance'*, i.e. the balance of flexible options to meet the residual load (RL), including in particular hours with a positive RL (VRE shortage) and hours with a negative RL (VRE surplus);
- The impact of DR on the so-called '*flexibility balance*', i.e. the total demand and supply of flexibility by the power system, where flexibility refers primarily to the *hourly* variability of the RL, defined and measured as the difference (Δ) between the RL in hour *t* and the RL in hour *t-1* (with *t* = 1,…., 8760).

The impact of demand response on the electricity balance
Table 4 summarises the major results regarding the impact of DR on the electricity balance – and some related variables – of the Netherlands in scenario years CA2030 and NM2050. The major findings and observations from this table include:

Table 4: Summary of major results regarding the impact of DR on the electricity balance – and related variables – of the Netherlands in CA2030 and NM2050 (DR versus NoDR)

		CA2030				NM2050		
	Unit	**NoDR**	**DR**	**Δ%**		**NoDR**	**DR**	**Δ%**
Electricity demand and supply								
Total domestic power demand	TWh	151.1	135.7	-10.2%		351.9	345.7	-1.8%
Total domestic power supply	TWh	179.4	177.7	-0.9%		362.2	388.4	7.2%
VRE supply before curtailment	TWh	100.4	100.4	0.0%		453.7	453.7	0.0%
VRE curtailment	TWh	0.1	0.0	-100%		101.6	73.0	-28.1%
VRE supply after curtailment	TWh	100.3	100.4	0.1%		352.1	380.7	8.1%
Gas-fired power generation	TWh	63.5	61.6	-3.0%		9.1	7.4	-18.7%
Exports	TWh	53.3	61.2	14.8%		200.5	161.7	-19.4%
Imports	TWh	25.0	19.1	-23.6%		190.3	119.0	-37.5%
Net trade	TWh	28.3	42.1	48.8%		10.2	42.7	318%
Interconnection capacity	GW	12.0	12.0	0.0%		46.5	33.2	-28.6%
Weighted average electricity price (per demand category, excluding grid tariffs, taxes, etc.)								
Conventional demand	€/MWh	73.8	54.8	-25.7%		27.2	15.5	-43.0%
P2Hydrogen	€/MWh	68.1	51.8	-24.0%		26.1	7.9	-69.7%
P2Heat (industry)	€/MWh	69.6	33.8	-51.4%		26.2	10.9	-58.2%
P2Heat (households)	€/MWh	85.3	54.2	-36.4%		29.9	19.5	-34.8%
P2Mobility (passenger EVs)	€/MWh	86.3	44.4	-48.6%		33.4	11.8	-64.8%
Total demand	€/MWh	73.0	54.0	-26.0%		27.3	12.0	-56.1%
VRE supply revenues								
Total VRE supply revenues	m€	5404	5003	-7.4%		6421	4188	-34.8%
Average revenue (per MWh)	€/MWh	53.9	49.9	-7.4%		18.2	11.0	-39.7%
Average revenue (per GW installed)	m€/GW	121.4	112.4	-7.4%		36.2	23.6	-34.8%
Total power system costs[a]	m€	1204	644	-46.5%		3241	2706	-16.5%

a) Including investment costs of new (additional) technology capacities installed in a certain scenario but excluding investment costs of baseline capacities as these costs are regarded as 'sunk costs' that are not affected in future scenario years.

- Compared to the scenario cases without DR (NoDR), DR reduces total domestic electricity demand, notably in CA2030 (-10%). This is mainly due to load curtailment by power-to-heat in industry (P2H-i), which in the scenario case with DR switches from electricity to gas for generating industrial heat in hours in which electricity prices are relatively high.

- DR reduces the curtailment of VRE power generation and, hence, increases the supply of electricity from VRE sources (after curtailment), in particular in NM2050 (+8%). As a result, DR reduces the need for fossil-fuel (notably gas-fired) power generation, e.g. in NM2050 by 19%.

- In addition, DR enhances the net electricity trade surplus of the Netherlands (electricity exports minus imports), i.e. by almost 50% in CA2030 and even by more than 300% in NM2050. In CA2030, the relatively large amount of load curtailment leads to, as noted above, a lower domestic electricity demand in a large number of hours, whereas domestic electricity supply remains more or less the same, resulting in both higher electricity exports and lower imports. In NM2050, the relatively large amount of load shifting (from VRE shortage to surplus hours) leads, as noted, to less VRE curtailment and, hence, to more domestic VRE supply (during VRE surplus hours). This results in, on balance, lower electricity export needs and even far lower import needs, thereby both improving the net electricity trade balance of the Netherlands and, more importantly, reducing its dependency on foreign electricity trade to safeguard power system security and flexibility.

- More specifically, the large amount of DR (load shifting) in NM2050 results in a lowering of the hourly peaks of electricity trade and, therefore, in a lower need for interconnection capacity in NM2050 (-29%). This implies not only a reduction of foreign dependency on energy security but above all a lowering of investment costs in interconnections and related inland transmission capacity.

- Due to DR, the weighted average electricity price (of the total load) decreases in CA2030 from 73 €/MWh (without DR) to 54 €/MWh (with DR, i.e. -26%). Due to the large (over) supply of electricity from VRE – with relatively low marginal costs – electricity prices are, on average, much lower in NM2050 (than in CA2030), i.e. about 27 €/MWh without DR and12 €/MWh with DR, implying that DR reduces average electricity prices even further in NM2050 by 56%. This indicates that in both scenarios (CA2030 and NM2050) the impact of DR is, on balance, much stronger in substantially decreasing high electricity prices during peak hours than in significantly increasing low electricity prices during off-peak hours.

- For some specific (flexible) end-users, however, the impact of DR on the average electricity price they have to pay is even stronger than the DR impact on the weighted electricity price mentioned above (for all electricity consumers). For instance, for passenger EV users in CA2030 the average electricity price (excluding grid tariffs, taxes, etc.) decreases from 86 €/MWh without DR to 44 €/MWh with DR – i.e., -49% due to DR – whereas in NM2050 the average price decreases from 26 €/MWh to 8 €/MWh, respectively (i.e., -70% due to DR).

- VRE producers, however, suffer from the DR impact on the (average) electricity price they receive (although this impact is less than the DR impact on the average electricity price for all producers/consumers mentioned above). In CA2030, the average revenue (‘price’) per MWh of VRE generation decreases from 54 € without DR to 50 € with DR (-7.4%) while in NM2050 it declines even from 18 € to 11 € (-40%) due to DR.

- In CA2030, the decline in average VRE revenues is largely due to the load curtailment of P2H-i, which results in a 10% decrease in total domestic electricity demand (while the installed VRE capacity – assumed exogenously – remains the same). In NM2050, the (relatively large) DR induced decline in the average electricity price received by VRE producers is likely, to some extent, due to some specific assumptions of this scenario, notably the assumed installed VRE capacity compared to the total domestic electricity demand.[1] In addition, the decline in average revenue per MWh in NM2050 is also partly caused (and compensated) by higher VRE output due to DR induced lower VRE curtailment, resulting in a slightly lower decline (-35%) of both total VRE supply revenues and average revenue per GW installed of VRE capacity.

- An additional, more fundamental explanation why VRE producers do not benefit from DR (in both CA2030 and NM2050) is that – following past and current practices – VRE producers pay hardly or not for the costs of integrating power generation into the power system, such as the costs of expanding the electricity network or balancing the power system by means of flexibility options. As a result, these VRE producers in turn benefit hardly or not from any of the system cost savings owing to demand response.

- In a sensitivity case of NM2050, in which the (assumed) installed VRE capacity is reduced substantially (-41%), the average electricity price received by VRE producers amounts to 12.5 €/MWh, i.e. 14% higher than in NM2050 with DR (11 €/MWh). Compared to NM2050 without DR (18 €/MWh), this price is still significantly lower (-31%) but, due to less DR induced VRE curtailment, the average VRE supply revenues per GW installed improves slightly (+2%) in the sensitivity case (compared to NM2050 without DR).

- Overall, DR reduces the total power system costs (excluding sunk investment costs of baseline capacities) by 47% in CA2030 and 17% in NM2050. More specifically, higher investments costs of new $P2H_2$ capacity (to operate flexible in the case with DR) are more than compensated by lower investments costs in new interconnection capacity (in NM2050), lower gas-fired generation costs and, on balance, lower electricity import cost and/or higher export revenues.

The impact of demand response on the residual load balance
Table 5 summarises the major results regarding the impact of DR on the mix of options to meet the residual load (RL) in the scenario year CA2030, while Table 6 presents similar results for the scenario year NM2050. The major findings and observations from these tables include:

- In CA2030, DR – i.e., primarily load curtailment by P2H-i – reduces the total VRE shortage aggregated over all hours with a positive RL by 14.6 TWh. Consequently, the net trade balance (less electricity imports/more electricity exports) improves by 12.8 TWh while the power generation from non-VRE sources (notably gas) declines by 1.8 TWh.

- On the other hand, DR (load curtailment) *enhances* the total VRE surplus aggregated over all hours with a negative RL in CA2030 by 0.9 TWh, resulting in a further improvement of the net trade balance by more or less the same amount.

- Overall, DR in CA2030 reduces total (positive + negative) RL by 15.5 TWh, resulting in an improvement of the net trade balance (13.8 TWh) and a reduction of non-VRE generation (1.7 TWh).

[1] See also discussion of Part II below. In a follow-up study this year (2022), we further explore the impact of (flexible) electricity demand – and other factors – on the business case of VRE investments.

Table 5: Summary of major results regarding the impact of DR on the mix of options to meet the residual load (RL) in the scenario year CA2030 with and without DR (DR versus NoDR)

		Non-VRE generation	VRE curtailment	Trade[b]	Storage[c]	Demand response	Total residual load
Total annual residual load (RL) met by option (TWh)							
NoDR	Pos. RL[a]	67.1	0.0	-10.4	0.0	0.0	56.6
	Neg. RL[a]	12.0	0.0	-17.8	0.0	0.0	-5.8
	Total RL	79.1	0.0	-28.3	0.0	0.0	50.8
DR	Pos. RL	65.3	0.0	-23.3	0.0	14.6	56.6
	Neg. RL	12.1	0.0	-18.8	0.0	0.9	-5.8
	Total RL	77.4	0.0	-42.1	0.0	15.5	50.8
As share of total annual residual load (%)							
NoDR	Pos. RL	118.4	0.0	-18.4	0.0	0.0	100.0
	Neg. RL	-207.2	0.0	307.2	0.0	0.0	100.0
	Total RL	155.6	0.0	-55.6	0.0	0.0	100.0
DR	Pos. RL	115.2	0.0	-41.0	0.0	25.8	100.0
	Neg. RL	-207.9	0.0	323.6	0.0	-15.8	100.0
	Total RL	152.2	0.0	-82.7	0.0	30.5	100.0
DR induced change in total annual residual load met by option (in TWh)							
DR-NoDR	Pos. RL	-1.8	0.0	-12.8	0.0	14.6	0.0
	Neg. RL	0.0	0.0	-1.0	0.0	0.9	0.0
	Total RL	-1.7	0.0	-13.8	0.0	15.5	0.0

a) ‘Pos. RL’ refers to the sum of hours with a positive residual load (‘VRE shortage’) while ‘Neg. RL’ refers to the sum of hours with a negative residual load (‘VRE surplus’).
b) A positive sign implies, on balance, net electricity imports while a negative sign refers to net electricity exports;
c) A positive sign implies, on balance, net storage discharges while a negative sign refers to net storage charges (including storage losses). Figures refer to total net storage transactions over the number of hours considered and, hence, may include both hours with (significant) storage charges and discharges (even if the net storage aggregated over these hours is – close to – zero). Similar qualifications apply also to the figures of the other options presented in the table.

- In NM2050, DR – primarily upward load shifting – reduces the total VRE shortage over all hours with a positive RL by 31 TWh. As a result, the net trade surplus of the Netherlands increases by 27 TWh (less electricity imports), non-VRE generation declines by 2 TWh while net storage decreases also by 2 TWh.

- On the other hand, DR – primarily downward load shifting – reduces the total VRE surplus over all hours with a negative RL in NM2050 by 28 TWh. As a result, VRE curtailment is reduced by a similar amount (28 TWh). Simultaneously, however, net storage charges are reduced by almost 6 TWh, resulting in more exports (5 TWh) and a lower need for non-VRE generation (1 TWh).

- Over all hours of NM2050, DR results in, on balance, less VRE curtailment (29 TWh), an improved trade balance (33 TWh), less non-VRE generation (2 TWh) and less storage needs, including less storage losses (4 TWh).

Table 6: Summary of major results regarding the impact of DR on the mix of options to meet the residual load (RL) in the scenario year NM2050 with and without DR (DR versus NoDR)

		Non-VRE generation	VRE curtailment	Trade[b]	Storage[c]	Demand response	Total residual load
Total annual residual load (RL) met by option (TWh)							
NoDR	Pos. RL[a]	5.3	-0.7	58.1	2.8	0.0	65.5
	Neg. RL[a]	4.7	-100.8	-68.3	-6.5	0.0	-170.9
	Total RL	10.0	-101.5	-10.2	-3.7	0.0	-105.4
DR	Pos. RL	3.4	-0.2	30.5	0.9	30.9	65.5
	Neg. RL	4.2	-72.7	-73.3	-0.9	-28.3	-170.9
	Total RL	7.6	-72.9	-42.7	0.0	2.6	-105.4
As share of total annual residual load (%)							
	Pos. RL	8.1	-1.1	88.6	4.3	0.0	100.0
	Neg. RL	-2.8	59.0	40.0	3.8	0.0	100.0
	Total RL	-9.5	96.3	9.7	3.5	0.0	100.0
	Pos. RL	5.3	-0.4	47.2	1.4	47.2	100.0
	Neg. RL	-2.5	42.8	43.1	0.5	16.5	100.0
	Total RL	-7.2	69.2	40.6	0.0	-2.5	100.0
DR induced change in total annual residual load met by option (in TWh)							
DR-NoDR	Pos. RL	-1.9	0.5	-27.5	-1.9	30.9	0.0
	Neg. RL	-0.5	28.1	-4.9	5.6	-28.3	0.0
	Total RL	-2.4	28.6	-32.5	3.7	2.6	0.0

a) – c): See notes below Table 5.

The impact of demand response on the flexibility balance

Table 7 summarises the major results regarding the impact of DR on the mix of supply options to meet the total annual demand for flexibility in CA2030 and NM2050 (including, for comparative reasons, the reference scenario R2015), whereas Figure 1 presents similar results on the *average* hourly demand for flexibility in these scenario years.

Table 7 shows that the total annual demand for (upward and downward) flexibility rises from 4.4 TWh in R2015 to 9.9 TWh in CA2030, i.e. an increase by some 125%. In NM2050, however, this demand for flexibility grows even harder to almost 52 TWh, i.e. an increase by about 420% compared to CA2030 and by approximately a factor 12 compared to R2015.

In addition, Table 7 shows that the total annual supply of flexibility by DR amounts to 1.6 TWh in CA2030 and increases more than tenfold to 17.5 TWh in NM2050, while Figure 1 illustrates that the *average* hourly supply of flexibility by DR increases similarly from 186 MW/#h in CA2030 to 2000 MWh in NM2050. As a share of the total annual flexibility demand in these scenario years (without DR), this implies that in CA2030 about one-sixth (16%) of this demand is met (or, actually, ‘reduced’) by means of flexibility offered by DR while in NM2050 this share rises to more than one-third (34%).

Table 7: Summary of major results regarding the impact of demand response (DR) on the mix of options to meet the total annual demand for flexibility in CA2030 and NM2050 with and without DR (DR versus NoDR), including the reference scenario year 2015 (R2015)

		Non-VRE generation	VRE curtailment	Trade	Storage	Demand response	Total flex demand/ supply
Total annual supply of (upward and downward) flexibility by option (TWh)							
R2015	NoDR	4.00	0.00	0.40	0.00	0.00	4.40
CA2030	NoDR	2.62	0.06	7.25	0.00	0.00	9.93
	DR	1.92	0.04	6.24	0.10	1.63	9.93
NM2050	NoDR	0.56	21.24	21.43	8.54	0.00	51.76
	DR	0.06	14.57	18.67	0.92	17.54	51.76
As share of total flex supply (%)							
R2015	NoDR	90.9	0.0	9.1	0.0	0.0	100
CA2030	NoDR	26.4	0.6	73.0	0.0	0.0	100
	DR	19.4	0.4	62.8	1.0	16.4	100
NM2050	NoDR	1.1	41.0	41.4	16.5	0.0	100
	DR	0.1	28.1	36.1	1.8	33.9	100
DR induced change in total annual supply of flexibility (in TWh)							
CA2030	DR-NoDR	-0.70	-0.02	-1.01	0.10	1.63	0.0
NM2050	DR-NoDR	-0.49	-6.67	-2.76	-7.62	17.54	0.0

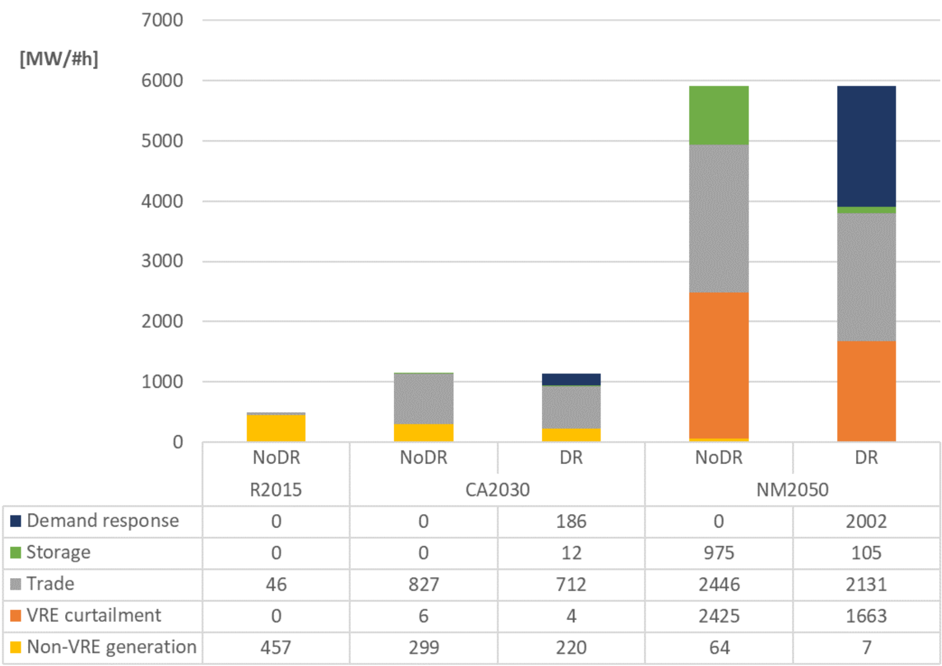

Figure 1: Mix of supply options to meet the average hourly demand for flexibility in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)

In CA2030, the total annual supply of flexibility by DR implies that less flexibility is needed from other sources, notably from trade (-1 TWh) and non-VRE generation (-0.7 TWh), while in NM2050 less flexibility is needed from particularly storage (-7.6 TWh), VRE curtailment (-6.7 TWh) and trade (-2.8 TWh; see Table 7).

Discussion of part II

The scenario results on the impact of DR on the power system of the Netherlands in the coming decades (2030-2050) do not only depend on the potential (size) of DR in these decades (as discussed in part I of this study) but also on the key assumptions of the respective scenarios. This applies in particular for the scenario year NM2050 (which includes more long-term uncertainties and bold assumptions than scenario CA2030).

The assumptions and parameters used for the (‘extreme’) scenario NM2050 result, among others, in a relatively high (‘suboptimal’) installed capacity/supply of VRE power generation versus a relatively low electricity demand. In turn, this results in a relatively large number of hours with a relatively large surplus of VRE power generation (compared to electricity demand), relatively large (net) exports of electricity, relatively large volumes of VRE curtailment, and a relatively large number of hours with low electricity prices.

It is hard to say whether and, in particular, to which extent the assumptions of the NM2050 scenario affect the results regarding the impact of DR in this scenario. In general, the direction and size (‘order of magnitude’) of this impact seems to be in line with the impact of DR in CA2030 (which has less long-term uncertainties and less ‘bold’ assumptions), accounting with the difference in the potential (size) of DR in these scenario years.

Moreover, it should be noted that the assumptions of the (uncertain, extreme) scenario NM2050 apply not only for the case with DR but also for the case without DR. Hence, by comparing the scenario results between the cases with and without DR some useful insights are obtained in the size and direction of the impact of DR within the scope and limits of the scenario (as within the scope and limits of any other long-term scenario).

Finally, it should be remarked that comparing the results of the NM2050 cases with and without DR does not only offer useful insights into the potential impact of DR (i.e., what can be achieved by means of DR) but also on the limitations of DR (i.e., what is hardly or not able to be achieved by DR). For instance, the NM2050 scenario results show that DR is able to reduce VRE curtailment from 102 TWh in the case without DR to 73 TWh with DR, i.e. a reduction by 29 TWh (-28%). Despite this significant reduction of VRE curtailment, a large amount of VRE curtailment is still left (73 TWh), which DR is not able to address.

Another interesting (related) example of the scope and limitation of DR refers to its impact on electricity prices. The COMPETES results for NM2050 show that over some 2400 hours electricity prices are substantially lower in the case with DR (compared to the relatively high electricity prices in the case without DR), whereas during some 1200 hours they are significantly higher (compared to the relatively low electricity prices in the case without DR). Over the remaining 5200 hours, however, DR has hardly or no impact as electricity prices are highly similar in the cases with and without DR, notably during some 4000 hours in which the electricity price is set at the low level of 2 €/MWh (by a marginal VRE unit). These are generally hours in which there is still a VRE surplus despite the deployment of DR and other flexible options such as VRE curtailment or cross-border trade (exports).

More generally, the two related examples outlined above show that DR, to some extent, is able to improve ('optimise') the performance of the power system as indicated by the DR induced reduction of the total system costs. However, if there is a fundamental mismatch between, e.g., the assumed (exogenously determined) capacity of VRE power generation and the demand for electricity, DR is only partially – but not fully – able to correct this mismatch and, hence, a sub-optimal situation – from a social cost perspective – will continue. Therefore, in order to move towards a more optimal social outcome with regard to the (future, climate-neutral) power system, an appropriate match between installed VRE generation capacity and electricity demand has to set initially (which can be further optimised by means of flexible options such as DR).

1 Introduction

Background

The Netherlands is aiming at a climate-neutral energy system in 2050. 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 due to the further penetration of so-called ‘power-to-X’ (P2X) technologies such as power-to-heat (P2H), power-to-hydrogen ($P2H_2$) or power-to-mobility (P2M), and – as a result of these two combined trends – (iii) a higher need for system integration and flexibility to deal with large fluctuations as well as with large surpluses and shortages of VRE power production in the short, medium and long term.

More specifically, low-carbon power systems with a relatively high share of VRE sources in total domestic electricity demand, such as the foreseen Dutch power system in 2030 and beyond, are usually characterised by two related issues regarding the so-called ‘*residual load*’ (RL) of the system, where residual load – or ‘*residual demand*’ – is defined as the difference between total electricity demand and the supply of electricity from VRE sources. These issues – or ‘challenges’ – include:

- The incidence of, on the one hand, a large number of hours with a (relatively large) *positive* RL – i.e., hours with a ‘*VRE shortage*’, usually characterised by high electricity prices – and, on the other hand, a large number of hours with a (relatively large) *negative* RL – i.e., hours with a ‘*VRE surplus’*, usually characterised by (very) low (or even negative) electricity prices. Hours with a VRE shortage raise the question how this shortage can be met, notably in a carbon-free and cost-effective way. Hours with a VRE surplus raise the question how this surplus can be used in an optimal way or, related to this, how low (negative) electricity prices can be avoided and increased to higher levels in order to improve the business case of market-based investments in VRE technologies.
- The high and increasing *variability* of the RL. The variability of the RL is the main source (‘cause’) of the need for flexibility (‘ramping’) by the power system. This raises the question how this high and increasing need for flexibility can be met in a reliable and cost-effective way, notably in a power system where the conventional supply of flexibility – i.e., by means of flexible fossil-fuel plants – is diminishing (or even disappearing).

Demand response is one of the options to deal with these two related issues. Firstly (to address the first RL issue), by increasing electricity demand in hours with a negative RL (VRE surplus) and decreasing electricity demand in hours with a positive RL (VRE shortage). Secondly (to address the second RL issue), by changing (‘*differentiating’*) the level of DR either *upwards*, thereby offering upward flexibility (‘*ramping’*) to the power system, or *downwards*, thereby offering downward flexibility. In the current study, DR – in both the ‘absolute’ and ‘differential’ way – is offered by four P2X technologies (also called ‘*flexible load options*’ or simply ‘*DR options*’):

- *Power-to hydrogen* ($P2H_2$);
- *Power-to-heat in industry* (P2H-i), notably hybrid (electricity/gas) boilers to generate industrial heat;
- *Power-to-heat in households* (P2H-h), in particular all-electric heat pumps for household space heating and hot water purposes;
- *Power-to-mobility* (P2M), especially passenger electric vehicles (EVs).

Besides DR, other major categories of flexible options to deal with the two RL issues outlined above, and included in the current study, refer to:

- *Non-VRE generation*, i.e. power generation from flexible and less flexible sources, excluding sun and wind, such as (green) gas, biomass, hydro or nuclear;
- *VRE curtailment,* i.e. curtailment of power generation from VRE sources;
- *Trade,* i.e. exports/imports of electricity to/from other countries;
- *Storage,* i.e. charges/discharges of electricity by means of storage technologies such as batteries or compressed air energy storage (CAES).

Objective and scope

The overall objective of the current study is to analyse the role of demand response in the power system of the Netherlands over the years 2030-2050. The *role* of demand response (DR) refers both to the *potential* (size) of DR in these years as well as to the *impact* of this potential on the performance of the power system in the Netherlands. In order to deal with the two related issues regarding the residual load of the power system, the role of demand response is analysed within the context of a European electricity market system, including other, competing flexible options such as trade or storage.

Approach

In order to reach the objective mentioned above, this study defines and uses two reference scenarios, one for 2030 and one for 2050, both with and without DR. These scenarios, as well as some sensitivity cases for 2050, are analysed by means of the COMPETES model. This is a European electricity market model – based on an hourly time resolution – which includes both a variety of power generation technologies, flexible P2X/DR technologies and other, competing flexible options such as trade or storage.

Report structure and definition of key concepts

This report consists primarily of two parts, focussing on the potential of DR and the impact of DR, respectively. Part I analyses the potential (size) of DR by the four selected P2X technologies – both individually and added together – in 2030 and 2050. This analysis is based on the definition and application of the following three related concepts:

- *Electricity demand ('load'),* i.e. the (hourly/annual) electricity use by a technology or set of technologies – or even by the power system as a whole – in a certain scenario year.
- *Demand response (DR),* i.e. either *load switching* (between certain hours, notably from hours with relatively high electricity prices to hours with relatively low prices) or *load curtailment* (at certain hours, in particular at hours with relatively high electricity prices). In this study, DR is defined and measured as the difference (Δ) between electricity demand in the (scenario) case with DR, i.e. demand responds to changes in electricity prices, and electricity demand in the (same) case without DR, i.e. demand is not responsive to changes in electricity prices. If this difference is positive, it is called *upward* DR, and *downward* DR if the difference is negative.
- *Flexibility by DR,* i.e. the flexibility offered to the power system by one or more demand-responsive technologies. In this study, flexibility by DR is defined and measured as the difference (Δ) between DR at a certain hour t and DR at the previous hour t-1 (t = 1,….., 8760). If this difference is positive, it is called *upward* flexibility (by DR) and *downward* flexibility if the difference is negative.

Part II of the study analyses the impact of DR on the power system of the Netherlands in the scenario years CA2030 and NM2050. This analysis is conducted at three related levels:

- The impact of DR on the *electricity balance*, i.e. on the major components of (total) electricity demand and supply, including the impact of DR on related variables such as electricity prices, VRE supply revenues and total system costs;
- The impact of DR on the so-called '*residual load balance'*, i.e. the balance of flexible options to meet the residual load (RL), including in particular hours with a positive RL (VRE shortage) and hours with a negative RL (VRE surplus);
- The impact of DR on the so-called '*flexibility balance*', i.e. the total demand and supply of flexibility by the power system, where flexibility refers primarily to the *hourly variability* of the residual load (RL), defined and measured as the difference (Δ) between the residual load in hour t and the residual load in hour $t-1$ (with t = 1,…., 8760).

More specifically, the structure of this report runs as follows. First, Chapter 2 outlines the approach of the current study, including a brief description of the COMPETES model used, the two reference scenarios considered, the major model parameters and assumptions of these scenarios, as well as the selected P2X/DR technologies analysed in this study.

Subsequently, Part I of the report presents and discusses the study results regarding the potential (size) of DR in the power system of the Netherlands (2030-2050). More specifically, Chapter 3 analyses the (potential) electricity demand by the four selected P2X/DR options in CA2030 and NM2050, Chapter 4 explores the demand response of these flexible load options in these scenario years, Chapter 5 considers the supply of flexibility by these DR options, while Chapter 6 provides a summary and discussion of Part I of the report.

Next, Part II of the report presents and discusses the results regarding the impact of DR on the power system of the Netherlands (2030-2050). More specifically, Chapter 7 analyses the impact (of DR) on the electricity balance, Chapter 8 explores the impact on the residual load balance, Chapter 9 considers the impact on the flexibility balance, Chapter 10 discusses the results of some sensitivity cases for the scenario year NM2050 while, finally, Chapter 11 provides a summary and discussion of Part II of the report.

2 Approach

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

2.1 Brief description of 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 (maximizing social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of power generation units and transmission interconnections across European countries and regions.[2]

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 2).[3] 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).

[2] 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.

[3] Note that in Figure 2 the Balkan region also includes two EU countries, i.e. Greece and Croatia.

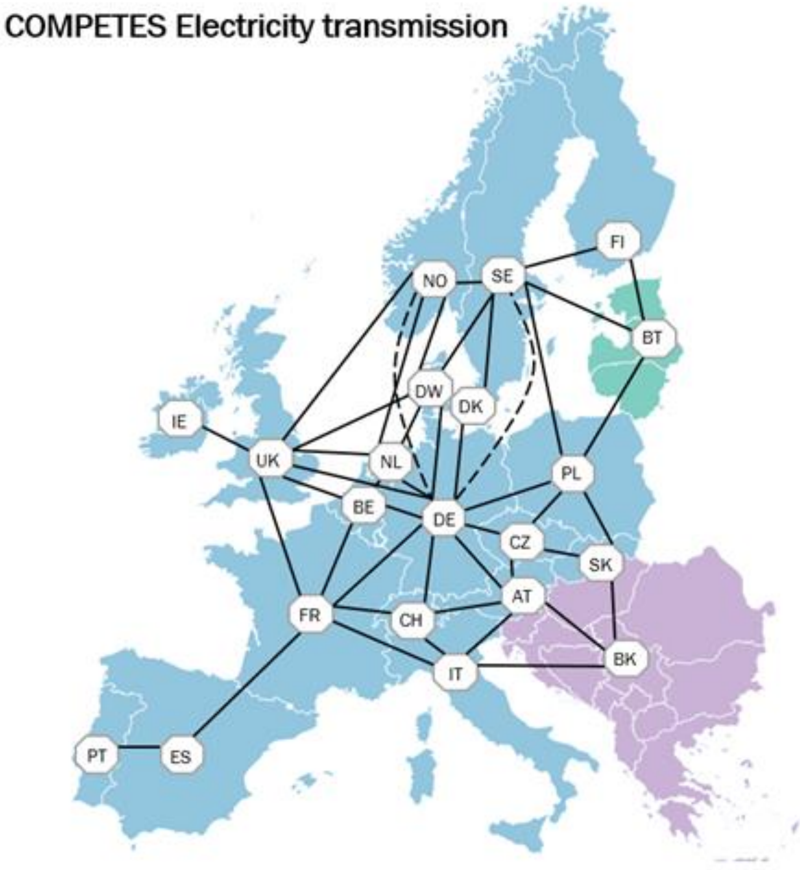

Figure 2: The geographical coverage of the COMPETES model

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, including:
    - Conventional electricity production, notably by means of natural gas and, to some extent, coal/nuclear energy;
    - Curtailment of renewable electricity generation from sun/wind;
- Cross-border power trade;

- Storage, in particular:
  - Pumped hydro (notably in other EU countries besides the Netherlands);
  - Compressed air energy storage (CAES), including both diabetic and advanced adiabatic CAES;
  - Batteries, including lead-acid (PB) batteries, vanadium redox (VR) batteries and, notably, lithium-ion (Li-ion) batteries, in particular for electric vehicles (EVs);
  - Underground storage of power-to-hydrogen ($P2H_2$);
- Demand response, notably by means of the following P2X technologies:[4]
  - Power-to hydrogen ($P2H_2$);
  - Power-to-heat in industry (P2H-i), notably hybrid (electricity/gas) boilers to generate industrial heat;
  - Power-to-heat in households (P2H-h), in particular all-electric heat pumps for household space heating and hot water purposes;
  - Power-to-mobility (P2M), especially passenger electric vehicles (EVs).

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 2.2 and 2.3. below.

2.2 Reference scenarios 2030 and 2050

As part of the current study, a reference scenario has been defined, quantified and analysed by COMPETES 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 (2.2.1 and 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

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[4] For details on the modelling of these technologies, see Section 2.4 below.

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 measures 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 below).

2.2.2 The National Management 2050 scenario

For 2050, our study is based on the so-called 'National Management 2050 scenario' (NM2050) as 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.[5] 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.

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 relatively high level of national energy self-sufficiency. Moreover, it shows a strong further electrification of all energy-use sectors, enabled by a very large installed capacity of sun PV and offshore wind (the biggest 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.

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

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 flexibility by the power system, including flexibility options such as energy storage and demand response.[6]

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 some sensitivity cases regarding this scenario (see Chapter 10).

2.3 Major model scenario parameters

2.3.1 Energy demand

Table 8 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:[7]

- *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 P2X technologies such as power-to-heat (P2H), power-to-mobility (P2M), or 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.[8]

More specifically, the additional power demand is distinguished into the following sub-categories (see lower part of Table 8):

- *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 112 TWh in NM2050;

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[6] The role of energy storage in the energy system of the Netherlands, 2030-2050, has been analysed in a previous study (Sijm et al., 2020), which has also used the NM2050 scenario to explore this role in 2050.

[7] Power demand assumptions for the Netherlands in 2030 are based on the policy targets and assumptions of the Dutch Climate Agreement of 2019, resulting in a total electricity demand of approximately 150 TWh in 2030. Based on the more recent EU's Fit-for-55 policy package, however, current (2022) power demand assumptions for the Netherlands are usually much higher, running up to about 200 TWh in 2030.

[8] 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 may be lower than indicated in Table 8, depending on the relative prices of electricity and gas to generate industrial heat (see also Chapters 3 and 4).

- *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;
- *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 passenger 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 million and 10.4 million EVs, respectively, using some 3 MWh per EV per annum.

Table 8: Electricity demand parameters for the Netherlands in CA2030 and NM2050 (without DR)

Parameter	Unit	CA2030	NM2050
Conventional power demand	TWh	116.9	116.9
Total additional power demand ('electrification')	TWh	34.2	231.4
Total power demand	*TWh*	*151.1*	*348.3*
Specification of additional power demand:			
# Baseload industry (fixed demand)	TWh	4.1	4.1
# Power-to-hydrogen (flexible demand)	TWh	10.0	111.1
# Power-to-heat (hybrid industrial boilers, flexible demand)	TWh	18.6	70.8
# Power-to-heat (household heat pumps, flexible demand)	TWh	0.3	14.3
# Power-to-mobility (passenger EVs, flexible demand)	TWh	1.2	31.1
Total additional power demand ('electrification')	*TWh*	*34.2*	*231.4*

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

For CA2030, the additional power demand figures presented in Table 8 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]

The only exception regarding additional power demand in CA2030 concerns the demand for power-to-hydrogen ($P2H_2$). In the above-mentioned scenario variant ('CA2030 Up'), 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

[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.

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 used in this study.

For NM2050, the additional power demand figures mentioned in Table 8 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).

For the other European countries and regions included in COMPETES similar electricity demand parameters for both CA2030 and NM2050 were obtained in line with the approach outlined above for the Netherlands (for details, see Appendix A, notably Table 51).

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, COMPETES includes a variety of (competing) primary energy sources and technologies, notably energy conversion technologies, e.g., from coal to electricity or from power to heat. In addition, it includes related technologies and options to reduce GHG emissions (renewables, CCS) in order to meet energy demand in a more sustainable, climate neutral way. Moreover, it covers also related technologies and options to offer flexibility to the system such as flexible generation, demand response, storage and trade in order to meet energy demand in a reliable, balanced way during each moment and time period of the year.

In the COMPETES model version used for this study, 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).[10] 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 9 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).[11] Subsequently, Table 10 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 52, of this study).

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[10] In a more recent, extended version of COMPETES, (dis)investments by these technologies can also be determined endogenously by the model.

[11] 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 9: Power generation technologies included in COMPETES

Fuel	Technology	Abbreviation	Exogenous[a]	Endogenous[b]	Deactivated[c]
Biomass	Co-firing	Bio-Co		x	x
Biomass	Standalone	Bio-St		x	x
Coal	Pulverized coal	Coal PC		x	x
Coal	Integrated gasification combined cycle	Coal IGCC	x		
Coal	Carbon capture and storage	Coal CCS		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		
Gas	Gas turbine	GT		x	
Gas	Combined cycle gas turbine	CCGT		x	
Gas	Combined heat and power	CHP		x	x
Gas	CCGT + Carbon capture and storage	CCS CCGT		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, the capacity for hydrogen electrolysis in CA2030 is assumed to be 2.0 GWe. Hence this capacity is set exogenously into COMPETES. To account for the (possible) additional power demand for H_2 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 COMPETES (see Table 10 below).

Table 10: Installed power generation capacity parameters for power generation technologies determined exogenously by COMPETES 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
Sun PV	GWe	25.1	106.0
Other RES-E	GWe	1.6	0.4

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

As mentioned, in addition to energy technologies, COMPETES includes also a variety of flexibility options. Table 11 presents the parameter values of available capacities of some major flexibility options in COMPETES for CA2030 and NM2050, both including and excluding demand response. 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 into COMPETES (notably for most DR options) while other parameters are optimised endogenously by the model (marked grey in Table 11).

Table 11: Available capacity of flexibility options in the Netherlands in CA2030 and NM2050 with and without demand response (DR versus NoDR)

Flexibility option	Unit	CA2030 NoDR	CA2030 DR	NM2050 NoDR	NM2050 DR
Demand response:					
Power-to-Mobility (EVs)	GWe	0	1.5	0	38.35
Power-to-Heat (household heat pumps)	GWe	0	0.205	0	9.47
Power-to-Heat (industrial hybrid boilers)	GWe	0	2.12	0	8.08
Power-to-Hydrogen	GWe	1.14	1.38	12.7	19.3
Storage size					
Li-ion batteries	GWh	0.4	0.4	0.5	0.5
VR batteries	GWh	0	0	9	0
H_2 underground	GWh	0	66	0	1536
Cross-border power trade:					
Interconnections	GWe	11.97	11.97	46.45	33.18

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).

2.3.3 *Hourly profiles*

COMPETES uses a variety of hourly profiles of energy demand and supply as inputs into the models. For the power sector, basically the same electricity demand profiles (before demand response) were used 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 COMPETES model.[12]

For the hourly profiles of power supply from variable renewable energy (VRE) sources, i.e. sun and wind, we basically used the same historic (2012) capacity factor profiles as in the FLEXNET project. We have, however, updated these profiles for 2030 and 2050 by means of the expected (higher) full load hours (FLHs) of these VRE technologies in these years (as these technologies are expected to become more efficient and, hence, more productive over these years).

Table 12 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 sun PV are expected to increase from 840 in 2015 to 924 in 2050 (+10%) and for offshore wind from 3580 to 5411, respectively (+51%).

Table 12: Full load hours of VRE power generation technologies in 2015, CA2030 and NM2050

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

As an example, Figure 3 shows the resulting hourly profiles of the capacity factor for sun 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.[13] In addition Figure 4 provides the duration curve of the hourly capacity factors for sun 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 sun 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 3). Therefore, these technologies have a different impact on the need for short-term (hourly/daily) flexibility of the energy system, including storage and demand response.
- Over the year as a whole (8760 hours), the profile of sun 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, sun 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 4). 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

[12] 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).

[13] 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.

some power production by wind up to 7000-8000 hours, whereas for sun PV this applies for less than 4000 hours (Figure 4). 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).

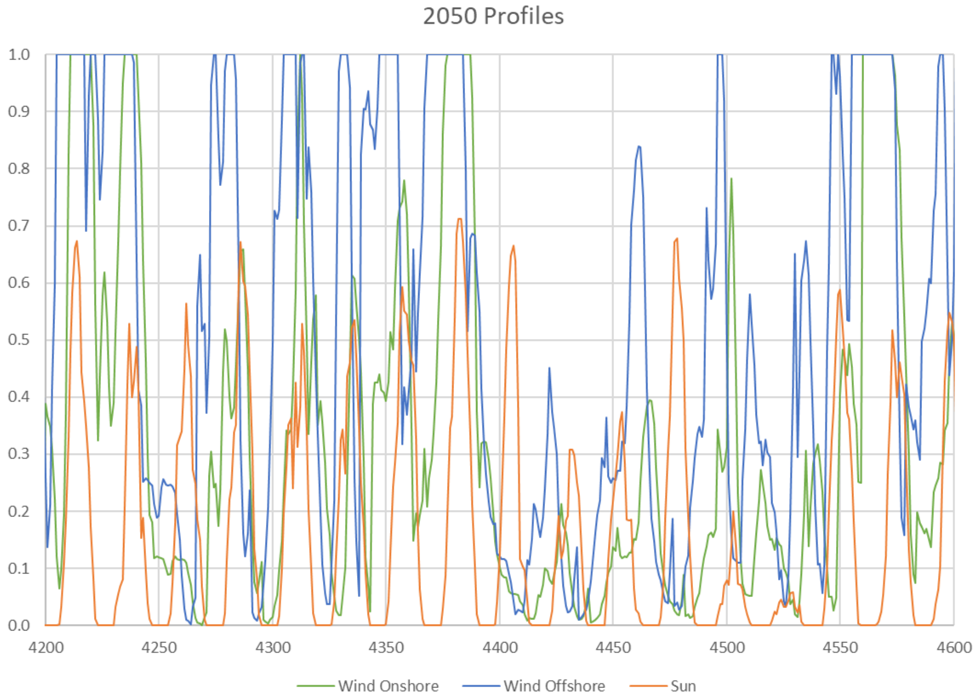

Figure 3: Hourly profiles of the capacity factor for sun PV and offshore wind during the middle of 2050 (hours 4200 – 4600)

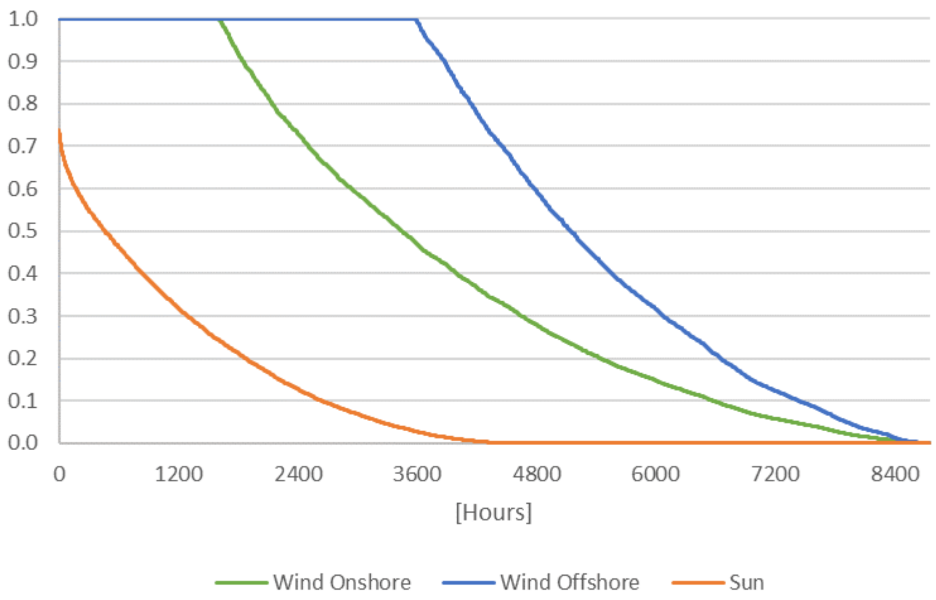

Figure 4: Duration curve of hourly capacity factors for sun PV and wind in 2050

2.3.4 *Fuel and CO_2 prices*

Table 13 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).

Table 13: Assumed fuel and CO_2 prices in CA2030 and NM2050

	Unit	2030	2050
Biomass UCO (foreign)	€_2020/GJ	17.47	17.47
Wood pellets (foreign)[a]	€_2020/GJ	3.09	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 actually 8.61 €_2020/GJ but 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 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 14).

Table 14: 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 national 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 for CA2030 and NM2050*

For the CA2030 scenario, COMPETES has used scenario parameters 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, COMPETES. Therefore, there is a close relationship between the inputs and outputs of the KEV2019 and the inputs and outputs of 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 (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.[14]

2.4 Demand response options modelled in COMPETES

All types of DR modelled in COMPETES can be characterised as either load shifting or load curtailment or a combination of both. More specifically, as said, the following flexible P2X technologies have been modelled as DR options in COMPETES:

- Power-to-mobility (P2M), especially passenger electric vehicles (EVs);
- Power-to-heat in households (P2H-h), in particular all-electric heat pumps for household space heating and hot water purposes;
- Power-to-heat in industry (P2H-i), notably hybrid (electricity/gas) boilers to generate industrial heat;
- Power-to hydrogen (P2H_2).

The modelling of these DR options in COMPETES is described briefly below.[15]

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[14] For a more detailed comparison of the modelling inputs and outputs (results) of the scenario NM2050 by COMPETES/TNO versus ETM/Berenschot and Kalavasta, see Sijm et al. (2020), notably Section 5.2.

