The demand for flexibility of the power system in the Netherlands, 2015-2050

Report of phase 1 of the FLEXNET project

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Acknowledgement

The overall objective of the FLEXNET project was to analyse demand and supply of flexibility in the power system of the Netherlands up to 2050 at both the national and regional level.[1] The project was commissioned and funded by the Top Sector Energy (TSE) under the tender programme System Integration (NL Ministry of Economic Affairs/RVO.nl; reference number TES0114010).

FLEXNET was carried out by a consortium consisting of the Energy research Centre of the Netherlands (ECN) and several members of Netbeheer Nederland – i.e. the Dutch branch organisation of energy network operators – in particular Alliander, Enexis, Stedin, TenneT and Gasunie Transport Services (GTS). In addition, the consortium included two other partners (GasTerra and Energie-Nederland) who were involved as co-funders of the project.

Over the lifetime of FLEXNET (March 2015 – August 2017), the project was supervised by a Steering Committee consisting of the following members: Eppe Luken (ECN, chair), Frans Nillesen (RVO.nl), Erik van der Hoofd (TenneT/Netbeheer Nederland), Erik ten Elshof (NL Ministry of Economic Affairs), Tjitske Brand (GasTerra) and Walter Ruijgrok (Energie-Nederland).

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The FLEXNET project consisted of three phases, each addressing a specific main question:

- *Phase 1 ('The demand for flexibility')*: what are the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050?
- *Phase 2 ('The supply of flexibility')*: which mix of robust flexibility options can meet the predicted flexibility needs in a socially optimal way?
- *Phase 3 ('Societal framework to trade-off grid reinforcement and deployment of flexibility')*: in which situations is deployment of flexibility a more attractive option than grid reinforcement to overcome predicted overloads of the power network?

[1] FLEXNET is an abbreviation that stands for "**FLEX**ibility of the power sector in the **NET**herlands".

The current report presents the methodology and major outcomes of the first phase of the project. It is based on contributions delivered primarily by the following persons (and institutions): Jos Sijm (ECN), Jeroen de Joode (ex-ECN, now ACM), Pieter Gockel (Alliander), Michiel Musterd (Alliander) and Werner van Westering (Alliander). In addition, the hourly demand profiles for the power load of heat pumps were designed by Robert de Smidt of the ECN unit Energy Efficiency. The information for the comparative analysis in Section 5.5 of the report was delivered basically by Stedin (with thanks to Jan Pellis). Finally, Section 5.6 and Appendix D were based on work conducted by TenneT (with thanks to Gerda de Jong).

At ECN, FLEXNET is administered under project number 5.3626. For further information, you can contact the project leader: Jos Sijm (sijm@ecn.nl; tel.: +31 6 1048 4843).

Abstract

The report presents the methodology and major results of the first phase of the FLEXNET project. This phase is focussed on identifying and analysing the flexibility needs of a sustainable and reliable power sector in the Netherlands up to 2050. The report distinguishes and analyses two main drivers of the demand for flexibility, i.e. (i) the increase and changing profiles of power demand, notably due to the increase of electric vehicles, heat pumps and other, additional means of electrification, and (ii) the increase in power generation from variable renewable energy (VRE), in particular sun and wind. More specifically, the report identifies and analyses three sources ('causes') of the demand for flexibility, i.e. flexibility needs due to (i) *the variability of the residual load* (defined as total power demand minus VRE generation), (ii) *the uncertainty of the residual load* (notably the lower predictability of VRE power output), and (iii) *the congestion of the grid* (in particular at the Liander distribution network level). The report concludes that from each perspective flexibility needs of the Dutch power system increase substantially over the coming decades, in particular over the years 2030-2050.

Contents

Appendices

Summary

Introduction and background

The Netherlands is aiming at a more sustainable, low-carbon energy system. For the power system this implies (i) a larger share of electricity from variable renewable energy (VRE), in particular from sun and wind, (ii) a larger share of electricity in total energy use, i.e. a higher rate of 'electrification' of the energy system, and – as a result of these two trends – (iii) a higher need for flexibility and system integration.

Against this background, the overall objective of the FLEXNET project was to analyse demand and supply of flexibility of the power system in the Netherlands up to 2050 at the national and regional level. More specifically, the FLEXNET project consisted of three phases, each addressing a particular main question:

- *Phase 1 ('The demand for flexibility')*: what are the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050?
- *Phase 2 ('The supply of flexibility')*: which mix of robust flexibility options can meet the predicted flexibility needs in a societal optimal way?
- *Phase 3 ('Societal framework to trade-off grid reinforcement and deployment of flexibility')*: in which situations is deployment of flexibility a more attractive option than grid reinforcement to overcome predicted overloads of the power network?

The current report outlines the approach and major results of the first phase of the FLEXNET project. This phase has been conducted at two levels: (i) the national level, i.e. for the power sector in the Netherlands as a whole, and (ii) the regional level, i.e. at the regional power distribution grid level of the Liander service area in the Netherlands.

More specifically, the central questions of the first phase of the FLEXNET project regarding these two levels include:

- What are the main drivers (determinants) of the demand for flexibility of the power sector in the Netherlands, and how will this demand develop quantitatively in some scenario cases over the period 2015-2050?
- What are the implications of these scenario cases – in particular of the assumed adoption rates of the emerging power sector technologies (electric vehicles, heat pumps, sun PV, wind energy) – for the load profiles of the regional Liander power distribution network?

A summary of the approach and major results at both the national and regional level is provided below.

Approach

Definition of flexibility

In the FLEXNET project, flexibility is defined briefly 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*." 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. total power load minus power production from variable renewable energy (VRE), notably from sun and wind.

Three sources ('causes') of the demand for flexibility

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 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 increase in electric vehicles, heat pumps, etc. – 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 mentioned above, although it was predominantly focussed on modelling and analysing the first and third type of flexibility and hardly on the second type, i.e. the demand for flexibility due to the uncertainty of the residual load.

Scenarios: focal years and major characteristics

In order to analyse quantitatively the demand for flexibility by the Dutch power sector over the period 2015-2050, we have developed two scenarios:

- *The Reference scenario*. This scenario is based on the '*accepted policy scenario*' of the '*National Energy Outlook 2015*' (ECN et al., 2015). Its major characteristics are: (i) a strong growth of installed VRE capacity in the power sector up to 2030, and (ii) a weak growth of additional electrification of the energy system as a whole. This scenario includes three focal years, labelled as 'R2015', 'R2023' and 'R2030' (where the letter R refers to the Reference scenario);
- *The Alternative scenario*. This scenario is similar to the reference scenario with one major exception, i.e. it assumes a strong growth of additional electrification of the Dutch energy system by means of electric vehicles (EVs), heating pumps (HPs), and other means of electrification of the energy system in households, services, transport, industry, etc. This scenario includes also three focal years, labelled as 'A2023', 'A2030' and 'A2050' (where the letter A refers to the Alternative scenario).

Table 1 provides a summary of the major assumptions and input variables of the FLEXNET scenario cases over the period 2015-2050. For each scenario, annual electricity demand and VRE power supply profiles have been developed on an hourly basis for four demand variables (conventional load, EVs, HPs and additional load for other means of electrification) and three VRE supply variables (wind on land, wind on sea and sun PV). Based on these profiles, the hourly variations in the residual power load have been determined in order to derive the resulting demand for flexibility by the power sector (at the national level) and the implications for the load of the Liander grid network (at the regional level).

Table 1: Major assumptions and input values of all scenario cases, 2015-2050

		Reference scenario			Alternative scenario		
	Unit	2015	2023	2030	2023	2030	2050
Electrification							
Share of EVs in total passenger cars	[%]	2.0%	4.7%	9.6%	12.0%	32.0%	74.0%
Share of HPs in total households	[%]	2.1%	6.5%	7.9%	8.0%	20.0%	69.0%
Conventional load	[TWh]	111.8	111.6	112.2	111.6	112.2	112.0
Additional load EVs	[TWh]	0.5	1.2	2.5	3.0	8.4	21.5
Additional load HPs	[TWh]	0.2	0.8	0.9	0.9	2.5	9.3
Add. load 'Other electrification'	[TWh]	0.0	0.0	0.0	10.0	30.0	90.0
Total final load	[TWh]	112.5	113.5	115.6	125.5	153.1	232.8
Power from variable renewable energy (VRE) sources							
Installed capacity:							
• Wind on land	[MWe]	2,630	6,020	6,330	6,020	6,330	6,800
• Wind on sea	[MWe]	360	4,120	6,060	4,120	6,060	28,900
• Sun PV	[MWe]	1,530	8,640	15,130	8,640	15,130	56,100
• Total VRE power capacity	[MWe]	4,520	18,780	27,520	18,780	27,520	91,800
Full load hours:							
• Wind on land	[hrs]	2310	2670	2860	2670	2860	2900
• Wind on sea	[hrs]	3580	4080	4120	4080	4120	4160
• Sun PV	[hrs]	840	820	820	820	820	820
VRE power generation (uncurtailed):[a]							
• Wind on land	[TWh]	6.1	16.1	18.1	16.1	18.1	19.7
• Wind on sea	[TWh]	1.3	16.8	25.0	16.8	25.0	120.2
• Sun PV	[TWh]	1.3	7.1	12.4	7.1	12.4	46.0
• Total VRE output	[TWh]	8.6	40.0	55.5	40.0	55.5	185.9
Total VRE output (uncurtailed) as share of total final power load:	[%]	8	35	48	32	36	80

a) *Uncurtailed* power generation refers to VRE output *before* any curtailment of electricity production from sun/wind takes place, based on installed capacity and full load hours, whereas *curtailed* power generation refers to VRE output *after* any curtailment of electricity production from sun/wind.

Major results at the national level

1. The demand for flexibility due to the variability of the residual power load

1.1 Trends in residual power load

Developing hourly electricity demand and VRE power supply profiles for each scenario case and, subsequently, analysing trends and changes in the (residual) power load of the Dutch electricity system over the years 2015-2050 has resulted in some major findings, including:

- *Total (hourly) power load* increases substantially between 2015 and 2050 and becomes much more volatile, mainly due to the additional electrification of the energy system through the increase in electric vehicles (EVs), heat pumps (HPs) and other means of electrification such as power-to-gas (P2G), power-to-heat (P2H), power-to-ammonia (P2A) or power-to-other-products (P2X).

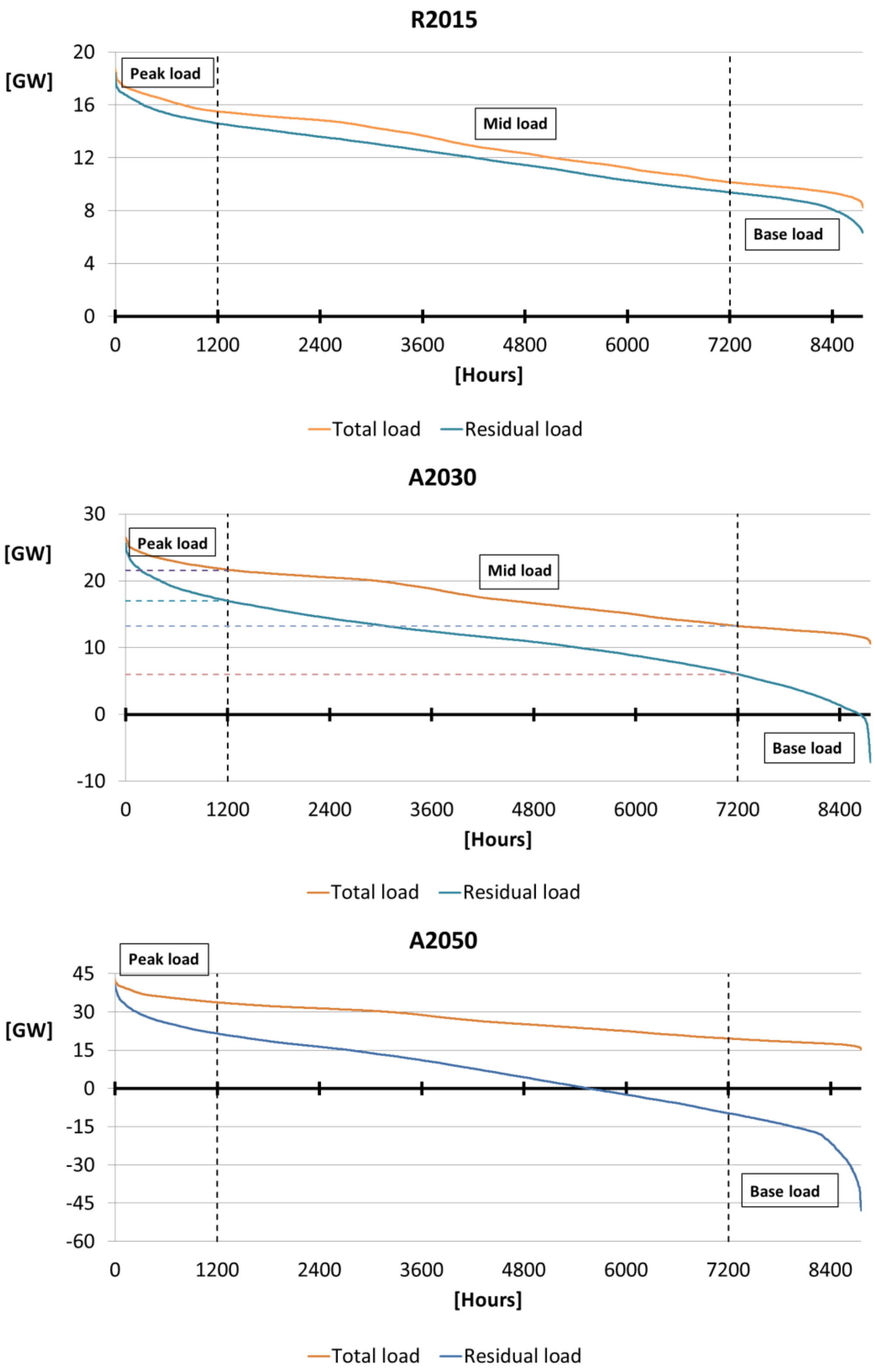
- *Power output from VRE sources (sun/wind)* increases substantially between 2015 and 2050. Hourly VRE output, however, is very volatile and fluctuates heavily over each period considered (day, week, month, etc.). Moreover, even in A2050, with a large share of VRE output in total annual power load (80%), there is still a large number of hours (1600-2600) in which VRE output is relatively low, covering only a small part of power demand (10-20%; see **Figure 1**). This implies that during these hours power demand has to be met largely (80-90%) by other supply sources besides VRE output, including other means of power generation (gas, coal, nuclear) or by flexibility options such as power imports, demand response or using electricity stored during other, surplus hours.

- As a result of the two trends mentioned above, *hourly residual power load* becomes much more volatile (variable) over time. In A2050, it varies even between *minus* 48 GW (i.e., actually, a large *VRE surplus*) and *plus* 41 GW (a large *VRE shortage*), compared to plus 6 GW and 18 GW in R2015, respectively (see **Figure 1**).

- A growing share of power production from sun and wind leads, hence, to a growing variability and an increase in extreme values of residual load, implying a higher need for flexibility to deal with these VRE-induced characteristics of the residual load.

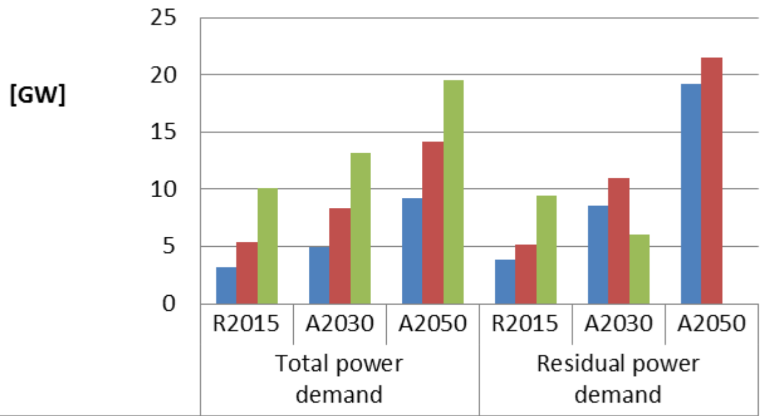
- More specifically, due to the increase in power supply from VRE sources, the need for residual *peak* load capacity increases substantially over time, whereas the need for residual *base* load capacity decreases significantly (and even becomes zero in A2050; see **Figure 1** and **Figure 2**). Peak load capacity, however, has to be rather flexible as it covers less than 1200 hours per annum spread throughout the year. Notably, the number of peak hours with relatively high levels of residual load is relatively small in A2050 (and A2030), i.e. it is usually even much smaller than 1200 hours (see left side of **Figure 1**). Therefore, capacity investments in (flexible) power generation – or other (flexible) power supply options – to meet these high residual load levels have to be recovered in a relatively small number of running hours.