[15] For a more extensive, recent paper on classifying and modelling demand response in power systems, see Morales-España et al. (2022). For the other EU27+ countries (besides the Netherlands), the same DR technologies – with the same characteristics, constraints, etc. – have been modelled in COMPETES as for the Netherlands, with the exception of hybrid heat technologies in industry in these other EU27+ countries due to a lack of relevant data.

2.4.1 *Electric vehicles (load shifting)*

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 controllable and the uncontrollable 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 respond to any change in the electricity price.

For the controllable part (70% of the total load), the model considers (i) availability, i.e. the hours 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 when EVs are connected to the grid, they 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 EVs by means of grid-to-vehicle (G2V) transactions.

EVs can also work as electrical storage by vehicle-to grid (V2G) transactions, where EVs can charge (during low prices) when being connected to the electric system and provide energy back (during high prices) if there is enough energy in the batteries for the next trip before departure. The model also makes sure that the degradation costs of the batteries are recovered when using V2G.[16]

2.4.2 *All-electric heat pumps in households (load shifting)*

In households, (all-electric) heat pumps (P2H-h) are used primarily for space heating and hot water purposes. For space heating with a heat pump there is inherently some flexibility due to the thermal inertia of the building. For example, it is possible to heat homes at night or during the day before the resident of the house gets up in the morning or gets home from work. Basically, the building is used as heat storage. Therefore, residential heat pumps can provide DR by load shifting. Especially in well-insulated buildings it is possible to shift the load to high VRE hours, without significantly reducing impacting the comfort level of the building (Patteeuw et al., 2015; De Wildt et al., 2022).

In COMPETES, all-electric heat pumps in households can shift their basic (‘dumb’) power consumption during a couple of hours – i.e. two hours forwards or backwards in the reference case – depending on the variable, hourly electricity price (Gils, 2014). Similar to EVs, the load of these heat pumps has a controllable part and an uncontrollable part. For the uncontrollable part (30% of the total load in the reference case), this load is just a fixed demand profile that does not respond to electricity prices and that is directly added to the conventional power demand.

For the controllable part (70% of the total load), the model can modify the initial demand profile by shifting part of the load according to the saturation and load recovery characteristics of thermostatically controlled load (O’Connell et al., 2016; Morales-España et al., 2022). The saturation characteristics imply that power load can be initially reduced (increased), but the local comfort constraints avoid that the

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[16] Further details about the mathematical modelling of EVs – including both demand response and electrical storage transactions – see Momber et al. (2014) and Morales-España et al. (2022).

temperature falls (increases) below (above) a given threshold. On the other hand, the load recovery characteristics imply that at the minimum temperature threshold level the local control will recover the load by forcing consumption to restart and bring the temperature level back to the set point.[17]

2.4.3 *Hybrid heat boilers in industry (load curtailment)*

Power-to-Heat in industry (P2H-i) refers to the use of electricity to generate heat for industrial processes. For this purpose, there are many different P2H technologies (Maruf et al., 2021). In COMPETES, the modelling of P2H in industry is restricted to the so-called E-boiler, including both the electric boiler and the electrode boiler.[18]

The E-boiler is an interesting option for demand response because it is an existing technology, which is very flexible, with low investment costs and a high efficiency (95-99,9%). Because most (energy-intensive) industries typically require a flat (fixed) baseload heat demand, an E-boiler can only be operated flexibly by some combination with either heat storage or heat production from another energy source. In COMPETES, only the latter option of a hybrid industrial boiler is modelled. With a hybrid industrial boiler heat can be supplied by either the E-boiler or the gas boiler depending on the relative gas and electricity prices. That results in electrical load when heat is provided by E-boilers, i.e. when the variable costs of producing heat from electricity are lower than that from gas.[19] Otherwise, the electrical load is curtailed and the heat load is supplied by the gas boiler (De Wildt et al., 2022).[20]

2.4.4 *Power-to-hydrogen (load shifting)*

Power-to-hydrogen (P2H_2) is the production of hydrogen through electrolysis, i.e. the process of splitting water into hydrogen and oxygen by means of electricity. For this process, three main types of electrolysers are available, including proton exchange membrane (PEM) electrolysers, alkaline electrolysers (AEL) and solid oxide electrolysers (SOE).

P2H_2 can provide demand response through load shifting, i.e. hydrogen production is increased when electricity prices are low and decreased when electricity prices are high. In the version of COMPETES used for this study, 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, in the COMPETES version used for this study, there is only one supply option to meet this demand, i.e. domestic production of hydrogen by means

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[17] More generally, saturation refers to the fact that at some level of load shifting or curtailment the maximum level is reached and it is not possible to further curtail or shift the load, whereas load recovery refers to the fact that after curtailment or load shifting, the load needs to recover to maintain on the same average level (Morales-España et al., 2022; De Wildt et al., 2022).

[18] Electric boilers use an electric heating element, whereas electrode boilers use the conductive and resistive properties of water to generate heat (Maruf et al., 2022).

[19] Note that in COMPETES the price of electricity is an endogenous model variable whereas the gas price is an exogenous model parameter.

[20] See Maruf et al. (2022) for a more extensive, recent paper on classifying and modelling power-to-heat and thermal energy storage technologies in energy systems (including both the residential sector and industry).

of electrolysis ($P2H_2$) without foreign trade of hydrogen.[21] 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 the electrolysers – 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.[22]

In the next chapters, the potential size of demand response by the four P2X technologies outlined above and its impact on a variety of power system variables by means of the COMPETES model for the scenarios CA2030 and NM2050 are further illustrated and analysed.

21 A more recent, upgraded version of the COMPETES model, however, also includes other options to produce hydrogen (notably SMR, i.e. by means of gas) as well as hydrogen interconnections between EU countries in order to trade hydrogen across these countries.

22 For a presentation and further analysis of the hourly profiles of hydrogen demand, supply and storage in CA2030 and NM2050 by means of the COMPETES version used for this study, see Chapter 3 of Sijm et al. (2020). See also Chapter 3 of the current report for a presentation of the hourly profiles (and duration curves) of P2H2 demand in CA2030 and NM2050 with and without demand response (DR versus NoDR), including the resulting potential size of DR by P2H2.

Part I: The potential of demand response

3 Electricity demand by flexible load options

This chapter considers the electricity demand by the four selected, flexible P2X technologies outlined in the previous chapter (Section 2.4) in the scenario years CA2030 and NM2050 with and without DR. More specifically, first of all Section 3.1 shows and discusses the hourly profiles and duration curves of the electricity demand (‘load’) of these flexible options, notably for NM2050. Subsequently, Section 3.2 presents and discusses results on maximum peak and off-peak load by the four flexible technologies in both CA2030 and NM2050, while Section 3.3 provides and analyses similar results on total (annual) and average (hourly) load. Finally, this chapter ends with a brief discussion (Section 3.4), in particular regarding the implications of the assumed default technology to generate industrial heat – i.e., by either a gas boiler or an E-boiler – notably for the electricity demand by power-to-heat in industry (P2H-i) in the scenario year CA2030 without DR.

3.1 Hourly profiles and duration curves of electricity demand by flexible load options

In order to determine the potential (size) of demand response by the four flexible load options, the first step is to develop and generate hourly profiles of the electricity demand by these options for the scenario years CA2030 and NM2050, both with and without DR, based on the assumed or estimated total annual electricity demand by each of these options in these scenario years (see Section 2.3.1, notably Table 8).

More specifically, for the technologies $P2H_2$ and P2H in industry in the scenarios without DR, we have assumed that the hourly load profile is basically flat, i.e. at a constant level equal to the total annual electricity demand by each of these technologies in a specific scenario year divided by the number of hours in the year (8760). For the other flexible P2X technologies (P2H in households and P2M by means of passenger EVs), we have basically used the same (normalised) load profiles as in the FLEXNET project (Sijm et al., 2017a).

For the scenarios with DR, the hourly load profiles of all four P2X options have been generated by the COMPETES model, based on dynamic (optimised) hourly electricity pricing. For NM2050 (both with and without DR), the resulting hourly load profiles are presented in the pages below for the four flexible P2X technologies, notably (i) $P2H_2$ (Figure 5), (ii) P2H in industry (Figure 6), (iii) P2H in households (Figure 7), (iv) P2M (Figure 8), and (v) all four flexible P2X technologies added together (Figure 9). For illustrative purposes, we have only presented the hourly profiles for two (contrasting) months, i.e. a winter month (January, hours 1-744) versus a summer month (July, hours 4345-5088; see the two upper graphs in each figure).

In addition to the hourly load profiles with and without DR, each graph also includes the hourly profiles of the (optimised, equilibrium) electricity prices with and without DR. Moreover, in the bottom graph of each figure, the duration curve of the electricity demand by each technology – and the four options added together – is presented over all hours of the year by ranking the hour(s) with the highest load in the upper left of the graph up to the hour(s) with the lowest demand in the bottom right.

Some observations from Figure 5 up to Figure 9 are discussed in the sections below.

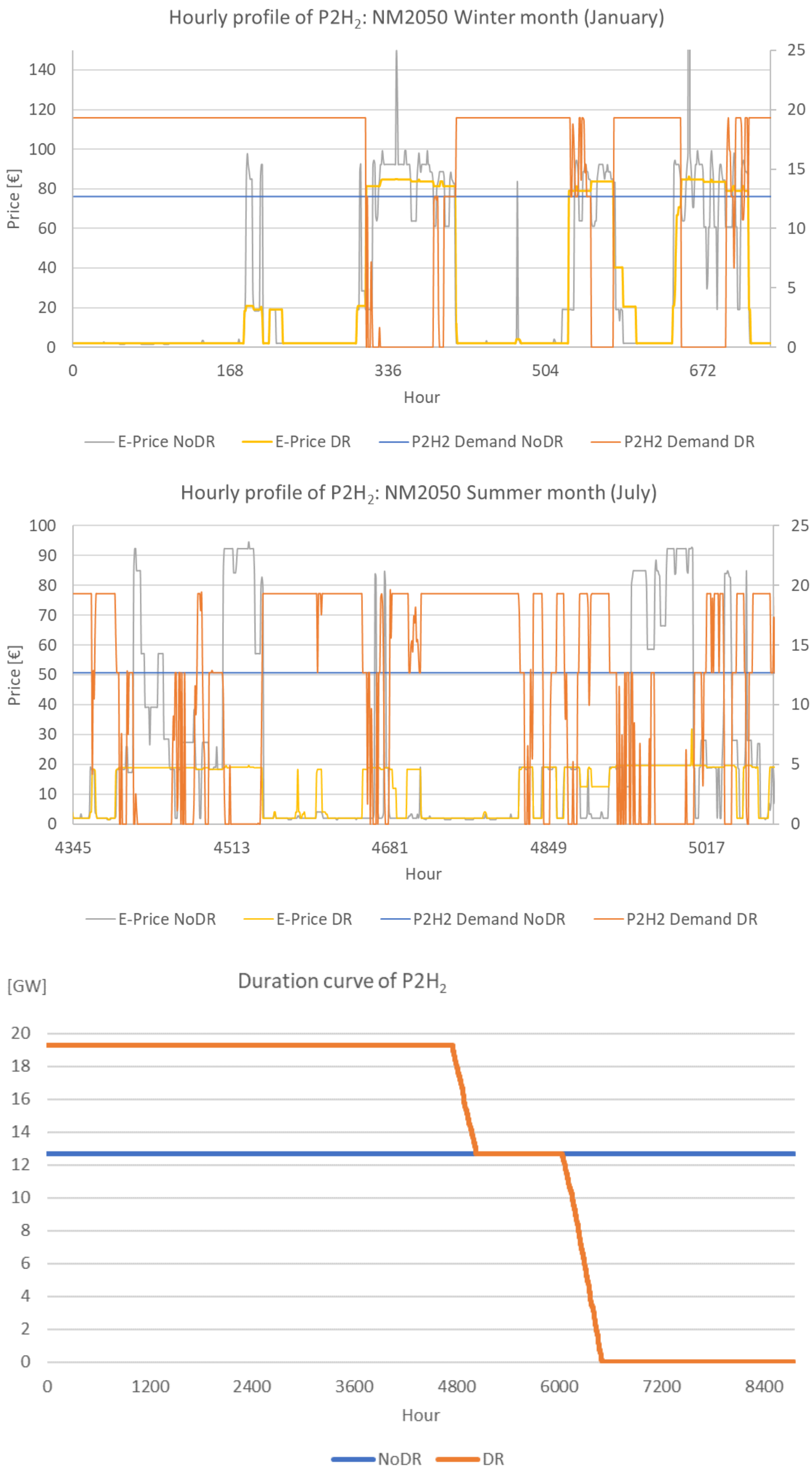

Figure 5: Hourly profile and duration curve of electricity demand by power-to-hydrogen ($P2H_2$) in NM2050, with and without demand response (DR versus NoDR)

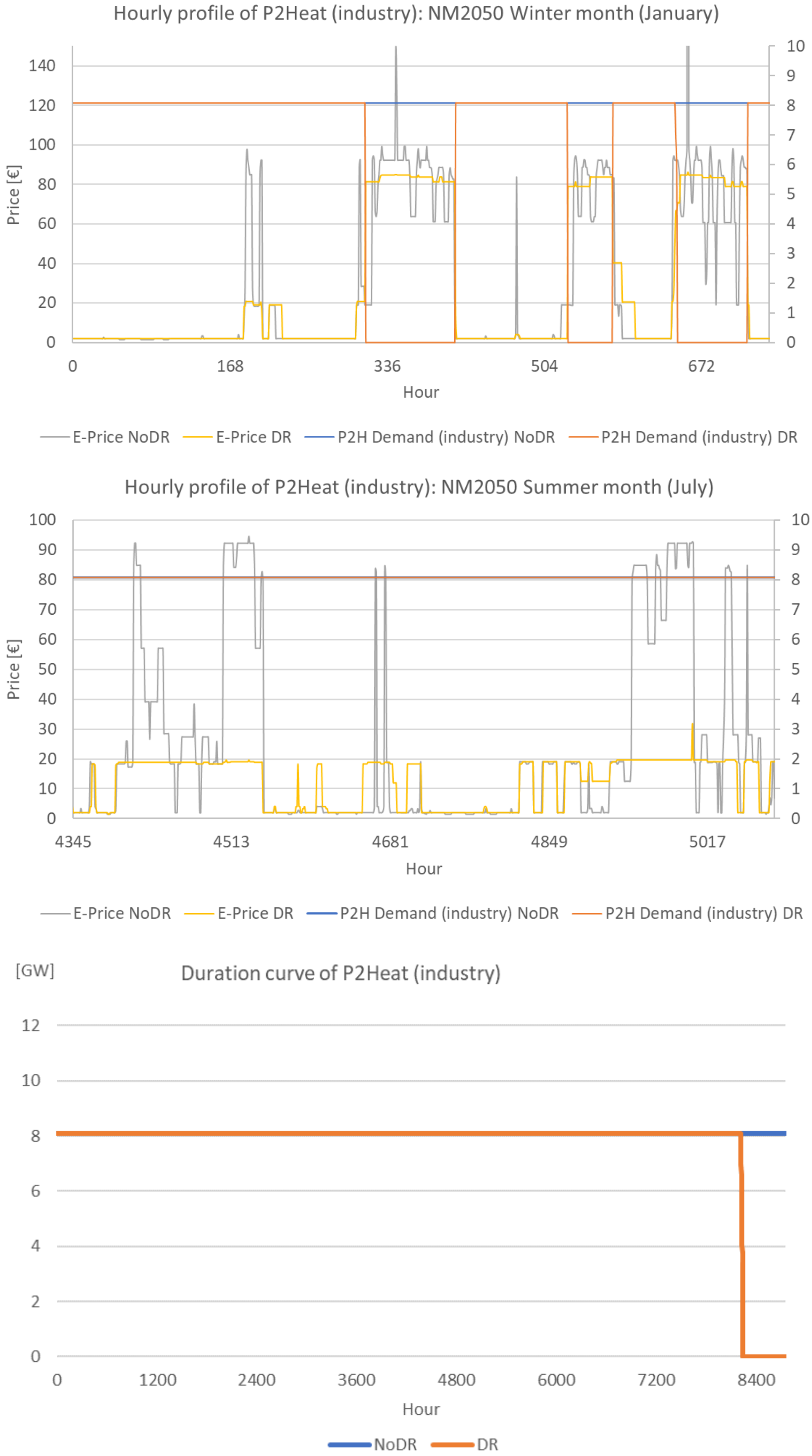

Figure 6: Hourly profile and duration curve of electricity demand by power-to-heat in industry (hybrid boilers) in NM2050, with and without demand response (DR versus NoDR)

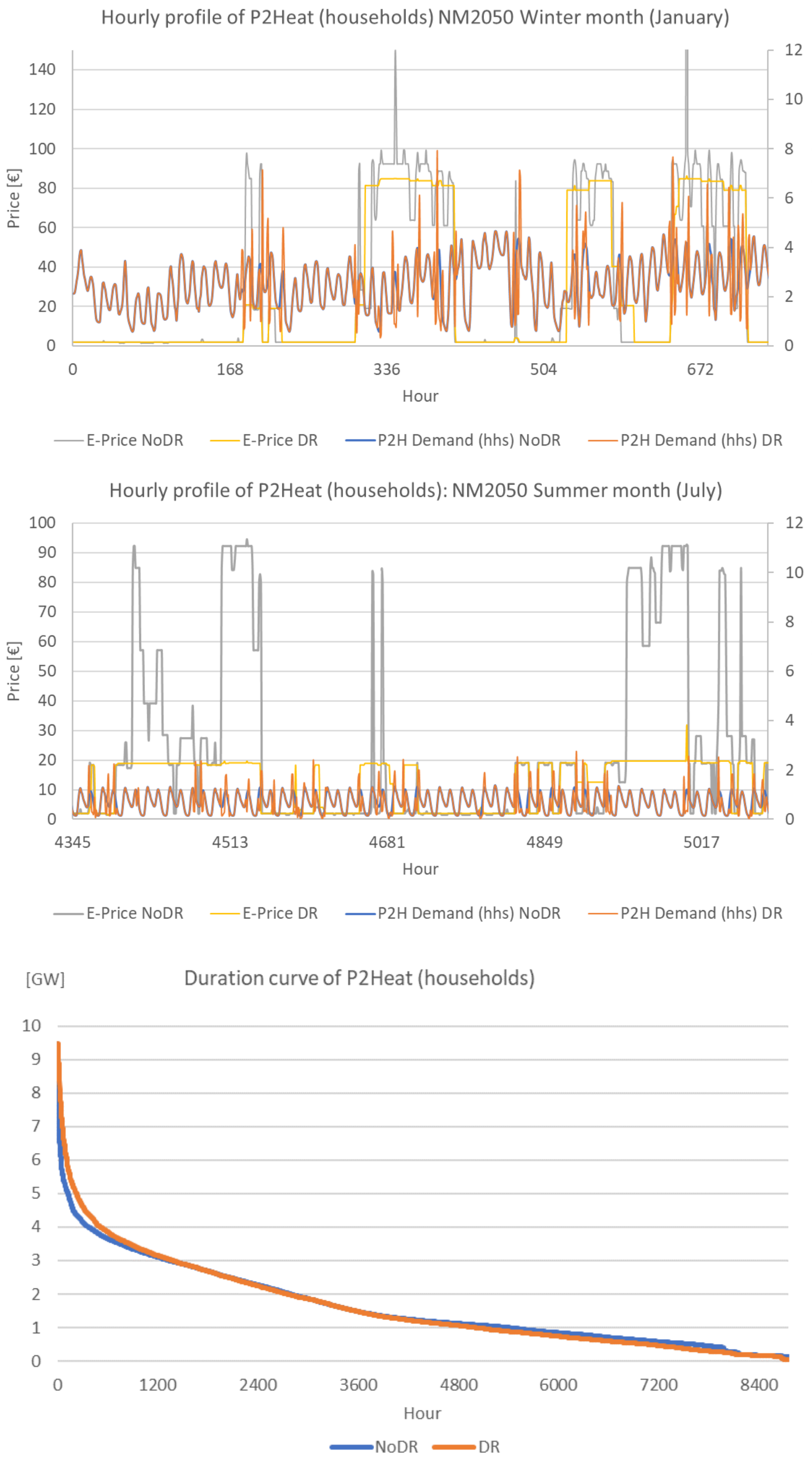

Figure 7: Hourly profile and duration curve of electricity demand by power-to-heat in households (heat pumps) in NM2050, with and without demand response (DR versus NoDR)

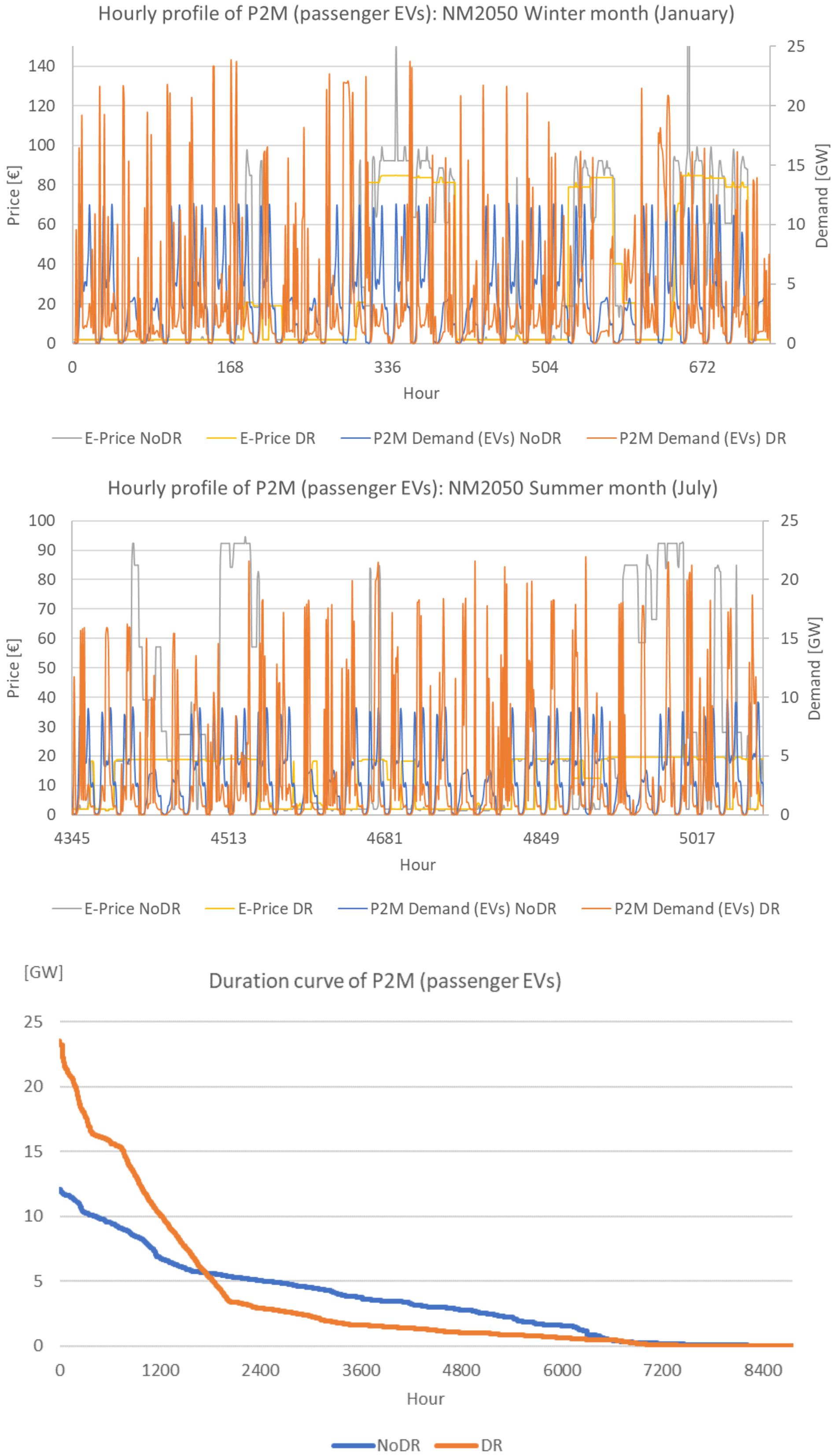

Figure 8: Hourly profile and duration curve of electricity demand by power-to-mobility (passenger EVs) in NM2050, with and without demand response (DR versus NoDR)

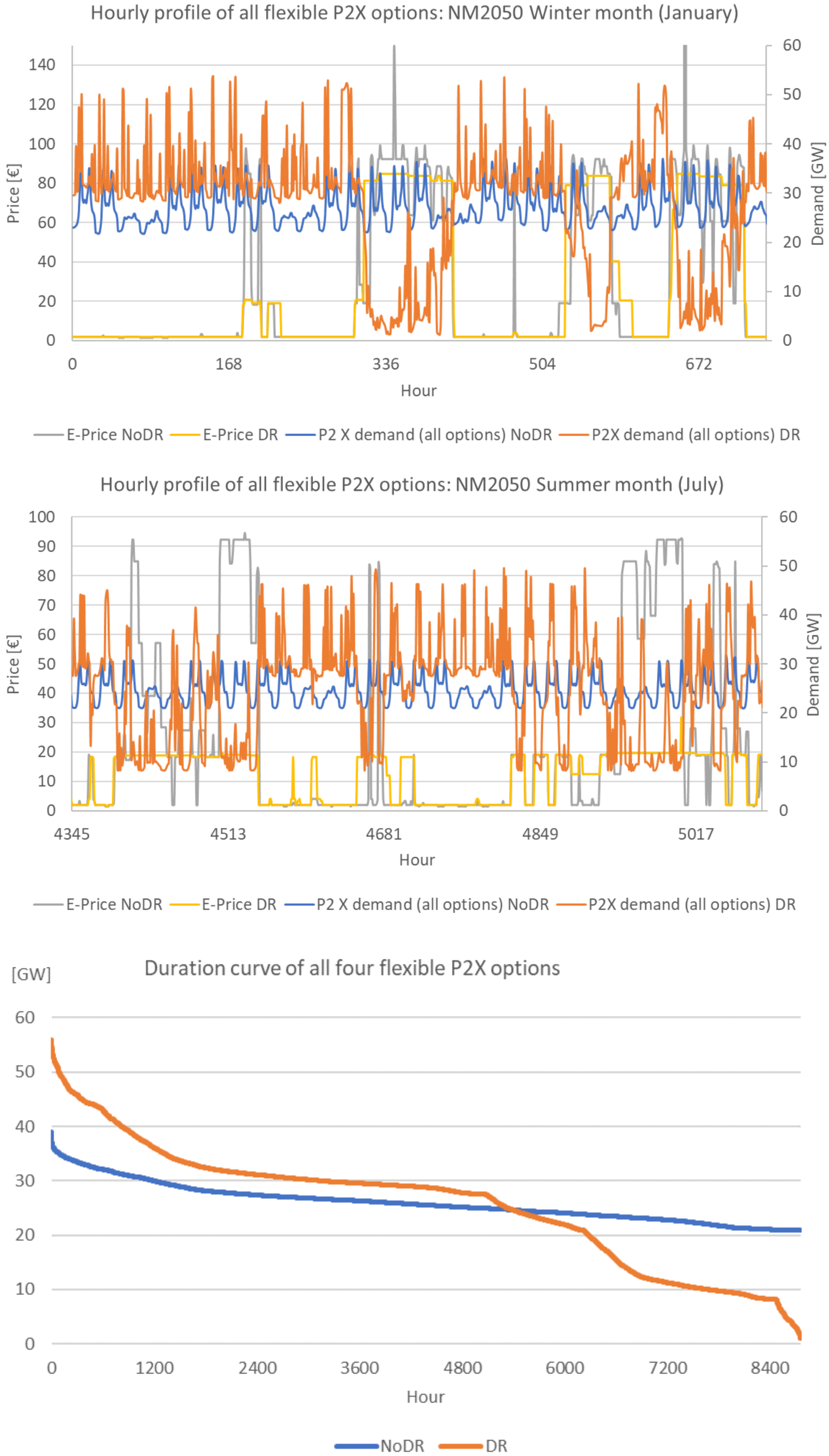

Figure 9: Hourly profile and duration curve of electricity demand by all four flexible P2X options in NM2050, with and without demand response (DR versus NoDR)

3.1.1 *Power-to-hydrogen ($P2H_2$, Figure 5)*

In order to enable DR by means of $P2H_2$ the total optimal capacity of the electrolysers in NM2050 is enhanced from 12.7 GWe (electricity input) in the reference case without DR to 19.3 GWe with DR, resulting in a lower capacity factor from 1.0 to about 0.7, respectively. In the case without DR (NoDR), electricity demand by $P2H_2$ is fixed (flat) at the level of 12.7 GWe throughout the year (see blue line in the two upper graphs of Figure 5). In the case with DR, however, electricity demand by $P2H_2$ fluctuates between zero and the upper capacity limit of 19.3 GWe (depending on the dynamic hourly electricity price level).

The upper graphs of Figure 5 illustrates that electricity demand by $P2H_2$ is more fluctuating ('price-responsive') in a summer month of NM2050 (July) than in a winter month (January). In the bottom graph of Figure 5, the annual duration curve of the hourly load by $P2H_2$ shows that in the case of DR over the year as a whole, this load is equal to the upper capacity limit of 19.3 GW during approximately 4800 hours – i.e., far above the flat (NoDR) level of 12.7 GWe – but zero during about 2200 hours of NM2050, i.e. far below the NoDR level, while it is somewhere between these two (extreme) levels over the remaining hours of the year.

3.1.2 *Power-to-heat in industry (P2H-i, Figure 6)*

Figure 6 shows that in the case of NM2050 without DR the flat demand for industrial heat is met by a fixed demand of P2H (i.e., E-boilers) at a constant level of 8.1 GW, i.e. the (assumed or estimated) annual demand for P2H in industry (70.8 TWh in NM2050) divided by the number of hours per year (8760). In the case with DR, however, this heat demand can be met by either an E-boiler or a gas boiler, depending on the relative prices (variable costs) of these two options.

The upper graph of Figure 6 shows that in January NM2050 (with DR) during most of the hours in this winter month the need for industrial heat is met by an E-boiler (P2H), while in the remaining hours it is met a gas boiler, i.e. only in those hours in which the electricity price after DR (by all flexible load options) remains relatively high. In July NM2050, the need for industrial heat in the case with DR is even met by an E-boiler during all hours of this (summer) month as the electricity price after DR remains relatively low throughout this period (see middle graph of Figure 6).

Finally, over the year as a whole, the lower graph of Figure 6 shows that in the case of NM2050 with DR the need for industrial heat is met by P2H (i.e., by E-boilers) during more than 8200 hours of the year, thereby covering about 94% of the annual demand for industrial heat. This implies that during the remaining hours over the year (about 600) gas boilers account for the remaining share (about 6%) of the annual industrial heat demand.[23]

3.1.3 *Power-to-heat in households (P2H-h, Figure 7)*

All-electric heat pumps in households are used primarily for space heating – notably during the winter period – and, to a lesser extent, for hot water purposes (throughout the year).[24] As a result, the hourly electricity demand by these heat pumps is usually

[23] Figure 6 presents the case of P2H-i only for the scenario year NM2050. It should be noted, however, that this case is completely different for scenario year CA2030 (as discussed further in Section 3.2.5).

[24] Some heat pumps can also be used for cooling during hot (summer) periods, but this option has not been included in the COMPETES model scenarios of this study.

much higher – and more volatile/irregular – during the winter season than during the summer period, as illustrated by the upper graphs of Figure 7 for the months January and July of NM2050, respectively. These graphs, however, also show that the differences in this demand between the cases with and without DR are generally small or even absent (or, in any case, hardly or not visible in these graphs), although notably in January (winter month) there are some hours with a significantly high(er) peak load and a large amount of hours with a slightly lower off-peak demand in the case with DR (but, as said, hardly visible in the graph concerned). This observation is confirmed by the P2H duration curve in the bottom graph of Figure 7, which shows that in NM2050 electricity demand by household heat pumps during a limited number of peak hours (upper left of the duration curve) is significantly higher in the case with DR (compared to NoDR), whereas during a large amount of mid- and off-peak hours it is slightly lower (bottom right of the duration curve).

3.1.4 Power-to-mobility (P2M by passenger EVs, Figure 8)

In contrast to the power load by household heat pumps, the differences in hourly electricity demand by passenger EVs in NM2050 are generally much smaller between a winter month (January) and a summer month (July), notably in the case without DR (see upper graph of Figure 8). On the other hand, however, these graphs indicate that the differences in this demand are usually much larger in both months between the cases with and without DR. This observation is confirmed by the P2M duration curve in the bottom graph of Figure 8, which illustrates that in NM2050 electricity demand by passenger EVs during a large number of peak hours (up to about 1500 hours) is substantially higher in the case with DR (compared to NoDR), whereas during even a larger amount of mid- and off-peak hours (i.e., more than 4000 hours) it is significantly lower.

3.1.5 All flexible P2X technologies (Figure 9)

Finally, Figure 9 presents the hourly profile of electricity demand by all four flexible P2X technologies in the months January and July for scenario NM2050 – simply by aggregating the respective load profiles of the individual technologies – as well the duration curve of this demand over the year as a whole (just by ranking the aggregated hourly load figures from the highest – peak – values in the upper left of the curve to the lowest – off-peak – values in the bottom right).

The most striking observation from the two (monthly) graphs of the hourly load profile is that the aggregated electricity demand of the four P2X options fluctuates far more heavily – i.e., both higher peaks and lower off-peaks – in the case with DR than without DR. This is confirmed by the bottom graph of Figure 9, showing that the load duration curve of all P2X options is much steeper in the NM2050 case with DR than without DR. More specifically, compared to the case without DR, hourly peak loads are substantially higher in the case with DR (for more than 5000 hours) whereas off-peak loads are substantially lower (for more than 3000 hours).

3.2 Maximum peak and off-peak load

Table 15 presents the maximum values of the peak and off-peak load by the four P2X technologies – both individually and added together – in CA2030 and NM2050 with and without DR. Note that for NM2050 these values correspond to the highest and lowest points of the load duration curves of the respective technologies in Figure 5 up to Figure 9. As indicated by these graphs, the peaks are usually (much) higher in the case with DR (compared to NoDR) whereas the off-peaks are often lower. For instance, in NM2050 without DR the highest peak load amounts to 39 GW while the lowest off-peak is 21 GW, compared to 56 GW and 1 GW, respectively in the case with DR. In CA2030, however, the spread ('variability') between the peak and off-peak values – both within and between the cases with and without DR – is generally much smaller than in NM2050, simply because the (total/average) electricity demand is still much smaller in CA2030 (see below).[25]

Table 15: Maximum values of peak and off-peak load by the four selected P2X technologies in CA2030 and NM2050 with and without demand response (DR versus NoDR)

[GW]	CA2030				NM2050			
	Peak		Off-peak		Peak		Off-peak	
	NoDR	DR	NoDR	DR	NoDR	DR	NoDR	DR
$P2H_2$	1.1	1.4	1.1	0.0	12.7	19.3	12.7	0.0
P2H-i	2.1	2.1	2.1	0.0	8.1	8.1	8.1	0.0
P2H-h	0.2	0.2	0.0	0.0	9.5	9.5	0.1	0.0
P2M (EVs)	0.5	1.0	0.0	0.0	12.1	23.5	0.0	0.0
All options	3.9	4.6	2.5	0.0	39.0	55.9	20.9	1.1

3.3 Total and average electricity demand

By aggregating hourly electricity demand over the number of hours in a year the total annual load is obtained. In Figure 5 up to Figure 9, i.e. for the respective P2X technologies, this total annual electricity demand corresponds to the surface of the areas between the X-axis and the load duration curves of the technologies in the bottom graphs of these figures.

Table 16 presents the total electricity demand of the P2X technologies in CA2030 and NM2050 with and without DR. For load shifting technologies, the total annual load in the case without DR is assumed (or expected) to be more or less equal to the total annual load with DR. In Table 16 this is indeed the case for the three load shifting technologies in CA2030 ($P2H_2$, P2H-h, P2M) as well as for P2H-h in NM2050 but not for $P2H_2$ and P2M in NM2050. For $P2H_2$, total annual load in NM2050 with DR is about 0.9 TWh higher than total annual load in NM2050 without DR, while for P2M it is 0.6 TWh higher. This is due to the fact that DR by $P2H_2$ and P2M leads to higher energy storage needs (of hydrogen and electricity, respectively), resulting in higher storage losses and, hence, to a higher electricity demand to cover these losses.[26]

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[25] Note that usually the maximum peak load of all options added together is lower than the sum of the maximum peak loads of the individual options (while the off-peak load of all options is often higher). For instance, in NM2050 with DR, the peak load of all options added together amounts to almost 56 GW, while the sum of the peak loads of all options individually amounts to more than 60 GW (Table 15). The reason for this is simply that the peak (off-peak) loads of individual P2X options are achieved in different (multiple) hours over the year whereas the peak (off-peak) load of all options added together is reached in a single hour.

[26] The small differences (less than 0.1 TWh) in electricity demand with and without DR by $P2H_2$ and P2M in CA2030 are also due to higher energy storage losses in the case with DR. The links between DR and energy storage – notably for $P2H_2$ – have been further explored in Sijm et al. (2020). Note that in the case of P2M (passenger EVs) DR encourages both grid-to-vehicle (G2V) and vehicle-to grid (V2G) transactions (for both car driving and power system balancing purposes), resulting in higher EV storage needs and, hence, in higher storage losses and, on balance, a higher electricity demand by EVs.

Table 16: Total and average electricity demand by the four selected P2X technologies in CA2030 and NM2050 with and without demand response (DR versus NoDR)

[TWh]	CA2030			NM2050		
	NoDR[a]	**DR**	**Difference**	**NoDR[a]**	**DR**	**Difference**
$P2H_2$	10.0	10.1	0.0	111.1	112.1	0.9
P2H-i	18.6	3.0	-15.6	70.8	66.6	-4.2
P2H-h	0.3	0.3	0.0	14.3	14.3	0.0
P2M (EVs)	1.2	1.3	0.0	31.1	31.7	0.6
All options	30.2	14.7	-15.5	227.3	224.7	-2.6
As % of total load by all options						
$P2H_2$	33%	69%		49%	50%	
P2H-i	62%	21%		31%	30%	
P2H-h	1%	2%		6%	6%	
P2M (EVs)	4%	9%		14%	14%	
All options	100%	100%		100%	100%	
Average electricity demand by all P2X options (GW/#h)						
All options	3.4	1.7		25.9	25.6	

a) See Section 2.3.1, notably Table 1.

For load curtailing technologies, electricity demand in the case with DR is (by definition) always lower than in the case without DR. More specifically, in case of power-to-heat in industry (P2H-i), an E-boiler is assumed to be the default technology during all hours of both CA2030 and NM2050 without DR. Hence, the demand for industrial heat in these scenario cases is met fully by means of electricity. In the case without DR, however, a part of the need for industrial heat may be met by gas boilers (depending on the relative prices of gas and electricity), resulting in a lower electricity demand by P2H-i (compared to the case with DR). In NM2050, this lower electricity demand amounts to 4.2 TWh and in CA2030 even to almost 16 TWh (see also Section 3.4 below).

In CA2030, total annual load by all four P2X technologies amounts to more than 30 TWh in the case without DR and to almost 15 TWh with DR, i.e. a relatively large difference in electricity demand due to DR of more than 15 TWh. As indicated above, this difference results primarily form the large amount of load curtailment by P2H-i in the case of CA2030 with DR. In NM2050, however, this difference in total electricity demand by all P2X technologies due to DR is much lower, i.e., on balance, about 2.6 TWh, while the total load figures in the cases with and without DR are much higher, i.e. about 225 and 227 TWh, respectively (see upper right of Table 16).

In CA2030 without DR, total electricity demand by all four P2X technologies is dominated by P2H-i (with a share of almost 62%) and, to a lesser extent, by $P2H_2$ (33%). In CA2030 with DR, however, electricity demand by P2H-i drops substantially – as noted above – and, consequently, these shares change drastically in this case to 21% and 69%, respectively. In NM2050, on the contrary, these shares are rather stable between the cases with and without DR, i.e. about 49-50% for $P2H_2$ and approximately 30-31% for P2H-i, whereas the remaining shares are accounted for by P2M (14%) and P2H-h (6%).

The bottom line of Table 16 presents the *average* electricity demand by the four selected P2X technologies in CA2030 and NM2050. It shows that in CA2030 this average load amount to 3.4 GW/#h in the case without DR and to 1.7 GW/#h with DR, whereas in NM2050 it is substantially higher, i.e. almost 26 GW/#h in both cases.

Table 17 presents the total annual (flexible) load by all four P2X technologies as a share of total domestic load in CA2030 and NM2050. It indicates that in CA2030 this share amounts to 20% in the case without DR, but drops to 11% with DR, whereas in NM2050 it rises to 65% in both cases.

Table 17: Total fixed and flexible electricity demand in CA2030 and NM2050 with and without demand response (DR versus NoDR)

[TWh]	CA2030		NM2050	
	NoDR	DR	NoDR	DR
Total (flexible) load by all four P2X technologies[a]	30.2	14.7	227.3	224.7
Total fixed load[b]	121.0	121.0	121.0	121.0
Total domestic load	*151.2*	*135.7*	*348.3*	*345.7*
Total (flexible) load by all four P2X technologies as % of total domestic load	20%	11%	65%	65%

a) For details see Table 16 above. Note that in the cases without DR total demand by all four P2X technologies is not flexible but fixed (i.e. not responding to hourly electricity prices).
b) Total fixed demand includes conventional power demand and additional industrial baseload. For details see Section 2.3.1, notably Table 8.

3.4 Discussion

As noted, for the case of power-to-heat in industry (P2H-i) it is assumed that an E-boiler is the default technology in the case without DR in both CA2030 and NM2050, i.e. an E-boiler is producing industrial heat during all hours of the year. For NM2050, this assumption makes sense as in the case with DR – allowing both gas and E-boilers, depending on their relative variable costs – an E-boiler is the dominant, competitive technology, i.e. meeting the demand for industrial heat at the lowest cost during more than 8200 hours of the year, thereby covering about 94% of this annual demand.

For CA2030, however, the assumption mentioned above may be questioned. Due to the relatively high electricity prices in the case of CA2030 with DR, the need for industrial heat is met by E-boilers only during some 1400 hours of the year, i.e. covering approximately 16% of the total annual industrial heat demand, whereas gas boilers account for about 84% of this demand during the rest of the year (some 7400 hours). Hence, it could be argued that for CA2030 a gas boiler should be the default technology in the case without DR.

Assuming that a gas boiler (rather than an E-boiler) would be the default technology in the case of CA2030 without DR would significantly change the picture of the electricity demand by P2H-i in this case (whereas it would remain the same in the case with DR). This is illustrated in Table 18, which presents the total annual load by the four selected P2X technologies in CA2030 with and without DR, assuming that a gas boiler is the default technology for industrial heat in the case without DR (while, as discussed, Table 16 provides comparative results assuming that an E-boiler is the default technology).

Table 18: Total electricity demand by the four selected P2X technologies in CA2030 with and without demand response (DR versus NoDR), assuming that a gas boiler (rather than an E-boiler) is the default technology in the case without DR

	Electricity demand [TWh]				As % of total load by all options	
	NoDR	**DR**	**Difference**		**NoDR**	**DR**
$P2H_2$	10.0	10.1	0.0		87%	69%
P2H-i	0.0	3.0	3.0		0%	21%
P2H-h	0.3	0.3	0.0		3%	2%
P2M (EVs)	1.2	1.3	0.0		11%	9%
All options	11.6	14.7	3.1		100%	100%

Table 18 shows that in the case of the assumed 'gas default technology' electricity demand by P2H-i amounts to zero in CA2030 without DR, compared to 18.6 TWh when assuming that an E-boiler is the default technology (Table 16). In addition, electricity demand by all four P2X technologies drops by a similar amount from more than 30 TWh (electricity default case) to less than 12 TWh (gas default). Consequently, the share of P2H-i in total electricity demand by all four P2X technologies falls from 62% (electricity default) to zero percent, while for $P2H_2$ it increases from 33% to 87%, respectively. Moreover, the difference in electricity demand by P2H-i (as well as by all four P2X technologies) between the CA2030 cases with and without DR changes substantially from a decrease by 16 TWh (electricity default) to an increase by approximately 3 TWh (gas default; compare Table 16 versus Table 18).[27]

[27] Note that, in addition, total electricity demand by all four P2X technologies as a share of total domestic load declines to about 9% in CA2030 without DR, compared to 20% recorded in Table 17 (electricity default).

4 Demand response by flexible load options

This chapter analyses the potential (size) of demand response (DR) by the four selected P2X technologies in the scenario years CA2030 and NM2050. More specifically, Section 4.1 starts with a discussion of the definition and measurement (indicators) of demand response in this study. Subsequently, Section 4.2. presents some illustrations of DR in NM2050 – notably by showing hourly profiles and annual duration curves of DR is this scenario year – and discusses some observations from these illustrations. Next, Section 4.3 presents and discusses briefly scenario results on maximum values (‘capacities) of upward and downward DR in both CA2030 and NM2050, while Section 4.4 provides and analyses similar results on total (annual) and average (hourly) DR. Finally, this chapter ends with a brief (follow-up) discussion on the implications of the default technology assumed to generate industrial heat, notably for the DR by power-to-heat in industry (P2H-i) in CA2030.

4.1 Definition and measurement of demand response

The U.S. Department of Energy (2006) defines DR as “*changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*” In practice, demand response refers usually to shifting or curtailment of electricity consumption (‘load’) at times when it is valuable to the electricity system (Morales-España et al., 2022).

More specifically, the term ‘*load shifting*’ refers to shifting of electricity consumption from hours with high electricity prices to hours with low electricity prices (within load saturation and recovery constraints). On the other hand, the term ‘*load curtailment*’ refers to cutting off electricity consumption during hours with (extremely) high electricity prices, for instance by either shutting down electricity-intensive industrial processes during these hours (thereby losing industrial output production and curtailing electricity consumption) or applying an alternative (‘hybrid’) technology to meet energy need, such as shifting from an E-boiler to a gas boiler in order to generate industrial heat.

Regarding the incentives for DR, a distinction is often made between implicit versus explicit DR (De Wildt et al., 2022). *Implicit* DR incentivises DR by time-varying prices to which end-users respond. *Explicit* DR incentivises DR by an explicit contract where end-users promise to respond to a signal or instruction to adjust the load, and to which they receive a reward or some compensation in return.

In this study, DR is restricted to implicit DR, based on dynamic electricity prices as determined by the integrated European P2X market model COMPETES. By means of this model, DR is defined and measured simply as the (hourly) difference between the amount of electricity demand in the (scenario) case with DR – i.e., load is responsive to changes in electricity prices – and the amount of electricity demand in the (same) case without DR, i.e. load is not responding to electricity prices. If this difference is positive, it is called upward DR (more electricity demand). If it is negative, it is called downward DR (less electricity demand). In both cases, DR is expressed in either capacity terms (e.g., in GW) or in energy terms (e.g., in GWh).

In Chapter 8 of this study, we will analyse the impact of DR by the four P2X technologies (added together) on the mix of flexible options to address the residual load of the power system in the Netherlands for the scenario years CA2030 and NM2050. In the sections below, however, we will first analyse the potential (size) of DR by these technologies (both individually and added together) in these scenario years.

4.2 Hourly profiles and duration curves of demand response by flexible load options

Based on the measurement definition of DR outlined above, Figure 10 presents the hourly profile of DR by the selected P2X technologies – both individually and added together – during the first month of NM2050 (January, i.e. hours 0-744), while Figure 11 shows the duration curve of DR by these technologies over the scenario year NM2050 as a whole.

Some observations from these two figures include:

- First of all, note that for both power-to-hydrogen ($P2H_2$) and power-to-heat in industry (P2H-i) the shape of both the hourly profiles and duration curves of DR (Figure 10-Figure 11) is similar to the shape of the respective hourly profiles and duration curves of electricity demand (with DR) by these technologies (Figure 5-Figure 6). Only the level of the DR graphs is lower than the respective electricity demand graphs, i.e. by 12.7 GW and 8.1 GW, respectively, reflecting the flat (fixed) level of electricity demand without DR by $P2H_2$ and P2H-i, respectively.

- More specifically, in the case of $P2H_2$, the DR duration curve shows five intervals ranging between 6.6 GW (upward DR) and minus 12.7 GW (downward flexibility):
  i. For some 4800 hours, upward DR is at its maximum capacity of 6.6 GW;
  ii. Over approximately 200 hours, upward DR varies between 6.6 GW and zero;
  iii. Over about 1000 hours, there is no DR;
  iv. For some 500 hours, downward DR ranges between 0 and (‘minus’) 12.7 GW;[28]
  v. For the remaining hours (about 2300) downward DR is at its maximum capacity of 12.7 GW.

- In the case of P2H-i, the DR duration curve for NM2050 shows actually only two intervals:
  i. Over more than 8200 hours, there is no DR at all (DR is zero) as the concerning P2H technology (an E-boiler) remains the same during this number of hours in both the case with and without DR;
  ii. For only the remaining number of hours (about 650), DR is downwards (‘negative’) at the maximum level of 8.1 GW as the technology to generate industrial heat switches in these hours from an E-boiler to a gas boiler.

[28] In graphs and figures of this study, downward DR (and downward flexibility in general) is usually illustrated by using negative numbers (i.e. presenting DR/flexibility below the X-axis), whereas in tables or the main text downward DR/flexibility is usually expressed in absolute (‘positive’) numbers, unless stated clearly otherwise.

Figure 10: Hourly profile of demand response by flexible P2X options during the first month of NM2050 (January, hours 0-744)

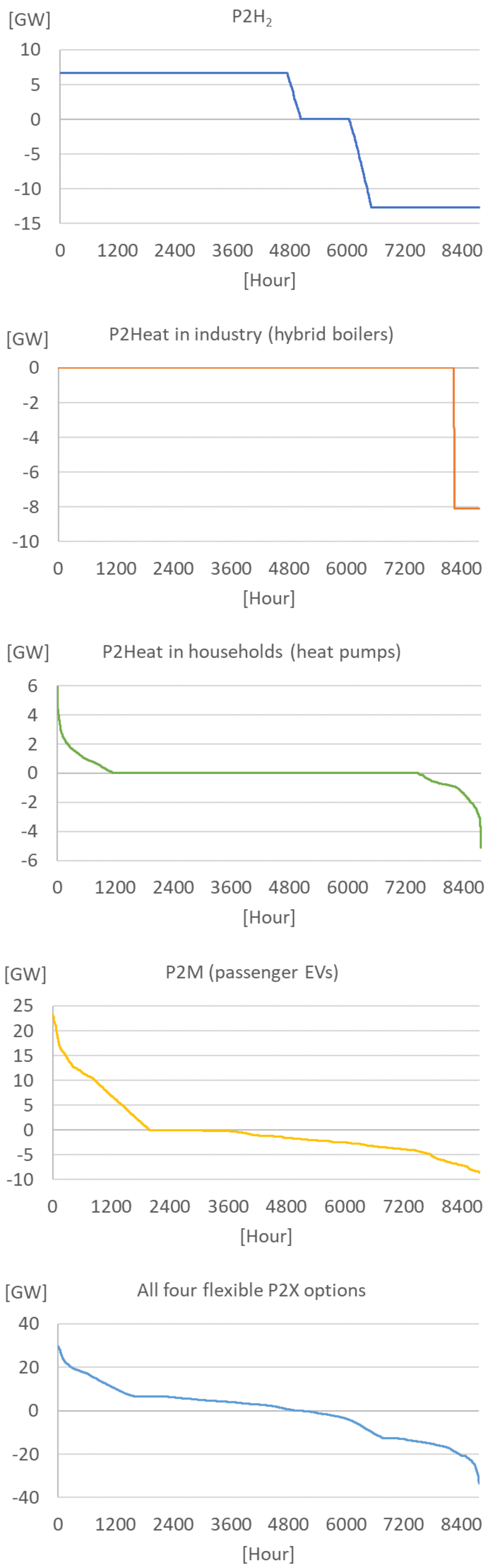

Figure 11: Duration curve of demand response by flexible P2X options in NM2050

- The hourly profile of DR by power-to-heat in households (P2H-h) indicates that in January NM2050 the number of hours with either upward or downward DR is rather limited while the number with no DR al all (zero) is relatively large (middle graph of Figure 10). More specifically, the DR of this load shifting technology over the scenario year NM2050 as a whole shows actually three intervals (middle graph of Figure 11):
    i. For some 1200 hours, upward DR varies between (slightly above) zero and 5.9 GW;
    ii. Over approximately 6400 hours, DR is zero;
    iii. For the remaining hours (about 1200), downward DR ranges between (slightly below) zero and ('minus') 5.1 GW.

- In contrast, the hourly profile of DR by power-to-mobility (P2M, i.e. by passenger EVs) fluctuates heavily and is either upwards or downwards during nearly all hours of January NM2050 (yellow graph of Figure 10). More specifically, the DR duration curve of this technology over the scenario year NM2050 as a whole also shows three intervals – similar to P2H-h – but with quite different ranges (Figure 11):
    i. Over some 2000 hours, upward DR varies from slightly above zero to more than 23 GW;
    ii. DR is more or less zero during some 1300 hours (see interval 2000-3300 hours in the yellow graph of Figure 11);
    iii. During the remaining number of hours (i.e., about 5500), downward DR ranges between (slightly below) zero and (minus) 8.6 GW.

- The DR curve of all four P2X technologies added together shows actually only two intervals:
    i. Up to some 4900 hours, upward DR ranges between zero and almost 30 GW;
    ii. For the remaining 3900 hours of NM2050, downward DR varies from zero to nearly 34 GW.

- For all four flexible P2X technologies added together the number of hours in which the (upward or downward) DR is smaller than (plus or minus) 5 GW in NM2050 amounts to about 3200. For some 2300 hours, the DR by these options falls within the range of (plus or minus) 5 to 10 GW, for about 2800 hours within the range of 10-20 GW, while for almost 700 hours it is larger than (plus or minus) 20 GW.

4.3 Maximum values of upward and downward demand response

Table 19 presents the maximum values ('capacities') of the upward and downward DR by the selected P2X technologies in CA2030 and NM2050, both individually and added together. Note that for NM2050 these optimised values correspond to the highest and lowest points of the DR duration curves of the respective technologies in the graphs of Figure 11.

Some observations from Table 19 include:

- As expected, the maximum DR values of all technologies (both individually and added together) are substantially lower in CA2030 than in NM2050 (as the hourly electricity demand of these technologies is also substantially lower in CA2030).

Table 19: Maximum values of upward and downward demand response by the four selected P2X technologies in CA2030 and NM2050

[GW]	CA2030		NM2050	
	Upward DR	Downward DR	Upward DR	Downward DR
$P2H_2$	0.2	1.1	6.6	12.7
P2H-i	0.0	2.1	0.0	8.1
P2H-h	0.2	0.1	5.9	5.1
P2M (passenger EVs)	0.9	1.2	23.1	8.6
All four P2X technologies:				
- sum of options individually	1.3	4.5	35.6	34.5
- sum of options added together	1.3	4.5	29.7	33.6

- For the three load shifting technologies ($P2H_2$, P2H-h and P2M) Table 19 shows maximum values for both upwards and downwards DR, whereas for the sole load curtailment technology (P2H-i) it provides only a maximum values of downward DR.

- In both scenario cases (CA2030 and NM2050) the maximum DR values of the four P2X technologies individually vary substantially, depending on the hourly load level as well as their opportunities and constraints to increase or decrease this level per hour. For instance, in NM2050 the maximum DR value ranges from 5.9 GW for P2H-h to 23.1 GW for P2M.

- In NM2050, the maximum (upward or downward) DR values of all four P2X technologies added together are lower than the sum of the DR values of these technologies individually. This is due to the fact that these latter values are reached generally in different hours over the year and, hence, the maximum value of all four P2X technologies added together in a specific hour is generally lower than the sum of the maximum values of the technologies individually. Moreover, in a variety of hours upwards DR by one or more individual technologies is matched by downward DR by one or more other individual technologies (in the same hour), thereby further reducing, on balance, the maximum values of the DR duration curve for all technologies added together.

- In several cases, the maximum value of upward DR by a certain technology deviates substantially from its maximum value of downward DR. For instance, for $P2H_2$ the maximum DR value in NM2050 amounts to 6.6 GW in case of upward DR, while it is about twice as high (12.7 GW) in case of downward DR. For P2M, on the contrary, the maximum value of upward DR (32.1 GW) is nearly three times higher than its maximum value of downward DR (8.6 GW).

4.4 Total and average demand response

By aggregating the hourly upward (downward) DR over all the hours in which it occurs the total annual upward (downward) DR can be calculated (in energy terms), both for the flexible load technologies individually and for these technologies together. In Figure 11 the total annual (upward/downward) DR is equal to the surface of the areas between the X-axis and the DR duration curves of the P2X technologies presented in the respective graphs of this figure.

Table 20: Total and average demand response by the four selected P2X technologies in CA2030

						All four P2X options	
	Unit	$P2H_2$	P2H-i	P2H-h	P2M	Sum of options individually	Sum of options added together
Upward DR	TWh	1.4	0.0	0.1	1.0	2.4	0.6
Downward DR	TWh	1.3	15.6	0.1	0.9	17.9	16.1
Total DR	TWh	2.7	15.6	0.2	1.9	20.3	16.7
Total annual DR as % of sum of options individually							
Upward DR	%	57%	0%	3%	40%	100%	26%
Downward DR	%	7%	87%	0%	5%	100%	90%
Total DR	%	13%	77%	1%	9%	100%	82%
Average demand response of all options added together							
Total DR	GW/#h	0.3	1.8	0.0	0.2	2.3	1.9
Load (NoDR)	TWh	10.0	18.6	0.3	1.2	30.2	30.2
Demand response as % of load (NoDR)							
Upward DR	%	14%	0%	24%	78%	8%	2%
Downwards DR	%	13%	84%	24%	76%	59%	53%
Total DR	%	27%	84%	48%	154%	67%	55%

Table 20 and Table 21 present the total annual upward and downward DR by the P2X technologies in CA2030 and NM2050, respectively, in both absolute terms (i.e., in TWh per year) and relative terms (i.e., as a % of electricity demand without DR). In addition, these tables provide the average (hourly) DR of the technologies by dividing the total annual (upward + downward) DR by the number of hours in a year.

Some observations from Table 20 and Table 21 include:

- For load shifting technologies the total annual upward DR is assumed to be equal to the total annual downward DR. In Table 20 this is indeed more or less the case for the three load shifting technologies in CA2030 ($P2H_2$ and P2M), as well as for P2H-h in NM2050, but not for $P2H_2$ and P2M in NM2050 (Table 21). This difference between upwards and downwards DR by these latter technologies corresponds to the difference in electricity demand in NM2050 between the cases with and without DR (see Section 3.3, notably Table 16). As explained in that section, this difference is due to the higher energy storage needs (hydrogen, electricity) in the case with DR, the resulting higher storage losses and, hence, the higher electricity demand to cover these losses.

Table 21: Total and average demand response by the four selected P2X technologies in NM2050

						All four P2X options	
	Unit	$P2H_2$	P2H-i	P2H-h	P2M	Sum of options individually	Sum of options added together
Upward DR	TWh	32.4	0.0	1.4	17.6	51.4	38.1
Downward DR	TWh	31.4	4.2	1.4	16.9	54.0	40.8
Total DR	TWh	63.8	4.2	2.9	34.5	105.4	78.9
Total annual DR as % of sum of options individually							
Upward DR	%	63%	0%	3%	34%	100%	74%
Downward DR	%	58%	8%	3%	31%	100%	75%
Total DR	%	61%	4%	3%	33%	100%	75%
Average demand response of all options added together							
Total DR	GW/#h	7.3	0.5	0.3	3.9	12.0	9.0
Load (NoDR)	TWh	111.1	70.8	14.3	31.1	227.3	227.3
Demand response as % of load (NoDR)							
Upward DR	%	29%	0%	10%	56%	23%	17%
Downwards DR	%	28%	6%	10%	54%	24%	18%
Total DR	%	57%	6%	20%	111%	46%	35%

- For load curtailing technologies, DR moves (by definition) in one direction only, i.e. downwards. Table 21 shows that the total annual downward DR by P2H-i amounts to 4.2 TWh in NM2050 and even to 15.6 TWh in CA2030 (Table 20).[29]

- In CA2030 total upward DR by all four P2X technologies added together amounts to 0.6 TWh, whereas total downward DR amounts to 16.1 TWh, resulting in a total DR of 16.7 TWh in absolute ('positive') terms. In relative terms, the total DR by all flexible technologies added together in CA2030 amounts to 55% of the total electricity demand (without DR) by these technologies (Table 20).

- In NM2050, however, the absolute amounts of upward and downward DR are substantially higher, i.e. 38.1 TWh and 40.8 TWh, respectively, mainly due to the substantially higher electricity demand by these technologies in NM2050, notably by $P2H_2$ and P2M. This results in a total annual DR by these technologies of almost 79 TWh in NM2050. In relative terms, on the contrary, total annual DR by all P2X technologies added together is substantially lower (than in CA2030), i.e. 35% of the total electricity demand (without DR) by these technologies (Table 21).

[29] These amounts of downward DR by P2H-i in CA2030 and NM2050 correspond to the differences in electricity demand by P2H-i in these scenario years between the cases with and without DR (see Table 16).

- Note that in both CA2030 and NM2050 the total (upward/downward) DR by all four P2X technologies added together is generally lower than the sum of the total DR by these technologies individually. This is due to the fact that in a substantial number of hours upward DR by one or more individual P2X technologies is matched by downward DR by one or more other individual technologies (in the same hour), resulting from optimising the deployment of these technologies (with different opportunities, constraints and other techno-economic characteristics) over the year as a whole within the context of an integrated European power system. Consequently, in these hours (and, hence, over the year as a whole), the total DR by all P2X technologies added together is lower than the sum of the DR by these technologies individually.

- In CA2030, total (downward) DR is dominated by a single technology, i.e. P2H-i, whereas the other P2X technologies play only a minor role (Table 20). In NM2050, on the contrary, total DR is dominated by two technologies, i.e. notably by $P2H_2$ and, to a lesser extent, P2M (offering total DR of almost 64 TWh and 35 TWh, respectively). On the other hand, the two P2H technologies (industrial boilers and household heat pumps) play only a minor role in NM2050, i.e. providing total DR of approximately 4.2 TWh and 2.9 TWh, respectively.

- Finally, in addition to data on the total (annual) DR, both Table 20 and Table 21 present some results on the *average* (hourly) DR by the four P2X technologies in CA2030 and NM2050. These tables show that the average DR by these technologies added together amounts to 1.9 GW/#h in CA2030 and to 9.0 GW/#h in NM2050.

4.5 Discussion

As discussed in Section 3.4 above, for the case of power-to-heat in industry (P2H-i) it is assumed that an E-boiler is the default technology in the case without DR in both CA2030 and NM2050. For CA2030, however, it could be argued that a gas boiler should be default technology (thereby avoiding an overestimation of DR by this technology in this scenario year). Table 22 presents the total and average DR by the four selected P2X technologies in CA2030 with and without DR, assuming that a gas boiler is the default technology for industrial heat in the case without DR (while, as discussed, Table 20 provides comparative results assuming that an E-boiler is the default technology).

Table 22 shows that in the case of the ‘gas default technology’, total (annual) DR by P2H-i in CA2030 is 3.0 TWh *upwards* compared to 15.5 TWh *downwards* when assuming that an E-boiler is the default technology (Table 20). As a result, the total and average DR by this technology – and by the four P2X technologies added together – is substantially lower in the default case of the gas boiler (rather than the E-boiler). Similarly, the share of total (upward and downward) DR by P2H-i in the total DR by all four P2X technologies is significantly lower in the ‘gas default’ case compared to the ‘electricity default’ case (compare Table 20 and Table 22).

Table 22: Total and average demand response by the four selected P2X technologies in CA2030, assuming that a gas boiler (rather than an E-boiler) is the default technology in the case without DR

						All four P2X options	
	Unit	**$P2H_2$**	**P2H-i**	**P2H-h**	**P2M**	**Sum of options individually**	**Sum of options added together**
Upward DR	TWh	1.4	3.0	0.1	1.0	5.4	3.7
Downward DR	TWh	1.3	0.0	0.1	0.9	2.3	0.5
Total DR	TWh	2.7	3.0	0.2	1.9	7.8	4.2
Total annual DR as % of sum of options individually							
Upward DR	%	25%	56%	1%	18%	100%	67%
Downward DR	%	57%	0%	3%	40%	100%	23%
Total DR	%	35%	39%	2%	24%	100%	54%
Average demand response of all options added together							
Total DR	GW/#h	0.3	0.3	0.0	0.2	0.9	0.5
Load (NoDR)	TWh	10.0	0.0	0.3	1.2	11.6	11.6
Demand response as % of load (NoDR)							
Upward DR	%	14%	n.a.	24%	78%	47%	32%
Downwards DR	%	13%	n.a.	24%	76%	20%	5%
Total DR	%	27%	n.a.	48%	154%	67%	36%

5 Flexibility supply by demand-responsive options

This chapter analyses the potential (size) of flexibility supply by the four selected, demand-responsive (DR) technology options in the scenario years CA2030 and NM2050. More specifically, Section 5.1 starts with a discussion of the definition and measurement (indicators) of the concept '*flexibility*' in general and '*flexibility by demand response (DR)*' in particular. Subsequently, Section 5.2 shows graphs of hourly profiles and duration curves of flexibility by DR in NM2050 and discusses some observations from these graphs. Next, Section 5.3 presents and discusses briefly some scenario results on maximum values ('capacities') of upward and downward flexibility by DR in both CA2030 and NM2050, while Section 5.4 provides and analyses similar results on total (annual) and average (hourly) flexibility by DR. Finally, Section 5.5 of this chapter ends with a brief (follow-up) discussion on the implications of the default technology to generate industrial heat, notably for the flexibility offered by P2H-i in CA2030.

5.1 Definition and measurement of flexibility

Following the FLEXNET project, flexibility is defined as "*the ability of the energy system to respond to the variability and uncertainty of the residual power load within the limits of the electricity grid*." (Sijm et al., 2017c). Major characteristics of this definition are:

- The problem (i.e., the demand for flexibility) is caused primarily by the power system;
- The solution (i.e., the supply of flexibility) may come from the energy system as a whole;
- The focus is on changes in residual power load, i.e. on changes in the difference between total power load and power production from variable renewable energy (VRE).

Another characteristic of the above-mentioned definition of flexibility is that it refers to the three main sources ('causes') of the need for flexibility of the power sector:

1. The demand for flexibility due to the *variability* of the residual power load, in particular due to the variability of electricity demand and power generation from VRE sources;
2. The demand for flexibility due to the *uncertainty* of the residual power load, notably due to the uncertainty (or lower predictability) of electricity output from VRE sources *('forecast error'*);
3. The demand for flexibility due to the *congestion* (overloading) of the power grid, resulting from the increase and changing profiles of electricity demand – due to the further penetration of P2X technologies – as well as the increase and changing profiles of power supply from VRE sources.

The FLEXNET project has considered all three types of flexibility demand, including the supply options to meet this demand (Sijm et al., 2017a, 2017b and 2017c). The current study, however, focusses only on the supply options – notably the role of demand response – to meet the first type of flexibility, i.e. the need for flexibility due to the variability of the residual (power) load.

In this study, flexibility refers primarily to the *hourly* variability of the residual load, defined and measured as the difference – or change (Δ) – between the residual load in hour *t* and the residual load in hour *t-1* (with *t* = 1,…., 8760). This difference (usually indicated as hourly '*ramp*') can be either positive – called '*ramp-up*' or '*upward flexibility*' – or negative, i.e., '*ramp down*' or '*downward flexibility*'.

Hourly ramp-ups and ramp-downs are the basic indicators of flexibility ('ramping') needs of the power system due to the variability of the residual load. Other, related indicators for the demand and supply of flexibility used in the current study include:
- *Total annual flexibility (upward/downward)*, i.e. the total amount of hourly ramps (up/down) aggregated over a year, expressed in energy terms per annum (usually TWh);
- *Average hourly flexibility,* i.e. the total annual (upward/downward) flexibility divided by the relevant number of hours over the year, expressed in average ('hourly') capacity terms (usually GW/#h);[30]
- *Marginal hourly flexibility,* i.e. the average hourly flexibility (demand or supply) divided by the volume of energy (demand or supply) concerned, usually expressed in MW/TWh.

In this study, flexibility offered by DR is one of the major options to address the variability of the residual load and, hence, to meet the need for flexibility by the power system. Besides DR, other flexibility supply options included in this study refer to (i) non-VRE generation, (ii) VRE curtailment, (iii) trade, and (iv) storage.[31]

It should be remarked that in the present study '*demand response'* (DR) and '*flexibility by DR*' are closely related but different concepts, which are defined and measured differently, and which refer to different levels of analysis.[32] In this study (see Section 4.1), demand response refers to the responsiveness of electricity demand to (changes in) electricity prices. By means of the COMPETES model, demand response is defined and measured as the (hourly) difference between the amount of electricity demand in the (scenario) case with DR – i.e., demand is responding to changes in electricity prices – and the amount of electricity demand in the (same) case without DR, i.e. demand is not responding to electricity prices. Hence, demand response refers to the difference (Δ) between two – separate, but nearly similar – cases of electricity demand, i.e. one case in which demand responds to (changes in) electricity prices versus the same case in which demand is not responsive to electricity prices. This concept of demand response is used primarily in this study to analyse the (flexible) options to meet the residual load, notably in situations with a high share of VRE power generation, resulting in (a large number of) hours with a (large) positive residual load ('VRE generation shortage') versus (a large number of) hours with a (large) negative residual load ('VRE generation surplus').

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[30] In case of average hourly upward (downward) flexibility, the relevant number of hours (#h) refers to the number of hours with upward (downward) flexibility over the year. Usually, the number of hours with upward flexibility differs (slightly) from the number of hours with downward flexibility. In case of average (hourly) total flexibility – i.e., including both upwards and downwards flexibility in absolute ('positive') terms – the relevant number of hours refers to the total number of hours over the year (8760).

[31] For further details on these aggregated categories – including specific options – see Section 4.1 and references mentioned there. For a further analysis of flexibility by DR and other supply options, see also Chapter 9 of the current study.

[32] Similar remarks refer to the other flexible/flexibility options such as trade, storage of VRE curtailment.

On the other hand, in this study the concept of flexibility refers primarily to the (hourly) *variability* of the residual load, defined and measured as the difference (Δ) between the residual load in hour *t* and the residual load in hour *t-1* (as discussed in the beginning of this section). Hence, the concept of flexibility in this study – and in power system analyses in general – refers primarily to the difference of a variable (such as residual load or demand response) between two consecutive hours.

As noted above, offering flexibility by DR is one of the options to address the variability of the residual load. Hence, following the general definition of flexibility mentioned above), the concept of 'flexibility by DR' (or by any other supply option) is defined at the difference (Δ) between the amount of DR in hour *t* and the amount of DR in hour *t-1* (expressed in capacity/energy terms). So, e.g., if upward DR amounts to 12 GW in hour t and to 10 GW in hour t-1, the (upward) flexibility offered by DR amounts to 2 GW in hour t. If downward DR in these hours, however, amounts to 15 GW and 18 GW, respectively, the downward flexibility supply by DR amounts to ('minus') 3 GW, while if DR remains at the same level during two or more consecutive hours, e.g. at 14 GW, flexibility by DR is zero.

In Chapter 9 of this study, we will analyse the impact (effects) of DR by the four selected P2X technologies added together on the mix of flexibility options to address the variability of the residual load in the power system of the Netherlands for the scenario years CA2030 and NM2050. In the sections below, however, we will first analyse the potential (size) of the flexibility offered by these technologies – both individually and added together – in these scenario years.

5.2 Hourly profiles and duration curves of flexibility by demand response

Based on the measurement definition of flexibility by DR discussed above, Figure 12 presents the hourly profile of flexibility by the four selected DR options – both individually and added together – during the first month of NM2050 (January, i.e. hours 0-744), while Figure 13 shows the duration curve of the flexibility supplied by these options over the scenario year NM2050 as a whole (8760 hours).

Some observations from Figure 12 and Figure 13 include:

- The number of hours in which DR offers either upward or downward flexibility varies heavily by technology. This is already indicated by Figure 12, which shows that in January NM2050 this number ranges from only 6 for power-to-heat in industry (P2H-i, i.e. 3 hours upwards and 3 hours downwards) to all hours of this month (744) for power-to-mobility (i.e., passenger EVs).

- The observation above is confirmed by Figure 13 for the scenario year NM2050 as a whole. For P2H-i, the number of hours in which it provides either upward or downward flexibility is restricted to about 40 hours, all with a maximum amount of flexibility of (plus or minus) 8.1 GW, while during the remaining hours of the year (8720) the supply of flexibility by P2H-i is zero.

- The reason for the low number of hours in which P2H-i provides either upwards or downwards flexibility in NM2050 is that the demand for industrial heat is flat and that in a large number of consecutive hours this heat is usually produced by

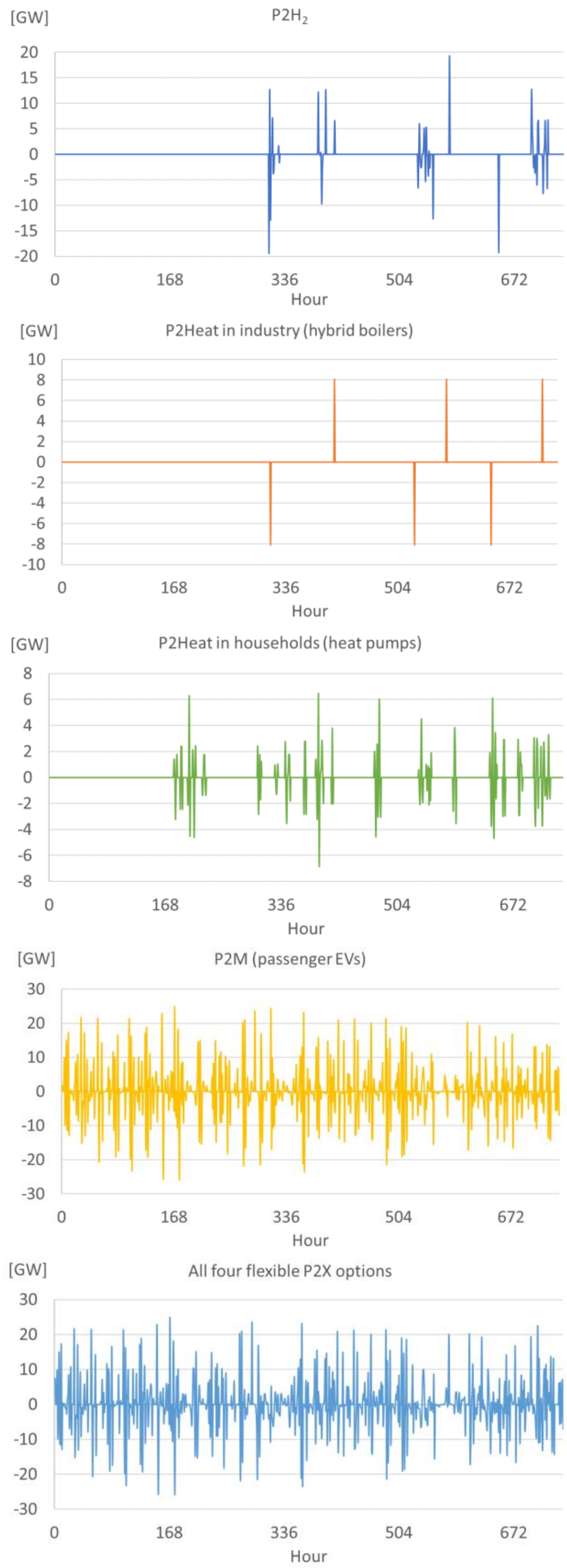


Figure 12: Hourly profile of flexibility supply by P2X options during the first month of NM2050 (January, hours 0-744)

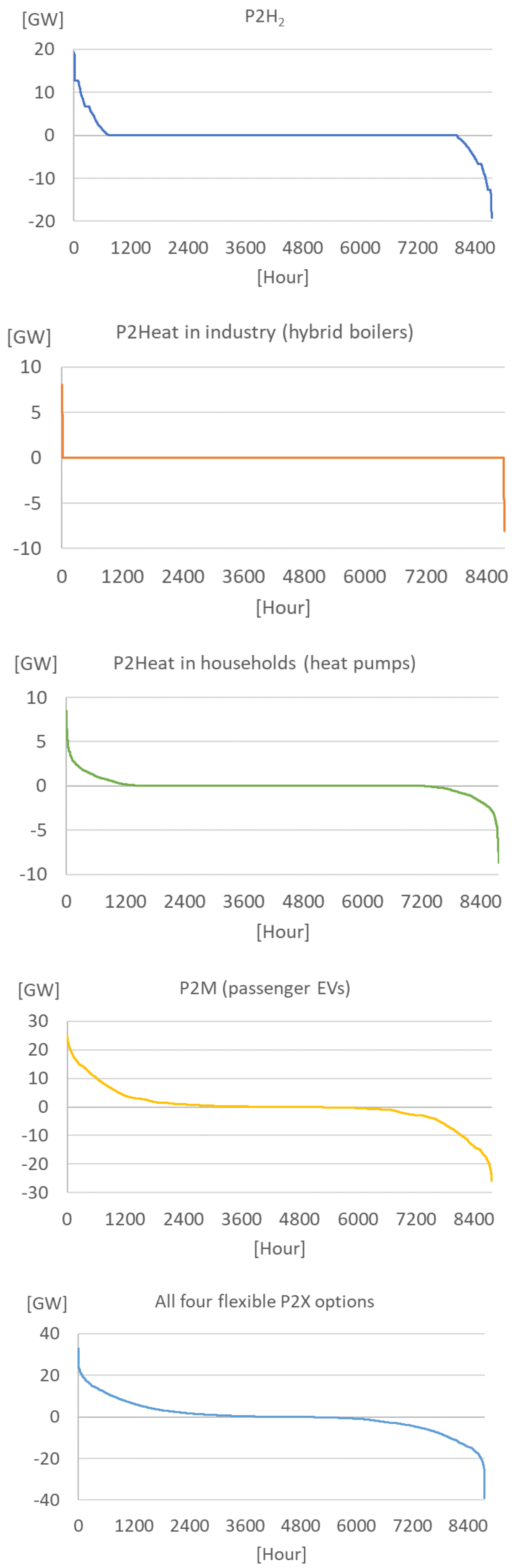


Figure 13: Duration curve of flexibility supply by flexible P2X options in NM2050

an E-boiler followed generally by a substantial number of hours in which industrial heat is generated by a gas boiler (see both Figure 6 and Figure 10). Only in the limited number of hours in which industrial heat production switches from gas to electricity – or from electricity to gas – P2H-i offers either upward or downward flexibility to the power system by means of DR.

- For P2M, on the contrary, all hours of the year provide some flexibility by DR.[33] In most of the hours, however, the amount of flexibility is relatively low. For instance, the number of hours in which P2M offers (upward or downward) flexibility by DR between zero and (plus or minus) 1 GW amounts to about 4300 in NM2050. For all four flexible load options together, this number is slightly lower, but it still amounts to approximately 3200 hours in NM2050.

- For power-to-heat in households (P2H-h), the number of hours in which flexibility supply by DR is zero amounts to about 5700, while for power-to-hydrogen ($P2H_2$) it is approximately even 7200. For $P2H_2$, however, the amount of flexibility delivered in the remaining 1600 hours of the year is often substantial. For instance, over some 800 hours the (upward or downward) flexibility by $P2H_2$ is larger than (plus or minus) 5 GW, while for P2H-h this amount of flexibility is delivered only during some 50 hours.

- For P2M (passenger EVs), the number of hours in which flexibility by DR is larger than (plus or minus) 5 GW amounts to about 2000. For all four flexible load options, this number is about 2800 hours.

5.3 Maximum values of upward and downward flexibility by demand response

Table 23 presents the maximum (optimised) values of the upward and downward flexibility by the four selected DR options – both individually and added together – in CA2030 and NM2050. Note that for NM2050 these maximum values ('capacities') correspond to the highest and lowest points of the flexibility duration curves of these options in the graphs of Figure 13.

Some observations from Table 23 include:

- As expected, the maximum values for the supply of flexibility by all DR options – both individually and added together – are much lower in CA2030 than in NM2050, as the hourly DR itself by these options is also substantially lower in CA2030.

- Note that all DR options – i.e., both the load shifting and the load curtailing technologies – provide both upward and downward flexibility by DR, while in the case of DR itself the sole load curtailing technology (P2H-i) provides only downward DR but no upward DR. The reason is that if the generation of industrial heat in a certain hour (in the scenario case with DR) switches from a gas boiler to an E-boiler, the 'upward' DR in this hour is zero (compared to the case without

[33] In addition, P2M provides flexibility by means of EV battery storage (V2G) transactions throughout the year (Sijm et al., 2020).

DR), while the resulting flexibility offered to the power system by this switch is positive (upwards) in this hour (compared to the previous hour).[34]

- For the individual P2X technologies, the maximum values of the upward flexibility by DR are more or less similar to the maximum values of the downward flexibility. Between these technologies, however, the maximum values of either upward or downward flexibility varies significantly (depending on the level and hourly changes of the electricity demand and DR of these technologies). For instance, for P2H-i the maximum (upward or downward) flexibility by DR amounts to 8.1 GW, while for P2M (passenger EVs) it amounts to 25-26 GW.

- The maximum values of the (upward or downward) flexibility by the DR options added together are generally (substantially) lower than the sum of these values of the options individually (e.g., about 33 GW and 61 GW, respectively, for the upward flexibility values in NM2050; see Table 23). Similar to the case of the maximum hourly values for electricity demand and DR, this is due to the fact that the maximum values for the flexible load options individually are reached generally in different hours over the year and, hence, the maximum flexibility by DR of all options added together in a specific hour is usually lower than the sum of the maximum hourly values of the technologies individually.[35]

Table 23: Maximum values of upward and downward flexibility by the four selected P2X technologies in CA2030 and NM2050

[GW]	CA2030		NM2050	
	Upward flex	Downward flex	Upward flex	Downward flex
P2Hydrogen	1.4	1.4	19.3	19.3
P2Heat- industry	2.1	2.1	8.1	8.1
P2Heat-households	0.2	0.2	8.5	8.7
P2Mobility (passenger EVs)	1.2	1.1	25.2	26.0
All four P2X technologies:				
- sum of options individually	4.9	4.8	61.1	62.1
- sum of options added together	4.3	3.7	33.1	39.1

5.4 Total and average flexibility by demand response

By aggregating the hourly upward (downward) flexibility by DR over all the hours of the year in which it occurs, the total annual upward (downward) DR can be calculated (in energy terms), both for the flexible load options individually and added together. In Figure 13, this total annual (upward/downward) flexibility is equal to the surface of the areas between the X-axis and the flexibility duration curves of the P2X technologies presented in the respective graphs of this figure.

[34] Note that when the generation of industrial heat in a certain hour switches from an E-boiler to a gas boiler, the DR in this hour is negative (downwards), while the resulting flexibility by this swich is also negative (downwards) in this hour.

[35] Moreover, in a variety of hours upward flexibility by one or more individual P2X technologies is matched by downward flexibility by one or more other technologies (in the same hour), thereby further reducing, on balance, the maximum values of the flexibility by all DR options added together.

Table 24: Total and average flexibility by demand response of the four selected P2X technologies in CA2030

						All four P2X options	
	Unit	$P2H_2$	P2H-i	P2H-h	P2M	Sum of options individually	Sum of options added together
Upward flex	TWh	0.4	0.3	0.1	0.6	1.4	1.3
Downward flex	TWh	0.4	0.3	0.1	0.6	1.4	1.3
Total flex	TWh	0.8	0.7	0.2	1.2	2.8	2.6
Total annual flexibility by DR as % of sum of options individually							
Upward flex	%	27%	24%	6%	43%	100%	94%
Downward flex	%	27%	24%	6%	43%	100%	94%
Total flex	%	27%	24%	6%	43%	100%	94%
Average flexibility by demand response of all options added together							
Total flex	GW/#h	0.09	0.08	0.02	0.14	0.32	0.30
Load (NoDR)	TWh	10.0	18.6	0.3	1.2	30.2	30.2
Flexibility by DR as % of load (NoDR)							
Upward flex	%	4%	2%	28%	49%	5%	4%
Downward flex	%	4%	2%	28%	49%	5%	4%
Total flex	%	8%	4%	55%	99%	9%	9%

Table 24 and Table 25 present the total upward and downward flexibility by the four selected DR options in CA2030 and NM2050, respectively, in both absolute terms (i.e., in TWh per year) and in relative terms (i.e., as a % of electricity demand without DR). in addition, these tables provide the average (hourly) flexibility by these options by dividing their total annual (upward and downward) flexibility by the numbers of hour in the year.

Some major observations from Table 24 and Table 25 include:

➢ For all flexible P2X options (both load switching and load curtailing technologies) in both CA2030 and NM2050, the total annual amount of upward flexibility by DR is equal to the total annual amount of downward flexibility by DR (implying that electricity demand by these flexible technologies varies over the year but, at least in the model scenario year concerned, it ends in the last hour of the year more or less at the same level as it begins in the first hour of the year).

➢ The amount of total annual (upward/downward) flexibility by the DR options, however, is substantially higher in NM2050 than in CA2030 (as the electricity demand and the DR by these options is also significantly higher in NM2050, as discussed in Sections 3.3 and 4.4 above). For instance, in CA2030 the total annual flexibility by the DR technologies added together amounts to 2.6 TWh, i.e.

Table 25: Total and average flexibility by demand response of the four selected P2X technologies in NM2050

						All four P2X options	
	Unit	$P2H_2$	P2H-i	P2H-h	P2M	Sum of options individually	Sum of options added together
Upward flex	TWh	4.3	0.1	1.8	16.2	22.4	20.1
Downward flex	TWh	4.3	0.1	1.8	16.2	22.4	20.1
Total flex	TWh	8.7	0.3	3.6	32.4	44.9	40.2
Total annual flexibility by DR as % of sum of options individually							
Upward flex	%	19%	1%	8%	72%	100%	90%
Downward flex	%	19%	1%	8%	72%	100%	90%
Total flex	%	19%	1%	8%	72%	100%	90%
Average flexibility by demand response of all options added together							
Total flex	GW/#h	0.99	0.03	0.41	3.69	5.12	4.58
Load (NoDR)	TWh	111.1	70.8	14.3	31.1	227.3	227.3
Total annual flexibility by DR as % of load (NoDR)							
Upward flex	%	4%	0%	12%	52%	10%	9%
Downward flex	%	4%	0%	12%	52%	10%	9%
Total flex	%	8%	0%	25%	104%	20%	18%

approximately 9% of the total electricity demand by these technologies (Table 24). In NM2050, however, the comparative amount rises to more than 40 TWh, i.e. about 15 times higher than in CA2030 and corresponding to some 18% of the total load by the four DR options (Table 25).

- Note that in both CA2030 and NM2050 the total annual flexibility by all four DR options added together is slightly lower (6-10%) than the sum of the total annual flexibility by these options individually. Similar to the case for DR itself (discussed in Section 4.4 above), this is due to the fact that in a substantial number of hours upward flexibility by one or more individual P2X technologies is matched by downward flexibility by one or more other individual technologies (in the same hour). Consequently, in these hours (and, hence, over the year as a whole), the flexibility offered by all P2X technologies added together is lower than the sum of the flexibility by these technologies individually.

- In CA2030, the total annual amount of flexibility by each P2X technology individually (as a share of the sum of the total annual flexibility by all P2X technologies individually) varies from 6% for P2H-h to 43% for P2M. In NM2050, this share ranges more widely from 1% for P2H-i to 72% for P2M (Table 25). The reason why the share of P2H-i is relatively low (only 1%) – despite the fact that its share in electricity demand by all flexible P2X options in NM2050 is substantial (more than 30%) and the flexibility offered by hour is, on average, large (about 8

GW) – is that the number of hours in which it actually provides flexibility is rather low (about 40 hour), as explained above (Section 4.2).

- For P2M (passenger EVs), on the contrary, the share in electricity demand by all flexible P2X options in NM2050 is significantly lower (about 14%), but it is supplying flexibility during almost every hour of the year while over a large number of hours the amount of upward and downward flexibility is quite substantial, ranging between 5 and 25 GW in absolute terms (as illustrated and discussed in Section 4.4, notably Figure 13).

- Finally, in addition to scenario results on the total (annual) flexibility by DR, both Table 24 and Table 25 provide similar results on the average (hourly) flexibility by the four P2X technologies in CA2030 and NM2050. These tables show that the average flexibility offered by these technologies added together amounts to 0.3 GW/#h in CA2030 and 4.6 GW/#h in NM2050.

5.5 Discussion

In Sections 3.4 and 4.5, it was explained that, from the perspective of electricity demand and DR, for a load curtailing technology such as P2H-i it makes quite a difference which technology – i.e., in this case, either a gas boiler or an E-boiler – is assumed to be the default technology to produce industrial heat in the scenario without DR. From the perspective of flexibility by DR over a certain scenario year, however, it does not matter which technology is assumed to be the default technology.

The above-mentioned finding can be explained by the graph of the hourly profile of flexibility supply by P2H-i in the first month of NM2050 (see Section 5.2, Figure 12). For flexibility by DR, only the hour *t* in which the amount of DR differs from its previous hour (*t-1*) is relevant. In NM2050 – where an E-boiler is assumed to be the default technology to generate industrial heat in the scenario without DR – this is, for instance, the case in hours 313 and 409. In hour 313, the technology generating industrial heat switches from an E-boiler to a gas boiler, resulting in a *downward* flexibility supply by DR of 8.1 GW. If it would have been assumed that a gas boiler is the default technology, we would see a similar technology switch in the same hour (313) but this time resulting in an *upward* flexibility supply by DR of the same amount.

The opposite applies for hour 409, i.e. an upward flexibility supply by P2H-i of 8.1 GW when assuming that an E-boiler is the default technology versus a downward flexibility supply of the same amount when assuming that a gas boiler would be the default technology.

The same story applies for the other hours in (January) NM2050, showing a switch in the technology to generate industrial heat, and resulting in a change of DR by P2H-i and, hence, in (either an upward or downward) flexibility supply by this technology. Therefore, although the direction of the flexibility offered in a certain hour (either upward or downward) depends on the assumption of the specific default technology in the case with DR, over a scenario year as a whole there is no difference in the total annual (upward/downward) flexibility offered by a (hybrid) load curtailing technology such as P2H-i.

6 Summary and discussion of Part I

6.1 Summary

Part I of the study analyses the potential (size) of demand response by the four selected P2X technologies – both individually and added together – in CA2030 and NM2050. This analysis is based on the definition and application of the following three related concepts:

- *Electricity demand ('load'),* i.e. the (hourly/annual) electricity use by a technology or set of technologies – or even by the power system as a whole – in a certain scenario year.
- *Demand response (DR),* i.e. either *load switching* (between certain hours, notably between hours with relatively high electricity prices versus relatively low prices) or *load curtailment* (at certain hours, in particular at hours with relatively high electricity prices). In this study, demand response is defined and measured as the difference (Δ) between electricity demand in the (scenario) case with DR, i.e. demand responds to changes in electricity prices, and electricity demand in the (same) case without DR, i.e. demand is not responsive to changes in electricity prices. If this difference is positive, it is called *upward* DR, and *downward* DR if the difference is negative.
- *Flexibility by DR,* i.e. the flexibility offered to the power system by one or more demand-responsive technologies. In this study, flexibility by DR is defined and measured as the difference (Δ) between DR at a certain hour t and DR at the previous hour t-1 (t = 1,….., 8760). If this difference is positive, it is called *upward* flexibility (by DR) and *downward* flexibility if the difference is negative.

In this study (and the underlying model scenarios), these concepts are applied and analysed on an hourly basis, expressed in either capacity terms (e.g., in GW) or energy terms (e.g., in GWh or TWh). Usually, however, they are aggregated over a certain scenario year – resulting in total annual values of load, DR or flexibility by DR – and, subsequently, averaged over this year – i.e., dividing the total annual volumes by the number of hours over a year (8760) – resulting in average (hourly) values of load, DR or flexibility by DR, expressed in (average) capacity terms for the number of hours concerned (e.g., in MW/#h or GW/#h).

The major findings of part 1 of the study are summarised in the following three tables:

- Table 26 presents scenario results on the total annual electricity demand by the four selected technologies in CA2030 and NM2050, both with and without DR;
- Table 27 provides similar scenario results on total annual DR potentials, including both potentials of total annual upward and downward DR as well as potentials of total annual upward and downward flexibility by DR, expressed in absolute energy terms;
- Table 28 presents some comparative results on both total (annual) and average (hourly) electricity demand and DR potentials by the four selected P2X technologies added together (as a single option) in CA2030 and NM2050.