Figure 1: Duration curves of total load and residual load in three scenario cases



Note: for visibility reasons, the scale of the Y-axis differs between the three pictures. As a result, the slope of the residual load duration curve is actually much steeper in A2050 – compared to R2015 – than suggested in the figure. Moreover, the difference between the total load and residual load duration curves is actually much wider in A2050 – compared to R2015 – than suggested in the figure.

Figure 2: Capacity needs to meet power demand in different load periods in three scenario cases



	Total power demand			Residual power demand		
	R2015	A2030	A2050	R2015	A2030	A2050
Peak load (<1200 hours)	3.2	4.9	9.2	3.8	8.6	19.2
Mid load (1200-7200 h.)	5.4	8.4	14.2	5.2	11.0	21.5
Base load (>7200 hours)	10.1	13.2	19.5	9.4	6.0	0.0

- As the share of VRE generation in total load increases significantly over the period 2015-2050, both (i) the number of hours with a VRE surplus (i.e. a 'negative residual load'), (ii) the maximum hourly VRE surplus, (iii) the total hourly VRE surplus per annum, and (iv) the maximum number of consecutive VRE surplus hours tend to increase as well (see **Table 2**). For instance, while the VRE share in total load increases from 8% in R2015 to 80% in A2050, the number of VRE surplus hours increases from zero to more than 3200, whereas the total hourly VRE surplus rises from zero to approximately 35 TWh over this period. This raises both new challenges and opportunities in terms of flexibility demand and supply in the power system. For instance, the incidence and alternation of (large) hourly VRE shortages versus (large) VRE surpluses enhances the issue how to deal with these fluctuations in residual load (and the related fluctuations in hourly electricity prices). On the other hand, these fluctuations create also opportunities in terms of energy storage and demand response.

1.2 Trends in hourly variations of residual load and resulting flexibility needs

Hourly load variations ('*ramps*') are defined as the difference between load in hour *t* and load in hour *t-1* (with t = 1,…..n). These variations can be either positive ('ramp-up') or negative ('ramp-down'). Ramp-ups and ramp-downs are major indicators of the flexibility ('ramping') needs of the power sector due to the variation of the (residual) power load. Calculating and analysing hourly load variations in the Dutch power system over the period 2015-2050 has resulted in the following major findings:

- The hourly variations of the *total power load* – including load for EVs, HPs and other means of additional electrification – are generally larger than the hourly variations of the *conventional load* whereas, in turn, the hourly variations of the *residual load* – due to the additional, strong variability of VRE output – are usually (significantly) larger than the hourly variations of *total load* (see **Figure 3**).

Table 2: Summary data on residual load, VRE shortages and VRE surpluses in all scenario cases, 2015-2050

		Reference scenario			Alternative scenario		
	Unit	2015	2023	2030	2023	2030	2050
Total power load	TWh	112.5	113.5	115.6	125.5	153.1	232.8
Total VRE output	TWh	8.6	40.0	55.5	40.0	55.5	186.0
Total residual load	TWh	103.8	73.6	60.2	85.6	97.6	46.8
VRE share in total load	%	8%	35%	48%	32%	36%	80%
Hours with a positive residual load ('VRE shortage')							
Total number of VRE shortage hours (p.a.)	Hrs	8760	8615	7887	8731	8640	5543
Maximum hourly VRE shortage	GW	18.4	17.9	18.4	20.1	25.6	40.7
Total hourly VRE shortage (p.a.)	TWh	103.8	73.7	62.0	85.6	97.8	81.9
Hours with a negative residual load ('VRE surplus')							
Total number of VRE surplus hours (p.a.)	Hrs	0	145	873	29	120	3217
Maximum number of consecutive VRE surplus hours	Hrs	0	10	21	8	10	61
Maximum hourly VRE surplus	GW	0	4.7	10.6	3.6	7.2	47.9
Total hourly VRE surplus (p.a.)	TWh	0	0.1	1.8	0.0	0.2	35.1

- The hourly variations of total load and, particularly, of the residual load increase substantially between R2015 and A2050 due to the increase in total load and, notably, the increase in total VRE output over this period. This implies that the need for hourly ramping (flexibility) increases significantly over time (as indicated below).

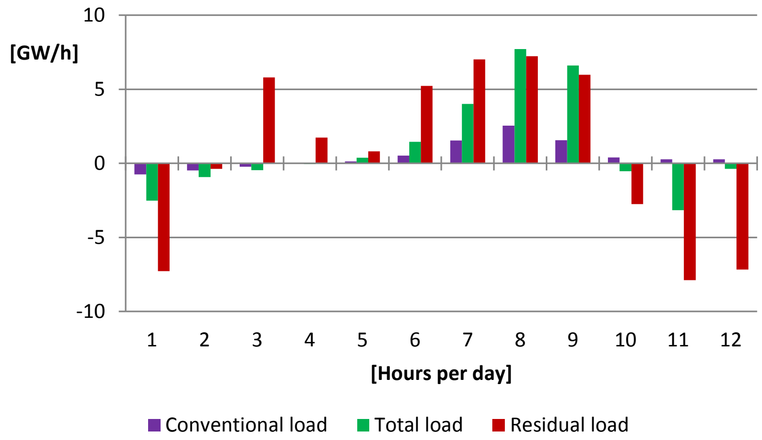
- Ramping needs alternate regularly between hours of upwards versus downward ramping. Occasionally, however, ramping needs may move in the same direction – either upwards or downwards – during several consecutive hours (**Figure 3**). Therefore, the (maximum) cumulative need for either ramping-up or ramping-down of the power system during these consecutive hours is larger than the (maximum) ramping need during a single hour.

Indicators and trends of ramping needs

Table 3 provides a summary overview of the demand for flexibility by the Dutch power sector due to the hourly variation of the residual load in the FLEXNET scenario cases over the years 2015-2050. The table distinguishes between three indicators for this type of the demand for flexibility:

- *Maximum hourly ramp*, in both directions (upwards and downwards), i.e. the maximum hourly variation in residual load over a year, expressed in capacity terms per hour (GW/h);
- *Maximum cumulative ramp,* in both directions (upwards and downwards), i.e. the maximum variation in residual load – either upwards or downwards – during some consecutive hours in a year, expressed in capacity terms per number of consecutive hours (GW/#h);

Figure 3: Illustration of hourly variations ('ramps') of conventional load, total load and residual load during the first 12 hours of the first day (Monday) of week 4 in A2050



- *Total hourly ramps,* in both directions (upwards and downwards), i.e. the total annual amount of hourly ramps – either up or down – aggregated over a year, expressed in energy terms per annum (TWh).

Table 3 shows that, for each of the indicators considered, the demand for flexibility due to the variation in residual load increases substantially over time, notably between 2030 and 2050. For instance, total hourly ramps (either upwards or downwards) increase from 2.2 TWh in R2015 to 5.5 TWh in A2030 (+150%) and to more than 15 TWh in 2050 (+580%; see also **Figure 4**).

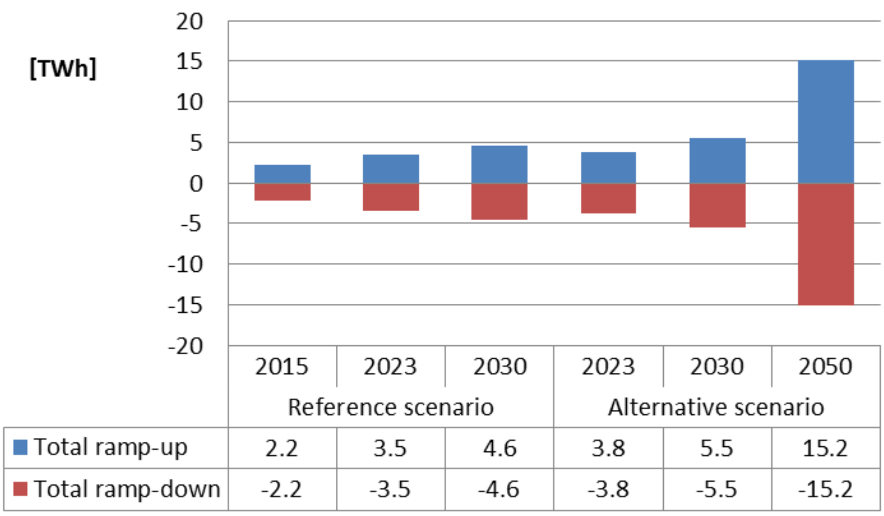
Major drivers (determinants) of the demand for hourly ramping
A comparative analysis of the flexibility ('ramping') needs for different constituent components of the residual load (conventional load, additional load, VRE power generation) shows that the demand for flexibility due to the hourly variation in residual load is (i) higher for total load than for conventional load, largely due to the hourly variations in the additional load for passenger EVs rather than in additional load for household HPs or other means of electrification, and (ii) higher for residual load than for total load, mainly due to the hourly variations in VRE output from wind (on sea), rather than from sun PV.

Additional *sensitivity analyses* show, among others, that if the volume of the respective scenario input variables is changed by the same amount (i.e., by +8 TWh), the resulting change in the required *maximum hourly capacity for ramp-up (or ramp-down)* is relatively lowest – varying from -1.7% to +1.4% – for conventional load, EV load and HP load, while it is relatively highest – ranging between 14% and 23% - for wind on land and wind on sea. For sun PV, the resulting change in the required maximum hourly capacity to meet the demand for flexibility amounts to +0.7 GW (+8%) for ramping up and zero for ramping down. On the other hand, the resulting change in the *total annual demand for flexibility (either upward or downward)* is relatively highest for sun PV (+23%) and EV (+16%) and relatively lowest for conventional load (+2%) and HP (+5%), with a middle position for wind on land and wind on sea (both approximately +7%).

Table 3: Summary overview of the demand for flexibility due to hourly variations in residual load ('ramps') in all scenario cases, 2015-2050

	Reference scenario			Alternative scenario		
	2015	**2023**	**2030**	**2023**	**2030**	**2050**
Demand for flexibility						
Maximum hourly ramp-up (in GW/h)	3.0	6.3	8.5	6.2	8.2	29.6
Maximum hourly ramp-down (in GW/h)	3.1	8.6	10.2	8.7	10.4	28.6
Maximum cumulative ramp-up (in GW/#h)	9.7	16.4	20.7	17.7	20.6	66.2
• *Number of consecutive ramp-up hours*	*14*	*14*	*9*	*14*	*9*	*10*
Maximum cumulative ramp-down (in GW/#h)	10.3	16.8	21.7	16.8	22.2	65.0
• *Number of consecutive ramp-down hours*	*10*	*17*	*17*	*19*	*17*	*17*
Total hourly ramp-up (p.a.; in TWh)	2.2	3.5	4.6	3.8	5.5	15.2
Total hourly ramp-down (p.a.; in TWh)	2.2	3.5	4.6	3.8	5.5	15.2
Change in demand for flexibility (in %, compared to 2015)						
Maximum hourly ramp-up (in %)		108	183	105	174	884
Maximum hourly ramp-down (in %)		181	232	184	240	836
Maximum cumulative ramp-up (in %)		69	113	82	112	581
Maximum cumulative ramp-down (in %)		63	110	63	116	530
Total hourly ramp-up (p.a.; in %)		57	106	70	148	582
Total hourly ramp-down (p.a.; in %)		57	106	70	148	582

Figure 4: Need for total annual hourly ramps ('flexibility') in all scenario cases, 2015-2050



Based on these comparative and sensitivity analyses, the major conclusions regarding the main drivers of the demand for flexibility include:

- The main driver of the demand for flexibility is the increase in electricity production from VRE power sources, in particular from wind (on sea) and – to a lesser extent – from sun PV.
- Another, less important driver – at least in a direct sense – is the increase in the additional load due to the further electrification of the energy system.
- In an indirect sense, however, the increase in electrification is an important driver of the demand for flexibility if it is assumed that the resulting additional load is largely met by electricity from VRE power sources.

Flexibility needs in extreme situations

In addition to the 'normal' ('representative') situations discussed above, we have also analysed briefly the implications of two 'extreme' situations – i.e. a long cold winter and a long hot summer – for the flexibility needs of the Dutch power system in A2030 and A2050. The results show, among others, that in terms of maximum hourly ramps, the need for flexibility increases by almost 5% in the extreme cold case of A2050, whereas it decreases by 17% in the extreme hot case. In terms of the other two indicators defined above – i.e. maximum cumulative ramps and total hourly ramps – the difference in the demand for flexibility in extreme situations is, however, much smaller (i.e. <3%).

2. The demand for flexibility due to the uncertainty of the residual power load

Table 4 presents estimates of the demand for flexibility on the intraday/balancing market due to the uncertainty of the residual power load, in particular due to the forecast error of wind generation in the FLEXNET scenario cases up to 2050. It shows, for instance, that due to the wind forecast error over this period the maximum need for hourly ramp-up increases from 1.1 GW in R2015 to almost 14 GW in A2050, while the total annual demand for ramp-down rises from 0.4 TWh to 5.3 TWh, respectively.

Table 4: Demand for flexibility on the intraday/balancing market due to the forecast error of wind generation in all scenarios, 2015-2050

		Reference scenarios			Alternative scenarios		
	Unit	**2015**	**2023**	**2030**	**2023**	**2030**	**2050**
Maximum hourly ramp-up	GW/h	1.1	3.9	4.7	3.9	4.7	13.7
Maximum hourly ramp-down	GW/h	1.1	3.6	4.4	3.6	4.4	12.8
Annual demand for ramp-up	TWh	0.7	2.4	3.0	2.4	3.0	8.5
Annual demand for ramp-down	TWh	0.4	1.5	1.8	1.5	1.8	5.3

It should be stressed, however, that the flexibility needs indicated in **Table 4** are based on the assumption that the wind forecast error over this period will remain the same per unit installed wind capacity as actually measured in 2012. If, on the contrary, it is assumed that over time, the weather-based forecast of wind generation will improve significantly – and, hence, the wind forecast error will decline substantially – the need for flexibility due to the wind forecast error will decrease accordingly (although overall it may still grow significantly in absolute terms due to the increase in total VRE output from wind over time).

On the other hand, it should be realised that **Table 4** includes only the need for flexibility due to the wind forecast error, but ignores the demand for flexibility of the power system due to the sun forecast error or to other uncertainties such as the uncertainty of power demand or the uncertainty of power supply from conventional installations (for instance, due to a sudden, unplanned breakdown of a coal plant). Including these variables – notably the fast-growing power supply from sun PV – will significantly enhance the demand for flexibility due to the uncertainty of the residual load.

Major results at the regional Liander network distribution level

3. The demand for flexibility due to the congestion of the power grid

The Liander regional grid analysis has assessed the implications of the FLEXNET scenario cases – in particular of the assumed adoption rates of EVs, HPs, and sun PV – for the load profiles of the Liander distribution network. Over 80,000 km of power cables and 36,000 transformers have been evaluated as part of this assessment. Many data sources have been combined to predict and evaluate grid loading up to 2050 on a very granular, local level. By means of the Liander bottom-up network model ANDES, the FLEXNET scenario cases have been converted into power load time series with a 15-minute interval. Using these detailed load profiles, the impact of the adoption of sun PV, EVs and HPs on the Liander regional distribution grid has been evaluated.

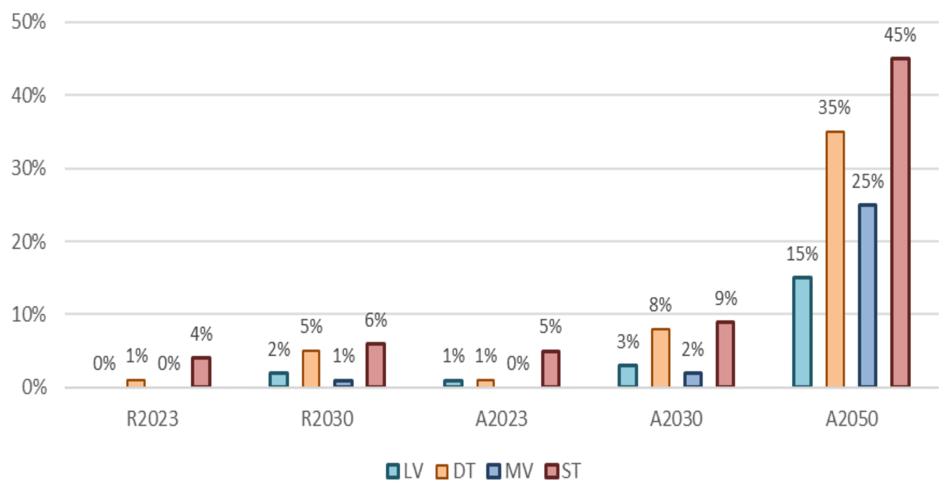
The regional grid assessment shows that the load profiles are expected to alter considerably due to the adoption of sun PV, EVs and HPs over the next decades. The loads on all the assets of the distribution network are observed to become much more volatile. Furthermore, the winter load peaks intensify due to electrical heating while in the summer many areas have an energy surplus caused by the penetration of sun PV.