The main findings and observations from the three tables mentioned above include:

Table 26: Total annual electricity demand by the four selected P2X technologies in CA2030 and NM2050 with and without demand response (DR versus NoDR)

	In absolute volumes [TWh][a]					**As % of all options**			
	CA2030		**NM2050**			**CA2030**		**NM2050**	
	NoDR	**DR**	**NoDR**	**DR**		**NoDR**	**DR**	**NoDR**	**DR**
$P2H_2$	10.0	10.1	111.1	112.1		33%	69%	49%	50%
P2H-i	18.6	3.0	70.8	66.6		62%	21%	31%	30%
P2H-h	0.3	0.3	14.3	14.3		1%	2%	6%	6%
P2M (EVs)	1.2	1.3	31.1	31.7		4%	9%	14%	14%
All options	30.2	14.7	227.3	224.7		100%	100%	100%	100%

a) In the case of load curtailing technologies (i.e., P2H-i), the difference between total annual electricity demand with and without DR is due to the load curtailment (i.e. downward DR). In the case of load shifting technologies (i.e., $P2H_2$, P2H-h and P2M), this difference is due to higher energy storage losses – hydrogen/electricity – in the scenario with DR and, hence, the resulting higher electricity needs to cover these losses.

- In CA2030, the electricity demand by the four selected flexible load options is significantly lower in the case with DR (almost 15 TWh) than without DR (about 30 TWh). This is mainly due to the large downward DR (almost 16 TWh) by power-to-heat in industry (P2H-i), resulting from the fact that in the case without DR this load curtailing technology, i.e. an E-boiler, is assumed to be the default technology to generate industrial heat during all hours of the year, whereas in the CA2030 case with DR a gas boiler turns out to be the dominant, competitive technology during most hours of the year (about 7400) in which electricity prices are relatively high (compared to gas). Consequently, in CA2030, the share of P2H-i in total electricity demand by all four flexible load options amounts to 62% in the case without DR (and to 33% for $P2H_2$), whereas it drops to 21% in the case with DR (and rises to 69% for $P2H_2$).

- In NM2050, on the contrary, the difference in total electricity demand by the four DR options in the cases with and without DR is rather low in both absolute and relative terms, i.e. 225 TWh versus 227 TWh, respectively (Table 26). In addition to the higher energy storage losses for power-to-heat in households (P2H-h) and power-to-mobility (P2M, i.e. passenger EVs), this difference is, on balance, largely due to the relatively small downward DR by P2H-i (about 4 TWh), resulting from the fact that in the case without DR this technology is assumed to be the default technology to produce industrial heat, while in the case with DR it turns out to be indeed the dominant, competitive technology during most hours of the year (more than 8200). Hence, (downward) DR occurs only during a small number of hours over the year (less than 600). As a percentage of total electricity demand by all flexible P2X technologies, the share of P2H-i remains rather stable in NM2050 with and without DR, i.e. about 30% (while for $P2H_2$ this share amounts to approximately 50%).

- Total annual (upwards + downwards) DR by all four flexible load options aggregated individually amount to 20 TWh in CA2030, while it is more than five times higher in NM2050, i.e. about 105 TWh (almost half of the total flexible load by these options in NM2050; see Table 26 and Table 27). As a percentage of this total annual DR, the share of P2H-i in CA2030 amounts to 77% (as downward DR is offered in a large number of hours), while for the other three flexible options

– $P2H_2$, P2M and P2H-h – the shares amount to 13%, 9% and 1%, respectively. In NM2050, however, the share of P2H-i drops to 4% (as downward DR by this load curtailing technology is provided only during a relatively small number of hours), while for the other three flexible technologies the comparative shares – and, even more significantly, the underlying absolute amounts of DR – increase substantially to 61%, 33% and 3%, respectively.

- The total annual (upward + downward) flexibility by all four DR options aggregated together, however, is significantly lower than the total annual DR by the options individually, notably is CA2030, but still it amounts to almost 3 TWh in CA2030 and even to 45 TWh in NM2050 (Table 27). As a percentage of this total annual supply of flexibility by DR, the share of P2H-i amounts to 24% in CA2030 but drops to 1% in NM2050, while for P2M it increases significantly from 43% to 72%, respectively.

- The main reason why the share of P2H-i in total annual flexibility by all DR options aggregated individually is relatively low in NM2050 (1%) is that the number of hours in which the industrial heat technology switches between gas and electricity – and, hence, offers either upward or downward flexibility – is rather low, i.e. about 40 hours in this scenario year, as industrial heat is generated by either a gas boiler or – predominantly – an E-boiler during a large number of consecutive hours at the same capacity level (8.1 GW). On the other hand, the main reason why the comparative rate for P2M is relatively high (79%) is that this load shifting technology is offering flexibility during almost every hour of the year, while over a large number of hours the amount of upward or downward flexibility is quite substantial, ranging between 5 and 25 GW in absolute terms.

Table 27: Total annual DR potentials by the four selected P2X technologies in CA2030 and NM2050

	In absolute volumes [TWh][a]					**As % of all options individually**			
	Total demand response (DR)		**Total flexibility by DR**			**Total demand response (DR)**		**Total flexibility by DR**	
	CA'30	**NM'50**	**CA'30**	**NM'50**		**CA'30**	**NM'50**	**CA'30**	**NM'50**
$P2H_2$	2.7	63.8	0.8	8.7		13%	61%	27%	19%
P2H-i	15.6	4.2	0.7	0.3		77%	4%	24%	1%
P2H-h	0.2	2.9	0.2	3.6		1%	3%	6%	8%
P2M (EVs)	1.9	34.5	1.2	32.4		9%	33%	43%	72%
All options:[b]									
- individually	20.3	105.4	2.8	44.9		100%	100%	100%	100%
- together	16.7	78.9	2.6	40.2		82%	75%	94%	90%

a) Total annual DR potentials refer to both potentials of total annual upward and downward DR as well as potentials of total annual upward and downward flexibility by DR, expressed in absolute volumes, i.e. in positive (+) energy terms only and, hence, added up accordingly.

b) In the case of DR and flexibility by DR, the values of these variables in a certain hour often show opposite signs (positive versus negative) for the technologies individually, i.e. DR/flexibility by one or more of the technologies is moving upwards while simultaneously (in the same hour) it is moving downwards for one of more other technologies. As a result, the total annual sum of the parts (i.e. the technologies considered individually) is usually higher than the sum of the whole (i.e. the technologies added together as a single, flexible option).

Table 28: Comparative data on total (annual) and average (hourly) electricity demand and DR potentials by all four flexible load options added together in CA2030 and NM2050

	Total (per annum; in TWh)		**Average (per hour; in GW/#h)**	
	CA2030	**NM2050**	**CA2030**	**NM2050**
Total domestic load (before DR)[a]	151.2	348.3	17.3	39.8
Flexible load (before DR)[b]	30.2	227.3	3.4	25.9
Demand response (DR)[b]	16.7	78.9	1.9	9.0
Flexibility by DR[b]	2.6	40.2	0.3	4.6
As % of total/average domestic load (before DR)				
Flexible load (before DR)	20%	65%	20%	65%
Demand response (DR)	11%	23%	11%	23%
Flexibility by DR	2%	12%	2%	12%
As % of flexible load (before DR)				
Demand response (DR)	55%	35%	55%	35%
Flexibility by DR	9%	18%	9%	18%
As % of demand response				
Flexibility by DR	16%	51%	16%	51%

a) By all domestic (NL) sectors and all electricity demand technologies added together.

b) By the four selected, flexible P2X ('DR') technologies added together (as a single option).

- Note that in all cases considered in Table 27, the total annual potentials of both demand response (DR) and flexibility by DR are generally significantly lower for the four P2X technologies added together (as a single, flexible option) than the sum of the DR potentials by the options aggregated individually. For instance, in NM2050, the total annual DR by all four options summed up individually amounts to 105 TWh, whereas it is approximately 25% lower – i.e., about 79 TWh – for the four technologies aggregated together as a single option. The reason is that, in the case of DR and flexibility by DR – as part of the system optimisation process - the values of these variables in a certain hour often show opposite signs (positive versus negative) for the technologies individually, i.e. DR/flexibility by one or more of the technologies is moving upwards while simultaneously (in the same hour) it is moving downwards for one of more other technologies. As a result, the total annual sum of the parts (i.e. the technologies considered individually) is usually higher than the sum of the whole (i.e. the technologies added together as a single, flexible option).

- As said, dividing the total annual volumes of electricity demand and DR potentials by the number of hour in a year leads to comparative, average (hourly) values of these variables (expressed in GW/#h). Table 28 shows that, as a result, in CA2030 these values for all DR options added together amount to about 3.4 GW/#h for the average flexible load by these options (without DR), 1.9 GW/#h for the average DR, and 0.3 GW/#h for the average flexibility by DR. Expressed as a percentage of the average total domestic load without DR (including both fixed and flexible load by all domestic sectors and technologies), these average values correspond to 20%, 11% and 2%, respectively. Expressed as a percentage of the total/average flexible load (without DR) of the four P2X technologies added together, however, the average/total DR by these technologies in CA2030 amounts to 55% and the average/total flexibility by DR to 9%.

- Finally, in NM2050, however, both the total (annual) and (average) figures on electricity demand and DR potentials by the four P2X technologies added together are substantially (5 to 15 times) higher than in CA2030. For instance, for this group of technologies, the average flexible load in NM2050 (without DR) amounts to almost 26 GW/#h, the average DR to 9 GW/#h, and the average flexibility by DR to 4.6 GW/#h. Expressed as a percentage of the average total domestic load, these values correspond to 65%, 23% and 12%, respectively. Expressed as a percentage of the total/average flexible load (without DR) by the four P2X technologies added together, however, the average/total DR by these technologies amounts to 35% in NM2050 and the average/total flexibility by DR to 18%.

6.2 Discussion

The current study shows that there is a large potential for demand response – and the resulting flexibility by DR – in the power system of the Netherlands. This applies already for the scenario year CA2030 but in particular for the scenario year NM2050, when, e.g., the total annual potential of flexibility by DR amounts to about 40 TWh, i.e. more than 15 times higher than in CA2030 (2.6 TWh). Some qualifications, however, can be added to the assessment of these DR potentials.

On the one hand, there are some arguments that the DR potentials assessed in this study may be underestimated. Firstly, in this study, power demand assumptions for the Netherlands in 2030 are based on the policy targets and assumptions of the Dutch Climate Agreement of 2019, resulting in a total electricity demand of approximately 150 TWh in 2030. Based on the more recent EU's Fit-for-55 policy package, however, current (2022) power demand assumptions for the Netherlands are usually much higher, running up to about 200 TWh in 2030. A higher electricity demand in 2030 (or, similarly, in 2050) implies that the potential for demand response is also higher.

Secondly, the current study is focussed on DR by four specific P2X technologies in certain sectors. Although the electricity demand by these technologies is substantial, notably in NM2050 (i.e., almost 230 TWh or about 65% of total domestic power load in NM2050), there may be other technologies or sectors that may be able to provide a significant additional amount of DR in NM2050 (or maybe even in CA2030) such as power-to-heat in the non-household residential sector (services, offices, etc.) or by power-to-mobility by non-passenger EVs.

Thirdly, the current study – and the underlying COMPETES model – does not include explicit heat storage technologies (although it does include implicit thermal energy storage by – well insulated – homes by all-electric, household heat pumps). By 2030 and, notably, 2050, however, there may be some competitive thermal energy storage options available that could be mixed with power-to-heat technologies, both in the industrial and residential sectors (see Maruf et al., 2021, and references cited there). If so, the DR potentials of the technologies concerned would increase accordingly.

Fourthly, the current study is focussed on analysing the potential of DR to meet the flexibility needs of the power system due to the hourly variability of the residual load (notably on the day-ahead market). It does not cover, however, the need for flexibility due to other reasons – such as congestion of the power grid or uncertainty of the residual load due to, for instance, difficulties and resulting errors to forecast the short-term electricity demand or the availability of sun and wind – or on other electricity markets such as the intraday market or the markets for electricity balancing and (other) ancillary services (Sijm et al., 2017b and 2021). Although the day-ahead market is – and likely remains – by far the most important electricity market for offering DR potentials to address the variability of the residual load up to 2050 in both energy volume and monetary terms, providing DR potentials for these alternative purposes or markets may become (more) attractive and, hence, (more) significant over the coming decades.

Finally, the current study is primarily focussed on *implicit* DR, i.e. DR incentivised by time-varying prices to which end-users respond. In some case, however, additional potential of DR may be offered by *explicit* DR, i.e. DR incentivised by an explicit contract where end-users promise to respond to a signal or instruction to adjust the load, and to which they receive a reward or some compensation in return. For instance, in this study DR by power-to-heat in industry (P2H-i) assumes implicit DR, which implies that offering flexibility by this technology is restricted to the (limited) number of hours in which the relative electricity/gas price incentive changes effectively for all P2H-i end-users simultaneously and, hence, in which the full demand for industrial heat by all end-users switches simultaneously from electricity to gas (or vice versa). Explicit DR offers the opportunity to differentiate the signal and related reward incentive across different P2H-i end-users over a larger number of hours in a year, which may result in a higher potential of DR and flexibility provided by these end-users.

On the other hand, there are also arguments that the DR potentials assessed in this study may be (seriously) overestimated. Firstly, as already indicated above, the assessment of the DR potential for the load curtailing technology power-to heat in industry (P2H-i) assumes that an E-boiler is the default technology to meet the flat demand for industrial heat in the case without DR (over all hours of the year). For NM2050, this assumption makes sense as an E-boiler turns out to be the dominant, competitive technology to produce industrial heat during almost all hours of the year (8200). For CA2030, however, this assumption may be questioned as a gas boiler turns out to be the dominant, competitive technology over most hours of the year (7400). As a result, the assumption concerned leads to a high (over) estimation of the total (annual) and average (hourly) DR by P2H-i in CA2030. Surprisingly, however, this assumption does not lead to an over- or underestimation of the total or average flexibility offered by this technology as it neither changes the number of hours in which the industrial heat technology switches between gas and electricity nor the flat amount of DR during each of these hours.

Secondly (and likely most importantly), this study – and the underlying COMPETES model in particular – has included a variety of constraints to DR by the four selected P2X technologies (such as the controllability and availability of these technologies (including the willingness and ability to provide DR), the investment costs of expanding $P2H_2$ capacity (in order to become more demand-responsive), the variable costs of hybrid heat technologies in industry, the specific (minimum) charging requirements of EVs, the specific saturation and load recovery constraints of flexible heat pumps in households, etc. (for more details see Section 2.4).

In a companion project deliverable to this study, however, we have analysed a large variety of (other) constraints – called 'barriers' – to demand response in general and to DR by the four P2X technologies of the current study in particular (De Wildt et al., 2022). Apart from barriers to the further (future) electrification of the energy system in general and the further penetration of these technologies in particular, the barriers to demand response include, among others, lack of required preconditions for DR (e.g., proper price incentives, no distorted incentives from grid tariffs and taxation, adequate grid capacity, lack of awareness, data or other information, accurate measurement and enforcement of DR), financial (upfront investment) constraints, system or people's inertia, and all kinds of behavioural constraints such as consumer values, preferences, privacy issues, etc. (for details, see De Wildt et al., 2022). The incidence of these barriers to DR can substantially reduce (the realisation of) the potential DR as assessed in the current study.

Finally, it has to remarked that the (over- or under)assessment of the future DR potentials depends also on the specific characteristics and specifications of the model used and of the model scenarios in particular (see Chapter 2). For instance, these potentials do not only depend on the way the flexible P2X technologies – and other technologies/flexible options – are modelled and optimised, but also on the (assumed or obtained) hourly profiles of these technologies or on the (assumed) future electrification of the energy system and the further penetration of the selected P2X technologies in particular.

6.3 Key messages

Overall, it is hard to say whether – and to which extent – the future DR potentials are, on balance, over- or underestimated by the current study. A major message of this study, however, is that – regardless of its specific size – there is, in principle but also in practice, a large, future potential of DR, which has a variety of beneficial impacts on the performance of the power system (as analysed in the next part of this study).

In addition, another key message (or policy implication) of this study – and its related companion project deliverable on DR barriers (De Wildt et al., 2022) – is that in order to realise the potential of DR (and its potential beneficial impacts on the power system) a set of market-design and other policies is required to reduce the barriers to DR and create the appropriate (pre)conditions for DR, including policies to set the right price incentives (and to avoid distorted incentives from grid tariffs and taxation), to provide access for relevant DR suppliers to relevant electricity markets, to enable adequate grid and EV charging infrastructures, to reduce (upfront) financial constraints, and to address awareness, information, data, privacy and other behavioural issues.

Part II: The impact of demand response

7 The impact of demand response on the electricity balance

This chapter presents and analyses the COMPETES model results on the impact of DR on the electricity balance of the Netherlands in the scenario years CA2030 and NM2050, including related variables to this balance such as electricity prices, VRE revenues and system costs. In order to put these scenario results in perspective, this chapter includes also comparative results for the reference scenario year 2015, indicated as '*R2015*', which is based on a previous, comparative study on the role of flexibility options – including DR – in the power system of the Netherlands up to 2050 (called '*FLEXNET*'; see Sijm et al., 2017a, 2017b and 2017c). This reference year, however, includes only results for the case without DR and not for the case with DR (as it is assumed that in the reference year 2015 there was actually hardly or no DR).

More specifically, the contents of this chapter runs as follows. Section 7.1 explains first of all the equation of the electricity balance and the approach applied in this chapter. Subsequently, Section 7.2 analyses the impact of DR on the total annual demand and supply of electricity (including cross-border trade) by the Netherlands in CA2030 and NM2050. The following sections focus their attention on the impact of DR on some specific variables or issues related to the electricity balance, in particular on (i) the installed power generation and interconnection capacities (Section 7.3), (ii) the curtailment of VRE power generation (Section 7.4), (iii) the electricity prices (Section 7.5), (iv) the generation revenues for VRE power producers (Section 7.6), (v) the electricity demand costs for various end-users (Section 7.7), and (vi) the power system costs (Section 7.8). Finally, Section 7.9 provides a discussion on some results of this chapter, notably on the possible implications of some assumptions regarding NM2050 for some results on the impact of DR in this scenario year.

7.1 The electricity balance

For the purpose of part II of this study, i.e. to analyse the impact of DR on the power system of the Netherlands (2030-2050), we use – as a starting point – the following equation of the electricity balance for the Netherlands:

$$DD(NoDR)_t + DR_t + ST_t + EX_t = VRE(AC)_t + NONVRE_t + IM_t \quad (1),$$

where:

$DD(NoDR)_t$	=	Domestic demand of electricity (without DR) in hour *t* (*t* = 1,……, 8760),
DR_t	=	Demand response (either upwards or downwards) in hour *t*,
EX_t	=	Exports of electricity in hour *t*,
IM_t	=	Imports of electricity in hour *t*,
$NONVRE_t$	=	Domestic production (supply) of electricity from non-VRE sources in hour *t*, including electricity from fossil fuels – notably coal and gas – as well as from other (renewable) energy sources (besides sun and wind) such as hydro, biomass or nuclear,
ST_t	=	Storage transactions (including storage losses) in hour *t*, i.e. storage charges (SC_t) minus storage discharges (SD_t) in hour *t*,

$VRE(AC)_t$ = Domestic production (supply) of electricity from variable renewables (VRE) sources, notably sun and wind, in hour *t* (after curtailment – if any – of VRE power generation).

Aggregating the hourly values of the variables of the electricity balance over the number of hours during a year results in the total annual values of these variables (in TWh). Dividing these total annual values by the number of hours over the year leads to the average (hourly) values of these variables (in GW/#h).

Equation 1 can be used to analyse the impact of DR on the electricity balance (and related variables) by comparing the values of the equation variables between the cases with and without DR. In the case without DR (NoDR), the variable DR_t is equal to zero while the values of the other variables are determined by the COMPETES model – within the specifications of the scenario concerned – until an (optimal) equilibrium is achieved between the demand and supply side of equation 1.

In the case with DR, the variable DR_t is not equal to zero in the hours concerned, while the value of at least one other variable – but likely of more or even all other variables – is adjusted consequently until a new equilibrium is reached between the demand and supply side of equation 1. Comparing the values of these variables between the cases with and without DR shows the impact of DR on these variables. This is basically the approach used below in the remaining sections of this chapter.

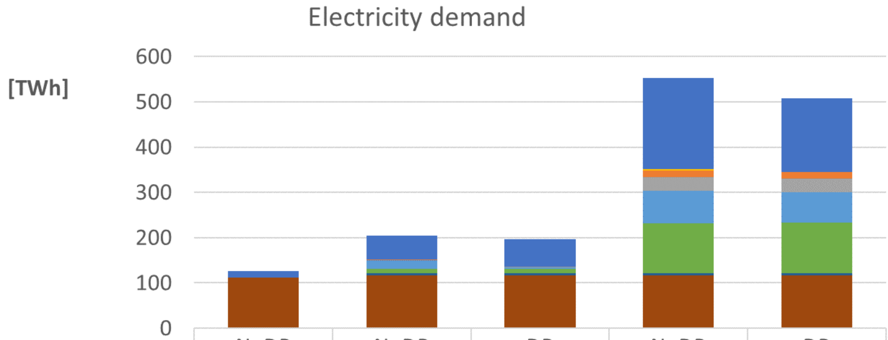
7.2 Total annual electricity demand and supply

Figure 14 presents the total annual values of the electricity balance of the Netherlands in the scenario years R2015, CA2030 and NM2050 with and without DR. More specifically, the upper part of Figure 14 shows the national (NL) electricity demand in these years, including (i) the (domestic) conventional electricity demand, (ii) the additional, fixed industrial load in CA2030 and NM2050, (iii) the electricity demand by the four selected, flexible P2X technologies ($P2H_2$, P2H-i, P2H-h and P2M), as well as (iv) the electricity demand to cover electricity storage losses (if any), and (v) the (domestic) electricity demand to meet (cross-border) exports of electricity.[36]

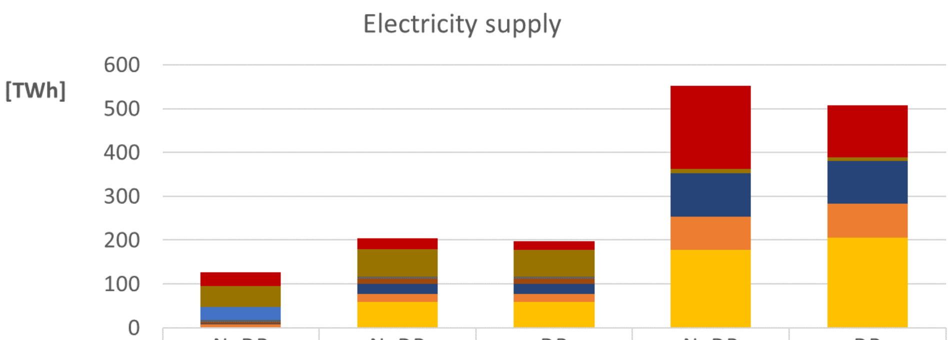
On the other hand, the lower part of Figure 14 shows the related national (NL) electricity supply in the respective scenario years, including (i) VRE electricity generation, notably by wind offshore, wind onshore and solar PV, (ii) non-VRE electricity production, in particular by means of fossil fuels (coal, gas), nuclear and 'other RES-E' (i.e., notably biomass), as well as (iii) domestic electricity supply from (cross-border) imports of electricity.

Figure 14 illustrates the impact of DR on the electricity balance in CA2030 and NM2050 by comparing the scenarios cases with and without DR in these years (whereas the reference scenario, R2015, only includes the case without DR).

[36] Electricity demand to cover electricity storage losses (notably in NM2050 without DR) refer particularly to losses of electricity stored in other batteries besides EV batteries, notably in vanadium redox (VR) flow batteries (for electricity balancing purposes). Electricity demand to cover EV storage losses are included in the electricity demand by P2M (passenger EVs), whereas electricity demand to cover $P2H_2$ storage losses are included in the electricity demand by $P2H_2$.



	R2015	CA2030		NM2050	
	NoDR	NoDR	DR	NoDR	DR
Exports	13.8	53.3	61.2	200.5	161.7
Storage losses	0.0	0.0	0.0	3.6	0.0
P2Heat (households)	0.2	0.3	0.3	14.3	14.3
P2Mobility (EVs)	0.5	1.2	1.3	31.1	31.7
P2Heat (industry)	0.0	18.6	3.0	70.8	66.6
P2Hydrogen (H2)	0.0	10.0	10.1	111.1	112.1
Fixed industrial demand	0.0	4.1	4.1	4.1	4.1
Conventional demand	111.8	116.9	116.9	116.9	116.9



	R2015	CA2030		NM2050	
	NoDR	NoDR	DR	NoDR	DR
Imports	30.5	25.0	19.1	190.3	119.0
Gas	48.9	63.5	61.6	9.1	7.4
Coal	29.2	0.0	0.0	0.0	0.0
Nuclear	4.1	4.1	4.1	0.0	0.0
Other RES-E	4.9	11.5	11.6	0.9	0.2
Solar PV	1.3	22.8	22.8	98.1	98.1
Wind Onshore	6.0	17.9	17.9	76.1	76.7
Wind Offshore	1.4	59.6	59.6	177.9	205.9

Figure 14: Electricity demand and supply (including trade) in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)

In particular, Figure 14 shows the impact of DR on the electricity demand by the four selected P2X technologies (as discussed and analysed in Chapter 3). In addition, it indicates the impact of DR on:

- *Electricity storage losses*, i.e. the (additional) electricity demand due to (higher) losses of electricity stored in other batteries besides EV batteries, in particular vanadium redox (VR) flow batteries for electricity balancing purposes. These losses are notably high (i.e., 3.6 TWh) in NM2050 without DR, as in this case the demand for flexible options is particularly high (compared to CA2030) while DR – as one these options – is lacking and, hence, there is more room for other flexible options, including electricity storage by VR batteries.[37]

- *Electricity exports/imports*, i.e. in the case with DR, electricity exports are significantly higher in CA2030, but substantially lower in NM2050 (compared to the case without DR; see upper graph of Figure 14). Electricity imports, however, are substantially lower in both scenario years with DR, but notably in NM2050 when electricity imports drop from more than 190 TWh in the case without DR to less than 120 TWh in the case with DR (see lower graph of Figure 14). These lower imports (and the changes in electricity exports) are due to the shifting (and curtailment) of domestic electricity demand from hours with relatively high electricity prices (notably 'VRE shortage' hours) to hours with relatively low electricity prices (particularly 'VRE surplus' hours), resulting in a lower need (or less opportunities) to import/export electricity.[38]

- *VRE generation*, i.e. due to DR – notably by shifting demand to VRE surplus hours – there is less need for curtailment of VRE power production during these hours and, hence, a higher total annual supply of VRE electricity. This is particularly the case in NM2050 where the supply of offshore wind is substantially higher in the case with DR (206 TWh) than without DR (178 TWh), implying 28 TWh less curtailment of offshore wind due to DR (see lower graph of Figure 14, as well as in Section 7.4 and Chapter 8 below).[39]

- *Non-VRE generation*, i.e. due to DR – notably by curtailing or shifting electricity demand from VRE shortage hours – there is less need for electricity production from other, non-VRE sources. This is notably the case in NM2050 where the power generation from gas and 'other RES-E' (biomass) is significantly lower in the case with DR than without DR (see lower graph of Figure 14, as well as Section 7.3 and Chapter 8 below).

Table 29 provides a summary overview of the (highly) aggregated electricity balance in the Netherlands in R2015, CA2030 and NM2050, including in particular the domestic power production balance versus the foreign power trade balance in these scenario years. It shows that, largely due to the expansion of domestic VRE power generation, the net production balance switches from a major domestic production deficit in R2015 (and, accordingly, a major foreign power trade deficit, i.e. net imports) to a significant domestic production surplus (and, accordingly, a significant foreign trade surplus, i.e. net exports) in both CA2030 and NM2050. Due to the impact of DR, however, these surpluses are substantially higher in the scenario cases with DR than without DR.

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[37] For a detailed analysis of the role of energy storage in the power system of the Netherlands (under different scenario and sensitivity cases), see Sijm et al. (2020). See also Chapters 8 and 9 of the current report.

[38] See also below, including Table 29 and Section 7.3, as well as Chapter 8 of the current study.

[39] As the operational costs of offshore wind are slightly higher in COMPETES than of onshore wind and solar PV, the model prefers to curtail offshore wind as a first option.

Table 29: Aggregated electricity balances in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)

[TWh]	R2015	CA2030		NM2050	
	NoDR	NoDR	DR	NoDr	DR
Domestic power demand	112.5	151.1	135.7	351.9	345.7
Domestic power supply	95.8	179.4	177.7	362.2	388.4
Domestic power production deficit[a]	+16.7	-28.3	-42.0	-10.3	-42.8
Power imports	30.5	25.0	19.1	190.3	119.0
Power exports	13.8	53.3	61.2	200.5	161.7
Foreign power trade deficit[b]	+16.7	-28.3	-42.0	-10.3	-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’).

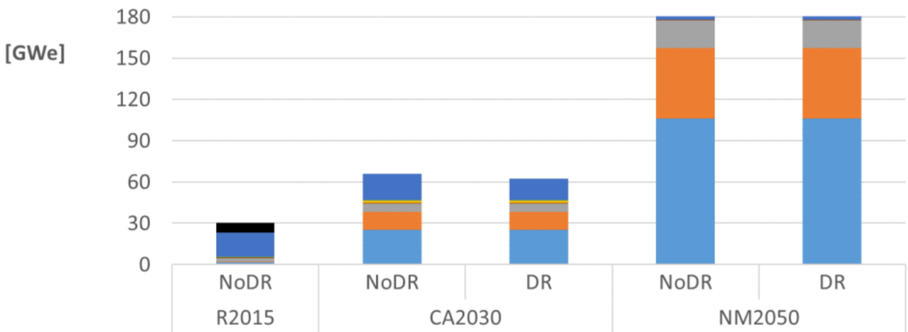
7.3 Installed power generation and interconnection capacities

Figure 15 presents the installed capacities of power generation technologies in R2015, CA2030 and NM2050 with and without DR. For several (policy) reasons, most of these capacities are set exogenously to the COMPETES model (for details, see Section 2.3.2). The capacities for gas plants, however, are determined endogenously by COMPETES.

Figure 15 shows that in CA2030 the installed capacity of gas plants amounts to 19.4 GW in the case without DR and to 15.5 GW with DR (implying less investments in new capacity or – more likely in this case – a higher decommissioning of existing gas plants due to DR). In NM2050, however, the installed gas capacity remains the same in the cases with and without DR (at 3.5 GW). Given the fact that the electricity output from gas declines from 9.1 TWh in NM2050 without DR to 7.4 TWh with DR (Figure 14), this implies that the gas capacity factor (or full load hours) decline accordingly due to DR.

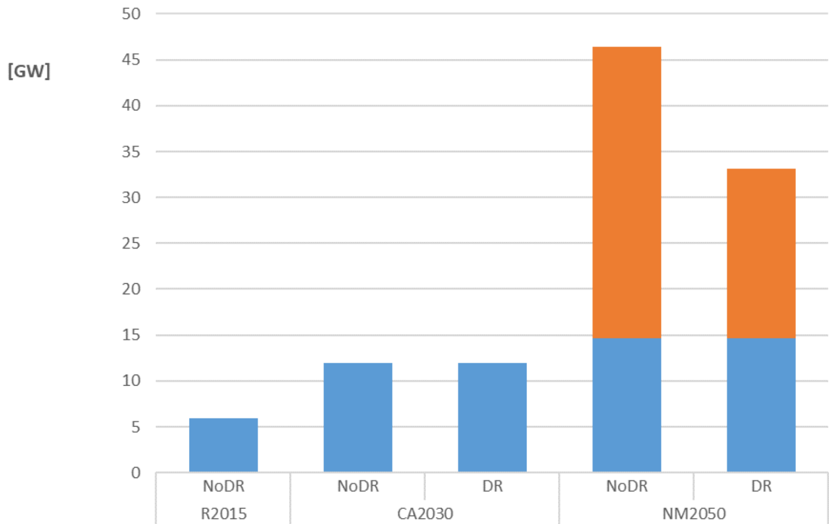
Figure 16 presents the interconnection capacity of the Netherlands (with its surrounding countries) in R2015, CA2030 and NM2050 with and without DR, including a distinction between baseline capacity and new transmission capacity. The baseline interconnection capacity is similar to the capacity in R2015 and the projected increase in this capacity up to 2030 as laid down in the Ten-Year Network Development Plan (TYNDP) of ENTSO-E (2018). The new transmission capacity is the additional interconnection capacity calculated by the COMPETES model in order to meet the optimal interconnection capacity in the respective scenario cases (i.e., the interconnection capacity resulting in the lowest total system costs across the EU27+).[40]

[40] The methodology to estimate additional cross-border transmission (interconnection) investments – and the related investment costs – is explained in Appendix A of Sijm et al. (2017b). The installed interconnection capacity of the Netherlands in the baseline scenario, 2015-2030, is clarified in Appendix B of that report. Finally, Appendix C of Sijm et al. (2017b) presents and discusses in some more details the expansion of the interconnection capacities across individual EU27+ countries in the respective scenario cases.



	R2015 NoDR	CA2030 NoDR	CA2030 DR	NM2050 NoDR	NM2050 DR
Coal	6.6	0	0	0	0
Gas	17.8	19.4	15.5	3.5	3.5
Nuclear	0.5	0.5	0.5	0	0
Other RES-E	0.1	1.1	1.1	0.3	0.3
Biomass	0.5	0.5	0.5	0.1	0.1
Wind Onshore	2.6	6.0	6.0	20.0	20.0
Wind Offshore	0.4	13.4	13.4	51.5	51.5
Solar PV	1.5	25.1	25.1	106.0	106.0

Figure 15: Installed capacities of power generation technologies in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)



	R2015 NoDR	CA2030 NoDR	CA2030 DR	NM2050 NoDR	NM2050 DR
New capacity investments	0	0	0	31.77	18.50
Baseline capacity	5.90	11.97	11.97	14.68	14.68

Figure 16: Interconnection capacity of the Netherlands in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR

Figure 16 shows that in CA2030 the baseline interconnection capacity of the Netherlands is the same in the cases with and without DR while, on the other hand, there are no new capacity investments in these cases. In NM2050, however, the baseline capacity is also the same in both cases (although higher than in CA2030) but in this scenario year the new capacity investments are substantially lower in the case with DR (almost 19 GW) than without DR (nearly 32 GW). This implies that due to DR – and the resulting lower (hourly peak) export and import needs of the Netherlands in NM2050 (see Table 29) – less interconnection capacity is required, leading to lower new capacity investments – and resulting cost savings – up to NM2050 (see also Section 7.8 below).

7.4 VRE curtailment

As mentioned in Section 7.2, the lower graph of Figure 14 presents data on electricity supply from VRE sources *after* curtailment (if any) of VRE power generation. As indicated in this section, due to DR – and, as a result, the lower VRE curtailment – the VRE output after curtailment, notably from offshore wind, is substantially higher in the scenario year NM2050 with DR than without DR.

Table 30 provides aggregated data on VRE power generation – both before and after VRE curtailment – in R2015, CA2030 and NM2050 with and without DR.[41] It shows that in CA2030 VRE curtailment is negligibly small in both the case with and without DR (i.e., close to zero). In NM2050, however, VRE curtailment amounts to almost 102 TWh in the case without DR but drops to 73 TWh without DR, i.e. corresponding to 22% and 16% of VRE supply before curtailment, respectively. Hence, as noted above, owing to DR – and the resulting lower VRE curtailment (about 29 TWh) – the VRE output after curtailment is accordingly higher in NM2050 with DR than without DR.[42]

Table 30: Curtailment of VRE power generation in R2015, CA2030 and NM2050 with and without demand response (DR vs NoDR)

		R2015	CA2030		NM2050	
	Unit	NoDR	NoDR	DR	NoDR	DR
VRE supply before curtailment (b.c.)	TWh	8.7	100.4	100.4	453.7	453.7
VRE curtailment	TWh	0.0	0.1	0.0	101.6	73.0
VRE supply after curtailment (a.c.)	TWh	8.7	100.3	100.4	352.1	380.7
VRE curtailment as % of VRE supply b.c.	%	0.0%	0.1%	0.0%	22.4%	16.1%

7.5 Electricity prices

In the COMPETES model, hourly electricity prices are determined endogenously in order to optimise the European power system (i.e., achieve certain energy objectives – within certain constraints – at the lowest social costs). Hence, in this model there is a dynamic relationship between electricity prices and other variables, such as demand response or electricity trade, affecting the outcomes of these variables until a set of equilibrium values for these variables is reached.

For illustrative purposes, Figure 17 presents the hourly profiles of electricity prices (generated by the COMPETES model) for the month of July in CA2030 and NM2050 with and without DR.[43] Some observations from this figure include:

[41] VRE supply before curtailment is simply obtained by multiplying the (exogenously assumed) installed capacity of VRE technologies and the (assumed) full load hours of these technologies in the respective scenario years (see Figure 15 and Table 12 in Section 2.3.3). VRE curtailment – and the resulting VRE supply after curtailment – is obtained by the COMPETES model, i.e. by optimising the European power investment and production mix, both with and without DR (based on, among others, the exogenously assumed installed capacities of VRE power technologies).

[42] To some extent, the findings on VRE curtailment in NM2050 (may) depend on some specific assumptions regarding this scenario (as discussed further in Section 7.9 below).

[43] See also Chapter 3, notably Figure 6 up to Figure 10, for the hourly profile of electricity prices in both January and July NM2050 with and without DR.

Figure 17: Hourly profile of electricity prices in the month July of CA2030 and NM2050 (hours 4345-5088) with and without demand response (DR versus NoDR)

- In all cases presented, hourly electricity prices are highly volatile. These prices, however, are the most volatile in the case of July NM2050 without DR and the least volatile in July NM2050 with DR.
- In most hours of July CA2030, the difference between electricity prices with and without DR is zero or relatively small. In NM2050, however, this difference is often relatively large (as also indicated above).

- Electricity prices are, on average, higher in CA2030 than in NM2050, notably in the case with DR. In turn, electricity prices in NM2050 are, on average, higher in the case without DR than with DR.

These observations are confirmed by Figure 18, which presents the duration curve of hourly electricity prices in CA2030 and NM2050 with and without DR. In particular, it shows that in CA2030 the price duration curve in the cases with and without DR are largely overlapping. Only during a limited number of hours over the year hourly electricity prices in the CA2030 case with DR are either (slightly) higher or lower than without DR.

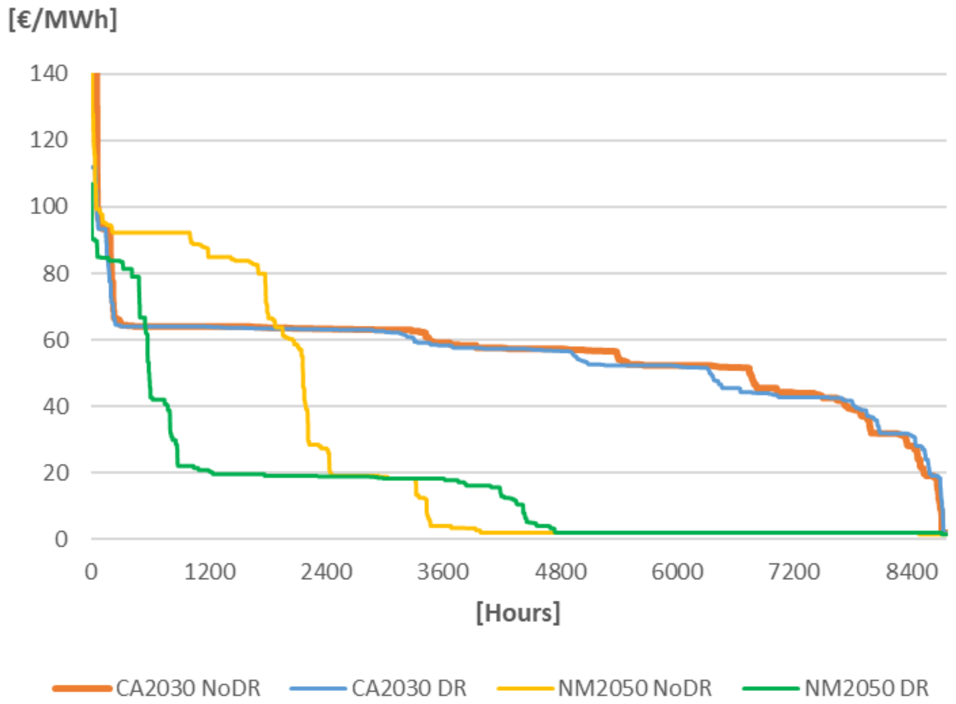


Figure 18: Duration curves of hourly electricity prices in CA2030 and NM2050 with and without demand response (DR versus no DR)

In NM2050, on the contrary, there are some major differences between the price duration curves in the cases with and without DR. Over some 2400 hours, electricity prices in NM2050 with DR are substantially lower (than without DR), whereas during some 1200 hours they are significantly higher. Over the remaining 5200 hours, however, electricity prices in NM2050 are highly similar in both cases, notably during some 4000 hours in which the electricity price is set at the low level of 2 €/MWh (as determined by the marginal VRE generation unit). In general, these are hours in which there is still a VRE surplus despite the deployment of DR, including other flexible options such as VRE curtailment or cross-border trade (i.e., in this case, electricity exports).

Finally, Table 31 provides a summary overview of the weighted average (hourly) electricity prices in CA2030 and NM2050 with and without DR.[44] It shows that the weighted average electricity price is relatively high in CA2030, notably in the case

[44] The hourly electricity prices have been weighted by the hourly total load (i.e., domestic electricity demand).

without DR (73 €/MWh), but that it drops to 54 €/MWh in the case with DR, i.e. a decrease of approximately 26%. In NM2050, on the contrary, the weighted average electricity price is relatively low in the case without DR (27 €/MWh), mainly due to the large (over)supply of VRE power generation setting the price during a large number of hours over the year. This average price, however, decreases even further in the case with DR to 12 MWh, i.e. a decline of approximately 56%.

Table 31: Weighted average (hourly) electricity prices in CA2030 and NM2050 with and without demand response (DR versus no DR)

	Unit	CA2030	NM2050
NoDR	€/MWh	73.0	27.3
DR	€/MWh	54.0	12.0
Change	%	-26%	-56%

These findings, including the observations above from Figure 17 and Figure 18, indicate that DR is able to substantially decrease high hourly electricity prices (notably during severe VRE shortage hours) but hardly or not to increase low hourly electricity prices (in particular during large VRE surplus hours).[45]

7.6 VRE generation revenues

In addition to supply (or sales) volumes, electricity prices are a major determinant of the revenues obtained from these volumes by VRE power producers and, hence, of the business case of investments in VRE power generation. Table 32 provides a summary overview of these total (and average) VRE supply revenues in CA2030 and NM2050, both with and without DR, based on the hourly output of the individual VRE technologies (after curtailment) multiplied by the electricity prices in the respective hours. More specifically, Table 32 assumes that VRE producers receive the electricity prices determined by the COMPETES model – as presented and discussed in the previous section – and that they do not receive any other revenues from their VRE investments activities such as VRE subsidies or revenues from activities on other markets (besides the day-ahead markets), e.g. from providing electricity balancing or other ancillary services.

Table 32 shows that in CA2030 the total VRE supply revenues for all VRE producers is about 7.4% lower in the case with DR than without DR. For specific categories of VRE producers, this rate varies from approximately 5% for wind onshore generators to almost 15% for solar PV generators. Since there is hardly or no (difference in) VRE curtailment between the cases with and without DR, these lower VRE revenues in the case with DR are solely due to the average (lower) electricity price received by the respective (categories of) VRE producers in this case, i.e. by the average VRE supply revenues obtained per MWh generated.

Table 32 shows the average VRE revenue/electricity price received by all VRE producers in CA2030 amounts to 53.9 €/MWh in the case without DR. This is far less than the weighted average electricity price in CA2030 without DR (i.e., 73 €/MWh, see Table 31 in the previous section).

[45] Similar to the findings on VRE curtailment, as discussed in Section 7.4 above, the findings on electricity prices in NM2050 depend on some specific assumptions of this scenario year (as discussed further in Section 7.9 below).

Table 32: Total and average VRE revenues in CA2030 and NM2050 with and without demand response (DR versus NoDR)

Type of VRE supply	Unit	CA2030				NM2050			
		NoDR	DR	Δ	In %	NoDR	DR	Δ	In %
Total VRE supply revenues									
Wind Onshore	m€	928	884	-44	-4.7	887	629	-258	-29.1
Wind Offshore	m€	3167	3003	-164	-5.2	3895	2599	-1295	-33.3
Solar PV	m€	1308	1115	-193	-14.7	1639	960	-679	-41.4
Total	m€	5404	5003	-401	-7.4	6421	4188	-2233	-34.8
VRE generation									
Wind Onshore	TWh	17.89	17.89	0.00	0.00	76.1	76.7	0.6	0.8
Wind Offshore	TWh	59.60	59.64	0.03	0.06	177.9	205.9	28.0	15.7
Solar PV	TWh	22.82	22.82	0.00	0.00	98.1	98.1	0.0	0.0
Total	TWh	100.31	100.34	0.03	0.03	352.2	380.8	28.6	8.1
Average VRE supply revenues per MWh generated ('weighted average VRE supply price')									
Wind Onshore	€/MWh	51.9	49.4	-2.5	-4.7	11.6	8.2	-3.5	-29.7
Wind Offshore	€/MWh	53.1	50.4	-2.8	-5.2	21.9	12.6	-9.3	-42.3
Solar PV	€/MWh	57.3	48.9	-8.5	-14.7	16.7	9.8	-6.9	-41.4
Total	€/MWh	53.9	49.9	-4.0	-7.4	18.2	11.0	-7.2	-39.7
Installed VRE capacities									
Wind Onshore	GW	6.0	6.0	0.0	0.0	20.0	20.0	0.0	0.0
Wind Offshore	GW	13.4	13.4	0.0	0.0	51.5	51.5	0.0	0.0
Solar PV	GW	25.1	25.1	0.0	0.0	106.0	106.0	0.0	0.0
Total	GW	44.5	44.5	0.0	0.0	177.5	177.5	0.0	0.0
Average VRE supply revenues per GW installed									
Wind Onshore	m€/GW	154.7	147.4	-7.3	-4.7	44.3	31.4	-12.9	-29.1
Wind Offshore	m€/GW	236.4	224.1	-12.2	-5.2	75.6	50.5	-25.2	-33.3
Solar PV	m€/GW	52.1	44.4	-7.7	-14.7	15.5	9.1	-6.4	-41.4
Total	m€/GW	121.4	112.4	-9.0	-7.4	36.2	23.6	-12.6	-34.8

In the scenario CA2030 without DR, however, the average electricity price received by all VRE producers amounts to 49.9 €/MWh, i.e. 4.0 €/MWh (7.4%) less than in the case without DR (Table 32) and 4.1 €/MWh (7.6%) less than the weighted average electricity price in CA2030 without DR (i.e., 54 €/MWh, see Table 31). The decline in average VRE revenues is largely due to the load curtailment of P2H-i, which results in a 10% decrease in total domestic electricity demand (while the installed VRE capacity – assumed exogenously – remains the same).

Table 32 shows also that there are some striking differences regarding the impact of DR on the average electricity price received in CA2030 between the major categories of VRE producers, notably between solar PV generators versus onshore/offshore wind generators. More specifically, Table 32 shows that the average electricity price received in CA2030 by solar PV producers amounts to 57.3 €/MWh in the case without DR, i.e. significantly higher than the average electricity price received by all VRE producers (53.9 €/MWh) as well as by all power generators (54.3 €/MWh).

In CA2030 with DR, however, the average electricity price received by solar PV generators amount to 48.9 €/MWh, i.e. somewhat lower than the average electricity price received by all VRE producers (49.9 €/MWh) but, as noted above, substantially lower than the average electricity price received by all power producers in CA2030 with DR (54.3 €/MWh).

This implies that in CA2030 DR results in a significant lower average electricity price for solar PV producers, i.e. a price difference of 8.5 €/MWh (-15%) between the cases with and without DR. For wind producers, this difference is much smaller, i.e. about 2.5-2.8 €/MWh (-5%, see Table 32). This indicates that, at least in CA2030, DR has – on balance – a significant negative impact on the electricity prices in particular those hours in which solar PV producers generate their output.

In addition, Table 32 shows that there are some striking findings and differences in NM2050, notably regarding (i) the average electricity price received by all VRE producers between the cases NM2050 with and without DR, (ii) the average electricity price received by all VRE producers versus all power generators (in both cases), and (iii) the average electricity price received by different categories of VRE producers.

More specifically, regarding NM2050, the middle part of Table 32 shows that the average electricity price received by all VRE producers amounts to 18.2 €/MWh in the case without DR and to 11.0 €/MWh with DR, i.e. an average price decrease of 7.2 €/MWh (-40%) due to DR. These prices are not only substantially lower than the comparative prices in CA2030 but also compared to the weighted average electricity prices (received by all power producers) in NM2050 without and with DR (i.e., 27.3 €/MWh and 12.0 €/MWh, respectively; see Table 31).

Within the group of VRE producers, there are some striking differences in average electricity prices received in NM2050 between solar PV versus wind producers but, in particular, between offshore versus onshore wind producers. For solar PV producers, the average electricity price received amounts to 16.7 €/MWh in NM2050 without DR and to 9.8 €/MWh with DR, i.e. a price difference due to DR of -6.9 €/MWh (-41%). For onshore wind producers, however, these average prices are lower (11.6 €/MWh and 8.2 €/MWh, respectively), i.e. the price difference due to DR is also lower in both absolute terms (-3.5 €/MWh) and relative terms (-30%). For offshore wind producers, on the contrary, these average prices are higher (21.9 €/MWh and 12.6 €/MWh, respectively), i.e. the price difference due to DR is also higher in both absolute terms (-9.3 €/MWh) and relative terms (-42%).

In NM2050, the (relatively large) DR induced decline in the average electricity price received by VRE producers is likely, to some extent, due to some specific assumptions of this scenario, notably the assumed installed VRE capacity compared to the total domestic electricity demand.[46]

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[46] See also discussion of Part II below. In a follow-up study this year (2022), we further explore the impact of (flexible) electricity demand – and other factors – on the business case of VRE investments.

In addition, the relatively high average price decrease for offshore wind producers – due to DR in NM2050 – is partly caused (and compensated) by the increase in electricity supply from offshore wind in NM2050 with DR, resulting from the DR induced lower curtailment of offshore wind in this case (see also Sections 7.2 and 7.4 above). More specifically, Table 32 shows that, owing to DR induced less curtailment, the output of offshore wind increases from 178 TWh in NM2050 without DR to 206 TWh with DR, i.e. an increase of 28 TWh (+16%). A similar curtailment (volume) effect is much lower for onshore wind (less than 1%) or even missing for solar PV (0%). Consequently, by multiplying the volume effect and the average price effect, total VRE supply revenues in NM2050 decrease due to DR by some 29% for onshore wind producers, 33% for offshore wind generators, and by 41% for solar PV producers (see upper part of Table 32).

Finally, in addition to average VRE supply revenues per MWh generated, Table 32 presents also data on average VRE supply revenues per GW installed in CA2030 and NM2050 with and without DR.[47] More specifically, the lower part of Table 32 shows that these capacity revenues for all VRE producers as a whole decline in CA2030 from 121 m€/GW in the case without DR to 112 m€/GW with DR (i.e., minus 7% due to DR). In addition, it shows that – due to predominantly the different capacity factors (full load hours) of the different VRE technologies – these revenues vary largely across these technologies. For instance, in CA2030 without and with DR, the average VRE supply revenues per GW installed of solar PV amount to approximately 52 and 44 m€/GW, respectively (i.e., minus 15%), whereas for offshore wind they amount to 236 and 224 m€/GW, respectively (i.e., minus 5%).[48]

7.7 Electricity demand costs

Demand response does not only affect the electricity prices received by VRE producers (and, hence, their VRE supply revenues) but also the electricity prices paid by electricity consumers and, therefore, their electricity demand costs. Table 33 presents the total and average electricity costs – for both flexible P2X and conventional end-users – in CA2030 and NM2050 with and without DR. The table assumes that all end-users – regardless of whether they are demand-response (‘flexible’) or not – pay the same hourly (variable) day-ahead electricity market prices (as determined by the COMPETES model). Moreover, the table considers only these day-ahead prices and ignores other electricity demand costs such as grid tariffs or electricity taxes (assuming that these other costs are not affected by DR).

The upper part of Table 33 presents the total electricity demand costs. It shows that in CA2030 the total electricity costs for all end-users amount to about 11 b€ in the case without DR and to 7.3 b€ with DR, while in NM2050 these costs amount to 9.5 b€ and 4.1 b€, respectively. Due to DR, this implies a total cost saving for all electricity end-users of 3.7 b€ in CA2030 (-34%) and of 5.4 b€ in NM2050 (-56%).

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[47] Comparing the VRE supply revenues per GW installed with the (capital and operational) costs per GW installed provides an indication of the business case of investments in VRE sources. This issue will be further explored in a follow-up project this year (2022) in which we will include also some other scenario/sensitivity analyses as well as some other factors (besides DR) affecting the business case of VRE investments. See also Sections 7.9 and10.4 below.

[48] Note that, since the (exogenously assumed) installed VRE capacities do not change in the respective scenario cases with and without DR, the relative change (in %) in the average VRE supply revenues per GW installed – due to DR – is similar to the relative change in the total VRE supply revenues (see upper versus lower part of Table 32).

Table 33: Total and average electricity demand costs in CA2030 and NM2050 with and without demand response (DR versus NoDR)

Type of electricity demand		**CA2030**				**NM2050**			
	Unit	**NoDR**	**DR**	**Δ**	**In %**	**NoDR**	**DR**	**Δ**	**In %**
Total electricity demand costs									
Conventional[a]	m€	8922	6631	-2291	-25.7	3294	1877	-1417	-43.0
P2Hydrogen	m€	684	522	-162	-23.7	2899	885	-2014	-69.5
P2Heat (industry)[b]	m€	1295	103	-1192	-92.1	1852	728	-1124	-60.7
P2Heat (households)	m€	26	17	-10	-36.4	428	279	-149	-34.8
P2M (passenger EVs)	m€	105	56	-50	-47.2	1038	373	-665	-64.0
Total electricity costs	**m€**	**11033**	**7328**	**-3705**	**-33.6**	**9510**	**4142**	-5369	**-56.4**
NB: Gas (hybrid P2H-i)[b]	m€		481				203		
Total energy costs	*m€*	*11033*	*7809*	*-3225*	*-29.2*	*9510*	*4345*	*-5089*	*-53.5*
NB: E- costs per EV	*€*	*259*	*137*	*-122*	*-47.2*	*100*	*36*	*-64*	*-64.0*
Per controllable EV	€	259	123	-136	-52.5	100	32	-68	-68.0
Per uncontrollable EV	€	259	170	-89	-34.3	100	45	-55	-55.0
Electricity demand									
Conventional	TWh	121.0	121.0	0.0	0.0	121.0	121.0	0.0	0.0
P2Hydrogen[b]	TWh	10.0	10.1	0.0	0.4	111.1	112.1	0.9	0.9
P2Heat (industry)	TWh	18.6	3.0	-15.6	-83.7	70.8	66.6	-4.2	-6.0
P2Heat (households)	TWh	0.3	0.3	0.0	0.0	14.3	14.3	0.0	0.0
P2M (passenger EVs)[c]	TWh	1.2	1.3	0.0	2.7	31.1	31.7	0.6	2.0
Total electricity demand	**TWh**	**151.2**	**135.7**	**-15.5**	**-10.3**	**348.3**	**345.6**	**-2.6**	**-0.8**
NB: E-demand per EV[d]	*MWh*	*3.0*	*3.1*	*0.1*	*2.7*	*3.0*	*3.1*	*0.1*	*2.0*
Average electricity demand costs ('weighted average electricity demand price')									
Conventional	€/MWh	73.8	54.8	-18.9	-25.7	27.2	15.5	-11.7	-43.0
P2Hydrogen	€/MWh	68.1	51.8	-16.4	-24.0	26.1	7.9	-18.2	-69.7
P2Heat (industry)	€/MWh	69.6	33.8	-35.7	-51.4	26.2	10.9	-15.2	-58.2
P2Heat (households)	€/MWh	85.3	54.2	-31.1	-36.4	29.9	19.5	-10.4	-34.8
P2M (passenger EVs)	€/MWh	86.3	44.4	-41.9	-48.6	33.4	11.8	-21.6	-64.8
Average electricity costs	**€/MWh**	**73.0**	**54.0**	**-19.0**	**-26.0**	**27.3**	**12.0**	**-15.3**	**-56.1**

a) Including (additional) fixed industrial demand.

b) P2Heat in industry refers to hybrid heat boilers. It is assumed that in the scenarios without demand response (NoDR) industrial heat demand is met fully by means of electricity, whereas in the scenarios with DR it is met by either electricity or gas depending on their relative energy prices per unit of heat demand. Hence, to make an appropriate energy cost comparison between cases with and without DR, the gas costs of hybrid heat boilers in industry should be included in the cases with DR. Including gas cost implies that total energy costs of P2H-i amount to 584 m€ in CA2030 with DR, i.e. 711 m€ lower than in CA2030 without DR (-54.9%). In NM2050, total energy costs of P2H-i (including gas) amount to 931 m€ in the case with DR, i.e. 921 m€ lower than without DR (-49.7%).

c) In scenarios with DR, the electricity demand for $P2H_2$ is higher due to higher (average) volumes of (green) hydrogen storage, resulting in higher losses of hydrogen storage and, hence, a higher demand for hydrogen and, consequently, a higher electricity demand for $P2H_2$.

d) In scenarios with DR (including V2G transactions), the average electricity demand per EV is slightly higher due to higher battery storage losses.

In CA2030, the main beneficiaries of the DR induced electricity cost savings are the (inflexible) conventional end-users – as in CA2030 they are by far still the largest group of end-users, accounting for some 80% of total electricity demand – as well as the industrial end-users of power-to-heat (P2H-i), although the main part of their electricity cost saving is caused by DR induced load curtailment – i.e., switching from electricity to gas – rather than lower (average) electricity prices (see below).[49]

In NM2050, the main beneficiaries of the DR induced electricity cost savings – in absolute amounts – are the $P2H_2$ end-users (saving some 2 b€, i.e. -70% compared to the case with DR) as well as the conventional end-users, still accounting for almost one-third of total electricity demand (and saving about 1.4 b€, i.e. -43%).

Table 33 provides also the total savings of electricity demand cost by power-to-mobility (P2M) due to DR, both for all passenger EV users as a group and for a single (average) EV user. It shows that these cost savings for all EV users amount to 50 m€ (-47%) in CA2030 and to almost 670 m€ (-64%) in NM2050. For a single EV user, these annual savings amount to about 120 € and 64 €, respectively, i.e. approximately 10 € and 5 € of electricity cost savings per month per EV owing to DR.

As indicated in Section 2.4.2, however, not all passenger EV users are demand-responsive, i.e. only 70% of the EV load/users is demand-responsive (‘controllable’), while 30% is uncontrollable, i.e. not responding to changes in electricity prices. Hence, uncontrollable EV drivers do not change their ‘dumb’ charging pattern, but they are affected by – and may even benefit from – the electricity price changes induced by ‘controllable’ EV drivers (and all other demand-responsive end-users). On the other hand, controllable EV drivers do not only benefit from these DR induced changes in electricity prices but also from switching their load charging from high to low electricity price hours. Table 33 shows that, owing to DR, average electricity costs in CA2030 decline by 89 € per uncontrollable EV driver (-34%) and by 136 € per controllable EV driver (-53%). In NM2050, these cost savings amount to 55 € (-55%) and 68 € (-68%), respectively.

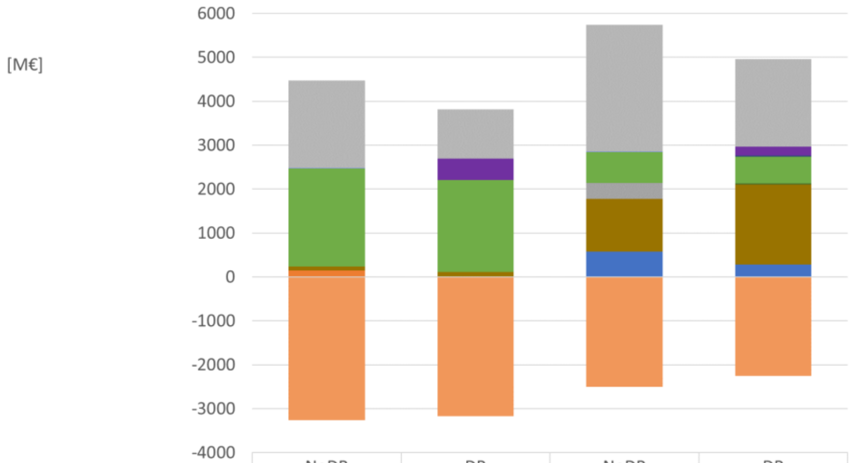
Accounting for the DR induced volume changes – or, more correctly, dividing the total electricity demand costs by the electricity demand volumes, both with and without DR – results in the average electricity demand costs, i.e. the weighted average electricity (demand) price. The lower part of Table 33 shows that this average cost (price) for all end-users amount to 73 €/MWh in CA2030 without DR and to 54 €/MWh with DR, while in NM2050 it amounts to 27 €/MWh and 12 €/MWh, respectively.[50] Owing to DR, this implies an average cost savings for all electricity end-users of 19 €/MWh in CA2030 (-26%) and of 15 €/MWh in NM2050 (-56%). For some specific end-users, however, these cost savings are sometimes much higher. For instance, in CA2030 the average electricity cost savings due to DR amount to 48 €/MWh (-49%) for EV users and 36 €/MWh (-51%) for P2H users in industry, while in NM2050 they amount to 22 €/MWh (-65%) for EV users and 18 €/MWh (-70%) for $P2H_2$ users.

[49] In addition, it should be noted that, because of the switching from electricity to gas by industrial heat users, an appropriate energy cost comparison of DR versus NoDR cases should include also the gas costs of hybrid heat boilers in industry. Including these gas costs implies that in the case of CA2030 with DR the total energy costs are 481 m€ higher for both P2H-i end-users and all electricity end-users as a group and, hence, their energy cost savings due to DR are accordingly lower. For more details, see Table 33 (notably note b).

[50] These average electricity costs are similar to the weighted average electricity prices recorded in Table 31.

7.8 Power system costs

Figure 19 presents the major constituent components of the power system costs in the Netherlands in CA2030 and NM2050 with and without DR. Actually, these cost components refer to the 'power-to-X' (P2X) system of the Netherlands as besides 'conventional' components, such as the investment costs of new power generation capacity or the variable electricity production costs, they also include 'new' (P2X) components such as investment costs of new $P2H_2$ capacity. Investment costs refer only to the investment cost of new capacities up to a certain scenario year, and not to the investment cost of the baseline capacities as these are regarded as 'sunk costs' that are not affected over future scenario years.



	NoDR	DR	NoDR	DR
	CA2030		NM2050	
Electricity import costs	1990	1121	2886	1999
Electricity export costs	-3265	-3170	-2501	-2253
H2 curtailment costs	15	0	9	0
Variable gas-to-heat costs	0	481	0	203
Variable energy storage costs	0	4	6	23
Variable electricity generation costs	2227	2091	705	602
Investment costs of new H2 storage capacity	0	1	0	26
Investment costs of new E-storage capacity	0	0	363	0
Investment costs of new P2H2 capacity	97	116	1196	1820
Investment costs of new generation capacity	142	0	0	0
Investment costs of new HVDC grid overlay	0	0	576	287

Figure 19: Major constituent components of the power system costs of the Netherlands in CA2030 and NM2050 with and without demand response (DR versus no DR)

In addition, the P2X system costs include the so-called 'variable gas-to-heat costs' – i.e., the variable costs of generating industrial heat by a gas boiler as part of a hybrid, flexible P2H system – in order to make an appropriate ('fair') comparison of the energy system costs with and without DR.

Moreover, the P2X system costs of the Netherlands include also the costs of electricity imports and exports by the Netherlands. From a national perspective, however, electricity exports are actually revenues (rather than costs) as the domestic costs of generating these exports are already included in other cost components such as new capacity investments or variable generation costs. Therefore, in Figure 19 electricity exports are presented as negative costs (i.e., 'revenues') and, hence, they are subtracted from (rather than added to) to the total power system costs (as discussed below).

Figure 19 shows some striking differences in power system cost components in the scenarios with and without DR. For instance, in both CA2030 and NM2050 variable gas-to-heat costs are (by definition) higher in the cases with DR than without DR. On the other hand, costs of electricity imports are substantially lower in the scenario cases with DR than without DR. In addition, in NM2050 the investment costs of new '*HVDC grid overlay*' are also lower in the case with DR than without DR. These costs refer to the High Voltage Direct Current (HVDC) network, notably to the investment costs of new cross-border interconnection capacity as well as the related investment costs of new inland transmission capacity. As discussed in Section 7.3, due to DR, there is less need for electricity trade in NM2050 (with DR) and, hence, less need for investments in new interconnection capacity and related inland transmission networks. Therefore, the costs of these investments are substantially lower in the case of NM2050 with DR than without DR.[51]

Investment costs of new $P2H_2$ capacity, on the contrary, are significantly higher in the case with DR (than without DR), notably in NM2050. As explained in Section 3.1.1, in the case with DR there is a need for additional (new) electrolyser capacity in order to enable electricity demand by $P2H_2$ to respond flexibly to (changes in) electricity prices while still meeting the demand for green hydrogen over a scenario year. Therefore, the investments costs related to this additional capacity are higher in the case with DR.

Finally, Table 34 provides a summary overview of the aggregated power system costs of the Netherlands in CA2030 and NM2050 with and without DR. It shows that, on balance, these total costs amount to some 1200 m€ in CA2030 with DR and to about 640 m€ without DR, while in NM2050 these costs amount to 3240 m€ and 2710 m€, respectively. This implies that, owing to DR, these costs are about 560 m€ lower in CA2030 (-47%) and approximately 530 m€ in NM2050 (-16%).

Table 34: Aggregated power system costs of the Netherlands in CA2030 and NM2050 with and without demand response (DR versus no DR)

		The Netherlands		EU27+	
	Unit	CA2030	NM2050	CA2030	NM2050
NoDR	m€	1,204	3,241	62,224	70,413
DR	m€	644	2,706	60,261	49,507
Change	m€	560	535	1,963	20,906
Change	%	-47%	-16%	-3.2%	-30%

For the Netherlands, the DR induced change in aggregated system costs are to a large extent affected by the DR induced changes in electricity trade. For all European countries and regions covered by the COMPETES model ('EU27+'), the model does not include any external electricity trade and, hence, the aggregated system costs for the EU27+ do not account for any electricity costs. The right part of Table 34 shows that the aggregated system costs for the EU27+ as a whole decrease from 62.2 b€ in CA2030 without DR to 60.3 b€ with DR, i.e. a cost saving of almost 2 b€ (-3.2%) due to DR. In NM2050, however, these costs decline even from 70.4 b€ without DR to 49.5 b€ with DR, i.e. a cost saving of almost 21 b€ (-30%) due to DR.

[51] For a discussion of the investments in new interconnection capacity and the methodology to estimate this capacity and the related HVDC grid overlay costs, see Section 7.3 and the references cited there (notably in footnote 40).

7.9 Discussion

The scenario results on the impact of DR on the electricity balance/power system of the Netherlands in the coming decades (2030-2050) – as analysed in the previous sections – do not only depend on the potential (size) of DR in these decades (as discussed in part I of this study) but also on the key assumptions of the respective scenarios. This applies in particular for the scenario year NM2050 (which includes more long-term uncertainties and bold assumptions than scenario CA2030).

As explained in Section 2.2, our 'National Management 2050' (NM2050) scenario is based on the eponymous scenario developed by Berenschot and Kalavasta (2020). This NM2050 scenario is one out of four 'extreme' scenarios explored in their study by means of the Energy Transition Model (ETM), i.e. a simulation model of the Dutch energy system developed by Quintel (2020). Similar to our study on the role of storage in the energy system of the Netherlands (Sijm et al., 2020), the current study – on the role of DR – has used, as far as possible, the same NM2050 assumptions and parameters in the COMPETES model as the Berenschot and Kalavasta study in the ETM. Nevertheless, there are still some major differences in underlying (implicit) assumptions and parameters used by the two respective NM2050 scenarios studies and, notably, in the methodology applied by COMPETES (i.e., optimisation) versus ETM (i.e., simulation).[52]

For the COMPETES model, the assumptions and parameters used for the ('extreme') scenario NM2050 result, among others, in a relatively high ('suboptimal') installed capacity/supply of VRE power generation versus a relatively low electricity demand. In turn, this results in a relatively large number of hours with a relatively large surplus of VRE power generation (compared to electricity demand), relatively large (net) exports of electricity, relatively large volumes of VRE curtailment, and a relatively large number of hours with low electricity prices (see, in particular, Sections 7.2, 7.4 and 7.4 of the current chapter as well as Sections 8.2 and 8.3 of the next chapter).

It is hard to say whether and, in particular, to which extent the assumptions of the NM2050 scenario affect the results regarding the impact of DR in this scenario as presented and discussed in the current chapter. In general, the direction and size ('order of magnitude') of this impact seems to be in line with the impact of DR in CA2030 (which has less long-term uncertainties and less 'bold' assumptions), accounting with the difference in the potential (size) of DR in these scenario years.

Moreover, notice that the assumptions of the (uncertain, extreme) scenario NM2050 apply not only for the case with DR but also for the case without DR. Hence, by comparing the scenario results between the cases with and without DR some useful insights are obtained in the size and direction of the impact of DR within the scope and limits of the scenario (as within the scope and limits of any other long-term scenario).

Finally, it should be remarked that comparing the results of the NM2050 cases with and without DR does not only offer useful insights into the potential impact of DR (i.e.,

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[52] For a detailed discussion on the differences between the two models (COMPETES and ETM), the different assumptions and parameters of these models applied to the NM2050 scenario, and the implications for the respective model scenario outcomes, see Sijm et al. (2020), in particular Section 5.2.

what can be achieved by means of DR) but also on the limitations of DR (i.e., what is hardly or not able to be achieved by DR). For instance, the NM2050 scenario results show that DR is able to reduce VRE curtailment from 102 TWh in the case without DR to 73 TWh with DR, i.e. a reduction by 29 TWh (-28%, see Section 7.4, notably Table 30). Despite this significant reduction of VRE curtailment, a large amount of VRE curtailment is still left (73 TWh), which DR is not able to address.

Another interesting (related) example of the scope and limitation of DR refers to its impact on electricity prices. The COMPETES results for NM2050 show that over some 2400 hours electricity prices are substantially lower in the case with DR (compared to the relatively high electricity prices in the case without DR), whereas during some 1200 hours they are significantly higher (compared to the relatively low electricity prices in the case without DR). Over the remaining 5200 hours, however, DR has hardly or no impact as electricity prices are highly similar in the cases with and without DR, notably during some 4000 hours in which the electricity price is set at the low level of 2 €/MWh (by the marginal VRE unit). As noted, these are generally hours in which there is still a VRE surplus despite the deployment of demand response and other flexible options such as VRE curtailment or cross-border trade (exports).

More generally, the two related examples outlined above show that DR, to some extent, is able to improve (‘optimise’) the performance of the power system (as indicated by the DR induced reduction of the total system costs; see Section 7.8). However, if there is a fundamental mismatch between, e.g., the assumed (exogenously determined) capacity of VRE power generation and the demand for electricity, DR is only partially – but not fully – able to correct this mismatch (and, hence, a sub-optimal situation – from a social cost perspective – will continue). Therefore, in order to move towards a more optimal social outcome with regard to the (future, climate-neutral) power system, an appropriate match between installed VRE generation capacity and electricity demand has to be set initially (which can be further optimised by means of flexible options such as DR).[53]

To get some insight into the implications of the major uncertainties and assumptions regarding scenario NM2050, we have defined and assessed some sensitivity analyses of this scenario, including a sensitivity case in which we have significantly reduced the assumed installed capacity of VRE power generation.[54] The major results of these sensitivity analyses are presented and discussed in Chapter 10. First of all, however, we present and discuss the results regarding the impact of DR on the residual load balance (Chapter 8) and the flexibility balance (Chapter 9), respectively.

[53] One of the options to approach this optimal social outcome is to use a power system optimisation model (such as COMPETES), in which the (investment) capacity and (operational) dispatch of VRE power generation technologies – as well as of competing technologies and flexible system options – are optimised endogenously by the model (within a dynamic price setting), given the baseline electricity demand within a European-wide, consistent (climate-neutral) scenario (see also next footnote).

[54] Moreover, we have planned a follow-up study for this year (2022), in which we will further explore the impact of (flexible) electricity demand on the optimal capacity and business case of VRE investments (including the electricity prices/revenues obtained by VRE power producers. For this follow-up study, we will use an improved (extended, updated) version of the COMPETES model in which the installed capacities of VRE power technologies (and other, competing technologies) are determined endogenously by the model within the context of an updated, consistent, EU-wide scenario for 2030 (‘fit for 55’) and 2050 (‘climate-neutral EU energy system’). The results of this follow-up study are planned to be published early next year (2023).

8 The impact of demand response on the residual load balance

This chapter presents and analyses the impact of DR on the so-called '*residual load balance*' of the Netherlands in the scenario years CA2030 and NM2050. First of all, Section 8.1 discusses the concept '*residual load*' as well as the equation(s) of the residual load balance in the scenario cases with and without DR. Subsequently, Section 8.2 analyses the impact of DR on the residual load. Finally, Section 8.3 presents and discusses the scenario results regarding the impact of DR on other flexible options to meet the residual load, such as electricity storage, trade or VRE curtailment.

8.1 The residual load balance

In order to explore the implications of a growing share of variable renewable energy (VRE) sources in total electricity generation, the concept '*residual load*' has been introduced in power system analyses. More specifically, this concept is defined (and measured) as the difference between domestic electricity demand (before any exports or any storage charges) and domestic electricity supply from VRE sources (before any imports, storage discharges or VRE curtailment).

Figure 20 presents the hourly profile of the residual load (RL) in CA2030 and NM2050, both without DR. It shows that the hourly RL 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 +55 and -112 GW.

In addition to the hourly variation of the residual load, Figure 20 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.[55]

By ranking the hourly residual load over a year from high to low, Figure 21 provides the duration curve of this load in CA2030 and NM2050. In addition to confirming the wide spread of the hourly RL observed above, it also shows that this load is negative during a large number of hours during the year, i.e. about 2500 hours in CA2030 and more than 5800 hours in NM2050.[56] A *negative RL* implies that the domestic power supply from VRE resources is larger than the domestic electricity demand, i.e. there is a domestic surplus of VRE electricity production (called '*VRE surplus'*), while a *positive RL* means that there is domestic shortage of VRE electricity generation (indicated as '*VRE shortage'*).

[55] See also Sijm et al. (2020), notably Appendix B, which shows also 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.

[56] Compared to CA2030, the larger number of hours with a negative RL ('VRE production surplus') in NM2050 is largely due to the higher share of VRE sources in total electricity generation in NM2050, including the relatively high installed capacity of VRE power generation (assumed exogenously) versus the total electricity demand (as discussed in Section 7.9 of the previous chapter).

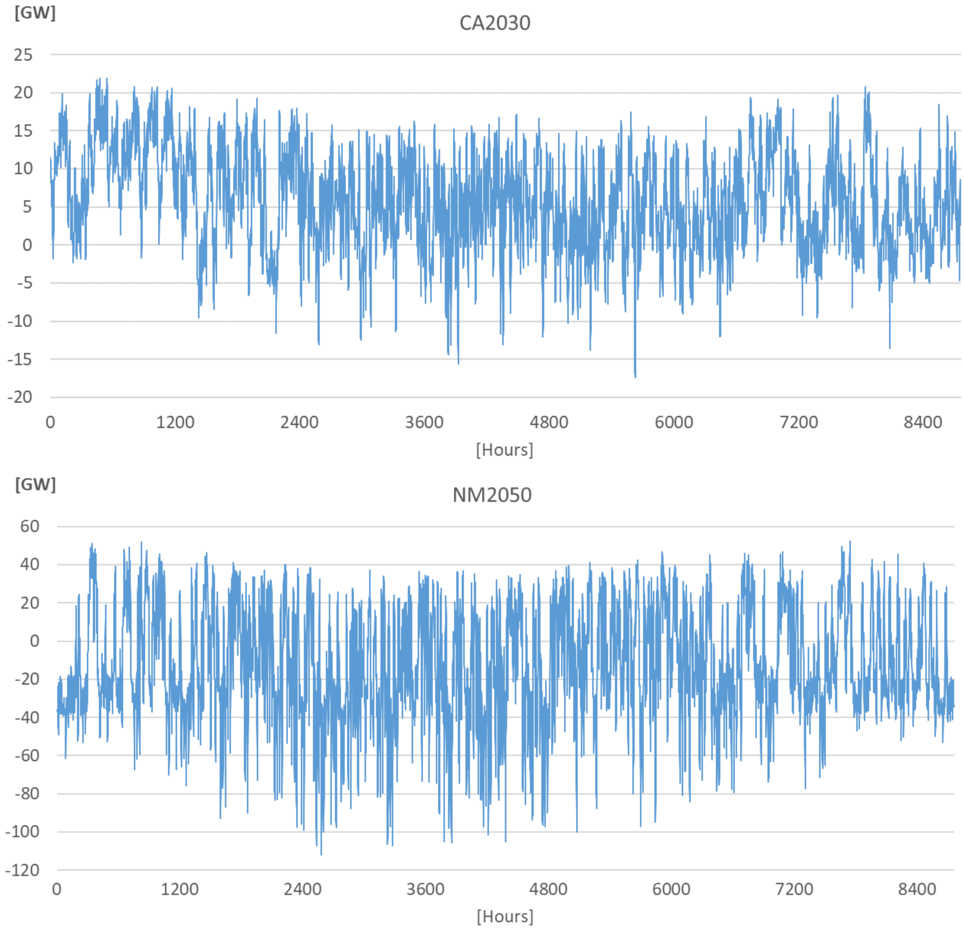


Figure 20: Hourly profile of residual load in CA2030 and NM2050 without demand response

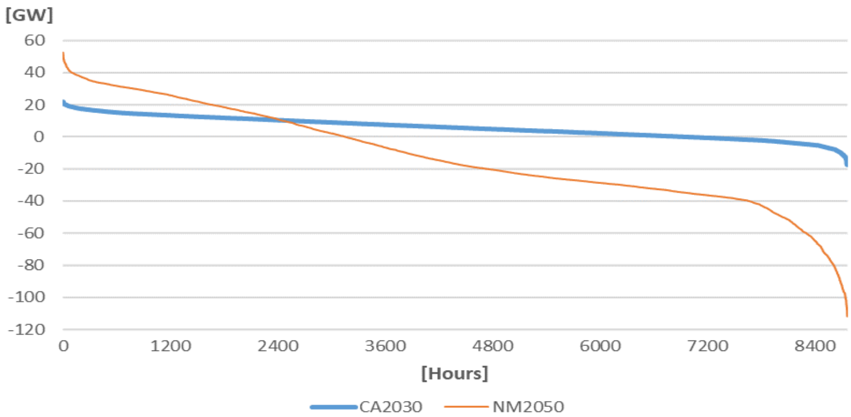


Figure 21: Duration curve of residual load in CA2030 and NM2050 without demand response

In this chapter we will analyse the role of DR versus the other flexible options – such as trade, storage or VRE curtailment – to meet the hourly RL (either positive or negative). In order to analyse this role, we introduce the concept of the 'residual load balance' (i.e., the mix of supply options to meet the residual load). Based on the definition of residual load (as mentioned in the beginning of the current section), we derive the equation of the RL balance from the equation of the electricity balance (see equation 1 in Section 7.1).

More specifically, by defining:

$$VRE(AC)_t = VRE(BC)_t - VRECUR_t \qquad (2)$$

and

$$NT_t = IM_t - EX_t \qquad (3),$$

we can rearrange the electricity balance equation 1 of Section 7.1 into the following equation:

$$DD(NoDR)_t + DR_t - VRE(BC)_t = NONVRE_t - VRECUR_t + NT_t - ST_t \qquad (4),$$

where:

$DD\ (NoDR)_t$	=	Domestic demand of electricity (without DR) in hour *t* (*t* = 1,……, 8760),
DR_t	=	Demand response (either upwards or downwards) in hour *t*,
EX_t	=	Exports of electricity in hour *t*,
IM_t	=	Imports of electricity in hour *t*,
$NONVRE_t$	=	Domestic production (supply) of electricity from non-VRE sources in hour *t*, including electricity from fossil fuels – notably coal and gas – as well as from other (renewable) energy sources (besides sun and wind) such as hydro biomass or nuclear,
NT_t	=	Net trade of electricity in hour *t*, defined as imports of electricity in hour *t* (IM_t) minus exports of electricity in hour *t* (EX_t),
ST_t	=	Storage transactions (including storage losses) in hour t, i.e. storage charges (SC_t) minus storage discharges (SD_t) in hour *t*,
$VRE(AC)_t$	=	Domestic production (supply) of electricity from variable renewable (VRE) sources, notably sun and wind, in hour *t* (after curtailment of VRE power generation),
$VRE(BC)_t$	=	Domestic production (supply) of electricity from VRE sources in hour *t* (before curtailment of VRE power generation),
$VRECUR_t$	=	Curtailment of electricity generation from VRE sources in hour *t*.

Subsequently, by defining:

$$RL_t = DD(NoDR)_t + DR_t - VRE(BC)_t \qquad (5)$$

as the residual load in hour t (RL_t), we obtain the following equation of the residual load balance:

$$RL_t = NONVRE_t - VRECUR_t + NT_t - ST_t \qquad (6)$$

Basically, equation 6 says that the residual load (RL) in hour *t* – which can be either positive or negative – can be met by (one or more of) the following four flexible options, i.e. (i) non-VRE generation [$NONVRE_t$], (ii) VRE curtailment [$VRECUR_t$], (iii) trade [NT_t] and/or (iv) storage [ST_t].

Equation 6 can be used to analyse the impact of DR on the RL balance by comparing the values of the equation variables between the scenario cases with and without DR. In the case without DR (NoDR), equation 6 translates simply into:

$$RL(NoDR)_t = NONVRE(NoDR)_t – VRECUR(NoDR)_t + NT(NoDR)_t – ST(NoDR)_t \quad (6a)$$

Whereas in the case with DR, equation 6 translates into:

$$RL(DR)_t = NONVRE(DR)_t – VRECUR(DR)_t + NT(DR)_t – ST(DR)_t \quad (6b)$$

Comparing the values of the left ('demand') side of the RL equation between the cases with and without DR, i.e. $RLDR)_t$ versus $RL(NoDR)_t$, shows the impact of DR on the RL. On the other hand, comparing the values of the variables ('other flexible options') on the right ('supply') side of the equation between the cases with and without DR presents the impact of DR on these other flexible options.

From an analytical and graphical point of view, however, a disadvantage of the approach outlined above is that demand response as a major flexible option to deal with the residual load in the case without DR, i.e. $RL(NoDR)_t$, is not explicitly included in either equation 6a or 6b (it is only implicitly included by the comparing the change – or difference – between the value of the RL_t variable on the left side of these equations). Therefore, since $RL(DR)_t = RL(NoDR)_t + DR_t$, we redefine equation 6b into:

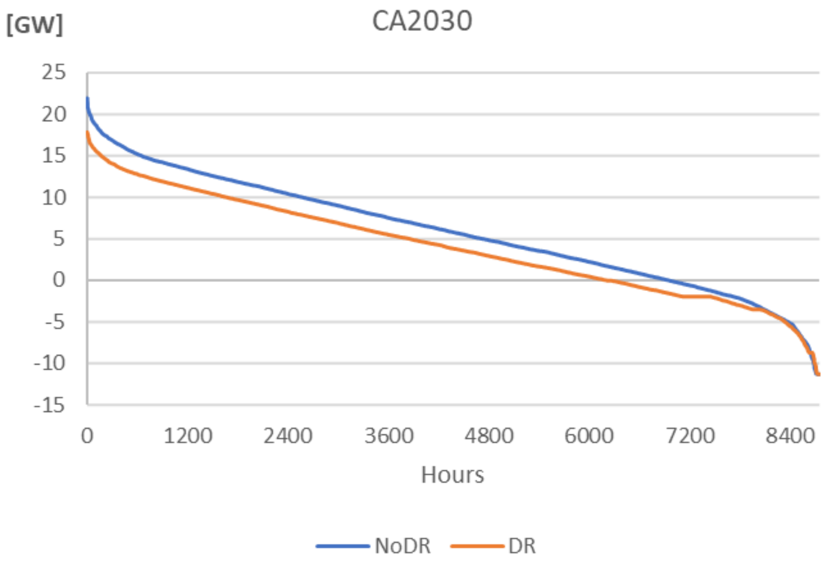
$$RL(DR)_t – DR_t = RL(NoDR)_t = NONVRE(DR)_t – VRECUR(DR)_t + NT(DR)_t – ST(DR)_t - DR_t \quad (6c)$$

In the sections below, we will use and compare equations 6a and 6c to present (graphically) and discuss (analytically) both the impact of DR on the RL in the scenario cases with and without DR, i.e. $RL(DR)_t$ versus $RL(NoDR)_t$, as well as the impact of DR on the other flexible options the meet the RL in the scenario cases with and without DR.

8.2 Impact of demand response on the residual load

In order to show the impact of DR on the residual load (RL) in CA2030 and NM2050, Figure 22 presents once again the RL duration curves in these scenario years – similar to Figure 21 in the previous section – but this time showing these curves for both the cases with and without DR and comparing these cases for CA2030 and NM2050 separately in the upper and lower graph of Figure 22, respectively.

In CA2030, demand response refers mainly to load curtailment – i.e., downward DR – by P2Heat in industry (P2H-i), and hardly or, at least, far less to load shifting – i.e., both upward and downward DR – by the three other flexible load options (see Chapter 4, notably Table 20). Consequently, the upper graph of Figure 22 shows that, due to DR, the residual load in CA2030 with DR is reduced (significantly) over a large number of hours over the year (about 8000 hours), compared to the case without DR, and that it remains more or less the same in both cases in the remaining hours of the year. In addition, it illustrates that, due to DR, the number of hours with a positive RL (VRE shortage) is reduced from approximately 7000 hours in the case without DR to about 6200 hours with DR, while the number of hours with a negative RL (VRE surplus) is enhanced accordingly from about 1800 to 1200 hours.



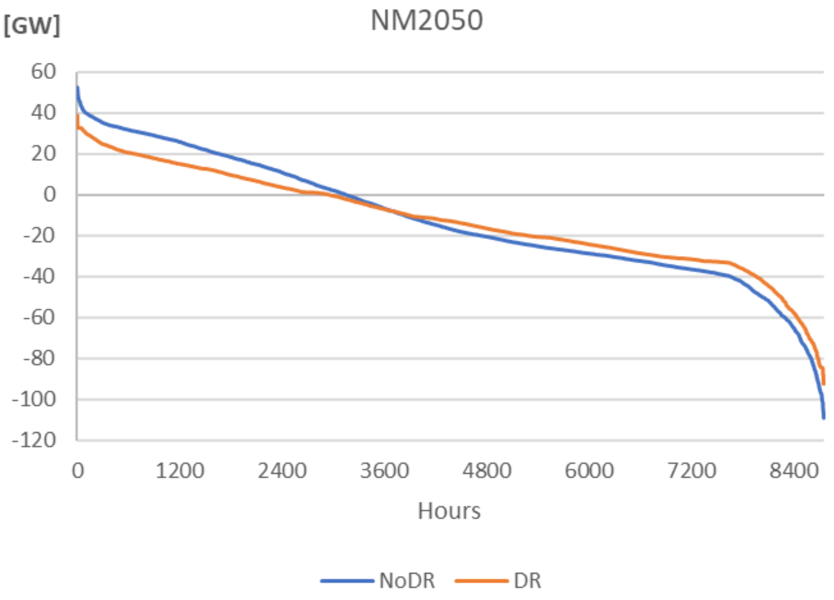


Figure 22: Duration curves of residual load in CA2050 and NM2050 with and without demand response (DR versus NoDR)

In NM2050, on the contrary, load shifting is far more substantial (compared to CA2030) while load curtailment is much less significant (compared to CA2030 but also compared to load shifting in NM2050; see Table 20 and Table 21 in Chapter 4). As a result, the lower graph of Figure 22 shows that, due to DR, the (generally positive) RL is decreased (significantly) over some 3600 hours over the year, while the (usually negative) RL is increased (significantly) over the remaining hours of the year. In addition, it illustrates that, due to DR, the number of hours with a positive RL is reduced from some 3200 hours in the case without DR to about 2900 hours with DR, while the number of hours with a negative RL is enhanced accordingly from approximately 5600 to 5900 hours.

Table 35: Minimum and maximum values of the hourly residual load (RL) in CA2030 and NM2050 with and without demand response (DR versus NoDR)

[GW]	CA2030			NM2050		
	NoDR[a]	**DR**	**Difference**	**NoDR[a]**	**DR**	**Difference**
Maximum RL	21.9	17.9	-4.0 (-18%)	52.5	33.1	-19.4 (-37%)
Minimum RL	-11.3	-11.3	0.0 (0%)	-111.9	-92.0	19.9 (18%)

Table 35 presents the minimum and maximum values of the hourly RL in CA2030 and NM2050 with and without DR. These values correspond to the highest and lowest points of the respective RL duration curves in Figure 22. Table 35 shows, for instance, that due to DR the maximum value of the RL decreases from more than 52 GW in NM2050 without DR to about 33 GW with DR, i.e. a downward DR of some 19 GW (minus 37%, compared to the case with DR). On the other hand, its minimum value increases from -112 GW to -92 GW, respectively, i.e. an upward DR of 20 GW (plus 18%).

Table 36 presents the total annual RL in CA2030 and NM2050 with and without DR, distinguished into positive RL (VRE shortage) and negative RL (VRE surplus) in these scenario cases. The values of these positive and negative RLs correspond to the area between the X-axis and the respective RL duration curves of the scenario cases in Figure 22. Table 36 shows, for instance, that due to DR the total annual positive RL decreases from more than 65 TWh in NM2050 without DR to about 38 TWh with DR, i.e. a total annual downward DR of approximately 27 TWh (or minus 27%, compared to the case without DR). On the other hand, the total annual negative RL in NM2050 increases from -171 TWh to -146 TWh, respectively, i.e. an upward DR of 25 TWh (plus 14%). Overall, due to DR, the total annual RL decreases from about -105 TWh in NM2050 with DR to -108 TWh with DR, i.e. a downward DR of approximately 2.6 TWh (i.e., minus 2.5%, compared to the case with DR).[57]

Table 36: Total annual residual load (RL) in CA2030 and NM2050 with and without demand response (DR versus NoDR)

[TWh]	CA2030			NM2050		
	NoDR[a]	**DR**	**Difference**	**NoDR[a]**	**DR**	**Difference**
Positive RL (VRE shortage)	56.6	42.8	-13.8 (-24%)	65.5	34.6	-30.9 (-47%)
Negative RL (VRE surplus)	-5.8	-7.5	-1.7 (30%)	-170.9	-142.6	28.3 (17%)
Total RL	50.8	35.3	-15.5 (-31%)	-105.4	-108.0	-2.6 -2.5%)

[57] The DR induced differences in total annual RL between the cases with and without DR correspond to the DR induced differences in total annual electricity demand (notably by the flexible load technologies) between these cases (as discussed in Chapters 3 and 4). Note also that the relatively large number of hours with a (relatively large) negative RL in NM2050 and, hence, the relatively large negative total annual RL result from the assumptions of this scenario, in particular the relatively high installed capacity of VRE power generation versus the relatively low total annual electricity demand (as discussed in Section 7.9).

The next section analyses the impact of DR on the other flexible options to meet the RL, both positive and negative, but is focussed predominantly on the scenario year NM2050 (although the last subsection 8.3.3 provides some comparative, summary results for the scenario year CA2030).