The ANDES modelling analysis indicates that the percentage of overloaded assets due to increasing adoption of PV, EV and HP is limited, at least until 2030 (<10%). In A2030, about 8% of the distribution transformers and 9% of the substation transformers will be overloaded (see **Figure 5**). The percentage of overloaded cables is even lower (2-3%). As a conclusion it can be said that most assets of the network, especially cables, will have sufficient capacity to facilitate the increased loads for at least the next 15 years.

In A2050, 35% of the distribution transformers and 45% of the substation transformers are expected to be overloaded. Although these overload percentages are significant, they are not alarming. Due to asset ageing, many of the assets indicated as overloaded in 2050 will most likely have been replaced before 2050. With bigger capacities, the additional costs of these bigger capacities are marginal, as most of the costs are caused by the required work, not the material. Moreover, several 'smart solutions' are expected to become available within this time span. Therefore, the actual number of grid overloads is likely lower than indicated by the ANDES modelling results.

Geographically, most overloads are expected to arise in city centres, because of relatively old networks. The fact that the adoption of PV, EV and HP is lower in the city centres is offset by the density of the urban population, resulting in a larger increase of power load in urban areas than in non-urban areas.

Figure 5: Percentage of overloaded assets per scenario case at different levels of the distribution grid



Note: LV = Low voltage cable; DT = Distribution transformer; MV = Medium voltage cable; ST = Substation transformer

Comparing Liander and Stedin results

Comparing the major outcomes of the Liander regional grid analysis with the major findings of a similar assessment by Stedin shows that the Stedin approach results in similar outcomes on grid congestion in 2030 but in a higher expected number of overloads in 2050. The differences in outcomes between Stedin and Liander for the year 2050 are due to differences in the current structure and capacity of their distribution networks as well as to differences in modelling approaches and inputs, including particularly differences in energy usage profiles and in translating future scenario assumptions to local developments.

Impact on HV transmission assets

The datasets and results of the Liander analysis have been used by TenneT to assess roughly the implications of the FLEXNET scenarios A2030 and A2050 for some of its high voltage (HV) grid assets in the north-western part of the Netherlands, i.e. in the province of North Holland. A major finding of this assessment is that only a rapid growth in further electrification can lead to significant additional loading of the HV grid by 2030. The growth in VRE power generation in any FLEXNET scenario up to 2030 is not big enough such that it could lead to additional bottlenecks on the HV grid by 2030. If by 2050, however, the penetration of PV becomes as big as predicted in the A2050 scenario, the HV grid as it is now will be overloaded significantly during the mid-day PV peak on sunny summer days.

The need for weighing flexibility versus network reinforcement is apparent, notably in the period beyond 2030. To avoid the spillage of VRE surpluses in case of grid overloads, power will have to be either curtailed or transported across large distances towards areas that require more power than is generated locally. Alternative measures are to temporarily store the energy locally or to shift (local) demand over time. It will depend on the specific situation what solution is most desirable (as analysed further during both the second and third phase of the FLEXNET project).

Key messages

National level

Increasing flexibility needs due to increasing variability of residual power load, in particular beyond 2030

Over the years 2015-2050, the variability of the residual load in the Dutch power system increases strongly, mainly due to the increase in power generation from variable renewable energy (VRE), in particular from sun and wind, but also partly due to the increase in total load, notably resulting from the increase in electric vehicles (EV), heat pumps (HPs) and other means of additional electrification. As a result, the total annual demand for flexibility more than doubles between 2015 and 2030 and increases even further – by a factor 3 – between 2030 and 2050.

Increasing need for flexible peak load capacity

Mainly due to the increase in power supply from VRE sources, the need for residual *peak* load capacity increases substantially over time, whereas the need for residual *base* load capacity decreases significantly (and even becomes zero in A2050). Peak load capacity, however, has to be rather flexible as it covers less than 1200 hours per annum spread throughout the year. Notably, the number of peak hours with relatively high levels of residual load is relatively small in A2050 (and A2030), i.e. it is usually even much smaller than 1200 hours. Therefore, capacity investments in (flexible) power generation – or other (flexible) power supply options – to meet these high residual load levels have to be recovered in a relatively small number of running hours (as further explored during phase 2 of the study).

Increasing number of hours with a VRE surplus

As the share of VRE generation in total load increases significantly over the period 2015-2050, both (i) the number of hours with a VRE surplus (i.e. a 'negative residual load'), (ii) the maximum hourly VRE surplus, (iii) the total hourly VRE surplus per annum, and (iv) the maximum number of consecutive VRE surplus hours increase as well. This raises both new challenges and opportunities in terms of flexibility demand and supply in the power system. For instance, the incidence and alternation of (large) hourly VRE shortages versus (large) VRE surpluses enhances the issue how to deal with these fluctuations in residual load (and the related fluctuations in hourly electricity prices). On the other hand, these fluctuations create also opportunities in terms of energy storage and demand response.

Wind (on sea) is the main driver of the increasing need for flexibility

The main driver of the increasing demand for flexibility is the increase in electricity production from VRE power sources, in particular from wind (on sea) and – to a lesser extent – from sun PV. Another, less important driver – at least in a direct sense – is the increase in the additional load due to the further electrification of the energy system, notably due to the hourly variations in the additional load for passenger EVs rather than in the additional for household HPs or other means of electrification. In an indirect sense, however, the increase in electrification is an important driver of the demand for flexibility if it is assumed that the resulting additional load is largely met by electricity from VRE power sources.

Flexibility needs due to the uncertainty of the residual load also increase strongly
The demand for flexibility due to the *uncertainty* of the residual load is also expected to increase rapidly up to 2050, in particular due to (i) the uncertainty – or lower predictability ('forecast error') – of power from wind, in combination with (ii) the large (dominant) increase in installed wind capacity over the years 2015-2050. The size of this type of flexibility demand, however, depends highly on the extent to which improvements in reducing the forecast error will be effectuated up to 2050.

Regional grid level

The expected percentage of overloaded assets as a result of the adoption of EV, HP, PV seems limited until 2030 relative to the conclusions of previous studies
The ANDES modelling analysis of the implications of the FLEXNET scenario cases for the load profiles of the Liander distribution grid indicates that the incidence of overloaded assets due to the increasing adoption of PV, EV and HP is limited, at least until 2030 (<10%). In A2030, about 8% (±3000) of the distribution transformers and 9% (about 40) of the substation transformers will be overloaded. The percentage of overloaded cables is even lower at 2-3% (±1500 km of LV cables and ±700km of MV cables). As a conclusion it can be said that most assets of the grid, especially cables, will have sufficient capacity to facilitate the increased loads for at least the next 15 years.

In absolute numbers, the overloads will lead to a significant amount of work and will become a serious challenge for the grid operator. Investments in the grid need to take into account future load increase to prevent "double" work (returning to the same asset for reinforcement during the operational lifetime of an asset). If not, this might endanger the achievement of the work assignment of the network operator, i.e. to maintain, reinforce and replace the network infrastructure.

Despite a limited total number of overloaded assets the regional distribution grids face great challenges in the form of large numbers of new connections for EV charging points, local congestion due to local concentrations of EV, PV and/or HP, a large increase of connections for medium size solar and wind farms, and the phase out of gas in the built environment that creates the need and natural moment to adapt the electricity grid.

Beyond 2030, the incidence of grid overloads is more significant, but most likely not alarming with the right investment strategy
According to the result of the ANDES model, 35% of the distribution transformers and 45% of the substation transformers are expected to be overloaded in the A2050 scenario case. Although these overload percentages are significant, they are not per se alarming. Due to asset ageing, many of the assets indicated as overloaded in 2050 will most likely have been replaced with larger capacity assets before becoming overloaded. The additional costs of installing assets with larger capacities are marginal, as most of the costs are caused by the required work, not the material. The model therefore assumes the investment strategy takes into account future load increase. Moreover, several 'smart solutions' are expected to become available within this time span. Therefore, the actual number of grid overloads is potentially lower than indicated by the ANDES modelling results. Again, most concerning to the grid operator will most likely be the achievement of the work assignment.

Most overloads are expected to arise in city centres
Geographically, most overloads are expected to arise in city centres, because of relatively old networks. The fact that the adoption of PV, EV and HP is lower in the city centres is offset by the density of the urban population, resulting in a larger increase of power load in urban areas than in non-urban areas.

Apparent need for trade-off between grid reinforcement and deployment of flexibility
From both a socioeconomic and a (regional) grid load perspective, there appears to be a clear need for weighing network reinforcements versus deployment of flexibility options, notably in the period beyond 2030 (when the incidence of grid overloads increases significantly). This trade-off, however, is also important in the coming years to use the efficiency potential of flexibility solutions and to deal with less predictable grid load increases where flexibility can be a good temporarily solution till grid reinforcement is carried out. This issue has been further analysed in both the second and third phase of the FLEXNET project (see below).

1

Introduction

The Netherlands is aiming at a more sustainable, low-carbon energy system. For the power system this implies (i) a larger share of electricity from variable renewable energy (VRE), in particular from sun and wind, (ii) a larger share of electricity in total energy use, i.e. a higher rate of 'electrification' of the energy system, and – as a result of these two trends – (iii) a higher need for flexibility and system integration.

Against this background, the overall objective of the FLEXNET project was to analyse demand and supply of flexibility of the power system in the Netherlands up to 2050 at the national and regional level. More specifically, the FLEXNET project consisted of three phases, each addressing a particular main question:

- *Phase 1 ('The demand for flexibility')*: what are the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050?
- *Phase 2 ('The supply of flexibility')*: which mix of robust flexibility options can meet the predicted flexibility needs in a socially optimal way?
- *Phase 3 ('Societal framework to trade-off grid reinforcement and deployment of flexibility')*: in which situations is deployment of flexibility a more attractive option than grid reinforcement to overcome predicted overloads of the power network?

The current report outlines the approach and major results of the first phase of the FLEXNET project. This phase has been conducted at two levels: (i) the national level, i.e. for the power sector in the Netherlands as a whole, and (ii) the regional level, i.e. at the regional power distribution network level of the Liander service area in the Netherlands.[2]

More specifically, the central questions of the first phase of the FLEXNET project regarding these two levels include:

- What are the main drivers (determinants) of the demand for flexibility of the power sector in the Netherlands, and how will this demand develop quantitatively in some scenario cases over the period 2015-2050?

2 The analysis at the national level was conducted by ECN (see particularly Chapters 3 and 4 of the current report), while the analysis at the regional level was carried out primarily by Alliander (see Chapter 5), including contributions made by TenneT and Stedin.

- What are the implications of these scenario cases – in particular of the assumed adoption rates of the emerging power sector technologies (electric vehicles, heat pumps, sun PV, wind energy) – for the load profiles of the regional Liander power distribution network?

Structure of report

Chapter 2 provides a definition of the term flexibility and outlines the approach (methodology) used during the first phase of the FLEXNET project. In this chapter, we identify three main sources ('causes') of the need for flexibility by the power system, i.e. the need for flexibility due to (i) *the variability of the residual load* (defined as total power demand minus VRE generation), (ii) *the uncertainty of the residual load* (notably the lower predictability of VRE power output), and (iii) *the congestion of the grid* (i.e. the incidence of network overloads resulting from the increase and changing profiles of electricity demand and VRE power supply).

In the remaining part of the report, these three sources of the demand for flexibility are further analysed in the context of moving towards a sustainable power system in the Netherlands up to 2050. More specifically, Chapter 3 analyses extensively the flexibility needs of the Dutch power system up to 2050 due to the (increasing) variability of the residual power load. Subsequently, Chapter 4 discusses briefly the demand for flexibility due to the uncertainty of the residual load (in particular due to the lower predictability – 'forecast error' – of power output from wind). Finally, Chapter 5 analyses the need for flexibility due to the congestion of the grid, in particular at the regional level of the Liander power distribution network.

2

Approach

This chapter explains the approach ('methodology') used during the first phase of the FLEXNET project aimed at quantifying and analysing the demand for flexibility of the power system in the Netherlands over the period 2015-2050. First of all, Section 2.1 discusses briefly the definition of the term flexibility applied during this project. Subsequently, Section 2.2 outlines the scenarios analysed in this project, in particular the major assumptions and input values of these scenarios. Next, Section 2.3 gives a brief description of the electricity demand and supply profiles used to quantify the demand for flexibility of the Dutch power system in the scenarios analysed. Finally, Sections 2.4 and 2.5 give a brief explanation of the approach applied at the national and regional level, respectively, in particular of the analytical tools used at the national system level and, subsequently, the Liander distribution network level.

2.1 Definition of flexibility

With regard to the energy system in general, and the power system in particular, there are presently several, different definitions – and indicators – of the concept *flexibility*.[3] For instance, Huber et al. (2014) define flexibility as "*the ability of a power system to respond to changes in power demand and generation".* The advantage – but also the limitation – of this definition is that it provides a rather general, less specific definition of the term flexibility, referring to changes in both the demand for electricity and the total supply of electricity. This includes not only the variable ('*intermittent*') generation of electricity from renewable sources, such as sun or wind, but also the '*dispatchable'* power production, for instance by means of coal- or gas-fired installations, as well as the fixed ('*must-run'*) generation of electricity by, for instance, industrial CHP plants.

[3] See, in addition to the examples and sources mentioned in the main text, the definition of the term flexibility in, among others, Koutstaal et al. (2014, pp. 17 and 21), Ecofys (2014, p. 1), Cochran et al. (2014, p.1) and Triple E (2015, p.15).

Lannoye et al. (2012) provide the following definition of flexibility: "*Flexibility is defined […] as the ability of a system to deploy its resources to changes in net load, where net load is defined as the remaining system load not served by variable generation*". The major characteristic of this definition is that the concept flexibility is related to one specific variable (indicator), namely to '*changes in net load*', i.e. the total demand for electricity minus the variable supply of electricity, in particular from renewable sources (sun/wind).

Holttinen et al. (2013) provide a slightly alternative definition of (power system) flexibility: *"The flexibility of the system represents its ability to accommodate the variability and uncertainty in the load-generation balance while maintaining satisfactory levels of performance for any time scale".* The advantage of this definition is that it refers to two fundamental causes of the need for flexibility – i.e. "the *variability* and *uncertainty* in the load-generation balance" – as well as to the different time scales of flexibility ("for any time scale"; see also the discussion below).

Recently, CE Delft (2016) considers flexibility as the ability of the power system to maintain in the short run the balance between power demand and supply *within the limits of the distribution and transmission system* (our translation and our italics). The main contribution of this consideration is that it adds a third potential source ('cause') of the need for flexibility of the power system, i.e. the congestion – or overloading – of the power grid.

Finally, Ma et al. (2013) define a power system as flexible "*if it can cope with uncertainty and variability in demand and generation to maintain system reliability at reasonable additional costs*". The added value of this definition is that it includes explicitly the ultimate goal of flexibility, i.e. "to maintain system reliability at reasonable additional costs".

Based on the above findings, it is proposed to use the following (extensive) definition of flexibility for the FLEXNET project:

> *Flexibility is the ability of the energy system to accommodate its resources to respond to the variability and uncertainty of the residual power load in order to maintain system reliability and stability at reasonable social costs within the limits of the electricity grid (where residual load is defined as total power demand minus generation of electricity from variable, renewable energy sources such as sun or wind).*

A derived, shorter and simpler definition of flexibility is: "*Flexibility is 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".* Note that in this – and in the abovementioned definition - the demand for flexibility is caused primarily by the power system, in particular by (expected and unexpected) changes in the residual power load, but that the solution of this issue – i.e. the supply of flexibility options – may come from the energy system as a whole, including not only the power system but also other systems such as the gas or heating system.

Following the above-mentioned definition, the FLEXNET project is focussed primarily on the demand for flexibility by the power system and, subsequently (in phase 2 of the project) on the supply of flexibility – to meet this demand – by the energy system as a whole. This focus is based on the assumption that, in (moving towards) a sustainable, carbon-free energy system, the (growing) demand for flexibility is primarily located at the electricity system and hardly or not at the other energy systems. These other systems, however, might be relevant, and even essential, for supplying flexibility to the power system, for instance through energy conversion technology options such as power-to-gas or power-to-heat.