8.3 Impact of demand response on other options to meet the residual load

8.3.1 Impact of DR options at the hourly level

First of all, Figure 23 presents the hourly profile of flexible options (including DR) to meet the RL during day 8 of NM2050 (hours 192-215), with and without DR. This figure – as well as all other figures in this section – is based on equations 6a and 6c (as explained in Section 8.1), i.e. in the case with DR (equation 6c) the variable DR_t is moved to the right ('supply') side of the RL equation, implying that DR is added to the other, competing options to meet the RL (rather than subtracted from the RL – without DR – on the left side of the equation).

The advantage of focussing first on a limited number of hours in Figure 23 is that it provides a nice, clear picture of the hourly pattern of the various flexible options to meet the RL (either positive or negative). For instance, Figure 23 shows that over a specific day (#8) there is a number of (consecutive) hours with a (highly varying) positive RL alternated by a number of (consecutive) hours with a (highly varying) negative RL (although it should be acknowledged that this daily pattern varies widely over the days, weeks, months, seasons or scenario years considered). In addition, it illustrates that in certain hours the RL is (largely) met by only one or two flexible options while in other hours (almost) all available options are used together.

In addition, Figure 23 shows that in certain hours all flexible options used have the same sign (either positive or negative), i.e. they move in the same direction (either upwards or downwards). In some hours, however, the flexible options used have different signs (both positive and negative), i.e. they move in different directions (both upwards and downwards). This implies that in these latter hours (or over a number of hours aggregated together over a certain period, e.g. a year) the sum of the flexible (RL) options added together is, on balance, lower than the sum of the (absolute) values of the flexible options individually.

Although part II of the current study is focussed on the impact of DR by the four P2X technologies added together (as a 'single' flexible option), Figure 24 illustrates once again the hourly profile of the DR by these technologies individually (see also part I, notably Chapter 4). Similar to Figure 23, Figure 24 present the hourly profile of DR by the individual P2X technologies only during day 8 of NM2050 (hours 192-215), so that Figure 24 gives a specification of the hourly profile of the DR by the four P2X technologies added together and presented in Figure 23.[58]

[58] Note that Figure 23 and Figure 24 have different scales on the Y-axis. Note also that, because DR has been shifted to the right ('supply') side of the RL equation, DR in Figure 23 below the X-axis represents actually upward DR and above the X-axis downward DR. In Figure 24, on the contrary, upward DR is presented (as usual) above the X-axis and downward DR below the X-axis.

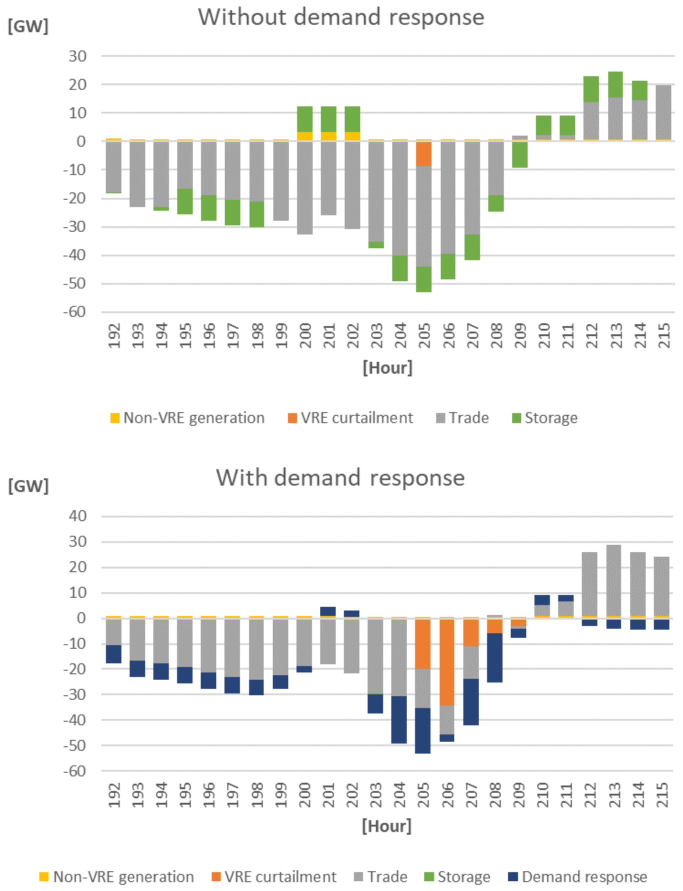


Figure 23: Hourly profile of flexible options to meet the residual load during day 8 of NM2050 (hours 192-215), with and without demand response

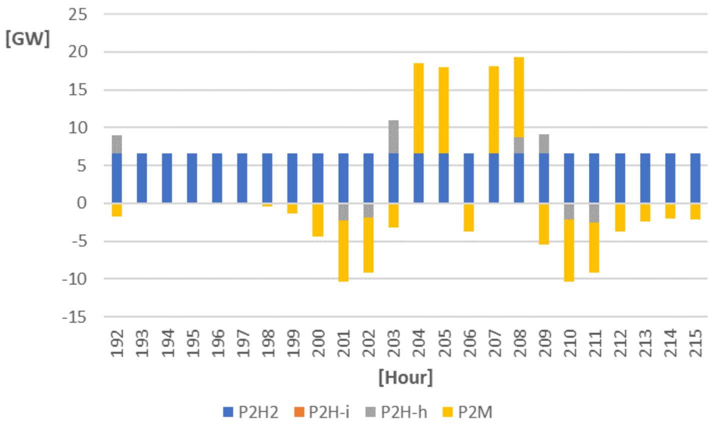


Figure 24: Hourly profile of demand response by P2X technologies during day 8 of NM2050 (hours 192-215)

As noted in part I of this study (particularly in Chapter 4), Figure 24 shows that in certain hours the DR by the individual flexible load options has different signs, i.e. move in different directions (both upwards and downwards). This implies that in these hours (or over a number of hours aggregated together, e.g. over a year), the sum of DR options added together is, on balance, lower than the sum of the (absolute) values of the DR options individually.

So, as outlined above, we observe two related phenomena. On the one hand, we see certain hours in which individual DR options move in different directions. On the other hand, we see certain hours – and occasionally they are even the same hours as mentioned in the previous sentence – in which flexible options (including DR) move in different directions. At first sight, these two phenomena seem a bit counter-intuitive or 'contradictory'– or even do not seem to make sense – as they imply that the impact of the individual options is partially or largely nullified.

Considered from a system optimisation perspective, however, these two phenomena do make sense as each individual (DR/RL) option is defined by its own set of techno-economic characteristics – including specific potentials, constraints, costs, etc. – while considered together the (hourly) values of the options concerned are determined by an optimisation model, such as COMPETES, over a certain period (e.g., a day or, more usually, a year) in order to achieve a social optimal outcome.[59]

8.3.2 Impact of demand response at the aggregated (annual) level

Figure 25 presents the hourly profile of flexible options to meet the RL in NM2050 with and without DR. Note that in both graphs of Figure 25 the hours are ranked according to the duration curve of the hourly RL in the case of NM2050 without DR (see Figure 22). Moreover, the lower graph of Figure 25 is based on equation 6c, i.e. the option DR is moved to the right side of the RL equation (see Section 8.1).

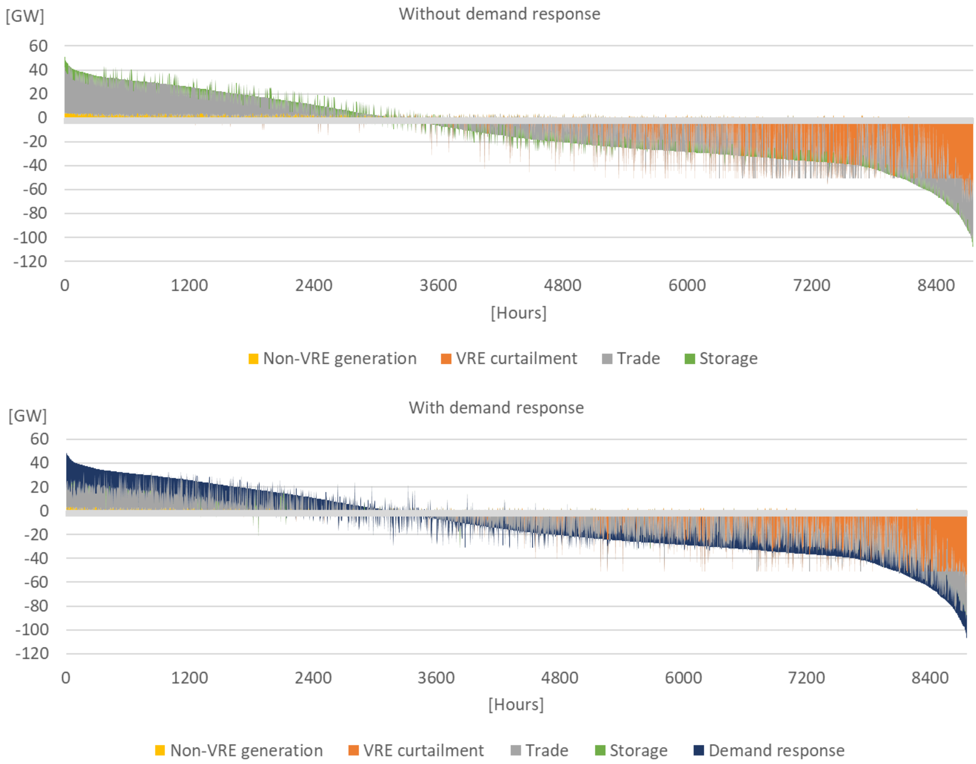
Figure 25 provides a first, overall impression of the impact of DR on the other flexible options to meet the RL in NM2050. It indicates that over some 300 hours DR has a (generally substantial) downward impact on the positive RL (before DR) at the expense of other flexible options, notably trade and storage (discharges). On the other hand, over the remaining 5800 hours of the year DR has a (usually less substantial) upward impact on the negative RL (before DR), mainly at the expense of VRE curtailment and storage (charges).

Figure 26 presents the duration curves of the five major categories of flexible options (ranked individually) to meet the RL in NM2050 with and without DR. In addition, Figure 27 provides the maximum ('capacity') values of these categories to meet the hourly RL in these scenario cases. As usual, these values correspond to the highest and lowest points of the respective duration curves in Figure 26.

The major observations and notions regarding Figure 26 and Figure 27 in general and the individual flexible options in particular include:

- *Non-VRE generation*: this option refers mainly to ('must-run') generation of electricity by (green) gas and biomass, including combined heat and power (CHP) plants. It is, however, hardly or not flexible, having a minimum (must-run) output of 0.7 GW throughout the year, even during hours with a large negative RL (thereby further increasing – rather than decreasing – the VRE surplus in these hours). Only during a limited number of (positive RL) hours, this option increases its (maximum) output significantly, i.e. up to 4.3 GW in NM2050 without DR and 3.3 GW with DR.

[59] It should be acknowledged that, although a model is a simple reflection of daily life, the same phenomena as outlined in the main text above – including similar, apparently 'contradictions' – can be observed in real life, including real electricity markets and power systems, often even more complex, with even more apparently – and real – 'contradictions'.



Note: In both cases, the options are ranked according to the duration curve of the hourly residual load in NM2050 without demand response

Figure 25: Profile of (flexible) demand and supply options to meet the hourly residual load in NM2050 with and without demand response

- *VRE curtailment*: by definition, this option is only able to reduce a VRE surplus (but not a VRE shortage). Hence, it is predominantly used during negative RL hours (with a large VRE surplus) although occasionally it is also applied in some positive RL hours (thereby further increasing – rather than decreasing – the VRE shortage). During most hours of the year, VRE curtailment amounts to zero, i.e. up to 5200 hours in NM2050 without DR and even more than 6100 hours with DR. During the remaining hours of the year, however, it is quite substantial, i.e. up to (minus) 52 GW, while during a limited number of hours it even reaches its maximum value of (minus) 72 GW.

- *Trade*: this option refers to electricity import and exports. In most hours of the year, there are large (although highly fluctuating) volumes of both electricity imports and exports (in the same hour). In NM2050, however, net imports occurred during some 4300 hours in the case without DR and about 3700 hours with DR, while net exports take place during the remaining hours of these cases. Due to DR, however, hourly volumes of net trade are usually significantly lower in the case of NM2050 with DR than without DR (see Figure 26 where net imports are shown above the X-axis and net exports below the X-axis). More specifically, the maximum (hourly) values of net imports amount to 45 GW in NM2050 without DR to 32 GW with DR, while for net exports these values amount to 47 GW and 33 GW, respectively (see Figure 27).

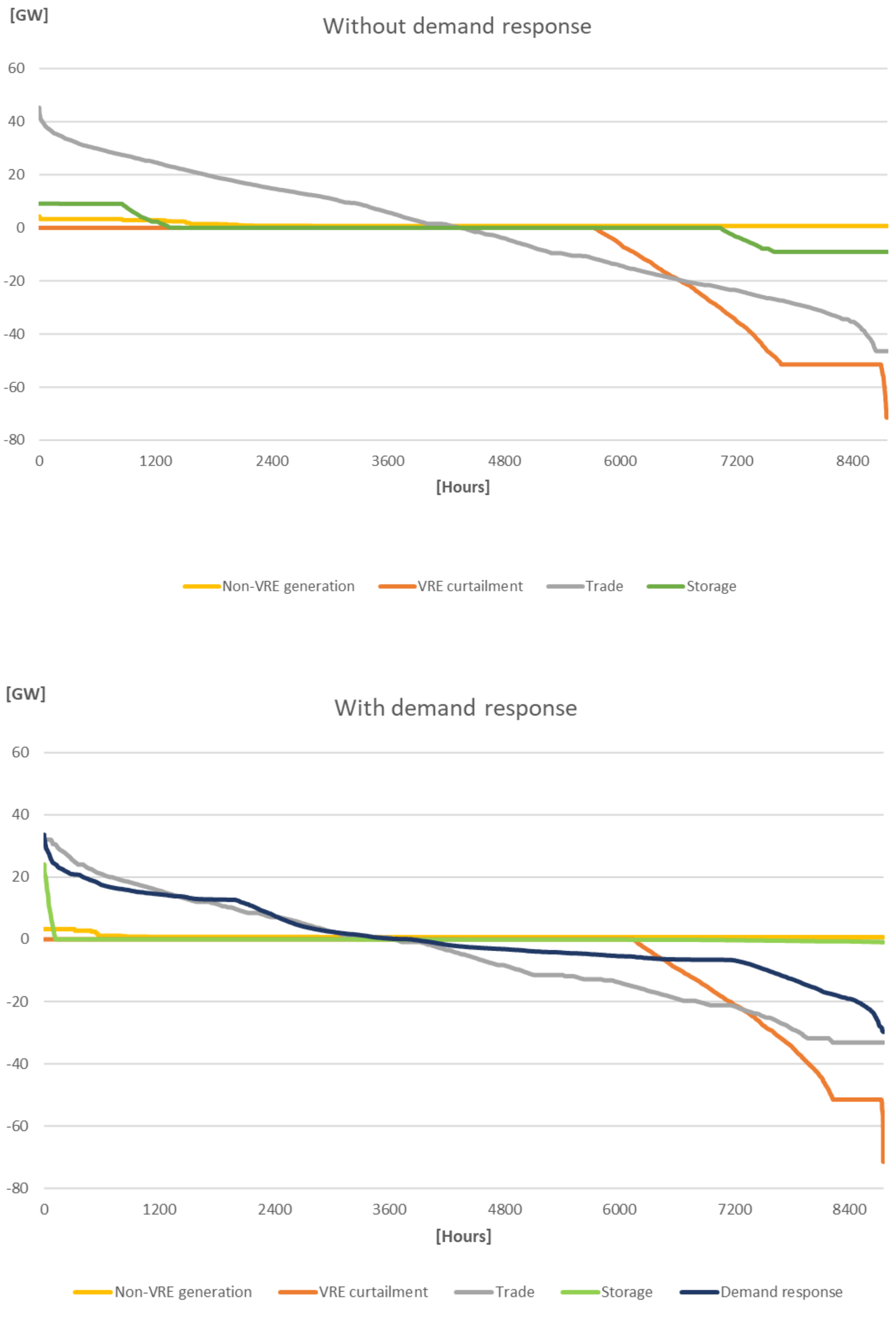
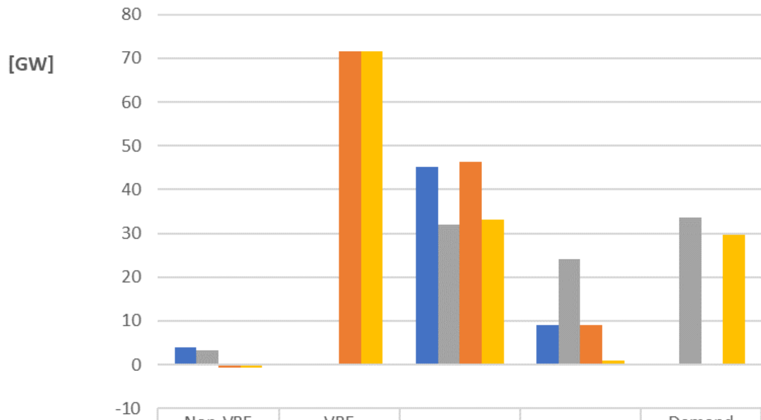


Figure 26: Duration curve of flexible options to meet the hourly residual load in NM2050 with and without demand response

- *Storage*: in NM2050 without DR, this option refers predominantly to charges and discharges by vanadium redox (VR) flow batteries (for electricity balancing purposes) and in NM2050 with DR to Li-ion batteries of passenger EVs. In the case of NM2050 without DR, storage transactions amount to zero over more than 5500 hours of the year, whereas storage discharges by VR batteries occur only during some 1500 hours (up to a maximum of 9 GW) and storage discharges during about 1800 hours (also up to 9 GW). In NM2050 with DR, on the contrary, storage transactions (by EV batteries) occur over almost all hours of the year, although during most hours the volume of these transactions is small. Only during a limited number of hours (about 250), storage discharges are quite substantial (up to a maximum of 24 GW), but during the rest of the year storage charges by EVs are rather small (i.e., close to zero up to a maximum of 0.9 GW).[60]

➢ *Demand response*: this option refers to the DR of the four P2X technologies added together (as analysed in some detail in Chapter 4), with a maximum upward DR of almost 30 GW and a maximum downward DR of 34 GW.



	Non-VRE generation	VRE curtailment	Trade	Storage	Demand response
NoDR: Reducing VRE shortage	3.9	0.0	45.3	9.1	0.0
DR: Reducing VRE shortage	3.3	0.0	32.0	24.1	33.6
NoDR: Reducing VRE surplus	-0.7	71.5	46.5	9.1	0.0
DR: Reducing VRE surplus	-0.7	71.5	33.2	0.9	29.7

Figure 27: Maximum (capacity) values of flexible options to meet the hourly residual load in NM2050 with and without demand response (DR versus NoDR)

Figure 28 presents a summary overview of the mix of flexible options to meet the positive, negative and total RL aggregated over the scenario year 2050 with and without DR. It shows, for instance, that in NM2050 without DR the aggregated positive RL (i.e., 65.5 TWh, see Table 36) is largely met by trade (i.e., imports of 58 TWh), non-VRE generation (5.3 TWh) and storage (i.e., discharges of 2.8 TWh).[61] As a percentage of the total positive RL in NM2050 without DR these three flexible options account for 89%, 8% and 4%, respectively (see first column of the upper and lower graph of Figure 28).

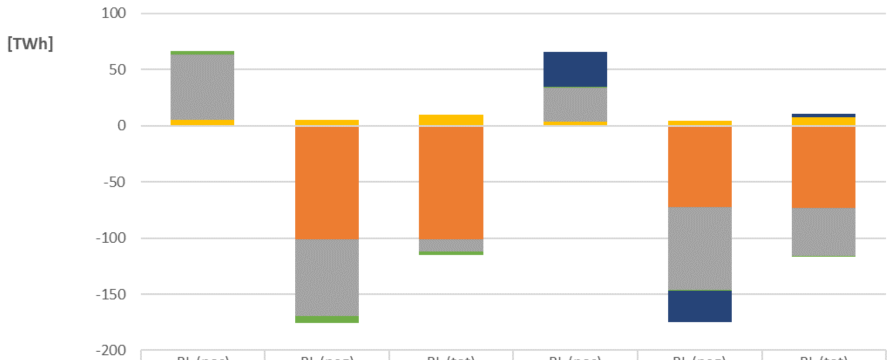
In NM2050 with DR, however, almost half of the total annual positive RL is met by downward DR (i.e., almost 31 TWh, or more than 47% of the required positive RL). As a result, the contributions of the other flexible options are reduced accordingly: (i) trade (imports) from 58 TWh to 31 TWh (i.e., from 89% to 47% of the considered positive RL of 65.5 TWh), (ii) non-VRE generation from 5.3 TWh to 3.4 TWh (i.e., from 8.1% to 5.3%), and (iii) storage (discharges) from 2.8 TWh to 0.9 TWh (i.e., from 4.3% to 1.4%; see first versus fourth column of the upper and lower graph of Figure

[60] For a more detailed analysis of the role of electricity storage in the power system of the Netherlands, notably in NM2050 with DR, see Sijm et al. (2020).

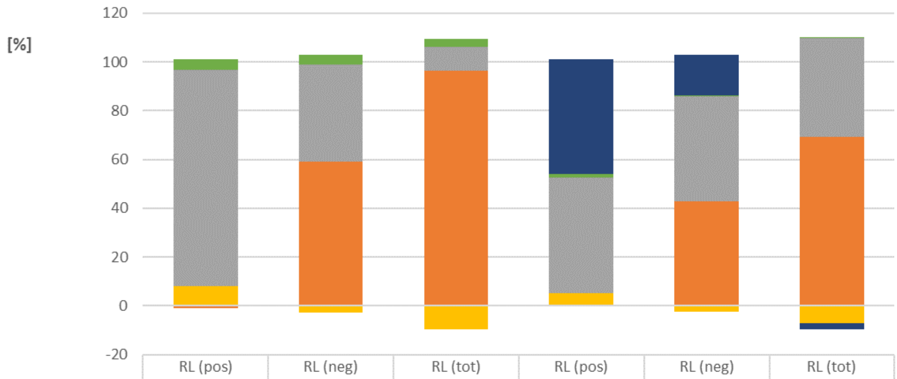
[61] Note that in NM2050 without DR there is some VRE curtailment (0.7 TWh) in hours with a positive RL, thereby further enhancing the VRE shortage in these hours (Figure 28).

28).[62] Hence, owing to downward DR, there is less need for imports (interconnection capacity), non-VRE generation and storage (discharges) during hours with a positive RL (VRE shortage).

On the other hand, Figure 28 shows that in NM2050 without DR the total annual negative RL (i.e., 171 TWh, see Table 36) is largely met by VRE curtailment (101 TWh), trade (i.e., exports of 68 TWh) and storage (i.e., charges of 6.5 TWh).[63] As a percentage of the total negative RL in NM2050 without DR, these three flexible options account for 59%, 40% and 4%, respectively (see second column of the upper and lower graph of Figure 28).



	Without demand response			With demand response		
	RL (pos)	RL (neg)	RL (tot)	RL (pos)	RL (neg)	RL (tot)
Demand response	0.0	0.0	0.0	30.9	-28.3	2.6
Storage	2.8	-6.5	-3.7	0.9	-0.9	0.0
Trade	58.1	-68.3	-10.3	30.5	-73.3	-42.8
VRE curtailment	-0.7	-100.8	-101.5	-0.2	-72.7	-72.9
Non-VRE generation	5.3	4.7	10.0	3.4	4.2	7.6



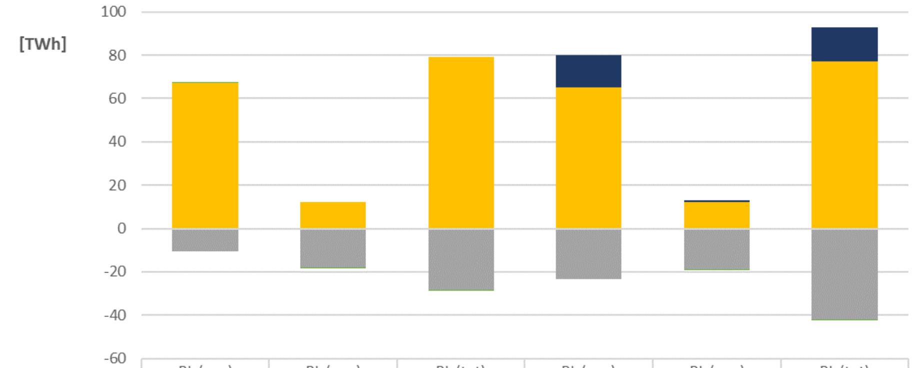
	Without demand response			With demand response		
	RL (pos)	RL (neg)	RL (tot)	RL (pos)	RL (neg)	RL (tot)
Demand response	0.0	0.0	0.0	47.2	16.5	-2.5
Storage	4.3	3.8	3.5	1.4	0.5	0.0
Trade	88.6	40.0	9.7	47.2	43.1	40.6
VRE curtailment	-1.1	59.0	96.3	-0.4	42.8	69.2
Non-VRE generation	8.1	-2.8	-9.5	5.3	-2.5	-7.2

Figure 28: Mix of flexible options to meet the positive, negative and total residual load (RL) aggregated over the scenario year NM2050 with and without demand response

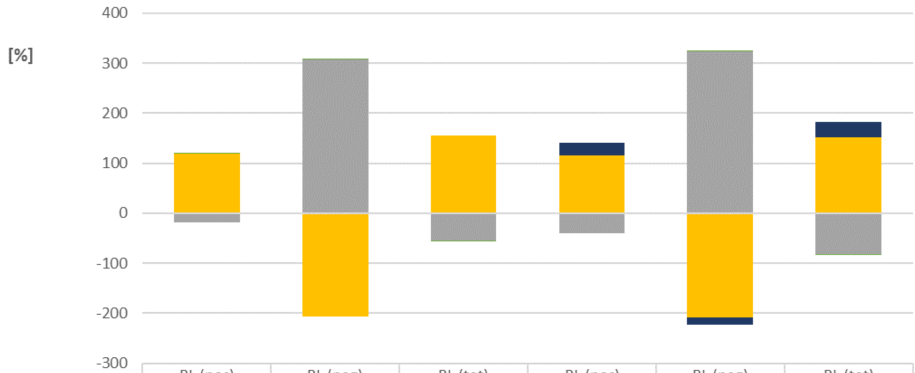
62 Actually, the positive RL in NM2050 with DR is reduced by DR from 65.5 TWh to 36.6 TWh, but – following equation 7c (Section 8.1) – for analytical and illustration (graphical) purposes we assume that DR is one of the flexible options on the right sight of the RL equation in order to meet the RL in the case without DR.

63 Note that in NM2050 without DR there is still some (must-run) non-VRE generation (4.7 TWh) in hours with a negative RL, thereby further enhancing the VRE surplus in these hours.

Finally, in NM2050 with DR, however, about one sixth (17%) of the negative RL of 101 TWh is met by upward DR (i.e., more than 28 TWh). As a result, the contributions of two other flexible options are reduced significantly: (i) VRE curtailment from 101 TWh to 73 TWh (i.e., from 59% to 43% of the considered negative RL of 171 TWh), and (ii) storage (charges) from 6.5 TWh to 0.9 TWh (i.e., from 3.8% to 0.5%), whereas the contribution of trade (exports) is slightly increased from 68 TWh to 73 TWh (i.e., from 40% to 43%; see second versus fifth column of the upper and lower graph of Figure 28). Hence, owing to upward DR, there is less need for VRE curtailment and storage (discharges) – and even some room for additional exports of electricity – during hours with a negative RL (VRE surplus).



	RL (pos)	RL (neg)	RL (tot)	RL (pos)	RL (neg)	RL (tot)
	Without demand response			With demand response		
Demand response	0.0	0.0	0.0	14.6	0.9	15.5
Storage	0.0	0.0	0.0	0.0	0.0	0.0
Trade	-10.4	-17.8	-28.3	-23.3	-18.8	-42.0
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0
Non-VRE generation	67.1	12.0	79.1	65.3	12.1	77.4



	RL (pos)	RL (neg)	RL (tot)	RL (pos)	RL (neg)	RL (tot)
	Without demand response			With demand response		
Demand response	0.0	0.0	0.0	25.8	-15.8	30.5
Storage	0.0	0.0	0.0	0.0	0.0	0.0
Trade	-18.4	307.2	-55.6	-41.0	323.6	-82.7
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0
Non-VRE generation	118.4	-207.2	155.6	115.2	-207.9	152.2

Figure 29: Mix of flexible options to meet the positive, negative and total residual load (RL) aggregated over the scenario year CA2030 with and without demand response

8.3.3 *Impact of DR on other options to meet the RL in CA2030*

Figure 29 provides the mix of flexible options to meet the total annual positive, negative and total RL in CA2030 with and without DR. Compared to NM2050, CA2030 is characterised by a substantially lower number of hours with a negative RL

– generally with, on average, significantly lower volumes of hourly VRE surpluses – and, hence, with a much lower total annual VRE surplus (see Figure 22 and Table 36). In addition, CA2030 is characterised predominantly by a large volume of load curtailment (by P2H-i) in the case with DR – rather than by load shifting – resulting in both a lower total annual electricity demand and a lower total annual RL of 15.5 TWh (see Table 36, as well as Chapters 3 and 4, notably Table 16 and Table 17).

Figure 29 shows that electricity storage and VRE curtailment do not play any (meaningful) role in meeting the RL in CA2030, both with and without DR. In CA2030 without DR, the total annual positive RL (VRE shortage) of almost 57 TWh (Table 36) is more than fully met by non-VRE generation (67 TWh) – mainly from gas-fired plants – resulting in, on balance, a domestic supply surplus (10 TWh) and corresponding to a net trade surplus (electricity exports minus imports) of the same amount (Figure 29).

The total annual negative RL in CA2030 without DR amounts to almost 6 TWh (Table 36). This domestic surplus is further enhanced by non-VRE generation (12 TWh), resulting in, on balance, total next exports of 18 TWh (Figure 29).

As mentioned above, due to DR, the total annual RL in CA2030 is reduced by 15.5 TWh, i.e. from 50.8 TWh in CA2030 without DR to 35.3 TWh with DR (Table 36). This amount of DR (RL reduction) results, to some extent, in a reduction of non-VRE generation (by 1.7 TWh, i.e. from 79.1 TWh in the case without DR to 77.4 TWh with DR) and, in particular, in a higher net trade surplus (more electricity exports and/or less electricity imports) of almost 14 TWh (i.e., from more than 28 TWh to about 42 TWh, respectively; see Figure 29).

9 The impact of demand response on the flexibility balance

This chapter presents and analyses the impact of DR on the '*flexibility balance*' of the Netherlands in the scenario years CA2030 and NM2050 (including, for comparative reasons, the reference scenario year R2015 without DR). First, Section 9.1 discusses the concept 'flexibility balance', notably by means of the equation(s) of this balance in the scenario cases with and without DR. Subsequently, Section 9.2 analyses the evolution of the demand for flexibility by the power system in the Netherlands over the period 2015-2050. Next, Section 9.3 presents and discusses the impact of DR on the mix of options to meet the need for flexibility such as trade, storage or VRE curtailment. Finally, Section 9.4 presents the balance of the demand and supply of flexibility by the four individual P2X/DR options of the current study (P2H$_2$, P2H-i, P2H-h and P2M).

9.1 The flexibility balance

In this study (as outlined in Section 5.1), flexibility refers primarily to the *hourly variability* of the residual load, defined and measured as the difference (Δ) between the residual load in hour *t* and the residual load in hour *t-1* (with *t* = 1,…., 8760).[64] Following this definition of flexibility and the equation of the residual load balance (6), the equation of the flexibility balance is defined as:

$$\Delta RL_t = \Delta NONVRE_t - \Delta VRECUR_t + \Delta NT_t - \Delta ST_t \tag{7}$$

where:

$$\Delta RL_t = RL_t - RL_{t-1}$$
$$\Delta NONVRE_t = NONVRE_t - NONVRE_{t-1}$$
$$\Delta VRECUR_t = VRECUR_t - VRECUR_{t-1}$$
$$\Delta NT_t = NT_t - NT_{t-1}$$
$$\Delta ST_t = ST_t - ST_{t-1}$$

Basically, equation 7 says that the demand for flexibility in hour *t* – which can be either positive (upwards) or negative (downwards) – can be met by (one or more of) the following four flexibility options, i.e. (i) non-VRE generation [$\Delta NONVRE_t$], (ii) VRE curtailment [$\Delta VRECUR_t$], (iii) trade [ΔNT_t] and/or (iv) storage [ΔST_t].

Equation 7 can be used to analyse the impact of DR on the flexibility balance by comparing the values of the equation variables between the scenario cases with and without DR. In the case without DR (NoDR), equation 7 translates into:

$$\Delta RL(NoDR)_t = \Delta NONVRE(NoDR)_t - \Delta VRECUR(NoDR)_t + \Delta NT(NoDR)_t - \Delta ST(NoDR)_t \tag{7a}$$

whereas in the case with DR, equation 7 translates into:

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64 This implies that in this study (and in this chapter in particular) we will not consider the demand and supply of flexibility due to other causes (besides the variability of the residual load), notably the uncertainty ('forecast errors') of the residual load or the congestion of the grid (see Section 5.1 and references cited there).

$$\Delta RL(DR)_t = \Delta NONVRE(DR)_t - \Delta VRECUR(DR)_t + \Delta NT(DR)_t - \Delta ST(DR)_t \quad (7b)$$

Comparing the values of the left ('demand') side of the flexibility equation between the cases with and without DR, i.e. $RL(DR)_t$ versus $RL(NoDR)_t$, shows the impact of DR on the need for flexibility by the power system. On the other hand, comparing the values of the variables ('other flexible options') on the right ('supply') side of the equation between the cases with and without DR presents the impact of DR on these other flexible options.

From an analytical and graphical point of view, however, a disadvantage of the approach outlined above is that the hourly change (Δ) in demand response as a major option to meet the need for flexibility in the case without DR, i.e. $\Delta RL(NoDR)_t$, is not explicitly included in either equation 7a or 7b (i.e., it is only implicitly included by comparing the difference between the value of the ΔRL_t variable on the left side of these equations). Therefore (similar to the approach suggested in Section 8.1), since $\Delta RL(DR)_t = \Delta RL(NoDR)_t + \Delta DR_t$, we redefine equation 7b into:

$$\Delta RL(DR)_t - \Delta DR_t = \Delta RL(NoDR)_t = \Delta NONVRE(DR)_t - \Delta VRECUR(DR)_t + \Delta NT(DR)_t - \Delta ST(DR)_t - \Delta DR_t \quad (7c)$$

In the sections below, we will use and compare equations 7a and 7c to present (graphically) and discuss (analytically) both the impact of DR on the need for flexibility in the scenario cases with and without DR, i.e. $\Delta RL(DR)_t$ versus $\Delta RL(NoDR)_t$, as well as the impact of DR on the other options the meet the need for flexibility in the scenario cases with and without DR.

9.2 The demand for flexibility

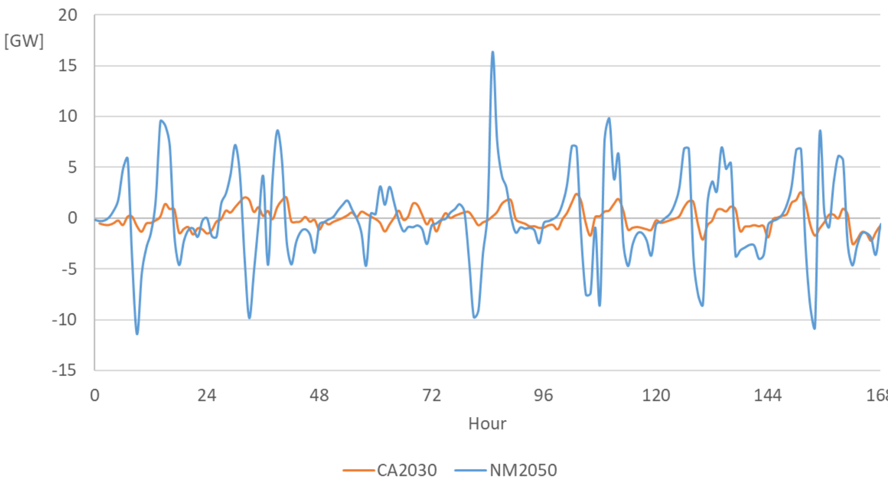


Figure 30: Hourly profile of the demand for flexibility in CA2030 and NM2050 (without demand response) during the first week of January (hours 0-168)

Figure 30 presents the hourly profile of the variability of the residual load (RL), i.e. the hourly profile of the demand for flexibility – as defined in the current study – in CA2030 and NM2050 (without DR) during the first week of January (hours 0-168). It shows that the demand for flexibility during this week is rather volatile, notably in NM2050, ranging from a downward flexibility need of more than (minus) 11 GW to an upward flexibility demand of more than (plus) 16 GW.

Figure 31 presents the duration curve of the hourly demand for flexibility over the scenario years CA2030 and NM2050 as a whole (for the case without DR). It indicates that during most hours of the year the need for flexibility is relatively low, i.e. less than 2 or 3 GW – notably in CA2030 – but that over a substantial number of hours it is rather high (and volatile), in particular in NM2050. For instance, in NM2050 the demand for flexibility ranges from almost 50 GW in the upper left of the duration curve to almost -42 GW in the bottom right.

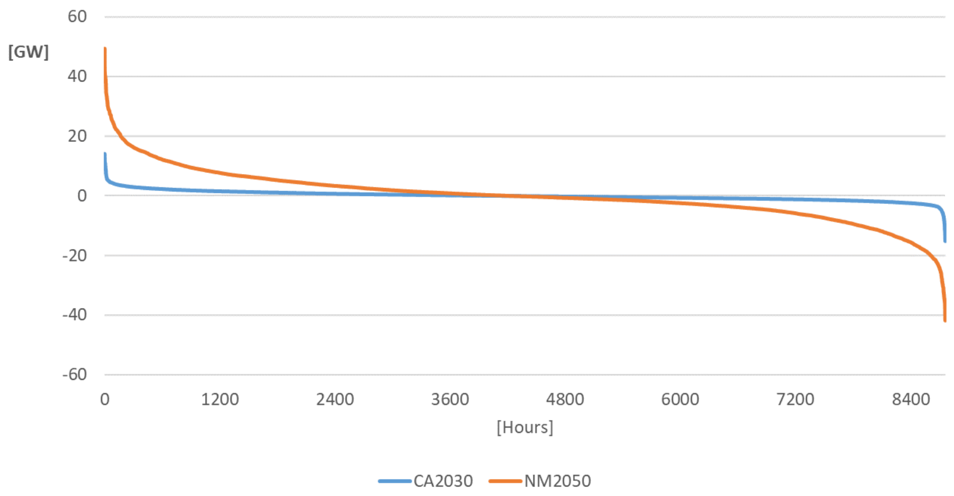


Figure 31: Duration curve of the hourly demand for flexibility in CA2030 and NM2050 (without demand response)

Table 37 presents some results regarding the total annual demand for flexibility in CA2030 and NM2050 (without DR). In order to put these future scenario results in some perspective, Table 37 provides also comparative data for the reference scenario 2015 (R2015), derived from the FLEXNET project (Sijm et al., 2017c). Table 37 shows that over a scenario year the total annual demand for *upward* flexibility is (more or less by definition) equal to the total annual demand for *downward* flexibility. The *number* of hours requiring upward flexibility, however, is usually slightly different from the number of hours requesting downward flexibility. As a result, the *average* hourly demand for upward flexibility is generally slightly different from the average hourly demand for downward flexibility (see upper part of Table 37).

In addition, Table 37 shows that, compared to R2015, the need for flexibility – by the power system in the Netherlands – grows rapidly in the scenarios CA2030 and NM2050. For instance, the total annual demand for (upward and downward) flexibility increases from 4.4 TWh in R2015 to 9.9 TWh in CA2030, i.e. an increase by some 125%. Up to NM2050, however, this demand for flexibility grows even harder to almost 52 TWh, i.e. an increase by about 420% compared to CA2030 and by approximately a factor 12 compared to R2015.

As a percentage of total electricity demand, the increase in the need for flexibility over the period 2015-2050 is less impressive although still substantial. Table 37 shows that this rate rises from 3.9% in R2015 to 6.6% in CA2030 and even to almost 15% in NM2050, i.e. an increase in NM2050 by a factor 3.8 compared to R2015.

Table 37: Total annual demand for flexibility in R2015, CA2030 and NM2050 (without demand response)

	Total annual demand for flexibility [TWh]			Hours [#]			Average hourly demand for flexibility (GW/#h)		
	R2015	CA2030	NM2050	R2015	CA2030	NM2050	R2015	CA2030	NM2050
Upward flexibility	2.2	5.0	25.9	4160	4110	4209	0.53	1.21	6.15
Downward flexibility	2.2	5.0	25.9	4600	4650	4551	0.48	1.07	5.69
Total flexibility demand	4.4	9.9	51.8	8760	8760	8760	0.50	1.14	5.91
Total electricity demand (NoDR)	112.5	151.1	348.3						
Total flexibility demand as % of total electricity demand	3.9%	6.6%	14.9%						

In this study, the demand for flexibility is solely due to the variability of the residual load (RL), defined simply as the variability of the difference between the total domestic electricity demand and the domestic electricity supply from VRE sources before curtailment. This implies that the need for flexibility is caused by the variable demand for electricity and the supply of variable renewable electricity. More specifically, in this study the demand for flexibility by the power system in the Netherlands is caused by the following sources:

- *Conventional power demand.* This demand is variable (i.e., it varies per hour and, hence, it enhances the demand for flexibility), but it is assumed to be inflexible in scenarios both with and without DR (i.e., it does not respond to hourly price changes and, hence, it does not offer flexibility).
- *New, additional power demand*, notably the variable power demand by the P2X technologies selected in this study. The power demand by these technologies is assumed to be flexible in scenarios with DR (i.e., responding to hourly price changes and, hence, offering flexibility) and inflexible in scenarios without DR. However, whereas the power demand in both scenario cases (with and without DR) is assumed to be fixed for P2Heat in industry and P2Hydrogen (i.e., it does not vary per hour and, hence, it does not enhance the demand for flexibility), it is assumed to be variable for P2Heat in households and P2Mobility (i.e., it varies per hour and, hence, it enhances the demand for flexibility).
- *VRE supply,* i.e. the supply of electricity from variable renewable energy (VRE) sources, notably sun and wind.

Table 38 presents the total annual demand for flexibility in R2015, CA2030 and NM2050 (without DR), distinguished by the above-mentioned sources (‘causes’) of this demand. It shows, for instance, that the demand for flexibility due to VRE supply increases from less than 1 TWh in R2015 to about 46 TWh in NM2050. As a percentage of the total demand for flexibility, the share of VRE supply increases from 21% in R2015 to 89% in NM2050, whereas the share of conventional electricity demand declines from 77% to 2%, respectively.

Table 38: Total annual demand for flexibility in R2015, CA2030 and NM2050 (without demand response), distinguished by the different sources ('causes') of this demand

	VRE supply	Conventional power demand[a]	Flexible power demand technologies[b]				Total flex demand
			$P2H_2$	P2H-i	P2H-h	P2M	
Demand for (upward + downward) flexibility by source (TWh)							
R2015	0.94	3.40	0.00	0.00	0.00	0.05	4.40
CA2030	8.45	1.34	0.00	0.00	0.02	0.14	9.94
NM2050	45.99	1.01	0.00	0.00	0.91	3.85	51.76
Demand for flexibility as share of total flex demand (%)							
R2015	21.4	77.4	0.0	0.0	0.0	1.2	100
CA2030	84.9	13.5	0.0	0.0	0.2	1.4	100
NM2050	88.8	1.9	0.0	0.0	1.8	7.4	100

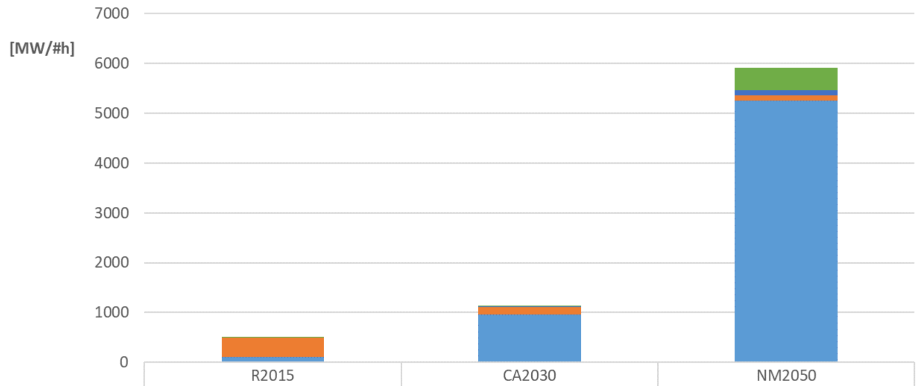
a) Conventional power demand is variable (i.e., it varies per hour and, hence, it enhances the demand for flexibility), but it is assumed to be inflexible in scenarios both with and without DR (i.e., it does not respond to hourly price changes and, hence, it does not offer flexibility);

b) The power demand by P2X technologies is assumed to be flexible in scenarios with demand response (i.e., responding to hourly price changes and, hence, offering flexibility) and inflexible in scenarios without demand response. However, whereas the power demand in both scenario cases (with and without DR) is assumed to be fixed for P2Heat in industry and P2Hydrogen (i.e., it does not vary per hour and, hence, it does not enhance the demand for flexibility), it is assumed to be variable for P2Heat in households and P2Mobility (i.e., it varies per hour and, hence, it enhances the demand for flexibility).