Sources ('causes') of flexibility needs

As indicated above, we distinguish between three different sources ('causes') of the demand for flexibility:

1. The demand for flexibility due to the (expected, predictable) *variability* of the residual power load, including the variability of total power demand and, in particular, the variability of power generation from variable renewable energy (VRE) such as sun or wind. This type of flexibility is closely related to balancing electricity demand and supply on the day-ahead/intraday market.
2. The demand for flexibility due to the *uncertainty* (lower predictability) of the residual load, including the uncertainty of total power demand and, in particular, the uncertainty ('forecast error') of power output from sun or wind. This type of flexibility is closed related to fine-tuning demand and supply on the intraday/balancing market.
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 increase in EVs, HPs, etc. –as well as the increase and changing profiles of power supply from VRE sources. This type of flexibility is closely related to transporting electricity demand and supply within the capacity limits of the power distribution and transmission network at different geographical levels (local, regional, national, etc.). In case the network is (expected to become) overloaded, the question – or trade off – arises whether this congestion has to be solved by network reinforcement or can be addressed better by the deployment of flexibility measures – as a means of congestion management – such as demand response, energy storage or VRE output curtailment.[4]

These three sources ('causes') of the need for flexibility correspond closely to the three domains ('segments') of operational flexibility distinguished by CE Delft (2016), i.e. flexibility related to (i) energy delivery ('energy balance'), (ii) balancing ('system balance'), and (iii) congestion management ('transport balance'). The first domain (flexibility to maintain the energy balance) is the primary responsibility of the energy suppliers (as part of their programme responsibility). The second domain (flexibility to maintain the system balance, including frequency control, etc.) is the primary responsibility of the national Transmission System Operator (TSO), i.e. TenneT. The third domain (flexibility to avoid network congestion and, hence, to maintain the transport balance) is the primary responsibility of the regional and national network operators, i.e. the regional Distribution System Operators (DSOs) and the national TSO (CE Delft, 2016).

4 For a further discussion of the issue of deploying flexibility as a means of congestion management, see Chapter 5 of the current report, as well as the reports on phase 2 and phase 3 of the FLEXNET project (Sijm et al., 2017; and Van der Welle and Sijm, 2017).

Focus and limitations of FLEXNET
The FLEXNET project has considered all three types of flexibility demand mentioned above, although it was predominantly focussed on modelling and analysing the first and third type of flexibility and hardly on the second type, i.e. the demand for flexibility due to the uncertainty of the residual load. Moreover, besides the uncertainty regarding the residual power load, there are several other uncertainties affecting the power system – including unexpected incidents – that may appeal to the flexibility of the power system (or the energy system as a whole). For instance, consider uncertainties or incidents such as the breakdown of a power plant, a lack of cooling water in the summer period, supply disruptions of coal or gas, a natural disaster, a terrorist attack, etc. The need for flexibility due to these uncertainties, incidents or other distortions can, in principle, be met by deploying so-called '*contingency reserves'* or applying all kinds of '*safety and reserve margins*'. These uncertainties or distortions, and the resulting needs for flexibility by the power system, however, are not further considered in the FLEXNET project.

Dimensions of flexibility
In addition to the three sources ('causes') of flexibility mentioned above, the concept of flexibility of the energy system can be further distinguished by at least the following dimensions:
- Direction;
- Geographic scale;
- Time.

Direction
Regarding the direction of flexibility, the following two opportunities are distinguished:
- *Upwards flexibility*, i.e. the need for flexibility due to an *increase* in the residual power load over a certain time scale, for instance a minute, hour, day, etc. (resulting from an *increase* in total electricity demand and/or a *decrease* in VRE generation over that period);
- *Downward flexibility,* i.e. the need for flexibility due to a decrease in the residual power load over a certain time scale (resulting from a decrease of total electricity demand and/or an increase in VRE generation over that period).

This distinction is particularly relevant because of differences in symmetry between diverse options to meet the demand for flexibility. For instance, some options are better (faster) in offering upward flexibility than downward flexibility or, in certain occasions, only able to offer either downward or upward flexibility – but not both opportunities at the same moment – for instance, because a flexible gas-fired generator is at a certain moment already either fully deployed or fully switched off.

Geographic scale
Flexibility of the energy system can be distinguished and analysed at different geographic scale levels, varying from the (inter)national level to the regional or local level. This distinction is particularly relevant because of the incidence of possible congestion issues in the transmission/distribution network at the respective scale level and, hence, – if so – for the need to make a trade-off between deploying flexibility options and network expansion at the respective scale level.

In the FLEXNET project, flexibility is analysed particularly at the following geographical scale levels:

- The *national level*, i.e. at the level of the Dutch power system as a whole, including the interconnections and trade in electricity between the Netherlands and its surrounding countries;
- The *regional/local level*, in particular the distribution area in the Netherlands served by the regional network operator Liander.

Time

Flexibility of the energy system, notably the power system, can also be distinguished and analysed at different time scales, varying from minutes – or even seconds – to hours, days, weeks, months, seasons or years. This distinction is particularly relevant for the size, type and cost effectiveness of different options to offer flexibility.

In the FLEXNET project the analysis of flexibility is primarily conducted on an hourly time scale, usually over an annual period of 8760 hours. Based on this hourly time scale, however, other – i.e. notably longer – time frames are also considered briefly, in particular per day, week and per season (within a year). On the other hand, we will not consider flexibility at shorter time frames such as, for instance, per minute or second.[5]

Indicators of flexibility

The need for flexibility can be characterised, measured and analysed by three related indicators of power demand and supply (NERC, 2010; CE Delft, 2016):

- *Capacity (GW).* Capacity is a measure for the speed with which (electrical) energy can be delivered or used, expressed in the unit of capacity considered, such as megawatt (MW) or gigawatt (GW). Enough supply capacity is needed to meet the (residual) demand for electricity at different time frames and at different situations.
- *Ramp (GW/h).* Ramp is a measure for the change in capacity per time unit, expressed usually in the change of capacity per hour – for instance, in MW/h or GW/h – or any other time unit considered, such as per second, minute, etc. Over a certain time unit, a change in (residual) power demand has to be met by a similar change in power supply in order to maintain system balancing.
- *Energy (GWh).* Energy is a measure for the amount of (electrical) energy delivered or used over a certain time frame, expresses usually as the amount of energy demand and supply over a year – in kWh, MWh, GWh, etc. – or any other time period considered, such as a day, week, month, etc. Over a certain time frame, the amount of energy demanded has to be similar to the amount of energy supplied.

Within the FLEXNET project, a major indicator for measuring, quantifying and analysing the demand for flexibility – notably due to the variability of the residual power load – is the *variation* (i.e. the *change* or *difference*) in the residual load *per hour*. As noted above, this variation is usually indicated as (hourly) '*ramp'*, distinguished into '*ramp-up*' – i.e. the demand for upward flexibility – and '*ramp-down*', i.e. the need for downward flexibility. Therefore, according to this indicator, the demand for flexibility = variation in residual load = ramp (per hour). This indicator of the demand for flexibility can be considered for a single hour, accumulated for a number of consecutive hours and aggregated – in energy terms – over a certain period, for instance in GWh or TWh per year (for details and illustrations, see Chapter 3).

[5] The only exception is at the Liander distribution level where we will check the incidence of possible congestion of the distribution network on a 15 minute time frame (for details, see Chapter 5).

Another indicator of the demand for flexibility – notably due to the uncertainty of the residual load in general and of the power generation from VRE resources in particular – is the so-called '*forecast error*', i.e. the difference between the forecasted residual load (VRE generation) and the realised residual load (VRE generation). This indicator can be expressed in capacity, ramping and/or energy terms (for details and illustrations, see Chapter 4).

A third indicator of the demand for flexibility – notably due to possible network congestion – is the incidence of overloading of different grid assets at different geographical levels (local, regional, etc.), This indicator is usually expressed in capacity terms, either in absolute terms – i.e. in MW or GW – or as a percentage of the available grid capacity (for details and illustrations, see Chapter 5).

2.2 Scenarios: major assumptions and input values

Scenarios and focal years

In the FLEXNET project, the analysis of the demand for flexibility of the power sector in the Netherlands has been conducted for two scenarios, each focussing on a limited number of (future) years. The two scenarios include:

- The reference scenario;
- The alternative scenario.

These scenarios are outlined briefly below.

The reference scenario

The reference scenario is similar to the '*realised policy scenario'* of the National Energy Outlook 2015 for the Netherlands.[6] For our analysis, the two major characteristics of this scenario include:

- A relatively strong ('ambitious') growth of installed VRE capacity up to 2030, resulting in a relatively strong growth of the share of electricity from VRE sources;[7]
- A relatively weak ('conservative') growth of the rate of electrification of the energy system due to a relatively slow growth of the use of electric vehicles, heat pumps and other means of electrification.[8]

The forecasts of the realised policy scenario in the National Energy Outlook (NEO) 2015 cover the period up to 2030. For the present study, we focus our reference scenario

6 In Dutch, this annual publication is called 'Nationale Energieverkenning' (NEV). For details on the NEV 2015, including details on the 'realised policy scenario', see ECN et al. (2015).

7 In the realised policy scenario of the NEV 2015, the installed VRE capacity increases from 4.5 MWe in 2015 to almost 28 MWe in 2030, resulting in an increase in the share of electricity from VRE resources from about 8% in 2015 to approximately 48% in 2030 (for details, see ECN et al., 2015, as well as **Table 5**, **Figure 8** and **Figure 9** discussed below in the present report).

8 In the realised policy scenario of the NEV 2015, the overall rate of electrification – i.e. the share of electricity in total final energy use – increases slightly from about 16% in 2015 to approximately 17% in 2030 (ECN et al., 2015).

analyses on three years, i.e. (i) 2015 (the reference or base year), (ii) 2023 (the end year of the Dutch 'Energy Agreement'; see SER, 2013), and (iii) 2030 (the last year of the NEO forecast period).

The alternative scenario

The alternative scenario is similar to the reference scenario with one major exception, i.e. it assumes a much stronger ('more ambitious') growth of the rate of electrification of the Dutch energy system through the use of electric vehicles, heat pumps and other, additional means of electrification such as power-to-heat in industrial sectors, the electrolysis of the production and use of hydrogen throughout the economy, etc. (see also below).[9]

The alternative scenario analyses also focus on three years. For comparative reasons, we have selected the same future years up to 2030 as in the reference scenario, i.e. (i) 2023 and (ii) 2030 (while the base year for the alternative scenario is exactly similar to the base year of the reference scenario, 2015, and therefore not analysed separately). In addition, however, we have added another, long-term future year, i.e. 2050, to the alternative scenario analyses.

The 2050 scenario case is characterised by (i) a further, strong growth in VRE installed capacity beyond 2030 up to 2050, resulting in a further, strong growth of the share of power generation from VRE resources in total electricity use, and (ii) a further, strong growth in the rate of electrification of the Dutch energy system (for details on the 2050 alternative scenario case, see Section 2.2 below as well as the scenario outcomes discussed in Chapter 3).

The overall assumption of the 2050 scenario case is that it meets the EU/Dutch policy target of reducing greenhouse gas emissions in the Netherlands by at least 85% in 2050 (compared to 1990). This scenario case is not based on (the realised policy scenario of) the National Energy Outlook 2015 but rather on a set of 85% GHG-reduction scenarios constructed and analysed by ECN as part of the study on the role of power-to-gas in the future Dutch energy system (De Joode et al., 2014; see also Section 2.2 and Chapter 3).

The 2050 scenario case is more uncertain (and less detailed) than the other – both reference and alternative – scenario cases. Its main purpose is not to give a precise, detailed forecast or prediction of the Dutch energy system in 2050 but rather to provide a 'rough vista' of the implications for the demand and supply of flexibility in the Dutch energy system of a scenario characterised by a (relatively) high rate of electrification of the energy system and a high rate of power generation from VRE resources in total electricity use.

9 Assuming a similar amount of total energy use in 2030 in the alternative scenario as in the reference scenario, the overall rate of electrification in the alternative scenario increases from about 16% in 2015 (base year) to approximately 23% in 2030 (compared to 17% in the reference scenario, see previous footnote). Note that the installed VRE capacity in the alternative scenario is assumed to be similar to the VRE capacity in the reference scenario. The background for this assumption is twofold, i.e. (i) the assumed growth in VRE capacity up to 2030 is already quite ambitious in the reference scenario and, hence, it is less realistic to assume an even more ambitious growth in VRE capacity in the alternative scenario, and (ii) in the alternative scenario we are primarily interested in the impact of a higher rate of electrification of the Dutch energy system on the demand for flexibility of the power system and, hence, we assume VRE installed capacity and output generation in the alternative scenario to be similar to the reference scenario. Consequently, however, the share of electricity from VRE resources in total electricity use increases less in the alternative scenario than in the reference scenario, i.e. from about 8% in 2015 to approximately 36% in 2030 in the alternative scenario compared to about 48% in the 2030 reference scenario (for details see **Table 5**, **Figure 8** and **Figure 9** discussed below).

So, overall, we have two scenarios and six scenario cases, i.e. three reference scenario cases focussing on the years 2015, 2023 and 2030 (labelled as 'R2015', 'R2023' and 'R2030') and three alternative scenario cases focussing on the years 2023, 2030 and 2050 (pinpointed as 'A2023', 'A2030' and 'A2050').

Major scenario assumptions and input values
Table 5 provides some detail on the major assumptions and input values for all scenario cases, in particular with regard to the demand for electricity (power load), including the extent of (additional) electrification of the Dutch energy system, as well to the supply of electricity from variable, renewable energy (VRE) resources. It shows, among others, that the share of electric vehicles (EVs) in total passenger cars is assumed to increase from 2% in R2015 to 74% in A2050, while the share of heat pumps (HPs) in the household sector rises from 2% to 69% over this period (see also **Figure 6**). Based on the assumed number of passenger cars and households, respectively, as well as on the assumed average electricity use of an EV and a HP in the respective scenario cases, this results in an additional power load for passenger EVs and household HPs in these cases, for instance in A2050 by approximately 22 and 9 TWh, respectively.

In addition, in the alternative scenario cases, we have assumed an additional power load for all other forms of 'other electrification' (in order to achieve at least 85% GHG reduction by 2050). This includes, among others, (i) the electrification of heat demand in the other tertiary, non-household sectors (services, business, utilities, etc.), (ii) electrification of other transport – besides passenger cars – by means of either batteries or hydrogen through electrolysis, and (iii) electrification in industrial sectors, including power-to-heat (P2H), power-to-gas (P2G), power-to-ammonia (P2A), power-to-products (P2P), including power to industrial non-energy use such as producing fertilizers, other chemicals, etc.

As mentioned above, based on a set of 85% GHG-reduction scenarios of the P2G study (De Joode et al., 2014), we have put the assumed amount of additional power load for 'other electrification' at a total value of 90 TWh in A2050. For the alternative scenario cases in 2023 and 2030, we have assumed rather roughly that the additional power load due to 'other electrification' amounts to about one-ninth and one-third of the A2050 value, i.e. 10 TWh in A2023 and 30 TWh in A2030, respectively.

Overall, total final power load is assumed to increase slightly in the reference scenario cases, i.e. from 113 TWh in R2015 to 116 TWh in R2030. In the alternative scenario, however, total load increases much faster, i.e. to 153 TWh in A2030 and even to 233 TWh in A2050 (see upper part of **Table 5** as well as **Figure 7**).

As noted, **Table 5** provides also the major assumptions and input values of the scenario cases regarding the deployment of variable renewable energy (VRE) sources in the power sector. It shows, for instance, that the total installed VRE capacity is assumed to grow from 4.5 GWe in R2015 to almost 92 GWe in A2050. More specifically, it shows that in R2015 the main part of installed VRE capacity consists of wind on land, whereas in A2050 it is expected to include particularly sun PV and wind on sea (see also upper part of **Figure 8**). In addition, **Table 5** gives the major assumptions and input values with regard to the full load hours and the resulting capacity factors of the installed VRE power sources (see also the middle part of **Figure 8**).