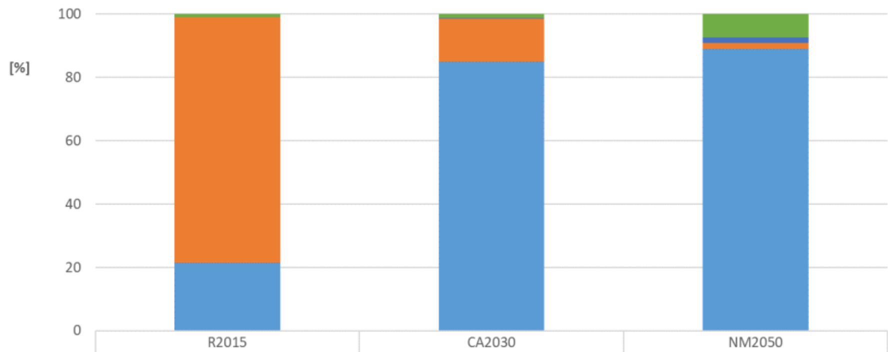
To some extent, the increase in the demand for flexibility over the period 2015-2050 is also caused by the increase in the electricity demand by the flexible P2X technologies, notably by the two technologies with a variable power demand, i.e. P2H-h and P2M. Table 38 shows that the need for flexibility due to the power demand by these two technologies amounts to (nearly) zero in R2015 but increases in NM2050 to about 0.9 TWh for P2H-h and even to almost 4 TWh for P2M, i.e. corresponding to 1.8% and 7.4% of the total demand for flexibility in NM2050.[65]

Dividing the total annual demand for flexibility by the total number of hours in a year results in the average hourly demand for flexibility (expressed in either GW/#h or MW/#h). Table 37 shows that this average flexibility demand increases from 0.5 GW/#h in R2015 to 5.9 GW/#h in NM2050. In addition, Figure 32 presents more specific, detailed data on the average hourly demand for flexibility in R2015, CA2030 and NM2050, distinguished by the different sources of this demand. Not surprisingly, however, this figure shows similar trends and shares in flexibility demand as observed in Table 38 regarding the total annual demand for flexibility in these scenario years.

[65] The figures in Table 38 refer only to the direct need for flexibility caused by the electricity demand of the P2X technologies. If it is assumed, however, that this demand is met by VRE supply, it also causes an indirect demand for flexibility. This issue is considered further in Section 9.4 below.



	R2015	CA2030	NM2050
P2M (Passenger EVs)	6	16	440
P2Heat (households)	0	2	104
P2Heat (industry)	0	0	0
P2Hydrogen	0	0	0
Conventional demand	389	153	115
VRE generation	108	965	5251



	R2015	CA2030	NM2050
P2M (Passenger EVs)	1.2	1.4	7.4
P2Heat (households)	0.0	0.2	1.8
P2Heat (industry)	0.0	0.0	0.0
P2Hydrogen	0.0	0.0	0.0
Conventional demand	77.4	13.5	1.9
VRE generation	21.4	84.9	88.8

Figure 32: Average hourly demand for flexibility in R2015, CA2030 and NM2050 (without DR), distinguished by the different sources ('causes') of this demand

9.3 The supply of flexibility by demand response and other options

9.3.1 Impact of demand response at the hourly level

Figure 33 presents the hourly profile of the options to meet the demand for flexibility during day 8 of NM2050 (hours 192-215), with and without DR. This figure – as well as all other figures in this section – is based on equations 7a and 7c (as explained in Section 9.1), i.e. in the case with DR (equation 7c) the variable ΔDR_t is moved to the right ('supply') side of the flexibility equation, implying that DR is added to the other (competing) flexibility options (rather than subtracted from the demand for flexibility – in the case without DR – on the left side of the equation).

Similar to Figure 23 (as discussed in Section 8.2), the advantage of focussing first on a limited number of hours in Figure 33 is that it provides a nice, clear picture of the hourly pattern of the options to meet the need for flexibility (either positive or negative). For instance, Figure 33 shows that over a specific day (#8) there is a number of (consecutive) hours with a (highly varying) need for upward flexibility alternated by a number of (consecutive) hours with a (highly varying) need for downward flexibility (although it should be acknowledged that this daily pattern varies widely over the days, weeks, months, seasons or scenario years considered). In addition, it illustrates that in certain hours the need for flexibility is (largely) met by only one or two flexible options while in other hours (almost) all available options are used together.

In addition, Figure 33 shows that in certain hours all flexibility options have the same sign (either positive or negative), i.e. they move in the same direction (either upwards or downwards). In some hours, however, the flexible options used have different signs (both positive and negative), i.e. they move in different directions (both upwards and downwards). This implies that in these latter hours (or over a number of hours aggregated together over a certain period, e.g. a year) the sum of the flexibility options added together is, on balance, lower than the sum of the (absolute) values of the flexibility options individually. Moreover, Figure 33 shows that in certain hours the demand for flexibility is, on balance, positive (upwards) whereas the supply of flexibility by DR is negative (downwards). The implications of this observation are discussed below in Section 9.3.2, notably in Box 1.

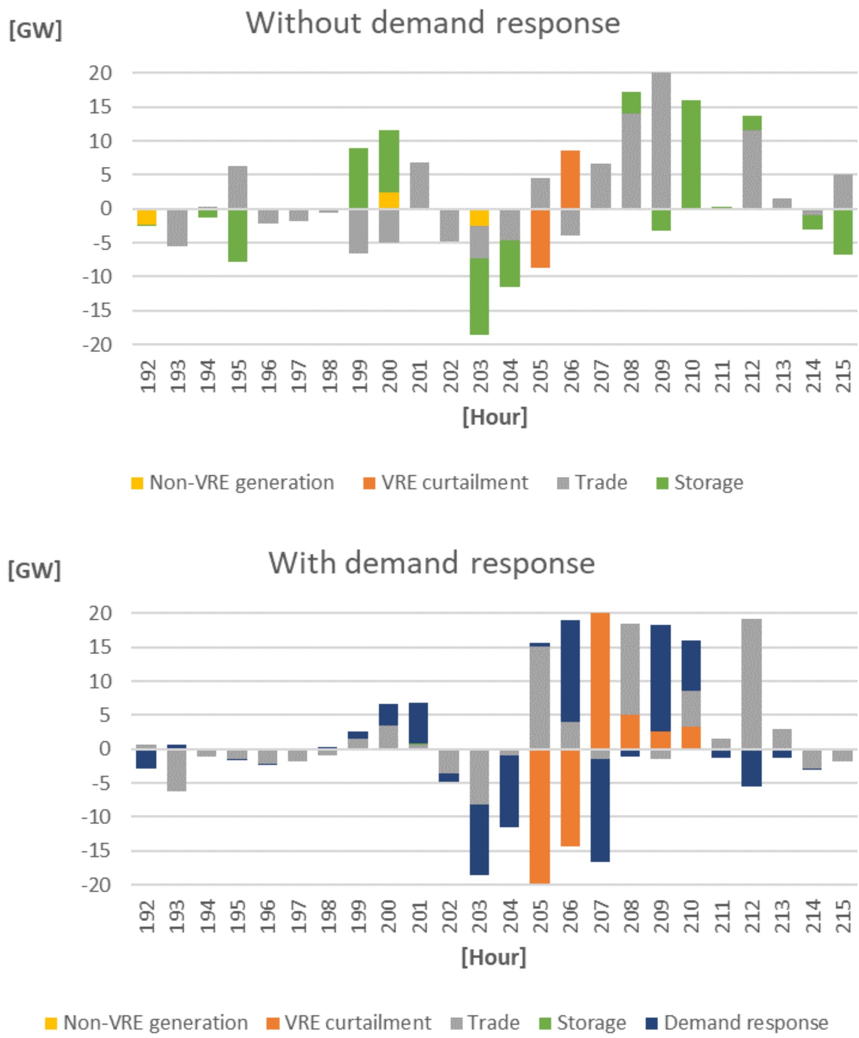


Figure 33: Hourly profile of options to meet the need for flexibility during day 8 of NM2050 (hours 192-215) with and without demand response

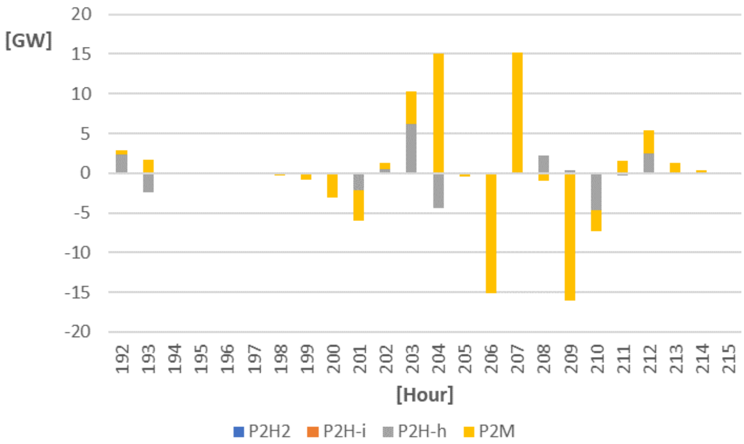


Figure 34: Hourly profile of flexible P2X options to meet the demand for flexibility during day 8 of NM2050 (hours 192-215)

Although part II of the current study is focussed on the impact of DR by the four P2X technologies added together (as a 'single' flexibility option), Figure 34 illustrates once again the hourly profile of the flexibility offered by these technologies individually (see also part I, notably Chapter 5). Similar to Figure 33, Figure 34 present the hourly profile of the individual DR technologies only during day 8 of NM2050 (hours 192-215), so that Figure 34 gives a specification of the hourly profile of the flexibility by the four DR technologies added together and presented in Figure 23.[66]

As noted in part I of this study (particularly in Chapter 5), Figure 34 shows that in certain hours the flexibility offered by individual DR options has different signs, i.e. move in different directions (both upwards and downwards). This implies that in these hours (or over a number of hours aggregated together, e.g. over a year), the sum of DR options added together is, on balance, lower than the sum of the (absolute) values of the DR options individually.

So, similar to what has been noticed in Section 8.3.1, we observe that in certain hours individual flexibility options (including individual DR options) move in different directions (i.e., both upwards and downwards in the same hour). As explained in Section 8.3.1, these apparently contradictory ('nullifying') directions are part of the (model) optimisation process of the power system.

9.3.2 Impact of demand response at the aggregated (annual) level

Figure 35 presents the hourly profile of supply options (including DR) to meet the flexibility in NM2050 with and without DR. Note that in both graphs the hours are ranked according to the duration curve of the demand for flexibility in the case of NM2050 without DR (see Figure 31). Moreover, the lower graph is based on equation 7c, i.e. the option DR is moved to the right side of the flexibility equation (as explained in Section 9.1).

[66] Note that, because DR has been shifted to the right ('supply') side of the flexibility equation, in Figure 33 flexibility below the X-axis represents actually upward flexibility and above the X-axis downward flexibility. In Figure 33, on the contrary, upward flexibility is presented (as usual) above the X-axis and downward flexibility below the X-axis.

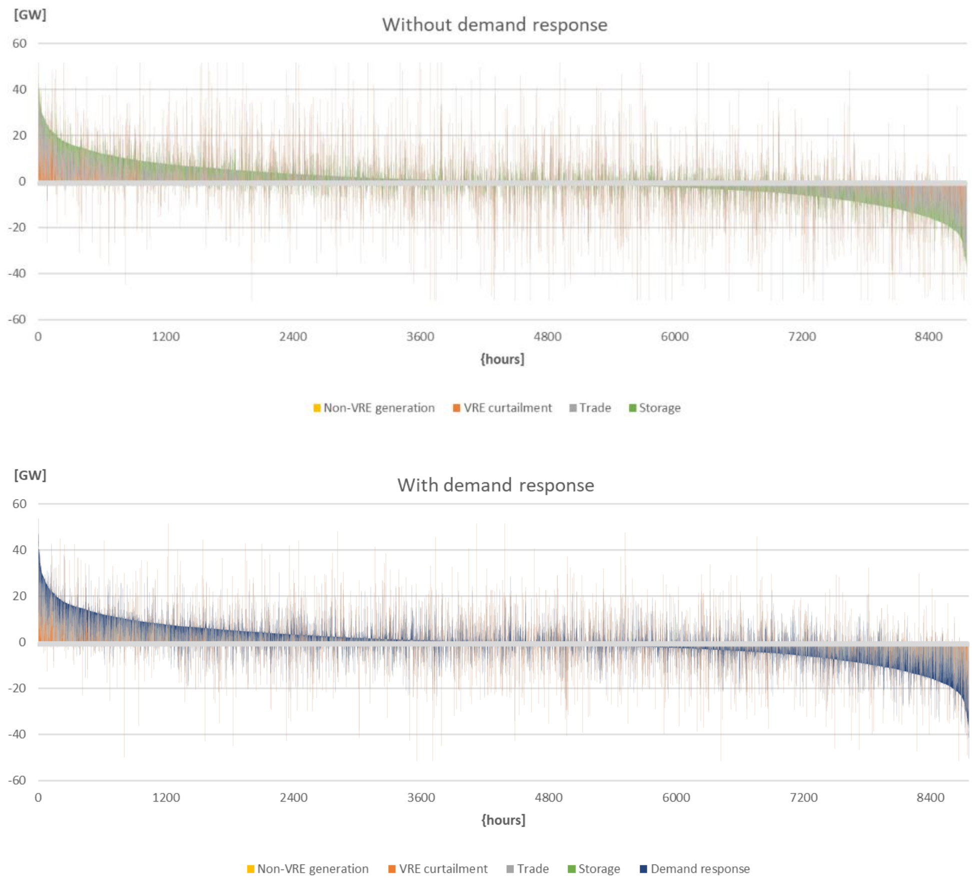


Figure 35: Hourly profile of options to meet the demand for flexibility in NM2050 with and without demand response

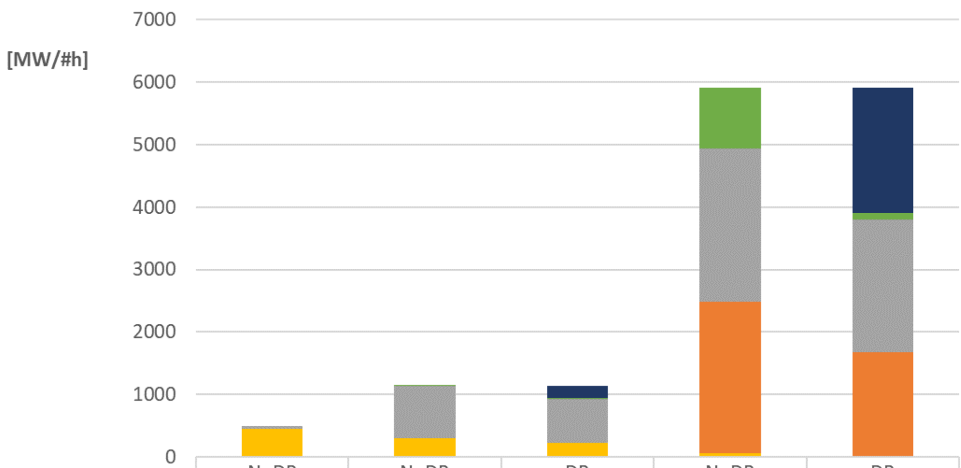
Figure 35 provides a first, overall impression of the impact of DR on the other (supply) options to meet the demand for flexibility in NM2050. It indicates that over the year as a whole flexibility by DR has a (generally significant) impact on the demand for flexibility (before DR) at the expense of other flexibility options, notably storage and VRE curtailment.

Table 39 provides some detailed, more specific data on the mix of supply options to meet the total annual demand for flexibility in both R2015, CA2030 and NM2050 (in TWh), whereas Figure 36 presents the similar mix but this time in terms of average hourly demand for flexibility (in MW/#h). In addition, Figure 37 presents the duration curves of the options to meet the need for flexibility in NM2050 with and without DR (ranked individually), whereas Figure 38 provides the maximum ('capacity') values of these options to meet this need. As usual, these values correspond to the highest and lowest points of the respective duration curves in Figure 37.

Table 39 shows that the total annual supply of flexibility by DR amounts to 1.6 TWh in CA2030 and increases more than tenfold to 17.5 TWh in NM2050 (see Box 1 for a further explanation of this latter result). As a share of the total annual flexibility demand in these scenario years (without DR), this implies that in CA2030 about one-sixth (16%) of this demand is met (or, actually, 'reduced') by means of flexibility offered by DR while in NM2050 this share rises to more than one-third (34%).

Table 39: Mix of supply options to meet the total annual demand for flexibility in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)

		Non-VRE generation	VRE curtailment	Trade	Storage	Demand response	Total flex demand/ supply
Total annual supply of (upward and downward) flexibility by option (TWh)							
R2015	NoDR	4.00	0.00	0.40	0.00	0.00	4.40
CA2030	NoDR	2.62	0.06	7.25	0.00	0.00	9.93
	DR	1.92	0.04	6.24	0.10	1.63	9.93
NM2050	NoDR	0.56	21.24	21.43	8.54	0.00	51.76
	DR	0.06	14.57	18.67	0.92	17.54	51.76
As share of total flex supply (%)							
R2015	NoDR	90.9	0.0	9.1	0.0	0.0	100
CA2030	NoDR	26.4	0.6	73.0	0.0	0.0	100
	DR	19.4	0.4	62.8	1.0	16.4	100
NM2050	NoDR	1.1	41.0	41.4	16.5	0.0	100
	DR	0.1	28.1	36.1	1.8	33.9	100
DR induced change in total annual supply of flexibility (in TWh)							
CA2030	DR-NoDR	-0.70	-0.02	-1.01	0.10	1.63	0.0
NM2050	DR-NoDR	-0.49	-6.67	-2.76	-7.62	17.54	0.0



	R2015 NoDR	CA2030 NoDR	CA2030 DR	NM2050 NoDR	NM2050 DR
Demand response	0	0	186	0	2002
Storage	0	0	12	975	105
Trade	46	827	712	2446	2131
VRE curtailment	0	6	4	2425	1663
Non-VRE generation	457	299	220	64	7

Figure 36: Mix of supply options to meet the average hourly demand for flexibility in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)

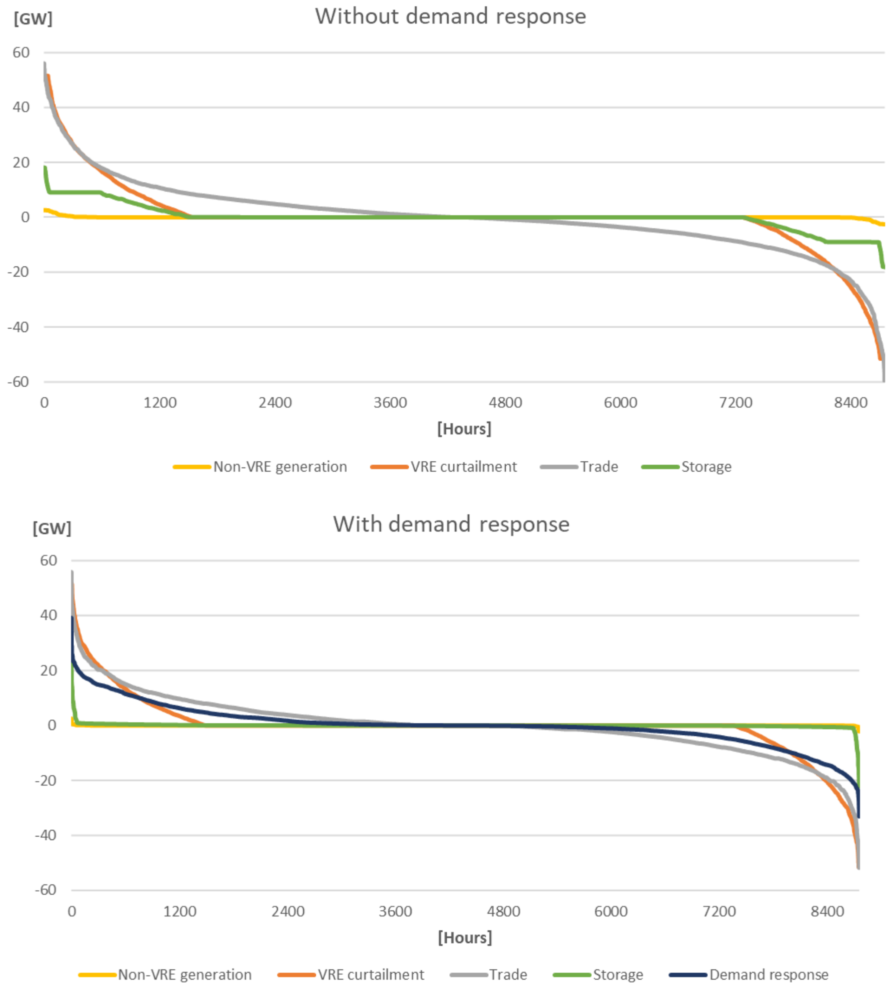
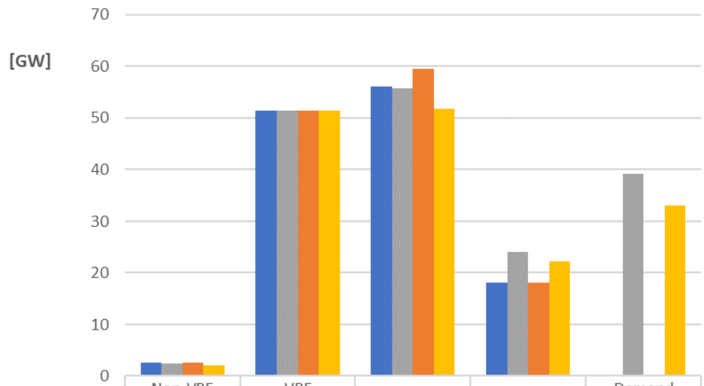


Figure 37: Duration curves of options to meet the need for flexibility in NM2050 with and without demand response



	Non-VRE generation	VRE curtailment	Trade	Storage	Demand response
NoDR Upward flexibility	2.6	51.5	56.0	18.1	0.0
DR Upward flexibility	2.5	51.5	55.8	24.1	39.1
NoDR Downward flexibility	2.6	51.5	59.6	18.2	0.0
DR Downward flexibility	2.1	51.5	51.8	22.2	33.1

Figure 38: Maximum hourly (capacity) values of options to meet the need for upward and downward flexibility in NM2050 with and without demand response (DR versus NoDR)

Box 1: Explaining the difference between potential and effective total annual flexibility by demand response

It should be noted that the (effective) total annual flexibility supply by DR recorded in Table 39 (i.e., 17,54 TWh) is substantially lower than the (potential) total annual flexibility supply by the four DR options added together in Table 25 (i.e., 40.2 TWh; see Chapter 5, Section 5.4). The amount of 40.2 TWh is referring to the *potential* flexibility supply by these DR options, consisting of 20.1 TWh upward flexibility and 20.1 TWh downward flexibility, corresponding to the surface of the areas between the X-axis and the duration curve of the flexibility supply by the four DR options added together in Figure 13 (and its 'mirror image' in Figure 37).

On the other hand, the amount of 17.54 TWh is referring to the *effective* total annual supply of flexibility by DR, consisting of 8.77 TWh upward flexibility and 8.77 downward flexibility. These numbers correspond to the sum of the hourly DR over the (4209) hours with an upward ('positive') flexibility demand in NM2050 and the remaining (4551) hours with a downward ('negative') flexibility demand, as illustrated in Figure 35 (see also Table 37 for the number of hours in NM2050 with an upward and downward flexibility demand).

During a large, substantial number of hours with an upward (downward) flexibility demand, however, the supply of flexibility by DR is downwards (upwards) as illustrated (less visible) in Figure 35 and (more clearly) in Figure 34 (as explained in Section 9.3.1). As a result, aggregating the hourly supply of both upward (positive) and downward (negative) flexibility by DR over the 4209 hours with an upward flexibility demand (Figure 35) results in a substantial lower amount of effective total annual upward flexibility supply by DR (i.e. 8.77 TWh) than aggregating the hourly supply of flexibility by DR over the number of hours with solely an upward (positive) supply of flexibility by DR over the year as a whole, resulting in a potential total annual upward flexibility by DR of 20.1 TWh (see Chapter 5, notably Figure 13 and Table 25). The same reasoning applies for the (4551) hours in NM2050 with a downward flexibility demand, including both hours with a downward flexibility supply by DR as well as hours with un upward flexibility supply by DR (Figure 35).

More specifically, out of the 4209 hours with an upward flexibility demand, about 2760 hours (66%) show an upward flexibility supply by DR (with a total upward flexibility supply of 14.2 TWh over these hours) and about 1440 hours (34%) show a downward flexibility supply by DR (with a total downward flexibility supply of -5.4 TWh). Out of the 4551 hours with a downward flexibility demand, about 3060 hours (67%) show a downward flexibility supply by DR (with a total downward flexibility supply of -14.7 TWh) and about 1490 hours (33%) show an upward flexibility supply by DR (with a total upward flexibility supply of 5.9 TWh). This implies that the total upward flexibility by DR over the year as a whole amounts to 20.1 TWh (14.2 TWh + 5.9 TWh) while the total downward flexibility by DR amounts to -20.1 TWh (-5.4 TWh – 14.7 TWh). However, over the 4209 hours with un upward flexibility demand the total (upward + downward supply of flexibility by DR amounts to only 8.8 TWh (14.2 TWh – 5.4 TWh) whereas during the 4551 hours with a downward flexibility demand the (upward + downward) supply of flexibility by DR amounts to -8.8 TWh (5.9 TWh – 14.7 TWh).

In CA2030, the total annual supply of flexibility by DR implies that less flexibility is needed from other sources, notably from trade (-1 TWh) and non-VRE generation (-0.7 TWh), while in NM2050 less flexibility is need from particularly storage (-7.6 TWh), VRE curtailment (-6.7 TWh) and trade (-2.8 TWh; see Table 39).

The lower graph of Figure 37 shows that in NM2050 flexibility by DR is provided during almost all hours over the year, although over a large number of hours it is relatively small (<5 GW) or even (close to) zero. In a substantial number of hours, however, either upward or downward flexibility by DR is quite significant (>5 GW), with a maximum (capacity) value amounting to 39 GW for downward flexibility by DR and 33 GW for upward flexibility by DR (Figure 37 and Figure 38).[67]

Finally, Figure 36 shows that the *average* hourly supply of flexibility by DR amounts to 186 MW/#h in CA2030 but – similar to the total annual supply of flexibility by DR – increases more than tenfold to 2000 MW/#h in NM2050. Consequently, the average hourly supply of flexibility by the other options (trade, storage, etc.) is reduced accordingly in these scenario years (comparable to the changes in the total annual supply of flexibility by these options in Table 39).[68]

9.3.3 *Supply of flexibility by individual DR options*

Table 40 presents the contribution of the individual P2X/DR options to meet the demand for flexibility in CA2030 and NM2050. It shows that in CA2030 out of the total annual flexibility supply by DR (1.6 TWh), power-to-heat in industry (P2H-i) offers the major part, i.e. 0.6 TWh (37%), followed by power-to-mobility (P2M: 0.5 TWh, 31%), power-to-hydrogen ($P2H_2$: 0.48 TWh, 29%) and, finally, power-to-heat in households (P2H-h: 0.04 TWh, 3%).

In NM2050, on the contrary, out of the total annual flexibility supply by DR (17.5 TWh), the major part is offered by P2M (11.2 TWh, 64%), followed by $P2H_2$ (5.1 TWh, 29%), P2H-h (1.1 TWh, 6%) and, finally, P2H-i (0.1 TWh, 1%).[69] This implies that between the two scenario years CA2030 and NM2050 the contribution to the total supply of flexibility by DR increases substantially for P2M but decreases significantly for P2H-i in both absolute energy terms (TWh) and in relative terms (%).

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[67] Note that in Figure 37 and Figure 38 DR is presented on the right ('supply') side of the flexibility equation rather than on the left ('demand') side (as explained in Section 9.1). As a result, the DR values in Figure 37 and Figure 38 have opposite signs compared to the respective DR values in Figure 13 and Table 23, respectively (Sections 5.3 and 5.4). Consequently, the DR duration curve in Figure 37 is actually the 'mirror image' of the DR duration curve in Figure 13.

[68] In CA2030, the supply of flexibility by storage increases in the case with DR (compared to the case without DR), while the supply of flexibility by the other options (apart from DR) decreases. This is due to the fact that in CA2030 without DR there is no need (or 'competitive room') for supply of flexibility by (expensive) storage options, whereas in CA2030 with DR flexible (passenger) EVs offer a relatively cheap opportunity for storage charges and discharges by G2V and V2G transactions, respectively (Sijm et al., 2020).

[69] Note that, since flexibility supply by DR accounts for about one-sixth (16%) of the total flexibility supply by all options in CA2030 (including storage, trade, etc.) and for about one-third (34%) in NM2050, the supply of flexibility by the individual DR options as a % of the total flexibility supply by all options are lower accordingly (see bottom two line of Table 40). Note also that the *effective* total annual flexibility supply by the individual DR options recorded in Table 40 is substantially lower than the potential total annual flexibility supply by these options presented in Table 25 (Section 5.4), as explained in Box 1 (Section 9.3.2).

Table 40: Contribution of individual demand response options to meet the demand for flexibility in CA2030 and NM2050

	P2Hydrogen	P2Heat (industry)	P2Heat (households)	P2Mobility (Passenger EVs)	Total flexibility supply by DR
Total annual supply of (upward and downward) flexibility by option (TWh)					
CA2030	0.48	0.60	0.04	0.50	1.63
NM2050	5.10	0.10	1.11	11.23	17.54
Average hourly supply of (upward and downward) flexibility by option (MW/#h)					
CA2030	55	69	5	57	186
NM2050	582	11	127	1282	2002
Supply of flexibility as share of total flex supply by all DR options (%)					
CA2030	29.3	37.1	2.7	30.8	100
NM2050	29.1	0.6	6.3	64.0	100
Supply of flexibility as share of total flex supply by all supply options (%)					
CA2030	4.8	6.1	0.4	5.1	16.4
NM2050	9.8	0.2	2.1	21.7	33.9

9.4 The balance of demand and supply of flexibility by demand response

Flexible P2X technologies do not only supply flexibility to the power system by means of demand response (DR) but also demand for flexibility, both directly – i.e., in case the demand for electricity by the respective technologies is variable – and indirectly, i.e. assuming that the demand for electricity by the respective technologies is met by the generation of electricity from VRE sources (which seems to a legitimate assumption for NM2050 where the share of VRE sources in total domestic electricity demand is very high, i.e. almost 100%).

Table 41 provides a summary overview of the balance of demand and supply of flexibility by the four individual P2X/DR technologies in NM2050. As the electricity demand in NM2050 without DR is fixed (flat) for P2H_2 and P2H-i, while it is variable for P2H-h and P2M, Table 41 (line B) shows that in this case the total annual (direct) demand for flexibility is zero for P2H_2 and P2H-i, whereas it amounts to 0.9 TWh for P2H_2 and 3.9 TWh for P2M (see also Table 38). This corresponds to an average hourly demand for flexibility for these two technologies of 104 MW/#h and 440 MW/#h, respectively (Table 41, line C). Dividing this average hourly demand for flexibility by the electricity demand of the two respective technologies (line A), results in the so-called '*direct marginal hourly demand for flexibility*'. Table 41 shows that this indicator amount to 7.3 MW/TWh for P2H-h and to 13.9 MW/TWh for P2M, whereas it is zero for P2H_2 and P2H-i (Section DR, line 'Direct').

As noted above, however, P2X technologies do not only cause a direct demand for flexibility – i.e., as far as their electricity demand is variable – but also an indirect demand for flexibility if their electricity demand is met from VRE sources. This indirect demand can be assessed by means of the so-called 'in*direct marginal hourly demand for flexibility*', i.e. the additional need for flexibility (both upward and downwards) due to the need to meet an additional electricity demand of 1 TWh by a similar change in the annual electricity supply from VRE sources. As the average hourly demand for flexibility due to VRE power generation amounts to 5251 MW in NM2050 (Figure 32), while the total supply of VRE sources (before curtailment) amounts to about 454

TWh, the resulting indirect marginal hourly demand for flexibility of VRE power generation amounts to 116 MW/TWh (see Table 41, Section D, line 'Indirect').

Adding the direct and indirect marginal hourly demand for flexibility results in the so-called '*total marginal hourly demand for flexibility*'. Table 41 shows that this indicator amounts to 11.6 MW/TWh for both $P2H_2$ and P2H-i (since they only cause an indirect demand for flexibility), while it amounts to 18.9 MW/TWh for P2H-h, 25.4 MW/TWh for P2M and, on average, 14 MW/TWh for all four P2X as a whole.

In addition, Table 41 presents similar indicators for the supply of flexibility by the individual P2X/DR technologies (see also Table 40) although these indicators refer to the direct supply of flexibility only since there is no indirect supply of flexibility by these technologies (i.e., this indirect supply amounts to zero in the assessment of Table 41). For instance, the (direct) annual supply of flexibility by $P2H_2$ amounts to 5.1 TWh, corresponding to an average hourly supply of flexibility of 582 MW. With a total electricity demand by $P2H_2$ of 112 TWh, this translates into a (direct) marginal hourly supply of flexibility of 5.2 MW/TWh.

By means of the above-mentioned indicators for the demand and supply of flexibility, the balance of flexibility for the P2X technologies can be assessed (see the lower part of Table 41). For instance, Table 41 shows that the balance of *direct* annual demand and supply of flexibility is positive for the P2X technologies although relatively small for the two P2H options, i.e. it amounts to 0.1 TWh for P2H-i, 0.2 TWh for P2H-h, 5.1 TWh for $P2H_2$, 7.4 TWh for P2M and almost 13 TWh for all four P2X technologies together (Section H, line 'Direct').

The balance of indirect annual demand and supply of flexibility, however, is negative for all four P2X technologies, notably for the two technologies ($P2H_2$ and P2H-i) with a relatively high (fixed) electricity demand in NM2050 and, hence, a high need for electricity supply from VRE sources. More specifically, this indirect balance amount to (minus) 1.4 TWh for P2H-h, 3.2 TWh for P2M, 6.8 TWh for P2H-i, more than 11 TWh for $P2H_2$ and almost 23 TWh for all four P2X technologies as a whole (Table 41, Section H, line 'Indirect').

Adding up the direct and indirect balance of total annual flexibility demand and supply results in the total annual flexibility balance for the respective technologies. This latter balance is positive only for P2M (4.2 TWh), whereas it is negative for the other P2X/DR technologies, i.e. -1.2 TWh for P2H-h, -6.3 for $P2H_2$ and -6.7 TWh for P2H-i. for the four P2X technologies as a whole, the total annual balance of flexibility amounts to -10 TWh.

In summary, the direct annual balance flexibility demand and supply by the selected P2X technologies is highly positive in NM2050 (12.8 TWh), whereas the indirect annual balance is even more highly negative (-22.8 TWh), resulting in a total annual balance of flexibility demand and supply by these technologies of -10 TWh in NM2050. This implies that a major part of the flexibility demand caused by these technologies both directly and indirectly is covered by means of the demand response of these technologies themselves (12.8 TWh) but that a remaining, substantial part (10 TWh) has to be met by other flexibility options such as trade, storage, VRE curtailment or flexible (carbon-free) non-VRE power generation.

Table 41: Balance of demand and supply of flexibility by individual P2X technologies in NM2050

	Unit	P2H$_2$	P2H-i	P2H-h	P2M	Total
A. Electricity demand	TWh	112.1	66.6	14.3	31.7	224.7
Demand for flexibility by DR option						
B. Direct annual demand for flexibility[a]	TWh	0.0	0.0	0.9	3.9	4.8
C. Average hourly demand for flexibility (B/8760)	MW	0.0	0.0	104	440	544
D. Marginal hourly demand for flexibility (C/A)						
> Direct[b]	MW/TWh	0.0	0.0	7.3	13.9	2.4
> Indirect[c]	MW/TWh	11.6	11.6	11.6	11.6	11.6
> Total	MW/TWh	11.6	11.6	18.9	25.4	14.0
Supply of flexibility by DR option						
E. Annual supply of flexibility[d]	TWh	5.1	0.1	1.1	11.2	17.5
F. Average hourly supply of flexibility (E/8760)	MW	582	11	127	1282	2002
G. Marginal hourly supply of flexibility (F/A)	MW/TWh	5.2	0.2	8.9	40.4	8.9
Balance of flexibility per DR option						
H. Annual balance of flexibility						
> Direct	TWh	5.1	0.1	0.2	7.4	12.8
> Indirect	TWh	-11.4	-6.8	-1.4	-3.2	-22.8
> Total	TWh	-6.3	-6.7	-1.3	4.2	-10.0
I. Average hourly balance flexibility (H/8760)						
> Direct	MW	582	11	23	842	1458
> Indirect	MW	-1297	-771	-165	-367	-2600
> Total	MW	-715	-760	-143	476	-1142
J. Marginal hourly balance of flexibility (I/A)						
> Direct	MW/TWh	5.2	0.2	1.6	26.6	6.5
> Indirect	MW/TWh	-11.6	-11.6	-11.6	-11.6	-11.6
> Total	MW/TWh	-6.4	-11.4	-10.0	15.0	-5.1

a) Including the demand for both upwards and downwards flexibility due to the hourly variability of the electricity demand of the P2X option concerned;

b) The direct marginal hourly demand for flexibility refers to the additional need for flexibility (both upwards and downwards) due to the additional (annual) electricity demand of the DR option concerned by 1 TWh;

c) The indirect marginal hourly demand for flexibility refers to the additional need for flexibility (both upwards and downwards) due to the need to meet an additional (annual) electricity demand of 1 TWh by a similar change in the annual electricity supply from VRE sources. As the average hourly demand for flexibility due to VRE power generation amounts to 5251 MW in NM2050 (Figure 32), while the total supply of electricity from VRE sources (before curtailments) amounts to about 454 TWh, the resulting indirect marginal hourly demand for flexibility of VRE power generation amounts to 11.6 MW/TWh.

d) Including the supply of both upward and downward flexibility due to the demand responsiveness of the option concerned.

More specifically (and more policy relevant), the findings outlined above imply that, assuming the additional electricity demand by P2X technologies is met from VRE sources, it does not make sense to encourage the penetration and use of these technologies for flexibility purposes only as the total balance of flexibility demand and supply by these technologies, except for P2M (although it may be hard to realise the positive flexibility balance for passenger EVs because of the incidence of a variety of DR barriers for this technology; see De Wildt et al., 2022).

However, assuming that the electricity demand by P2X technologies is already there or that the penetration and use of these technologies is primarily stimulated for other than flexibility purposes (e.g., to become climate-neutral), it does make sense to realise the DR potential of these technologies – e.g., by reducing their DR barriers – as, regardless from which supply sources the electricity demand by these technologies is met, it will have a positive impact on the actual balance of flexibility demand and supply by these technologies.

10 Some sensitivity analyses

In order to assess the potential impact of some uncertainties and assumptions regarding some modelling results for NM2050, we have conducted some sensitivity analyses for this scenario year. In brief, these cases include:[70]

- *Case 1A ('half DR capability'):* in this sensitivity case, 70% of the load by P2H-h and P2M is controllable – i.e., responds to changes in electricity prices (just like in the reference scenario) – but for P2H-h the time for load shifting – either forward or backward – is halved from 2 hours to 1 hour, whereas for P2M the battery capacity of passenger EVs is halved to 50 kW (compared to 100 kW in the reference scenario);
- *Case 1B ('half DR controllability'):* in this sensitivity case, the time period for load shifting by P2H-h is kept at 2 hours and, for P2M, the EV battery capacity is kept at 100 kW, but the rate of load controllability – i.e., the part of the load that is responsive to changes in electricity prices – is halved to 35% for both technologies (compared to 70% in the reference scenario);
- *Case 2A ('no trade'):* in this sensitivity case, the interconnection capacities of the Netherlands are set at zero in NM2050, i.e. there is not any cross-border electricity trade between the Netherlands and its neighbouring countries.
- *Case 3A ('reduced VRE capacity'):* in this sensitivity case, the assumed capacity of key VRE technologies are reduced substantially, compared to the reference scenario NM2050, i.e. for solar PV form 106 GW to 40 GW and for offshore wind from 51.5 GW to 45 GW.

In the sections below, we present and discuss briefly the major results of the above-mentioned sensitivity cases regarding the following variables:

- Demand and supply of flexibility (Section 10.1);
- Electricity prices (Section 10.2);
- Power system costs (Section 10.3);
- VRE supply revenues (Section 10.4).

10.1 Demand and supply of flexibility

10.1.1 Mix of all major categories to meet the demand for flexibility

Table 42 presents the optimal mix of the major options to meet the total annual demand for flexibility in NM2050, both for the reference scenarios (with and without DR) and for the sensitivity cases (with DR), whereas Figure 39 shows a similar mix to meet the average hourly demand for flexible in these scenario cases.

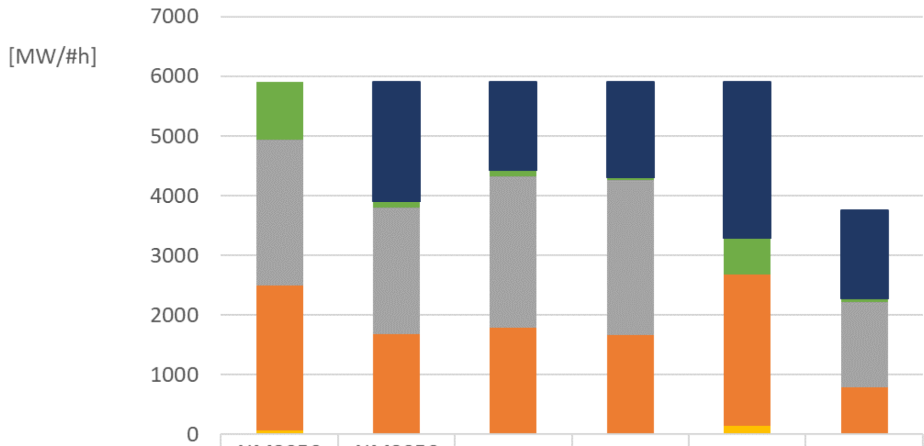
The major observation from Table 42 and Figure 39 include:

➢ The amounts of both total annual and average hourly demand/supply of flexibility are similar in the reference scenarios and sensitivity cases 1A, 1B and 2A of NM2050 (i.e., 51.76 TWh and 5.9 GW/#h, respectively), whereas they are substantially lower in case 3A (i.e., 32.89 TWh and 3.8 GW/#h, respectively) due to the reduced VRE capacity in this case (and the resulting lower demand for flexibility due to the lower supply of VRE).

[70] Besides the Netherlands, similar adjustments were also made for other EU27+ countries and regions in cases 1A, 1B and 2A but not for case 3A.

Table 42: Mix of options to meet the total annual demand for flexibility – Comparison of reference scenario and sensitivity cases of NM2050

	Non-VRE generation	VRE curtailment	Trade	Storage	Demand response	Total flex supply
Total annual supply of (upward and downward) flexibility by option (TWh)						
NM2050 NoDR	0.56	21.24	21.43	8.55	0.00	51.76
NM2050 DR	0.06	14.57	18.67	0.92	17.54	51.76
1A	0.11	15.56	22.13	1.04	12.94	51.76
1B	0.07	14.49	22.75	0.38	14.07	51.76
2A	1.20	22.20	0.00	5.44	22.93	51.76
3A	0.04	6.82	12.58	0.51	12.94	32.89
As share of total flex supply (%)						
NM2050 NoDR	1.1	41.0	41.4	16.5	0.0	100
NM2050 DR	0.1	28.1	36.1	1.8	33.9	100
1A	0.2	30.1	42.8	2.0	25.0	100
1B	0.1	28.0	44.0	0.7	27.2	100
2A	2.3	42.9	0.0	10.5	44.3	100
3A	0.1	20.7	38.2	1.5	39.3	100



	NM2050 NoDR	NM2050 DR	1A	1B	2A	3A
Demand response	0	2002	1477	1606	2617	1477
Storage	975	105	118	43	621	58
Trade	2446	2131	2526	2597	0	1436
VRE curtailment	2425	1663	1776	1654	2534	778
Non-VRE generation	64	7	12	8	137	5

Figure 39: Mix of options to meet the average hourly demand for flexibility – Comparison of reference scenario and sensitivity cases of NM2050

- Compared to the reference scenario NM2050 with DR, the total annual supply of flexibility by DR is significantly lower in case 1A ('half DR capability') and case 1B ('half DR controllability') – i.e., 17.5 TWh, 12.9 TWh and 14.1 TWh, respectively – but substantially higher (22.9 TWh) in case 2A ('no trade'). In case 3A ('reduced VRE capacity'), the total annual supply of flexibility by DR is also significantly lower in absolute terms (12.9 TWh) but higher as a share of total flexibility demand/supply, i.e. 39% (compared to 34% in the reference scenario NM2050 with DR).[71]

- In both case 1A ('half DR capability') and case 1B ('half DR controllability'), the resulting lower supply of flexibility by DR is met by a higher supply by other flexibility options, notably by cross-border trade.

- In case 2A ('no trade'), i.e. no flexibility supply by cross-border trade of electricity, not only the supply of flexibility by DR is substantially higher but also by the other supply options, in particular by VRE curtailment, storage and – to some extent – non-VRE generation.

- In case 3A ('reduced VRE capacity'), the resulting lower demand for flexibility does not only reduce the need for flexibility by DR (in absolute terms) but also for the other supply options, notably VRE curtailment (also in relative terms) and trade.

10.1.2 Contribution of individual DR options to meet the demand for flexibility

Table 43 presents the contribution of individual P2X technologies to meet the total annual demand for flexibility in NM2050, both for the reference scenario (with DR) and the sensitivity cases of NM2050 (all with DR), whereas Figure 40 shows their contribution to meet the average hourly demand for flexibility in these scenario cases.

The major observations from Table 43 and Figure 40 include:

- As expected, in case 1A ('half DR capability') and case 1B ('half DR controllability'), the supply of flexibility by the two P2X technologies concerned – i.e., P2H-h and, notably, P2M – decreases significantly, for instance for P2M in case 1A to 5.2 TWh (compared to 11.2 TWh in the reference scenario NM2050 with DR). As a result, the share of P2M in the supply by all flexibility options declines to 10% in 1A (compared to 22% in the reference scenario), while the share of P2M in the supply of flexibility by all DR options decreases to 40% (compared to 64% in the reference scenario).