Table 5: Major assumptions and input values of all scenario cases, 2015-2050

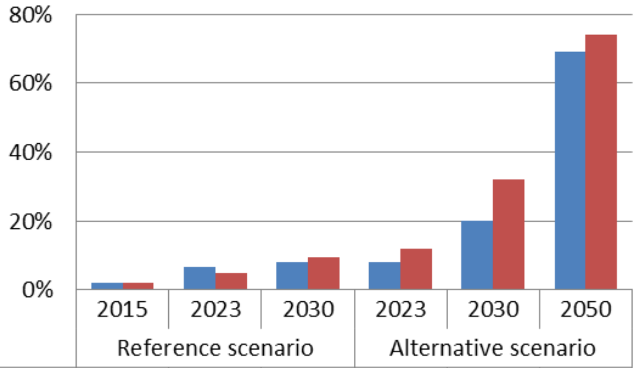
		Reference scenario			Alternative scenario		
	Unit	2015	2023	2030	2023	2030	2050
Electrification							
Number of EVs	[# x 1000]	156	398	841	1,007	2,793	7,175
Share of EVs in total passenger cars	[%]	2.0%	4.7%	9.6%	12.0%	32.0%	74.0%
Number of HPs in households	[# x 1000]	149	496	630	612	1,587	5,727
Share of HPs in total households	[%]	2.1%	6.5%	7.9%	8.0%	20.0%	69.0%
Conventional load	[TWh]	111.8	111.6	112.2	111.6	112.2	112.0
Additional load EVs	[TWh]	0.5	1.2	2.5	3.0	8.4	21.5
Additional load HPs	[TWh]	0.2	0.8	0.9	0.9	2.5	9.3
Add. load 'Other electrification'	[TWh]	0.0	0.0	0.0	10.0	30.0	90.0
Total final load	[TWh]	112.5	113.5	115.6	125.5	153.1	232.8
Power from variable renewable energy (VRE) sources							
Installed capacity:							
• Wind on land	[MWe]	2,630	6,020	6,330	6,020	6,330	6,800
• Wind on sea	[MWe]	360	4,120	6,060	4,120	6,060	28,900
• Sun PV	[MWe]	1,530	8,640	15,130	8,640	15,130	56,100
• Total VRE power capacity	[MWe]	4,520	18,780	27,520	18,780	27,520	91,800
Full load hours:							
• Wind on land	[hrs]	2310	2670	2860	2670	2860	2900
• Wind on sea	[hrs]	3580	4080	4120	4080	4120	4160
• Sun PV	[hrs]	840	820	820	820	820	820
Capacity factor:[a]							
• Wind on land	[%]	26.4%	30.5%	32.6%	30.5%	32.6%	33.1%
• Wind on sea	[%]	40.9%	46.6%	47.0%	46.6%	47.0%	47.5%
• Sun PV	[%]	9.6%	9.4%	9.4%	9.4%	9.4%	9.4%

a) The capacity factor is equal to the number of full load hours divided by the total hours in a year (8760).

Sources: All input values for the three reference scenario cases are derived from or based on the National Energy Outlook 2015 (ECN et al., 2015). The input values for the three alternative scenario cases, if different from the input values for the reference scenario cases in the respective years, are derived from or based on the following sources:

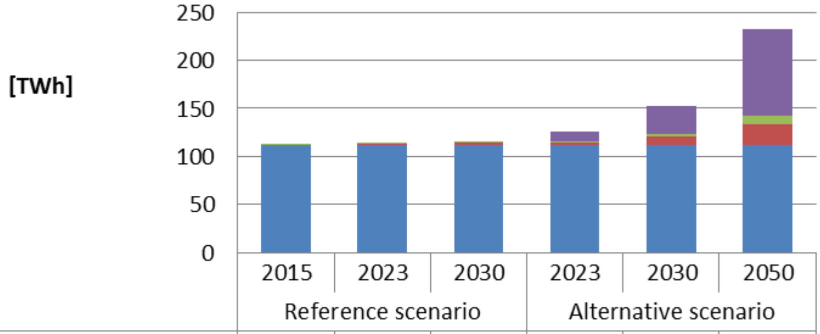
- Number/share of passenger EVs: Liander (2015; see also Appendix A);
- Number/share of household HPs: PBL (2014; see also Appendix A);
- Additional load EVs: number of passenger EVs (see above) times average electricity use per EV (for details, see Appendix A)
- Additional load HPs: number of household HPs (see above) times weighted average electricity use per HP (for details, see Appendix A);
- Conventional load and additional load ‘other electrification in A2050: expert guess ECN, based on set of 2050 scenarios (85% GHG reduction) in power-to-gas study (De Joode et al., 2014);
- Wind on land/sea: 85% of potential identified by PBL and ECN (2011);
- Sun PV: 85% of potential identified by DNV GL and PBL (2014);
- Full load hours in R2050: expert guess ECN, based on projection of R2015-2030 data.

Figure 6: Electrification rate of passenger transport and head demand of households in all scenario cases, 2015-2050



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Electrification heat demand (% of houses)	2.1%	6.5%	7.9%	8.0%	20.0%	69.0%
Electrification transport (% of passenger cars)	2.0%	4.7%	9.6%	12.0%	32.0%	74.0%

Figure 7: Total power load in all scenario cases, 2015-2050

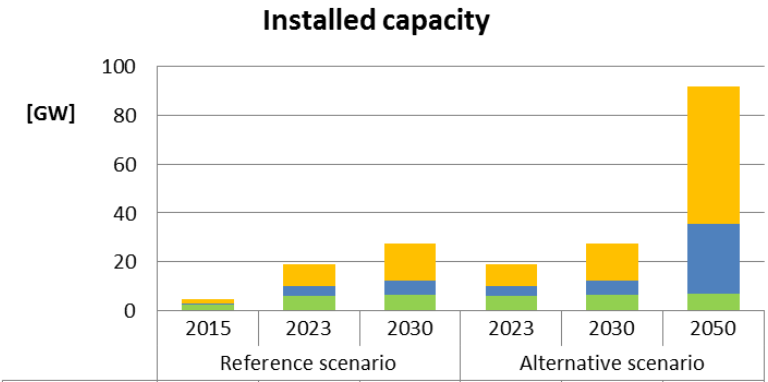


	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Additional load 'Other electrification'	0.0	0.0	0.0	10.0	30.0	90.0
Additional load HPs	0.2	0.8	0.9	0.9	2.5	9.3
Additional load EVs	0.5	1.2	2.5	3.0	8.4	21.5
Conventional load	111.8	111.6	112.2	111.6	112.2	112.0

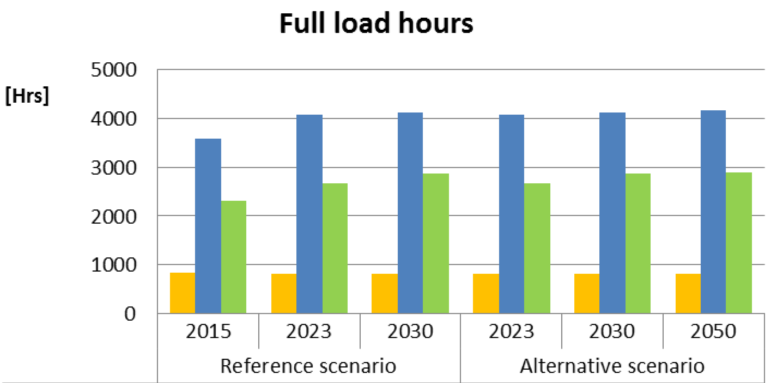
Multiplying VRE installed capacity by the respective full load hours results in electricity output, as presented in the lower part of **Figure 8** for each type of VRE power source in all scenario cases. It shows, for instance, that in R2015 the main part (about 70%) of total VRE power production comes from wind on land, while the remaining part is generated more or less equally by sun PV and wind on sea. In both R2030 and A2030, however, wind on sea has become the major VRE source with a share of 45%, followed by wind on land (33%) and sun PV (22%). In A2050, wind on sea has substantially strengthened its dominant position with an output of more than 120 TWh (i.e., about 65% of total VRE power output), followed by sun PV (46 TWh; 25%) and wind on land (20 TWh; 10%).[10]

[10] Note that the share of sun PV in total VRE power output is significantly lower than its share in total VRE installed capacity due to its significantly lower capacity factor (i.e. full load hours) compared to wind (see **Figure 8**).

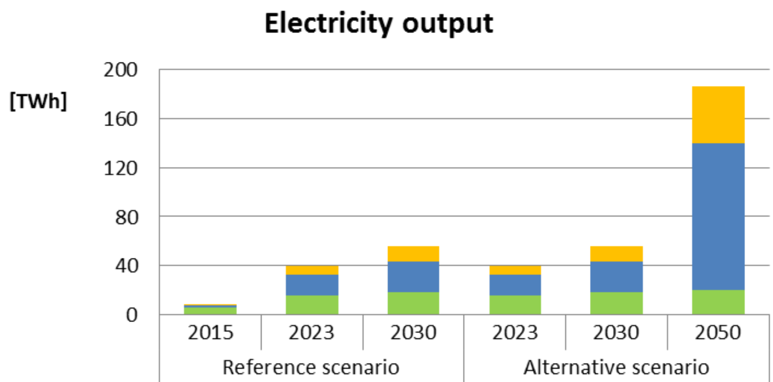
Figure 8: Assumed installed capacity, full load hours and resulting electricity output by VRE power sources in all scenario cases, 2015-2050



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Sun PV	1.5	8.6	15.1	8.6	15.1	56.1
Wind on sea	0.4	4.1	6.1	4.1	6.1	28.9
Wind on land	2.6	6.0	6.3	6.0	6.3	6.8



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Sun PV	840	820	820	820	820	820
Wind on sea	3580	4080	4120	4080	4120	4160
Wind on land	2310	2670	2860	2670	2860	2900



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Sun PV	1.3	7.1	12.4	7.1	12.4	46.0
Wind on sea	1.3	16.8	25.0	16.8	25.0	120.2
Wind on land	6.1	16.1	18.1	16.1	18.1	19.7

Figure 9: Share of VRE generation in total annual power load in all scenario cases, 2015-2050

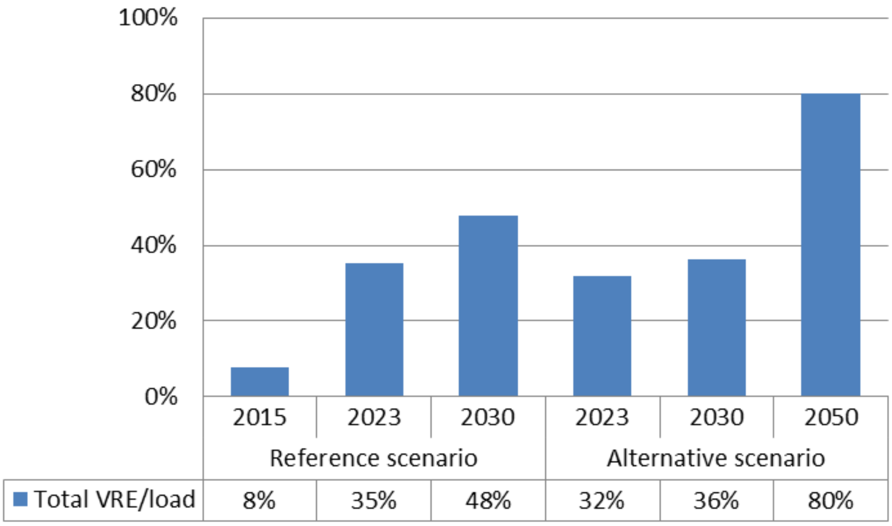


Figure 9 presents the resulting share of VRE power generation in total annual power load in all scenario cases. In the reference scenario this share increases from less than 8% in R2015 to about 35% in R2023 and almost 48% in R2030. Due to the higher (additional, total) load in A2023 and A2030, compared to R2023 and R2030, respectively, the comparative share of VRE output in total load is lower in A2023 and A2030, i.e. about 33% and 36%, respectively (as the VRE output is assumed to remain the same in the respective 2023 and 2030 scenario cases). Although power load further increases substantially in A2050, the share of VRE output in total load in this scenario case rises significantly up to some 83% due to the even more substantial increase in VRE output resulting from the assumed VRE installed capacity and full load hours in A2050 (see **Figure 8**).

2.3 Electricity demand and supply profiles

Table 6 provides a summary overview of the electricity demand and VRE supply profiles used during phase 1 of the FLEXNET project to analyse the hourly variation in residual load. In particular, normalised hourly profiles for a whole year (8760 hours) have been constructed by the project partners, or obtained from external sources, for three variables at the demand side of the electricity balance – i.e. conventional load, additional load for passenger EVs, and additional load for household HPs – as well as for three variables at the VRE supply side (i.e. wind on land, wind on sea and sun PV).[11]

[11] In the three alternative scenario cases (A2023, A2030 and A2050), total final power load at the national level includes an extra demand variable, i.e. additional load for all other forms of electrification (besides passenger EVs and households HPs). Since there is no profile readily available – or easily constructed – for this variable (which is actually a diverse, future mix of demand variables covering different sectors and end-uses), we have used the same (national, normalized) profile for this variable as for the variable 'conventional load' (which is also a diverse – but historical – mix of demand variables covering different sectors and end-uses).

Table 6: Overview of electricity demand and VRE supply profiles used during phase 1 of FLEXNET

Variable	National level	Regional level
Conventional load[a]	National (realised) profile for the year 2014, including all electricity users (obtained from ENTSO-E, 2016)	Regional (realised) profile for the year 2014, constructed by Alliander
Additional load EVs	National (realised) profile for the year 2014, constructed by Alliander	Idem
Additional load HPs	National (model-based) profile for the year 2012, constructed by the unit Energy Efficiency of ECN	Idem
Wind on land	National (forecast) profile for the year 2012, constructed by the unit Wind of ECN	Idem
Wind on sea	National (forecast) profile for the year 2012, constructed by the unit Wind of ECN	Not relevant
Sun PV	National (forecast) profile for the year 2015 (obtained from ENTSO-E, 2016)	Regional (realized) profile for the year 2014, constructed by Alliander

a) In the alternative scenario cases (A2023, A2030 and A2050), the normalized profile of the variable 'conventional load' is similar to the normalized profile of the variable 'additional load of other electrification'.

Note: for further details on these profiles, see Appendix A.

In general, hourly profiles have been used of recent 'representative' ('middle-of the-road') years and normalized to standard units (for instance, per MWh demanded or per MWe installed). Subsequently, in order to obtain the required hourly profiles for each scenario case (at the national, aggregated level), these normalized profiles have been multiplied by the volumes – or input values – of the respective scenario cases (see **Table 5**). As far as possible (i.e. if available), normalized profiles have been used of the same (recent, representative) year. **Table 6** shows, however, that this has not always been the case. In general, this should not be a real problem for long-term scenario analyses since, as noted, normalized profiles of recent, representative years have been used to construct possible , expected – but uncertain – patterns of hourly variations in power demand and VRE supply in future scenario cases.

Moreover, in general (i.e. if relevant), similar normalized profiles have been used for the analysis at the national and regional levels (**Table 6**). The major exceptions concern the profiles for conventional load and sun PV, where – for obvious reasons – national profiles have been downloaded from ENTSO-E (2016) while regional profiles have been constructed by Liander, i.e. the regional distribution network operator concerned.

For further details on the profiles, see Appendix A

2.4 National approach

The scenario analyses for phase 1 of the FLEXNET project have been conducted at both the national and regional level. The analysis at the national level has been carried out by ECN, while the analysis at the regional level has been conducted by Alliander. For the national level, ECN has set up an extensive spreadsheet model, i.e. a static simulation model, including and generating hourly data for a whole year (8760 hours) regarding domestic electricity demand and VRE power generation in the Netherlands for each of the six scenario cases analysed (applying the national electricity profiles and input values for these cases as outlined above).

Based on the abovementioned data, ECN has estimated and analysed the output results regarding the hourly variation and uncertainty of the residual power load, including the resulting demand for flexibility of the Dutch power system over the period 2015-2050 at the national level (see Chapters 3 and 4 for a further discussion of the national approach and the resulting output in terms of power demand and VRE supply profiles, trends and hourly variations in residual load, and the consequent demand for flexibility).

2.5 Regional approach

The regional analysis was performed using the Liander ANDES model. This model has been developed by Liander to determine the impact of the energy transition on the Liander distribution grid. Liander is the largest DSO in the Netherlands, supplying about one third of the Dutch households with electricity.

In phase 1, the model is used to generate load profiles on different levels of the grid (high voltage, medium voltage, and low voltage) for the six FLEXNET scenario cases. Based on these profiles, the model determines for each scenario case where and when overload may occur in the regional (Liander) power distribution network (see Chapter 5 for a further discussion of the regional approach and the resulting output in terms of network load profiles, expected grid overloads and arising flexibility needs.

3

The demand for flexibility due to the variability of the residual load

As outlined in the previous chapter, the demand for flexibility by the power system can be distinguished by three underlying sources ('causes'), i.e. the demand for flexibility due to (i) the variability of the residual load, (ii) the uncertainty of the residual load, and (iii) the congestion of the power grid.

In the present chapter, we analyse the first category of flexibility needs, while the second and third category are considered in Chapters 4 and 5, respectively. More specifically, in the present chapter we analyse first of all hourly profiles and scenario-based trends in the residual load of the power sector in the Netherlands over the period 2015-2050 (Section 3.1). Subsequently, we focus in particular on the hourly variation of the residual load and the resulting flexibility needs of the Dutch power system up to 2050 (Section 3.2). We conclude this chapter with three brief sections. Section 3.3 presents the main findings on some sensitivity analyses of the need for flexibility due to the hourly variations of the residual load, Section 3.4 indicates briefly the implications of some 'extreme situations' for this need, while Section 3.5 summarizes the main findings and messages of this chapter.

3.1 Trends in residual power load, 2015-2050

As explained in the previous chapter, in order to analyse developments and changes in the residual load of the Dutch power sector over the years 2015-2050, normalised hourly profiles for a whole year (8760 hours) have been developed for three variables at the demand side of the electricity balance – i.e. conventional load, additional load for passenger EVs, and additional load for household HPs – as well as for three variables at the VRE supply side (i.e. wind on land, wind on sea and sun PV).[12] Subsequently, these normalised profiles have been multiplied by the assumed input values of each scenario case in order to derive the hourly power demand and VRE supply profiles for each of the six scenario cases considered at the national level.

Below, the resulting hourly demand and VRE supply profiles are illustrated and explained first of all for some specific scenario cases and time intervals, i.e. usually for (the first day) of week 4 – and, occasionally, week 30 – of scenario cases R2015, A2030 and A2050. Subsequently, these hourly profiles are further analysed for all scenario cases and for the year as a whole.

3.1.1 Electricity demand and VRE supply profiles

Power load

Figure 10 shows the hourly variation of total power load in week 4 of three scenario cases (R2015, A2030 and A2050), including the profiles of the major constituent components of power load distinguished in the present study, i.e. (i) conventional load, (ii) additional load for heat pumps (HPs) in the household sector, (iii) additional load for personal electric vehicles (EVs), and – in the alternative scenario cases only – (iv) additional load for other forms of electrification.[13]

In the 2015 reference scenario, however, there is hardly any power load for heat pumps and electric vehicles – i.e., on average, less than about 60 MW and 180 MW in week 4, respectively – and, hence, total power load consists almost fully of conventional load. In the alternative 2030 scenario case, on the other hand, power demand by heat pumps and electric vehicles is already more substantial – i.e., on average, some 500 MW and 1000 MW in week 4, respectively – while the additional load for other means of electrification amounts to, on average, almost 4 GW. The conventional demand for electricity in A2030, however, is similar to the conventional load in R2015 (i.e., on average, about 14 GW in week 4 of both scenario cases).

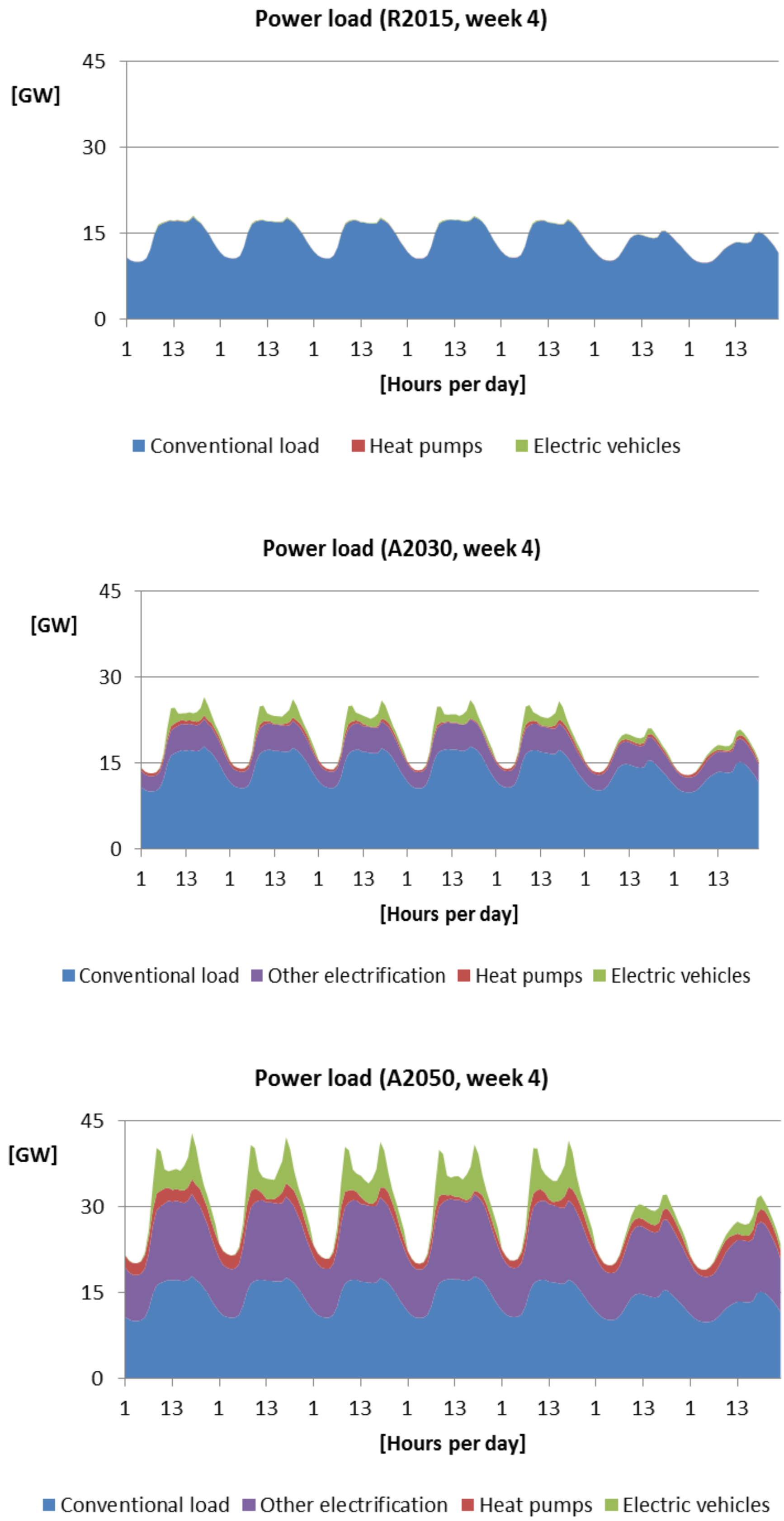
In the alternative scenario for 2050, the trends observed above in A2030 are even more outspoken. In particular, in week 4 of A2050 the power load for all additional means of electrification – including HPs, EVs and 'other electrification' – is, on average, even larger than the conventional power load, i.e. about 16 GW and 14 GW, respectively.

More specifically, **Figure 10** shows that the hourly load in week 4 of the selected scenario cases varies significantly per day. During working days (i.e. the first five days depicted in **Figure 10**), the demand for electricity is generally highest during the peak hours (17:00-19:00h) and lowest during the middle of the night (3:00-4:00h). For instance, during the working days of week 4 in R2015, power demand varies from approximately 10 GW in the base load hours to some 18 GW in the peak hours. During

[12] In the three alternative scenario cases (A2023, A2030 and A2050), total final power load at the national level includes an extra demand variable, i.e. additional load for all other forms of electrification (besides passenger EVs and households HPs). As explained, we have used the same (national, normalised) profile for this variable as for the variable 'conventional load'.

[13] For comparative reasons, we have opted for the same scale size on the Y-axis for each scenario case (if appropriate and relevant), although it may imply that in some cases – in particular for the 2015 reference case – the upper part of the figure becomes largely blank.

Figure 10: Power load during week 4 in some scenario cases, 2015-2050



the weekend (i.e. the last two days depicted in **Figure 10**), peak demand is usually less outspoken – i.e. lower – and, therefore, average power load is generally also lower during a weekend day than a working day.

Figure 10 also illustrates that, compared to R2015, the hourly variation in power load becomes significantly larger in A2030 and A2050 when substantial amounts of electricity demand are added to the conventional load due to the use of passenger EVs, household HPs and other means of electrification. Overall, the average hourly demand for electricity in week 4 increases from 14 GW in R2015 to 20 GW in A2030 and even to 30 GW in A2050. Hourly demand in week 4 of A2030, however, varies from 13 GW (base load) to 27 GW (peak load) and in A2050 from 19 GW to 42 GW, respectively (compared to 10 GW and 18 GW in R2015).

In addition, **Figure 10** shows that in A2030 and A2050 there are actually two outspoken peak periods per day, notably during working days, i.e. around 9 AM and 6 PM. This is largely due to the growing and widespread use of passenger EVs in these scenario cases, implying that during working days a large, growing amount of passenger EVs is uploaded when people have arrived at their working station (9 AM) and, subsequently, when they come back home (6 PM).

On the other hand, the hourly load for household heating pumps (HPs) is relatively more flat, particularly in A2050, when it is assumed that (i) most houses use particularly air/ground-source HPs, (ii) these houses are highly isolated, and therefore, (iii) the thermostat in these houses will be set at a fixed temperature throughout the week and, hence, the hourly load for household HPs will be relatively flat.[14]

So, the process of additional electrification implies not only that the average (hourly) power load increases but also that the daily and weekly profiles of electricity demand will change and, above all, that the hourly variation of total power load will be significantly larger and different.

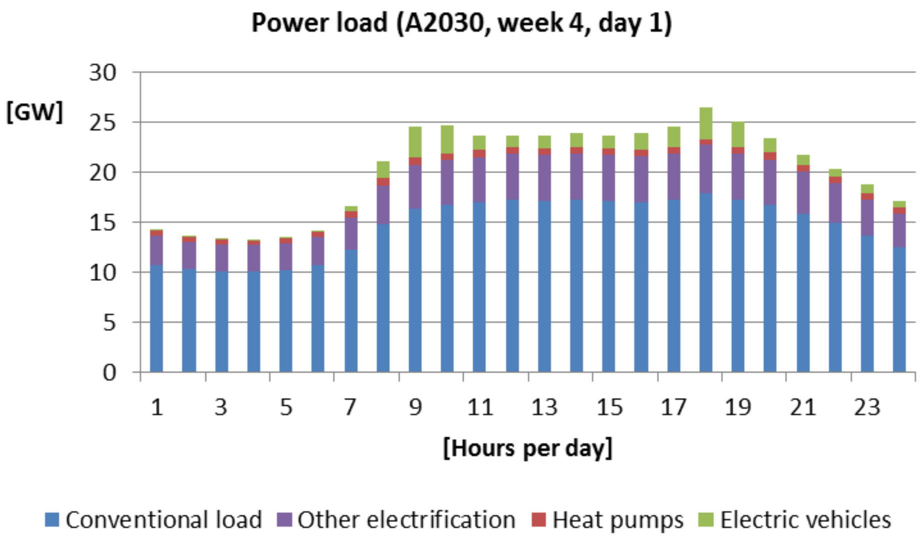
Figure 11 provides a more detailed and comparative picture of the hourly variation in power load in A2030 during the first day (Monday) of week 4 (winter; see upper part of the picture) versus the first day of week 30 (summer holidays, see lower part of **Figure 11**). Note that the average hourly load is generally lower in the summer (holidays) than in the winter, in particular during the peak hours of the working days, and that, therefore, the variation in hourly power load is also lower in the summer.

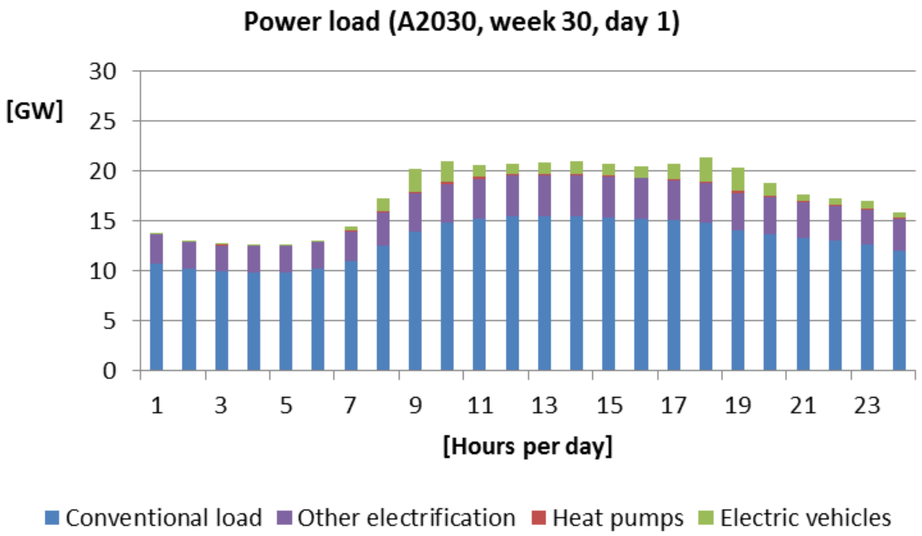
More specifically, the average total load during the first day of week 4 in A2030 amounts to 20 GW (varying from 13 GWh in hour 4 to 27 GWh in hour 18), while during the first day of week 30 it amounts to 18 GW (ranging from 13 GWh to 21 GWh, respectively). Apart from the (absolute) lower power load for conventional use and 'other electrification' during the summer period, in relative terms this is particularly due to the lower power load for passenger EVs and household HPs (see **Figure 11**).[15]

[14] For details on the household HP profiles, see Appendix A. Note that the hourly profile for 'other electrification' is assumed to be similar to the hourly profile for conventional load (for details, see also Appendix A).

[15] The average power load during the first day of week 30 in A2030 for household HPs amounts to 0.1 GW, compared to 0.6 GW in week 4. For conventional load, passenger EVs and 'other electrification', the comparative figures for week 30 (versus week 4) amount to (in GW): 13.1 (14.6), 1.0 (1.2), and 3.5 (3.9), respectively.

Figure 11: Power load during the first day (Monday) of weeks 4 and 30 in scenario A2030





VRE power supply

Figure 12 presents the hourly variation of power supply from variable, renewable energy sources during week 4 in three scenario cases (R2015, A2030 and A 2050). In R2015, hourly VRE generation during week 4 is still modest, i.e. on average less than 2 GW. Almost all of this supply (99%) comes from wind – largely on land – while there is hardly any power generation from sun PV during this (winter) week.[16] Due to the rapid growth of installed VRE capacity over the period 2015-2050 – in particular of sun PV (see Section 2.2, **Figure 8**). – VRE power supply increases accordingly to, on average, 8.2 GW during week 4 in A2030 and to 26 GW in A2050. But even in A2050, the share of power output from sun PV during this (winter) week remains relatively low (less than 3%).

16 Although hardly or not visible from the upper part of **Figure 12**, there is some tiny power production from sun PV during week 4 in R2015 (on average, about 21 MW), mostly focused around the mid-day hours (10:00-16:00h) of some days.