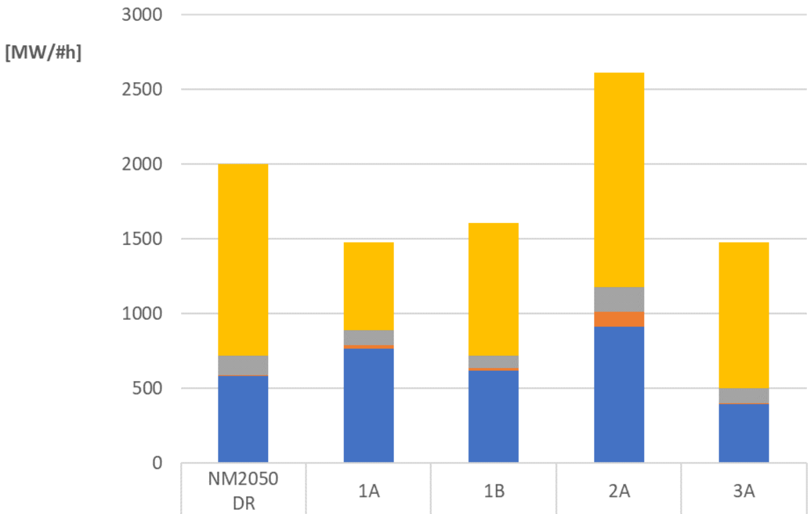
- On the other hand, the total annual supply of flexibility by the other two P2X technologies – i.e., P2H-i and, in particular, $P2H_2$ – increases to some extent, although far less than the decline in flexibility supply by P2M and P2H-h. Consequently (as already noted above regarding Table 43) the total annual supply of flexibility by all four P2X technologies is significantly lower in cases 1A and 1B (compared to the reference scenario).

- In case 2A ('no trade'), the total annual supply of flexibility by all DR options increases to almost 23 TWh (compared to 17.5 TWh in the reference scenario), i.e. more than 44% of the total supply by all flexibility options (compared to 34% in the reference scenario). In absolute terms, this increase in flexibility supply by DR (+5.4 TWh) is provided in particular by $P2H_2$ (+2.9 TWh), P2M (+1.4 TWh) and P2H-i (+0.8 TWh).

[71] Similar observations apply regarding the changes and differences in the average hourly supply of flexibility by DR (and other options) between the reference scenarios and sensitivity cases of NM2050 (see Figure 39).

Table 43: Contribution of individual P2X options to meet the total annual demand for flexibility – Comparison of reference scenario and sensitivity cases of NM2050

	$P2H_2$	P2H-i	P2H-h	P2M	Total flex supply by DR
Total annual supply of (upward and downward) flexibility by P2X option (TWh)					
NM2050 NoDR	0.00	0.00	0.00	0.00	0.00
NM2050 DR	5.10	0.10	1.11	11.23	17.54
1A	6.71	0.24	0.83	5.16	12.94
1B	5.45	0.16	0.71	7.75	14.07
2A	8.00	0.90	1.44	12.58	22.92
3A	3.46	0.09	0.84	8.55	12.94
Supply of flexibility by P2X option as share of total supply by all flexibility options (%)					
NM2050 NoDR	0.0	0.0	0.0	0.0	0.0
NM2050 DR	9.8	0.2	2.1	21.7	33.9
1A	13.0	0.5	1.6	10.0	25.0
1B	10.5	0.3	1.4	15.0	27.2
2A	15.4	1.7	2.8	24.3	44.3
3A	10.5	0.3	2.6	26.0	39.3
Supply of flexibility by P2X option as share of total flex supply by all P2X options (%)					
NM2050 NoDR	0.0	0.0	0.0	0.0	0.0
NM2050 DR	29.1	0.6	6.3	64.0	100
1A	51.9	1.8	6.4	39.9	100
1B	38.7	1.1	5.1	55.1	100
2A	34.9	3.9	6.3	54.9	100
3A	26.7	0.7	6.5	66.1	100



	NM2050 DR	1A	1B	2A	3A
P2M (Passenger EVs)	1282	589	885	1436	976
P2Heat-households	127	95	81	164	96
P2Heat-industry	11	27	18	103	10
P2Hydrogen	582	766	622	913	395

Figure 40: Contribution of individual P2X options to meet the average hourly demand for flexibility – Comparison of reference scenario and sensitivity cases of NM2050

- In case 3A ('reduced VRE capacity'), the total annual supply of flexibility by all DR options decreases to less than 13 TWh (compared to more than 17.5 TWh in the reference scenario). This decrease in flexibility supply by DR (-4.6 TWh) – due to the lower need for flexibility in this case – is born by particularly P2M (-2.6 TWh), P2H_2 (-1.6 TWh) and P2H-h (-0.3 TWh).

10.2 Electricity prices

Figure 41 presents the duration curve of the hourly electricity prices in NM2050, both for the reference and sensitivity cases of this scenario year, while **Error! Not a valid bookmark self-reference.** provides the weighted average electricity prices for these scenario cases.

The major observations from Figure 41 and **Error! Not a valid bookmark self-reference.** include:

- In case 1A ('half DR capability') and case 1B ('half DR controllability'), the weighted average electricity prices are slightly higher than in NM2050 with DR, i.e. they amount to 12.4 €/MWh, 12.1 €/MWh and 12.0 €/MWh, respectively. Compared to NM2050 without DR (27.3 €/MWh), however, the average electricity prices in these two sensitivity cases are still substantially lower (i.e., by about 55-56%). Only in the case 2A ('no trade') and case 3A ('reduced VRE capacity') are the average electricity prices a bit higher than in NM2050 with DR (14.7 €/MWh and 14.2 €/MWh, respectively) but still significantly lower compared to NM2050 without DR (by about 46-48%).

- The duration curves of the electricity prices in the cases 1A and B are more or less in line with the (relatively low) price duration curve of the reference scenario NM2050 with DR, i.e. up to 2400 hours significantly lower than the price duration curve of NM2050 without DR but significantly higher than this curve over some 1200 hours (in the range of hours 3600-4800, see Figure 41 as well as Figure 18 in Section 7.5).
- Up to 2400 hours, the price duration curve of case 2A ('no trade') is usually significantly higher than the price duration curve of NM2050 with DR but (apart from the first three hundred hours) significantly lower than the price duration curve of NM2050 without DR. Over the range 2400-4000 hours, on the contrary, the price duration curve of case 2A is usually significantly higher than the price duration curve of NM2050 without DR. Over the remaining, large range of 4000-8760 hours, however, these two curves are predominantly at the same low (bottom) level of approximately 2 €/MWh.

- Up to 3600 hours, the price duration curve of case 3A ('reduced VRE capacity') is usually in line with the price duration curve of NM2050 with DR (i.e., up to 2400 hours significantly lower the price duration curve of NM2050 without DR). In the range 3600-5400 hours, however, the 3A curve is significantly higher than the two reference curves, notably of NM2050 without DR, mainly because the supply of VRE power generation in this sensitivity case is effectively reduced over these hours. Over the range 5400-8760 hours, however, the (over)supply of VRE power generation in case 3A remains relatively high, resulting in low (bottom) electricity prices of approximately 2 €/MWh.

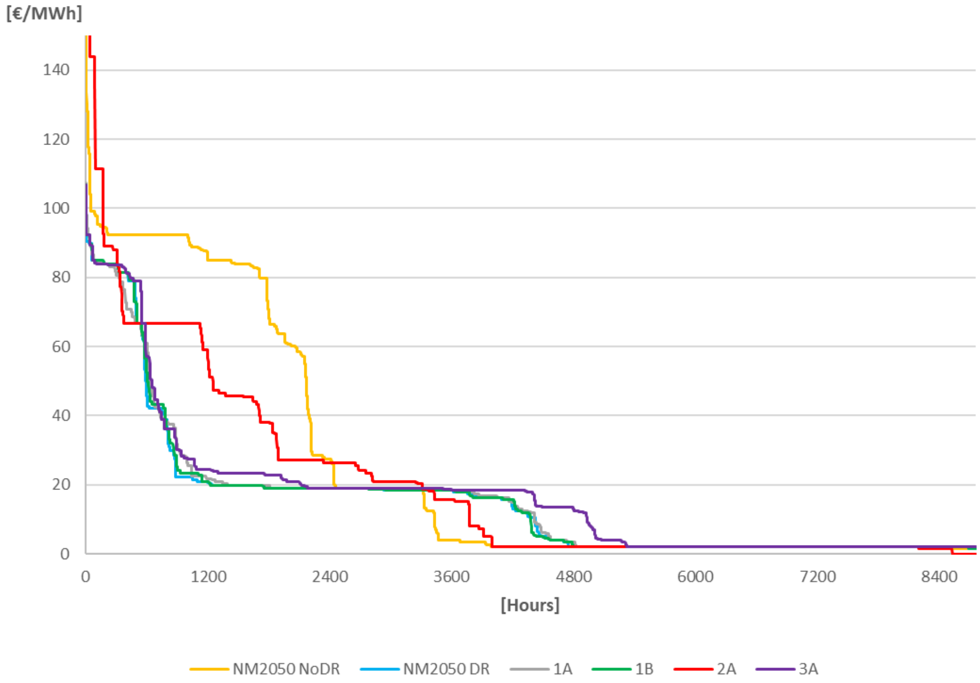


Figure 41: Duration curves of electricity prices – Comparison of reference scenario and sensitivity cases of NM2050

Table 44: Average annual electricity prices – Comparison of reference scenario and sensitivity cases of NM2050

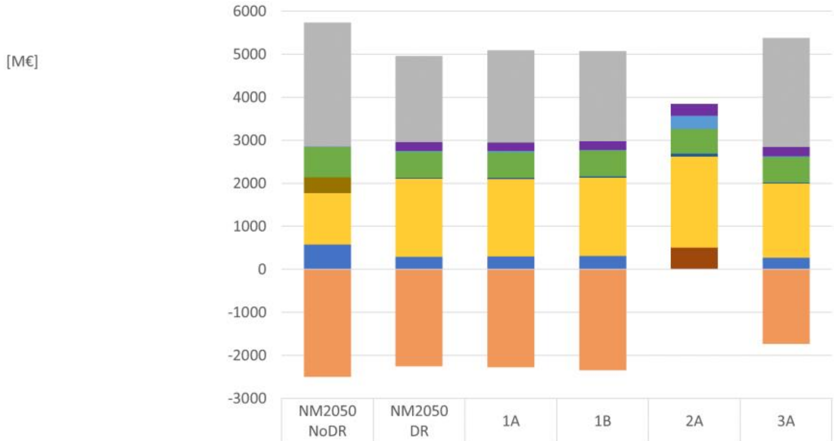
	Average electricity price [€/MWh]	Change compared to NM2050 NoDR [%]
NM2050 NoDR	27.3	0%
NM2050 DR	12.0	-56%
1A	12.4	-55%
1B	12.1	-56%
2A	14.7	-46%
3A	14.2	-48%

10.3 Power system costs

Figure 42 presents the components of the P2X system costs of the Netherlands in NM2050, both for the reference and sensitivity case of this reference year, while Table 45 provides the total P2X system costs in these scenario cases.

The major observation from Figure 42 and Table 45 include:

- Of all cases recorded in Table 45, the lowest total system costs refer to the reference scenario NM2050 with DR (about 2.7 b€, i.e. 16% lower than in NM2050 without DR, as discussed in Section 7.8). In case 1A ('half DR capability') and case 1B ('half DR controllability'), both the total system costs (Table 45) and the major cost components (Figure 42) are largely in line with this reference scenario. Only the electricity import costs are a bit higher (150 m€) in case 1A (compared to NM2050 with DR).



	NM2050 NoDR	NM2050 DR	1A	1B	2A	3A
Electricity import costs	2886	1999	2147	2095	0	2526
Electricity export costs	-2501	-2253	-2280	-2343	0	-1738
H2 curtailment costs	9	0	0	0	0	0
Variable gas-to-heat costs	0	203	196	205	274	223
Variable energy storage costs	6	23	33	14	304	19
Variable electricity generation costs	705	602	594	604	568	587
Investment costs of new H2 storage capacity	0	26	24	27	73	22
Investment costs of new E-storage capacity	363	0	0	0	0	0
Investment costs of new P2H2 capacity	1196	1820	1802	1825	2124	1728
Investment costs of new generation capacity	0	0	0	0	0	0
Investment costs of new HVDC grid overlay	576	287	302	305	0	270
Investment costs of new H2-2-power capacity	0	0	0	0	500	0

Figure 42: Components of P2X system costs – Comparison of reference scenario and sensitivity cases of NM2050

Table 45: Total P2X system costs: – Comparison of reference scenario and sensitivity cases of NM2050

	Total system costs [m€]	Change compared to NM2050 NoDR [%]
NM2050 NoDR	3241	0%
NM2050 DR	2706	-16%
1A	2818	-13%
1B	2733	-16%
2A	3842	19%
3A	3638	12%

- Of all cases recorded in Table 45, the highest total system costs refer to case 2A (about 3.8 b€, i.e. 19% higher than in the reference scenario NM2050 without DR and even 42% higher than in nm2050 with DR). On the one hand, in this case (‘no cross-border electricity trade’) the investment costs of new interconnections and other, related HCDC grid costs are significantly lower (compared to all other reference and sensitivity cases). On the other hand, the demand for green hydrogen – and the related demand for new electrolysis capacity – is much higher in case 2A, in particular because in a large number of hours the residual load (VRE shortage) is met by newly installed hydrogen-to-power plants (rather than by imports). As a result, the investment costs of both additional $P2H_2$ capacity and new $H_2$2P capacity are substantially higher in case 2A (compared to all other reference and sensitivity cases). Moreover, compared to NM2050 with DR and the cases 1A and 1B – which all show a major surplus of net trade revenues – this surplus is missing in the ‘no trade’ case 2A.

- In case 3A ('reduced VRE capacity'), the total system costs amount to approximately 3.6 b€, i.e. some 12% higher than in NM2050 without DR and even 34% higher in NM2050 with DR.[72] The main reason for the higher costs in 3A is that, due to the lower VRE capacity, the volume and/or the number of hours with a positive residual load (VRE shortage) is increased whereas, on the other hand, the volume and/or the number of hours with a negative residual load (VRE surplus) is decreased. As a result, the electricity import costs are substantially higher in 3A whereas the electricity export revenues are significantly lower (notably compared to NM2050 with DR).

10.4 VRE supply revenues

Finally, Table 46 presents the VRE generation revenues in case 3A ('reduced VRE capacity') compared to the reference scenario 2050 (both including DR). It shows that the total VRE supply revenues decline from 4.2 b€ in NM2050 with DR to 3.9 b€ in case 3A, i.e. a decrease of some 300 m€ (-7.5%). However, whereas these revenues decline by 435 m€ in case 3A for PV generators (-45%), they increase for both wind onshore and offshore producers by 82 m€ and 41 m€ (13% and 1.6%), respectively.

The large decline in total revenues for solar PV generators is primarily due to the lower (assumed) installed capacity of solar PV in case 3A, resulting in a similar decline in VRE power generation by solar PV (see Table 46). On the other hand, in case 3A the assumed capacity declines by less than 13% for offshore wind (compared to NM2050 with DR), whereas it remains the same for onshore wind. In addition, case 3A is characterised by less VRE curtailment, notably of offshore wind. As a result, the VRE power supply in case 3A declines by only 5% for offshore wind – compared to NM2050 with DR – while, above, it drops by 62% for solar PV.

Table 46 shows that – due to the changes outlined above – the *average* VRE supply revenues per MWh generated, i.e. the average electricity price received by VRE producers, increases from 11.0 €/MWh in NM2050 with DR to 12.5 €/MWh in case 3A (i.e., an increase of 14%). For solar PV producers, however, this increase is substantially higher - i.e., from 9.8 €/MWh to 14.2 €/MWh (+45%) – whereas it is significantly lower for offshore wind producers (+7%).

In addition, Table 46 shows that the average VRE supply revenues per GW installed increases from 24 m€/GW in NM2050 with DR to 37 m€/GW in case 3A, i.e. an increase of approximately 13 m€/GW (+56%). This implies that, compared to NM2050 with DR, a reduction in the (assumed) installed VRE capacity results not only in, on average, higher VRE supply revenues per MWh generated but, as expected, also in higher VRE supply revenues per GW installed and, hence, in a significant improvement of the business of VRE investments.[73]

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[72] It should be emphasized, however, that in both Figure 42 and Table 45 investment costs refer only to the (future) investment costs of new capacities in a certain scenario and not to the past investment costs of the (assumed) baseline capacities as these latter costs are regarded as ‘sunk costs’ that are not affected in future scenario years (as remarked in Section 7.8). This applies to all cases included in Figure 42 and Table 45, but less to case 3A, as the (assumed) baseline VRE capacity is much lower in this case than in the other cases. Hence, accounting for the (annualised) investment costs of the baseline VRE capacity would substantially increase the system costs of the other cases compared to 3A.

[73] Compared to NM2050 without DR, however, the average VRE supply revenues per MWh generated are still significantly lower in case 3A ('reduced VRE capacity') (i.e., 18.2 €/MWh

Table 46: Total and average VRE generation revenues – Comparison of NM2050 reference scenario and sensitivity case 3A (both including DR)

Type of VRE supply	Unit	NM2050 DR	Case 3A	∆	In %
VRE supply revenues					
Wind Onshore	m€	629	711	82	13.1
Wind Offshore	m€	2599	2640	41	1.6
Solar PV	m€	960	525	-435	-45.3
Total	m€	4188	3876	-312	-7.5
VRE generation					
Wind Onshore	TWh	76.7	76.9	0.2	0.2
Wind Offshore	TWh	205.9	195.1	-10.8	-5.2
Solar PV	TWh	98.1	37.0	-61.1	-62.3
Total	TWh	380.8	309.1	-71.7	-18.8
Average VRE supply revenues per MWh generated					
Wind Onshore	€/MWh	8.2	9.2	1.1	12.8
Wind Offshore	€/MWh	12.6	13.5	0.9	7.2
Solar PV	€/MWh	9.8	14.2	4.4	44.9
Total	€/MWh	11.0	12.5	1.5	14.0
Installed VRE capacities					
Wind Onshore	GW	20.0	20.0	0.0	0.0
Wind Offshore	GW	51.5	45.0	-6.5	-12.6
Solar PV	GW	106.0	40.0	-66.0	-62.3
Total	GW	177.5	105.0	-72.5	-40.8
Average VRE supply revenues per GW installed					
Wind Onshore	m€/GW	31.4	35.5	4.1	13.1
Wind Offshore	m€/GW	50.5	58.7	8.2	16.2
Solar PV	m€/GW	9.1	13.1	4.1	44.9
Total	m€/GW	23.6	36.9	13.3	56.4

versus 12.5 €/MWh), whereas the average VRE supply revenues per GW installed are more of less similar, i.e. 36.2 m€/GW versus 39.9 m€/GW (see Table 32 – in Section 7.6 – versus Table 46). As mentioned in Section 7.9, for this year (2022) we have planned a follow-up study in which we will further explore the impact of (flexible) electricity demand on the optimal capacity and business case of VRE investments (see in particular footnote 54).

11 Summary and discussion of part II

11.1 Summary

Part II of the study analyses the impact of demand response (DR) on the power system of the Netherlands in the scenario years CA2030 and NM2050. This analysis is conducted at three related levels:

- The impact of DR on the *electricity balance*, i.e. on the major components of (total) electricity demand and supply, including the impact of DR on related variables such as electricity prices, VRE supply revenues and total system costs;
- The impact of DR on the so-called '*residual load balance'*, i.e. the balance of flexible options to meet the residual load (RL), including in particular hours with a positive RL (VRE shortage) and hours with a negative RL (VRE surplus);
- The impact of DR on the so-called '*flexibility balance*', i.e. the total demand and supply of flexibility by the power system, where flexibility refers primarily to the *hourly* variability of the residual (RL), defined and measured as the difference (Δ) between the RL in hour *t* and the RL in hour *t-1* (with *t* = 1,…., 8760).

11.1.1 Impact of demand response on the electricity balance

Table 47 summarises the major results regarding the impact of DR on the electricity balance – and some related variables – of the Netherlands in scenario years CA2030 and NM2050. The major findings and observations from this table include:

- Compared to the scenario cases without DR (NoDR), DR reduces total domestic electricity demand, notably in CA2030 (-10%). This is mainly due to load curtailment by power-to-heat in industry (P2H-i), which in the scenario case with DR switches from electricity to gas for generating industrial heat in hours in which electricity prices are relatively high.

- DR reduces the curtailment of VRE power generation and, hence, increases the supply of electricity from VRE sources (after curtailment), in particular in NM2050 (+8%). As a result, DR reduces the need for fossil-fuel (notably gas-fired) power generation, e.g. in NM2050 by 19%.

- In addition, DR improves the net trade balance (electricity exports minus imports), i.e. by almost 50% in CA2030 and by even more than 300% in NM2050. In CA2030, the relatively large amount of load curtailment leads to, as noted above, a lower domestic electricity demand in a large number of hours, whereas domestic electricity supply remains more or less the same, resulting in both higher electricity exports and lower imports. In NM2050, the relatively large amount of load shifting (from VRE shortage to surplus hours) leads, as noted, to less VRE curtailment and, hence, to more domestic VRE supply (during VRE surplus hours), resulting in, on balance, lower electricity export needs and even far lower import needs (thereby substantially improving the net trade balance).

- More specifically, the large amount of DR (load shifting) in NM2050 results in a lowering of the hourly peaks of electricity trade and, therefore, in a lower need for interconnection capacity in NM2050 (-29%). This implies not only a reduction of foreign dependency on energy security but above all a lowering of investment costs in interconnections and related inland transmission capacity.

Table 47: Summary of major results regarding the impact of demand response (DR) on the electricity balance – and related variables – of the Netherlands in scenario years CA2030 and NM2050 (DR versus NoDR)

		CA2030				NM2050		
	Unit	**NoDR**	**DR**	**Δ%**		**NoDR**	**DR**	**Δ%**
Electricity demand and supply								
Total domestic power demand	TWh	151.1	135.7	-10.2%		351.9	345.7	-1.8%
Total domestic power supply	TWh	179.4	177.7	-0.9%		362.2	388.4	7.2%
VRE supply before curtailment	TWh	100.4	100.4	0.0%		453.7	453.7	0.0%
VRE curtailment	TWh	0.1	0.0	-100%		101.6	73.0	-28.1%
VRE supply after curtailment	TWh	100.3	100.4	0.1%		352.1	380.7	8.1%
Gas-fired power generation	TWh	63.5	61.6	-3.0%		9.1	7.4	-18.7%
Exports	TWh	53.3	61.2	14.8%		200.5	161.7	-19.4%
Imports	TWh	25.0	19.1	-23.6%		190.3	119.0	-37.5%
Net trade	TWh	28.3	42.1	48.8%		10.2	42.7	318%
Interconnection capacity	GW	12.0	12.0	0.0%		46.5	33.2	-28.6%
Weighted average electricity price (per demand category, excluding grid tariffs, taxes, etc.)								
Conventional demand	€/MWh	73.8	54.8	-25.7%		27.2	15.5	-43.0%
P2Hydrogen	€/MWh	68.1	51.8	-24.0%		26.1	7.9	-69.7%
P2Heat (industry)	€/MWh	69.6	33.8	-51.4%		26.2	10.9	-58.2%
P2Heat (households)	€/MWh	85.3	54.2	-36.4%		29.9	19.5	-34.8%
P2Mobility (passenger EVs)	€/MWh	86.3	44.4	-48.6%		33.4	11.8	-64.8%
Total demand	€/MWh	73.0	54.0	-26.0%		27.3	12.0	-56.1%
VRE supply revenues								
Total VRE supply revenues	m€	5404	5003	-7.4%		6421	4188	-34.8%
Average revenue (per MWh)	€/MWh	53.9	49.9	-7.4%		18.2	11.0	-39.7%
Average revenue (per GW installed)	m€/GW	121.4	112.4	-7.4%		36.2	23.6	-34.8%
Total power system costs[a]	m€	1204	644	-46.5%		3241	2706	-16.5%

a) Including investment costs of new (additional) technology capacities installed in a certain scenario but excluding investment costs of baseline capacities as these costs are regarded as 'sunk costs' that are not affected in future scenario years.

- Due to DR, the weighted average electricity price (of the total load) decreases in CA2030 from 73 €/MWh (without DR) to 54 €/MWh (with DR, i.e. -26%). Due to the large (over) supply of electricity from VRE – with relatively low marginal costs – electricity prices are, on average, much lower in NM2050 (than in CA2030), i.e. about 27 €/MWh without DR and12 €/MWh with DR, implying that DR reduces average electricity prices even further in NM2050 by 56%. This indicates that in both scenarios (CA2030 and NM2050) the impact of DR is, on balance, much stronger in substantially decreasing high electricity prices during peak hours than in significantly increasing low electricity prices during off-peak hours.

- For some specific (flexible) end-users, however, the impact of DR on the average electricity price they have to pay is even stronger than the DR impact on the weighted electricity price mentioned above (for all electricity consumers). For instance, for passenger EV users in CA2030 the average electricity price (excluding grid tariffs, taxes, etc.) decreases from 86 €/MWh without DR to 44 €/MWh with DR – i.e., -49% due to DR – whereas in NM2050 the average price decreases from 26 €/MWh to 8 €/MWh, respectively (i.e., -70% due to DR).

- VRE producers, however, suffer from the DR impact on the (average) electricity price they receive In CA2030, the average revenue ('price') per MWh of VRE generation decreases from 54 € without DR to 50 € with DR (-7.4%) while in NM2050 it declines even from 18 € to 11 € (-40%) due to DR.

- In CA2030, the decline in average VRE revenues is largely due to the load curtailment of P2H-i, which results in a 10% decrease in total domestic electricity demand (while the installed VRE capacity – assumed exogenously – remains the same). In NM2050, the (relatively large) DR induced decline in the average electricity price received by VRE producers is likely, to some extent, due to some specific assumptions of this scenario, notably the assumed installed VRE capacity compared to the total domestic electricity demand.[74] In addition, the decline in average revenue per MWh in NM2050 is also partly caused (and compensated) by higher VRE output due to DR induced lower VRE curtailment, resulting in a slightly lower decline (-35%) of both total VRE supply revenues and average revenue per GW installed of VRE capacity.

- An additional, more fundamental explanation why VRE producers do not benefit from DR (in both CA2030 and NM2050) is that – following past and current practices – VRE producers pay hardly or not for the costs of integrating power generation into the power system, such as the costs of expanding the electricity network or balancing the power system by means of flexibility options. As a result, these VRE producers in turn benefit hardly or not from any of the system cost savings owing to demand response.

- In a sensitivity case of NM2050, in which the (assumed) installed VRE capacity is reduced substantially (-41%), the average electricity price received by VRE producers amounts to 12.5 €/MWh, i.e. 14% higher than in NM2050 with DR (11 €/MWh). Compared to NM2050 without DR (18 €/MWh), this price is still significantly lower (-31%) but, due to less DR induced VRE curtailment, the average VRE supply revenues per GW installed – and, hence, the business case of VRE investments – improves slightly (+2%) in the sensitivity case (compared to NM2050 without DR).

- Overall, DR reduces the total power system costs (excluding sunk investment costs of baseline capacities) by 47% in CA2030 and 17% in NM2050. More specifically, higher investments costs of new $P2H_2$ capacity (to operate flexible in the case with DR) are more than compensated by lower investments costs in new interconnection capacity (in NM2050), lower gas-fired generation costs and, on balance, lower electricity import cost and/or higher export revenues.

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[74] See also discussion of Part II below. In a follow-up study this year (2022), we further explore the impact of (flexible) electricity demand – and other factors – on the business case of VRE investments.

Table 48: Summary of major results regarding the impact of demand response (DR) on the mix of options to meet the residual load (RL) in the scenario year CA2030 with and without DR (DR versus NoDR)

		Non-VRE generation	VRE curtailment	Trade[b]	Storage[c]	Demand response[d]	Total residual load
Total annual residual load (RL) met by option (TWh)							
NoDR	Pos. RL[a]	67.1	0.0	-10.4	0.0	0.0	56.6
	Neg. RL[a]	12.0	0.0	-17.8	0.0	0.0	-5.8
	Total RL	79.1	0.0	-28.3	0.0	0.0	50.8
DR	Pos. RL	65.3	0.0	-23.3	0.0	14.6	56.6
	Neg. RL	12.1	0.0	-18.8	0.0	0.9	-5.8
	Total RL	77.4	0.0	-42.1	0.0	15.5	50.8
As share of total annual residual load (%)							
NoDR	Pos. RL	118.4	0.0	-18.4	0.0	0.0	100.0
	Neg. RL	-207.2	0.0	307.2	0.0	0.0	100.0
	Total RL	155.6	0.0	-55.6	0.0	0.0	100.0
DR	Pos. RL	115.2	0.0	-41.0	0.0	25.8	100.0
	Neg. RL	-207.9	0.0	323.6	0.0	-15.8	100.0
	Total RL	152.2	0.0	-82.7	0.0	30.5	100.0
DR induced change in total annual residual load met by option (in TWh)							
DR-NoDR	Pos. RL	-1.8	0.0	-12.8	0.0	14.6	0.0
	Neg. RL	0.0	0.0	-1.0	0.0	0.9	0.0
	Total RL	-1.7	0.0	-13.8	0.0	15.5	0.0

a) 'Pos. RL' refers to the sum of hours with a positive residual load ('VRE shortage') while 'Neg. RL' refers to the sum of hours with a negative residual load ('VRE surplus').
b) A positive sign implies, on balance, net electricity imports while a negative sign refers to net electricity exports;
c) A positive sign implies, on balance, net storage discharges while a negative sign refers to net storage charges (including storage losses). Note that figures in the table refer to total net storage transactions over the number of hours considered and, hence, may include both hours with (significant) storage charges and discharges (even if the net storage aggregated over these hours is – close to – zero). Similar qualifications apply also to the figures of the other options presented in the table.
d) Since DR has been moved to the right (supply) side of the RL equation, it appears with 'opposite signs' in the table, i.e. a positive sign implies downward DR while a negative sign refers to upward DR.

11.1.2 The impact of demand response on the residual load balance

Table 48 summarises the major results regarding the impact of DR on the mix of options to meet the residual load (RL) in the scenario year CA2030, while Table 49 presents similar results for the scenario year NM2050. The major findings and observations from these tables include:

- In CA2030, DR – i.e., primarily load curtailment by P2H-i – reduces the total VRE shortage aggregated over all hours with a positive RL by 14.6 TWh. Consequently, the net trade balance (less electricity imports/more electricity exports) improves by 12.8 TWh while the power generation from non-VRE sources (notably gas) declines by 1.8 TWh.

- On the other hand, DR (load curtailment) *enhances* the total VRE surplus aggregated over all hours with a negative RL in CA2030 by 0.9 TWh, resulting in a further improvement of the net trade balance by more or less the same amount.

- Overall, DR in CA2030 reduces total (positive + negative) RL by 15.5 TWh, resulting in an improvement of the net trade balance (13.8 TWh) and a reduction of non-VRE generation (1.7 TWh).

Table 49: Summary of major results regarding the impact of demand response (DR) on the mix of options to meet the residual load (RL) in the scenario year NM2050 with and without DR (DR versus NoDR)

		Non-VRE generation	VRE curtailment	Trade[b]	Storage[c]	Demand response[d]	Total residual load
Total annual residual load (RL) met by option (TWh)							
NoDR	Pos. RL[a]	5.3	-0.7	58.1	2.8	0.0	65.5
	Neg. RL[a]	4.7	-100.8	-68.3	-6.5	0.0	-170.9
	Total RL	10.0	-101.5	-10.2	-3.7	0.0	-105.4
DR	Pos. RL	3.4	-0.2	30.5	0.9	30.9	65.5
	Neg. RL	4.2	-72.7	-73.3	-0.9	-28.3	-170.9
	Total RL	7.6	-72.9	-42.7	0.0	2.6	-105.4
As share of total annual residual load (%)							
	Pos. RL	8.1	-1.1	88.6	4.3	0.0	100.0
	Neg. RL	-2.8	59.0	40.0	3.8	0.0	100.0
	Total RL	-9.5	96.3	9.7	3.5	0.0	100.0
	Pos. RL	5.3	-0.4	47.2	1.4	47.2	100.0
	Neg. RL	-2.5	42.8	43.1	0.5	16.5	100.0
	Total RL	-7.2	69.2	40.6	0.0	-2.5	100.0
DR induced change in total annual residual load met by option (in TWh)							
DR-NoDR	Pos. RL	-1.9	0.5	-27.5	-1.9	30.9	0.0
	Neg. RL	-0.5	28.1	-4.9	5.6	-28.3	0.0
	Total RL	-2.4	28.6	-32.5	3.7	2.6	0.0

a) – d): See notes below Table 48.

- In NM2050, DR – primarily upward load shifting – reduces the total VRE shortage aggregated over all hours with a positive RL by 31 TWh. As a result, the net trade balance (less electricity imports) improves by 27 TWh, non-VRE generation declines by 2 TWh while net storage discharges decrease also by 2 TWh.

- On the other hand, DR – primarily downward load shifting – reduces the total VRE surplus over all hours with a negative RL in NM2050 by 28 TWh. As a result, VRE curtailment is reduced by a similar amount (28 TWh). Simultaneously, however, net storage charges (including storage losses) are reduced by almost 6 TWh, resulting in more exports (5 TWh) and a lower need for non-VRE generation (1 TWh).

- Overall, i.e. over all (positive and negative) hours of NM2050, DR results in, on balance, less VRE curtailment (29 TWh), an improved trade balance for the Netherlands (33 TWh), less non-VRE generation (2 TWh) and less storage needs, including less storage losses (4 TWh).

11.1.3 *The impact of demand response on the flexibility balance*

Table 50 summarises the major results regarding the impact of DR on the mix of supply options to meet the total annual demand for flexibility in CA2030 and NM2050 (including, for comparative reasons, the reference scenario R2015), whereas Figure 43 presents similar results on the *average* hourly demand for flexibility in these scenario years.

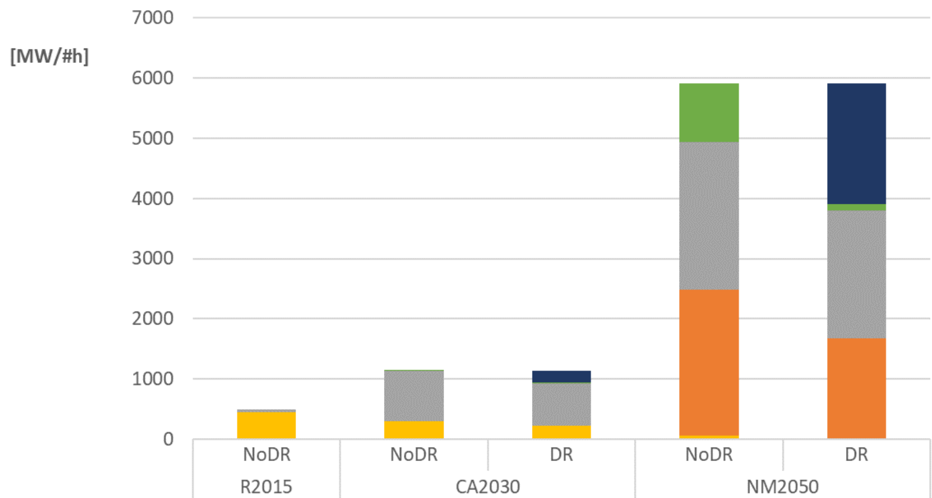
Table 50 shows that the total annual demand for (upward and downward) flexibility rises from 4.4 TWh in R2015 to 9.9 TWh in CA2030, i.e. an increase by some 125%. In NM2050, however, this demand for flexibility grows even harder to almost 52 TWh, i.e. an increase by about 420% compared to CA2030 and by approximately a factor 12 compared to R2015.

Table 50: Summary of major results regarding the impact of demand response (DR) on the mix of options to meet the total annual demand for flexibility in the scenario years CA2030 and NM2050 with and without DR (DR versus NoDR), including the reference scenario year 2015 (R2015)

		Non-VRE generation	VRE curtailment	Trade	Storage	Demand response	Total flex demand/ supply
Total annual supply of (upward and downward) flexibility by option (TWh)							
R2015	NoDR	4.00	0.00	0.40	0.00	0.00	4.40
CA2030	NoDR	2.62	0.06	7.25	0.00	0.00	9.93
	DR	1.92	0.04	6.24	0.10	1.63	9.93
NM2050	NoDR	0.56	21.24	21.43	8.54	0.00	51.76
	DR	0.06	14.57	18.67	0.92	17.54	51.76
As share of total flex supply (%)							
R2015	NoDR	90.9	0.0	9.1	0.0	0.0	100
CA2030	NoDR	26.4	0.6	73.0	0.0	0.0	100
	DR	19.4	0.4	62.8	1.0	16.4	100
NM2050	NoDR	1.1	41.0	41.4	16.5	0.0	100
	DR	0.1	28.1	36.1	1.8	33.9	100
DR induced change in total annual supply of flexibility (in TWh)							
CA2030	DR-NoDR	-0.70	-0.02	-1.01	0.10	1.63	0.0
NM2050	DR-NoDR	-0.49	-6.67	-2.76	-7.62	17.54	0.0

In addition, Table 50 shows that the total annual supply of flexibility by DR amounts to 1.6 TWh in CA2030 and increases more than tenfold to 17.5 TWh in NM2050, while Figure 43 illustrates that the *average* hourly supply of flexibility by DR increases similarly from 186 MW/#h in CA2030 to 2000 MWh in NM2050. As a share of the total annual flexibility demand in these scenario years (without DR), this implies that in CA2030 about one-sixth (16%) of this demand is met (or, actually, 'reduced') by means of flexibility offered by DR while in NM2050 this share rises to more than one-third (34%).

In CA2030, the total annual supply of flexibility by DR implies that less flexibility is needed from other sources, notably from trade (-1 TWh) and non-VRE generation (-0.7 TWh), while in NM2050 less flexibility is needed from particularly storage (-7.6 TWh), VRE curtailment (-6.7 TWh) and trade (-2.8 TWh; see Table 50).



	R2015 NoDR	CA2030 NoDR	CA2030 DR	NM2050 NoDR	NM2050 DR
Demand response	0	0	186	0	2002
Storage	0	0	12	975	105
Trade	46	827	712	2446	2131
VRE curtailment	0	6	4	2425	1663
Non-VRE generation	457	299	220	64	7

Figure 43: Mix of supply options to meet the average hourly demand for flexibility in R2015, CA2030 and NM2050 with and without demand response (DR versus NoDR)

11.2 Discussion

The scenario results on the impact of DR on the power system of the Netherlands in the coming decades (2030-2050) do not only depend on the potential (size) of DR in these decades (as discussed in part I of this study) but also on the key assumptions of the respective scenarios. This applies in particular for scenario NM2050 (which includes more long-term uncertainties and bold assumptions than scenario CA2030).

The assumptions and parameters used for the ('extreme') scenario NM2050 result, among others, in a relatively high ('suboptimal') installed capacity/supply of VRE power generation versus a relatively low electricity demand. In turn, this results in a relatively large number of hours with a relatively large surplus of VRE power generation (compared to electricity demand), relatively large (net) exports of electricity, relatively large volumes of VRE curtailment, and a relatively large number of hours with low electricity prices.

It is hard to say whether and, in particular, to which extent the assumptions of the NM2050 scenario affect the results regarding the impact of DR in this scenario. In general, the direction and size (‘order of magnitude’) of this impact seems to be in line with the impact of DR in CA2030 (which has less long-term uncertainties and less ‘bold’ assumptions), accounting with the difference in the potential (size) of DR in these scenario years.

Moreover, it should be noted that the assumptions of the (uncertain, extreme) scenario NM2050 apply not only for the case with DR but also for the case without DR. Hence, by comparing the scenario results between the cases with and without DR some useful insights are obtained in the size and direction of the impact of DR within the scope and limits of the scenario (as within the scope and limits of any other long-term scenario).

Finally, it should be remarked that comparing the results of the NM2050 cases with and without DR does not only offer useful insights into the potential impact of DR (i.e., what can be achieved by means of DR) but also on the limitations of DR (i.e., what is hardly or not able to be achieved by DR). For instance, the NM2050 scenario results show that DR is able to reduce VRE curtailment from 102 TWh in the case without DR to 73 TWh with DR, i.e. a reduction by 29 TWh (-28%). Despite this significant reduction of VRE curtailment, a large amount of VRE curtailment is still left (73 TWh), which DR is not able to address.

Another interesting (related) example of the scope and limitation of DR refers to its impact on electricity prices. The COMPETES results for NM2050 show that over some 2400 hours electricity prices are substantially lower in the case with DR (compared to the relatively high electricity prices in the case without DR), whereas during some 1200 hours they are significantly higher (compared to the relatively low electricity prices in the case without DR). Over the remaining 5200 hours, however, DR has hardly or no impact as electricity prices are highly similar in the cases with and without DR, notably during some 4000 hours in which the electricity price is set at the low level of 2 €/MWh (by the marginal VRE unit). As noted, these are generally hours in which there is still a VRE surplus despite the deployment of DR and other flexible options such as VRE curtailment or cross-border trade (exports).

More generally, the two related examples outlined above show that DR, to some extent, is able to improve (‘optimise’) the performance of the power system (as indicated by the DR induced reduction of the total system costs). However, if there is a fundamental mismatch between, e.g., the assumed (exogenously determined) capacity of VRE power generation and the demand for electricity, DR is only partially – but not fully – able to correct this mismatch (and, hence, a sub-optimal situation – from a social cost perspective – will continue). Therefore, in order to move towards a more optimal social outcome with regard to the (future, climate-neutral) power system, an appropriate match between installed VRE generation capacity and electricity demand has to set initially (which can be further optimised by means of flexible options such as DR).

11.3 Key messages

A major message of part II of the study is that DR offers a variety of beneficial impacts to the power system – and society at large – such as (i) less dependency on foreign trade for system security and flexibility, (ii) less need for (expensive) interconnection capacity, (iii) less need for (expensive) storage transactions, (iv) less need for curtailment of electricity generation from sun and wind, (v) less need for power generation from (more expensive/more polluting) other – i.e., non-VRE – sources, (vi) lower average electricity prices, notably for flexible end-users, and – as a result – (vii) lower total power system costs.

On the other hand, although VRE producers may benefit from (DR induced) less curtailment of power generation from VRE sources, they may suffer from DR induced lower average electricity prices. To some extent, the balance of these two contrasting impacts of DR on the total generation revenues of VRE producers – and, hence, on the business case of market-based VRE investments – depends on the relationship (‘match’) between total electricity demand and the supply of electricity from VRE sources. DR can improve (further optimise) this relationship to some extent – and, hence, the business case of merchant VRE investments – notably during hours with a VRE surplus by reducing VRE curtailment and/or raising electricity prices during these hours. However, if there is a fundamental ‘mismatch’ between electricity demand and VRE supply – in particular a large VRE surplus during a large number of hours, resulting in a poor business case for VRE investments – DR is not able to correct this mismatch in an adequate, sufficient way.

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A Additional tables and figures

Table 51: 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 8, and Section 3.1, Figure 14). 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 52: 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 9 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 51) with regard to the electricity demand in the alternative scenario for 2050 (A2050) of the FLEXNET project (Sijm et al, 2017a and 2017b).

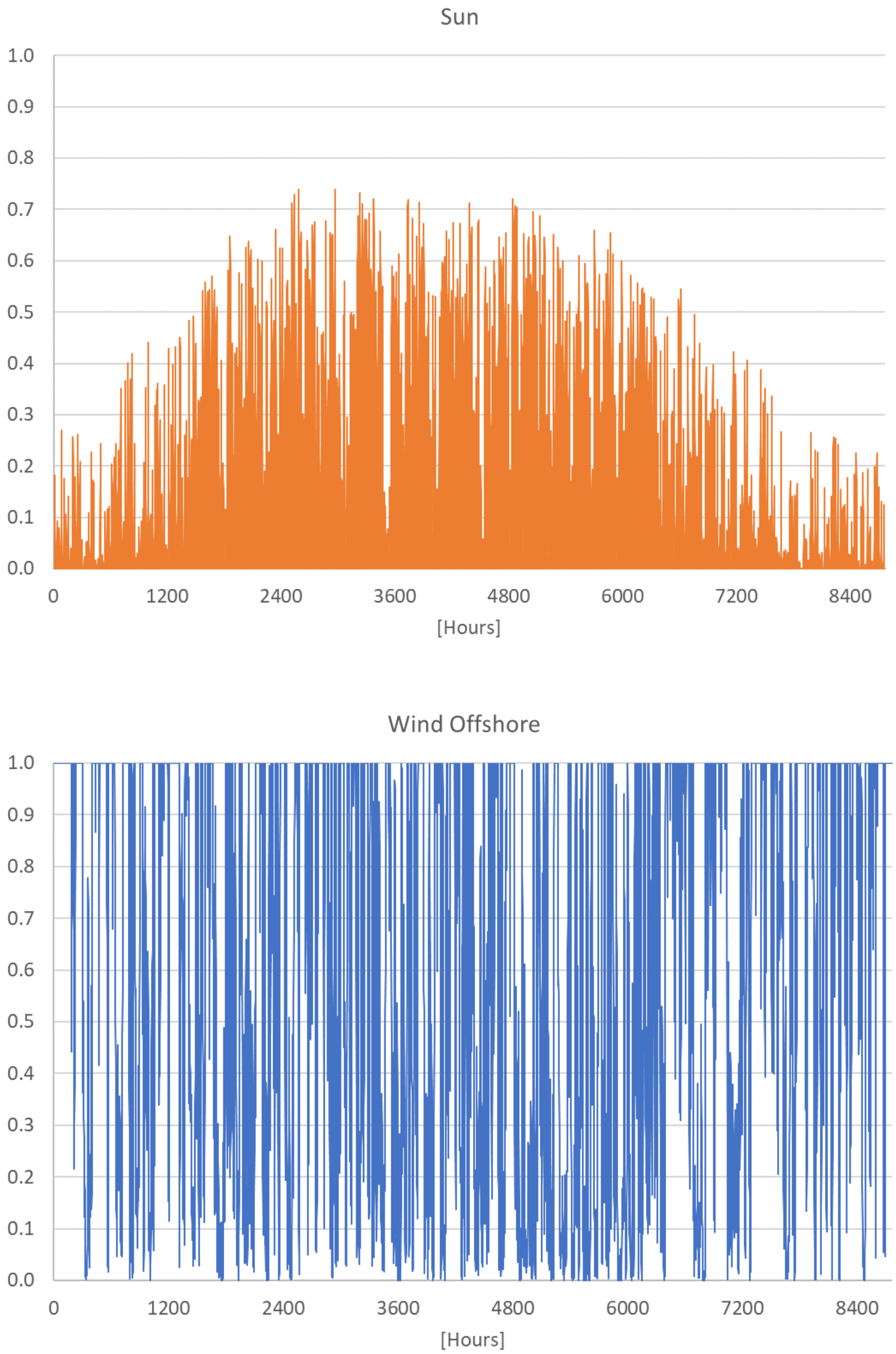

Figure 44: COMPETES and OPERA: Hourly profiles of the capacity factor for sun PV and offshore wind during the whole year 2050 (8760 hours)