Figure 12: VRE power supply during week 4 in some scenario cases, 2015-2050

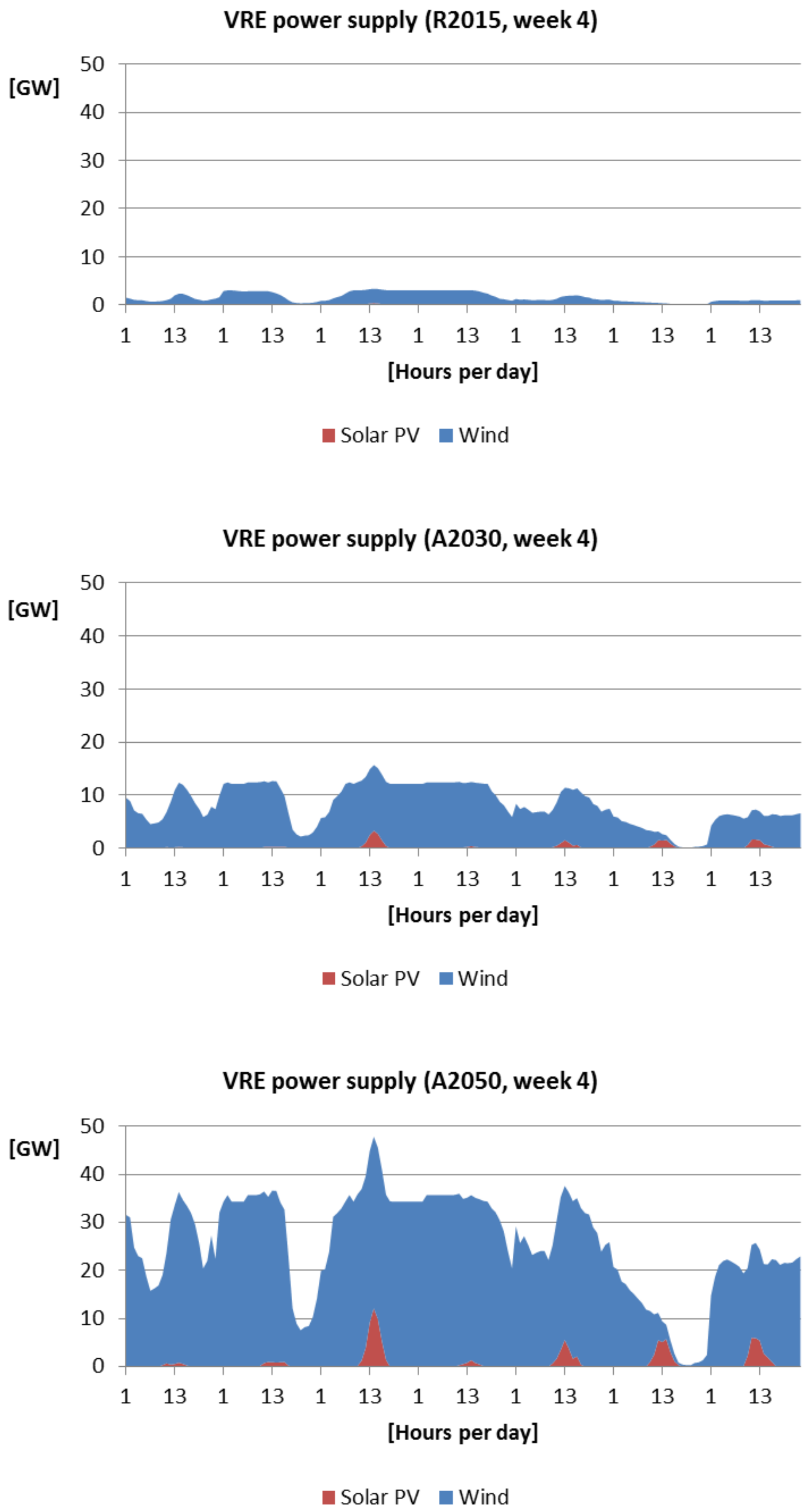


Figure 12 shows that the hourly variation of VRE power supply during week 4 of the selected scenario cases is usually large and, in absolute terms, increases substantially over time due to the rapid expansion of VRE installed capacity. For instance, in week 4 of A2050 VRE power supply varies from 0.32 GW to almost 48 GW.

In addition, **Figure 12** indicates that, usually, the variation of VRE power generation shows a more regular, predictable pattern for sun PV than for wind. In general, power production from sun PV is restricted to (clear, cloudless) daylight hours, with a peak production usually around 1-2 PM. Moreover, (clear, cloudless) daylight hours are generally longer and (peak) sun PV generation usually significantly higher during summer than winter periods. In contrast, power output from wind energy is usually less regular (more variable/uncertain), i.e. it may occur both by day and at night but its (peak) output may vary substantially by day and night, both during summer and winter periods. In both cases (sun PV and wind), however, there may be many (consecutive) hours – and even days – in which there is hardly or no generation from VRE sources at all, although the incidence (i.e. the number of hours/days) of hardly or no generation over a whole year is usually significantly higher for sun PV than for wind.

Figure 13 provides a more detailed and comparative picture of the hourly variation in VRE power supply in A2030 during the first day of week 4 (winter) versus the first day of week 30 (summer). VRE power supply is, on average, higher during the first day of week 30 in A2030 (8.3 GW) than during the first day of week 4 (7.7 GW), while the share of sun PV is also higher during the first day of week 30, although still relatively low (i.e. less than 9% during the first day of week 30, compared to less than 1% in week 4).[17] In addition, the hourly variation of VRE power production is also higher during the first day of week 30 in A2030 (ranging from 0.6 to 16 GW) than during the first day of week 4 (varying from 4.5 to 12 GW).

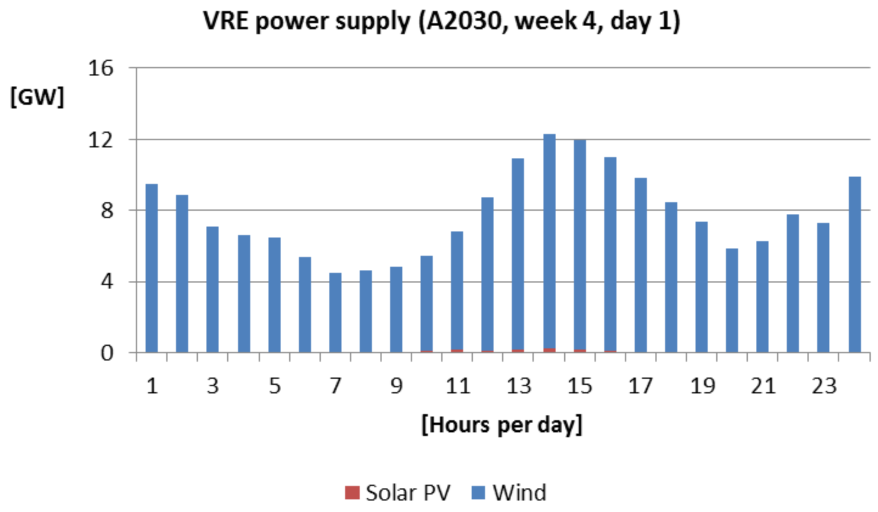
Residual load

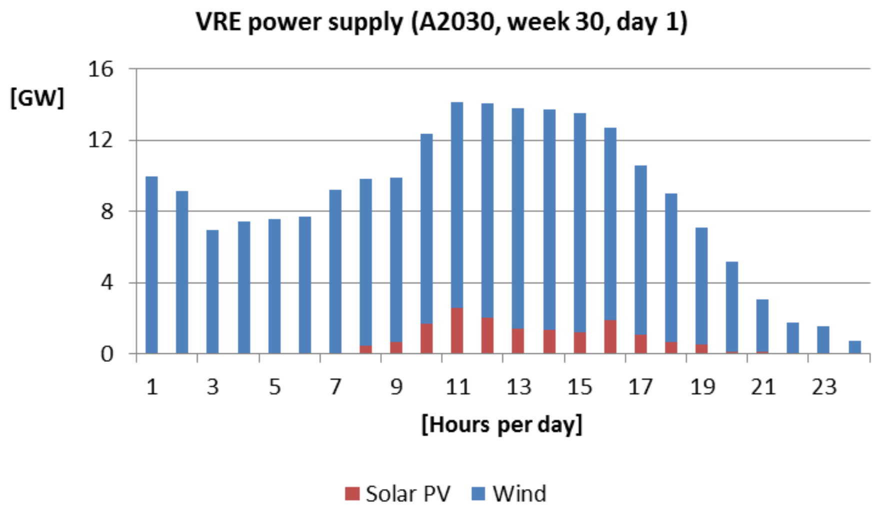
Figure 14 presents the hourly variation of the residual load – compared to total load – during week 4 in three scenario cases (R2015, A2030 and A2050), where residual load is defined as total load minus total VRE power generation. As noted above, in R2015 VRE power supply is relatively low and, therefore, both the level and variation of residual load is largely similar to the level and variation of total load.

In A2030, however, VRE power production is, in general, substantially higher, in particular during certain hours of the week, day or year. As a result, compared to total load, the average level of the residual load in A2030 is generally substantially lower whereas the hourly variation of the residual load is usually significantly higher. For instance, in week 4 of A2030, total power load amounts to, on average, 20 GW (varying between 13 and 27 GW), while the residual load is, on average, 11 GW (ranging from 1.3 GW to 23 GW).

[17] Note that, for consistency reasons, we have opted for the first day of week 30 (and week 4) although during several other days/weeks VRE power supply – notably from solar PV – is significantly higher. Note also that during other days of the week there may be hardly or no power generation from wind and that the daily pattern of power generation from wind may be significantly different from the pattern shown in **Figure 13**.

Figure 13: VRE power supply during the first day (Monday) of weeks 4 and 30 in scenario A2030

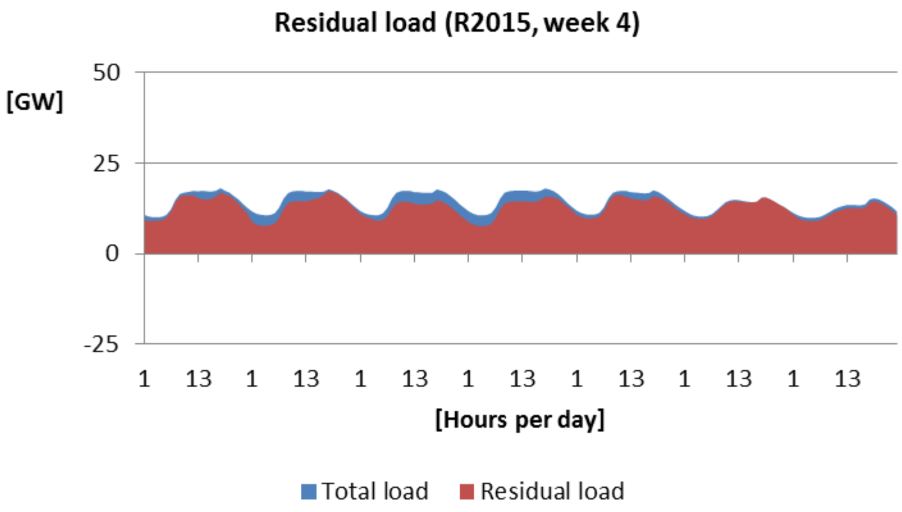


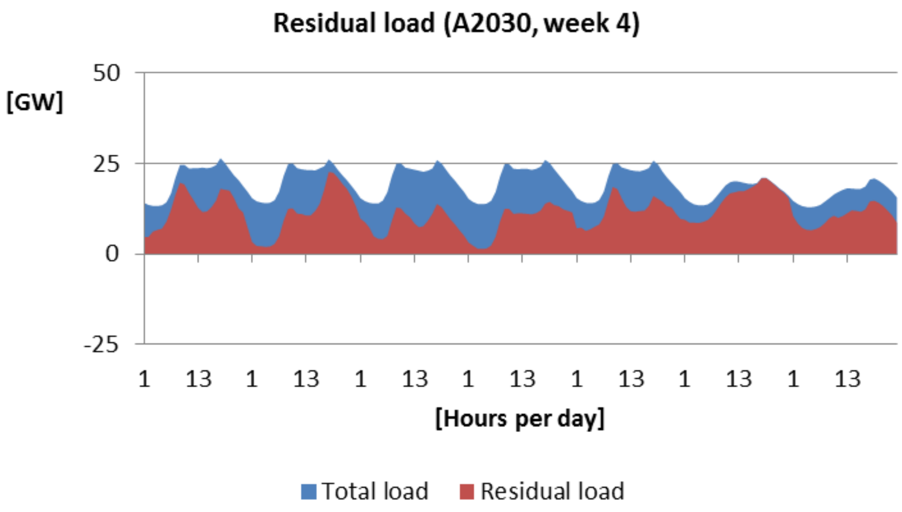


In A2050, VRE power generation is even much higher – i.e., on average, almost 17 times higher in absolute terms than in R2015 (and more than three times higher than in A2030) – while total load is only two times higher than in R2015. As a result, hourly residual load is usually much lower than total load in A2050 – and even substantially negative during many hours – while the hourly variation of residual load in A2050 is generally even much higher than in A2030. For instance, in week 4 of A2050, total power load amounts to, on average, 30 GW (varying between 19 and 43 GW), while the residual load is, on average, 4.1 GW (ranging between -16 and 32 GW).

Note that during some hours of week 4 in A2050 the residual load is even negative. This implies that during these hours the total VRE power supply is larger than total power demand and, hence, that the resulting negative residual load (or VRE surplus) has to be met by the supply of flexibility options such as storage, exports, VRE curtailment or demand response, including demand shifting and new, additional demand, for instance through conversion of power-to-gas, power-to-heat, etc.

Figure 14: Residual load during week 4 in some scenario cases, 2015-2050





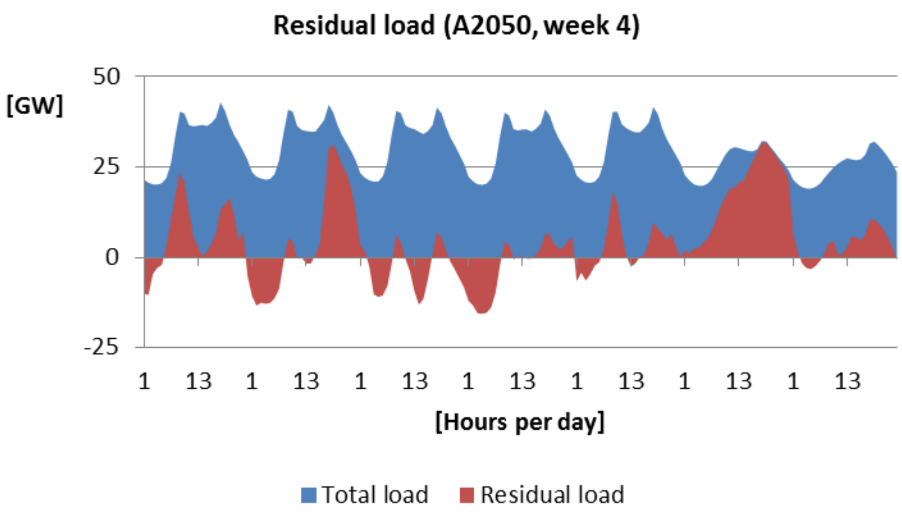
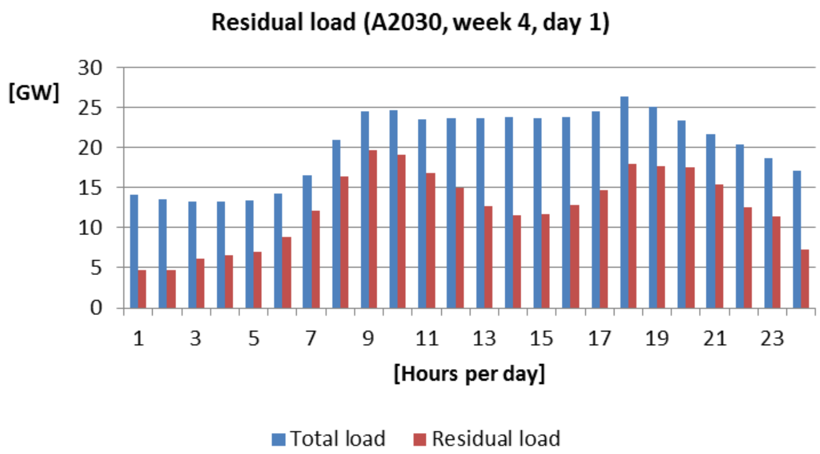


Figure 15: Residual load during the first day (Monday) of weeks 4 and 30 in scenario A2030



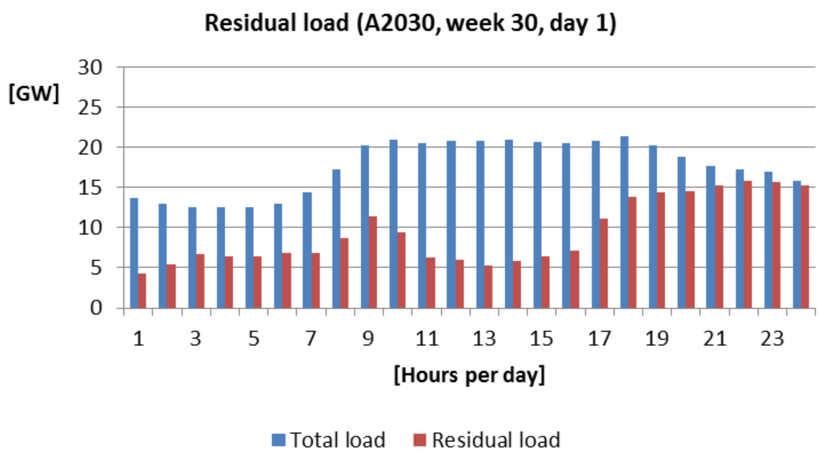


Figure 15 provides a more detailed and comparative picture of the variation in hourly residual load in A2030 during the first day of week 4 (winter) versus the first day of week 30 (summer). The residual load is, on average, higher during the first day of week 4 in A2030 (5.8 GW) than in week 30 (4.2 GW). This results from the dual fact that (i) power load is usually higher during winter than summer periods, and (ii) power generation from VRE sources is generally lower during winter than summer periods. Hence, the difference between total load and residual load is often higher in summer than winter periods, as indicated in **Figure 15** for the first day of week 4 versus week 30 in A2030, respectively.

3.1.2 Duration curves of power load and VRE supply

In power sector analyses, a duration curve ranks the consecutive (hourly) values of a certain variable over a certain period – usually over a whole year – from (the hour with) the highest value in the upper left of the picture to (the hour with) the lowest value in the bottom right. For variables such as power load or VRE surplus, the points on the curve present the value of the variable in capacity terms (for instance, in GW), whereas the surface between the curve and the X-axis represents the variable in energy volume terms (e.g., in GWh or TWh).

Figure 16 provides duration curves of three power sector variables in three scenario cases. The upper part of this figure presents the (hourly) load duration curve in R2015, A2030 and A2050. The surface between this curve and the X-axis represents the total annual power load in these scenario cases. The picture shows that both the average level and the variance of total load are significantly higher in A2050 than in A2030 and even much higher than in R2015. For instance, in A2050 hourly load amounts to, on average, approximately 27 GW and varies between 15 GW (lowest, minimum value) and 43 GW (highest, maximum value). In R015, these figures amount to about 13 GW, 8 GW and 19 GW, respectively (see also **Figure 55** below, including data for all other scenario cases).

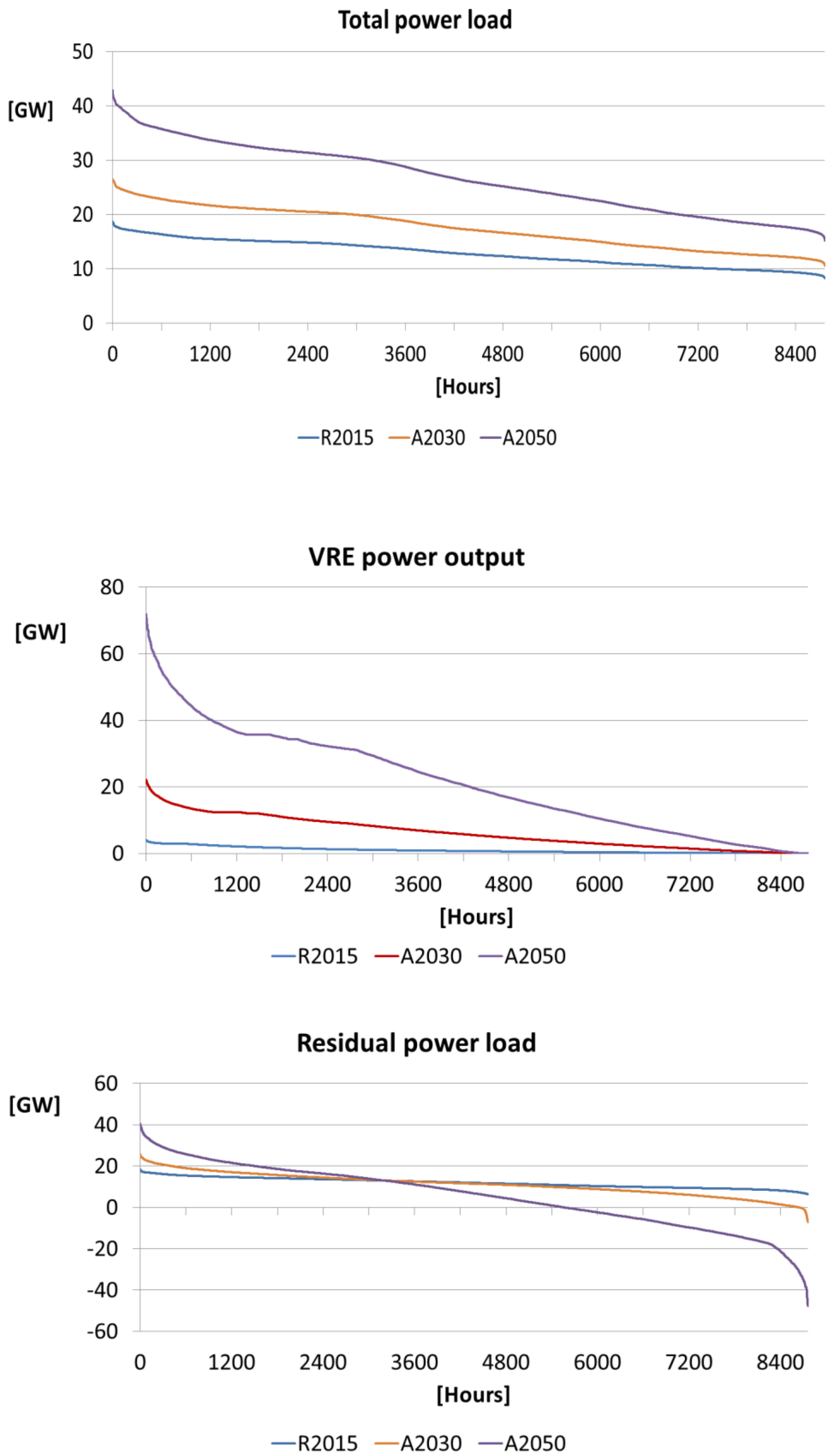
The middle part of **Figure 16** presents the VRE output duration curve in R2015, A2030 and A2050. The surface between this curve and the X-axis represents the total annual VRE output in these scenario cases. The picture shows that in A2050 the level of the hourly VRE output – notably in the upper left of the duration curve – as well as the variation of this output are substantially higher than in A2030 and even much higher than in R2015. For instance, in A2050 hourly VRE output amounts to, on average, 21 GW while the maximum output reaches a level of almost 72 GW. In R2015, these figures amount to approximately 1.0 and 4.0 GW, respectively, and in A2030 to 6.3 and 22 GW, respectively (see also **Figure 55** below, including data for all other scenario cases).

In all scenario cases, however, there is a large amount of hours in which VRE output is relatively low – compared to hourly total load – or even close to zero. For instance, in R2015 VRE output is less than 10% of average hourly load, i.e. 1.3 GW, in almost 6300 hours of the year. In A2030, the comparative figure amounts to approximately 1900 hours of VRE output below 10% of average hourly load in that scenario case (i.e. 1.8 GW). But even in A2050, with a large share of VRE output in total annual power load (80%), there are still more than 1600 hours with VRE output below 10% average hourly load (i.e. below 2.7 GW) and about 2600 hours with VRE output below 20% of average hourly load in A2050 (5.4 GW). This implies that, on average, power load during these hours has to be largely (80-90%) met by other supply sources besides VRE output, including other means of power generation (gas, coal, nuclear) or by flexibility options such as raising power imports, demand response or using electricity stored during other, surplus hours.

The lower part of **Figure 16** presents the residual load duration curve for R2015, A2030 and A2050. The surface between this curve and the X-axis represents the total annual residual load (which – in some hours – may be negative, i.e. below the X-axis). The picture shows that the slope of the residual load duration curve in A2050 is significantly steeper than in A2030 and even far steeper than in R2015. This implies that the variation of the residual load is generally significantly higher in A2050 than in A2030 and even much higher than in R2015 (see also **Figure 55** below, including data on minimum, maximum and average residual load per hour in all scenario cases).

Note that the lower part of **Figure 16**also shows that the residual load is negative during some hours in A2030 and, in particular, during a large number of hours in A2050. This implies that VRE output production is larger than total load during these hours and, hence, that there is a VRE surplus.

Figure 16: Duration curves of hourly total load, VRE output and residual load in three scenario cases, 2015-2050



Hourly load and capacity needs

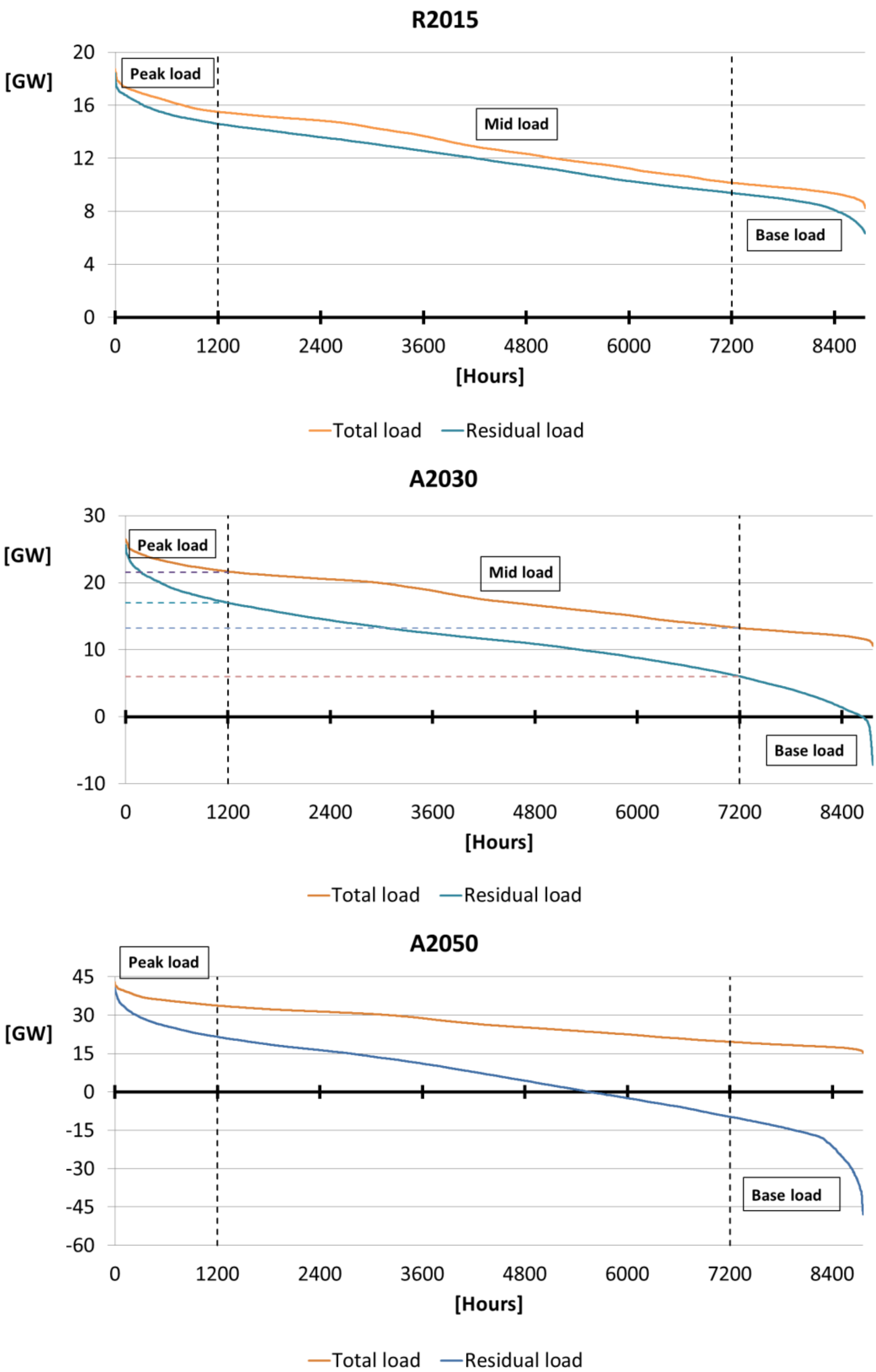
Figure 17 shows once again the duration curves of hourly total load and hourly residual load but this time presented per scenario case (R2015, A2030 and A2050) and distinguishing between different load periods (i.e. peak, mid and base load). These curves indicate how many hours a certain capacity of power supply – including power generation, power imports and/or other (flexible) power supply options – is needed to meet a certain level of (residual) power demand. By comparing these curves – both mutually and over time – a first, rough impression is obtained from the necessary changes in these capacity needs resulting from (i) a significant increase of total power demand (mainly due to the further electrification of the energy system) and, in particular, (ii) a significant increase of VRE generation output over the years 2015-2050. A summary overview of these changes in hourly (residual) power load and resulting capacity needs in scenario cases R2015, A2030 and A2050 is presented in **Table 7** (see also **Figure 18**).

Figure 17 shows that on the left part of the each graph, i.e. during peak hours, the difference between total load and residual load is small. This refers particularly to hours with a relatively high power demand and a relatively low supply of electricity from VRE sources (sun/wind). For instance, in A2050 the maximum hourly load over the year as a whole amounts to almost 43 GW, whereas the maximum hourly residual load is nearly 41 GW (**Table 7**). This implies that despite the significant increase in VRE capacity from less than 5 GW in R2015 to almost 92 GW in A2050, the difference in capacity need to meet the maximum hourly residual load – compared to the maximum hourly total load – amounts to only 2 GW.

Moving to the right in each graph of **Figure 17**shows that the difference between the total load duration curve and the residual load duration curve becomes larger, notably in A2030 but, above all, in A2050. This refers particularly to hours with a relatively low electricity demand and a relatively high (and growing) supply of VRE power supply. For instance, in A2050 the minimum hourly load over at least 1200 hours ('peak load') amounts to almost 34 GW, whereas the comparable hourly residual load is about 22 GW, i.e. approximately 12 GW lower (see also **Table 7** and **Figure 18**). Similarly, in A2050 the minimum hourly load over at least 7200 hours ('mid load') amounts to nearly 20 GW, whereas the comparable hourly residual load is even negative (-9.8 GW), i.e. a difference of approximately 30 GW. Finally, in the most extreme case of A2050 (on the outer right of **Figure 17**), the minimum hourly load over the year as a whole amounts to more than 15 GW, whereas the comparable residual load is almost -48 GW, i.e. a large VRE output surplus, making an absolute difference of more than 63 GW.

The growing differences between the curves of total load and residual load – both when moving to the right and when moving over time – result from the high variability of VRE generation output as well as from the growing, higher amount of VRE installed capacity over the period R2015-A2050. Therefore, a growing share of power production from sun and wind leads to a growing variability and an increase in extreme values of residual load, implying a higher need for flexibility to deal with these VRE-induced characteristics of the residual power load.

Figure 17: Duration curves of total load and residual load in three scenario cases



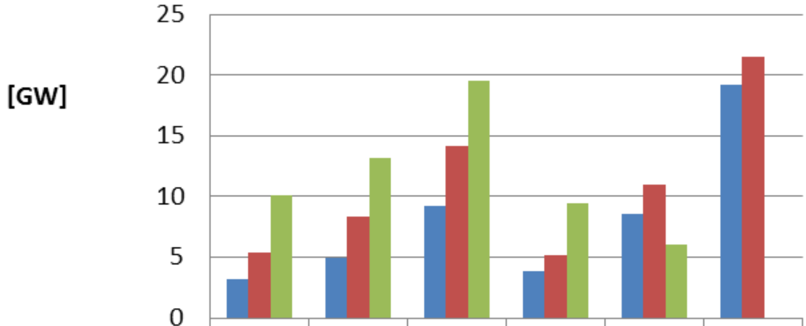
Note: for visibility reasons, the scale of the Y-axis differs between the three pictures. As a result, the slope of the residual load duration curve is actually much steeper in A2050 – compared to R2015 – than suggested in the figure. Moreover, the difference between the total load and residual load duration curves is actually much wider in A2050 – compared to R2015 – than suggested in the figure.

Table 7: Hourly load and capacity needs in different load periods in three scenario cases (in GW)

						Difference compared to R2015	
		R2015	A2030	A2050		A2030	A2050
Hourly load							
Maximum hourly load (over all hours of the year)	Total load	18.7	26.5	42.9		7.8	24.2
	Residual load	18.4	25.6	40.7		7.2	22.3
Minimum hourly load over at least 1200 hours per year ('peak load')	Total load	15.5	21.6	33.7		6.1	18.2
	Residual load	14.6	17.0	21.5		2.4	6.9
Minimum hourly load over at least 7200 hours per year (‘mid load')	Total load	10.1	13.2	19.5		3.1	9.4
	Residual load	9.4	6.0	-9.8		-3.4	-19.2
Minimum hourly load (over all hours of the year)	Total load	8.2	10.6	15.3		2.4	7.1
	Residual load	6.3	-7.2	-47.9		-13.5	-54.2
Capacity needs							
Peak load (<1200 hours)	Total load	3.2	4.9	9.2		1.7	6.0
	Residual load	3.8	8.6	19.2		4.8	15.4
Mid load (1200-7200 hours)	Total load	5.4	8.4	14.2		3	8.8
	Residual load	5.2	11.0	21.5		5.8	16.3
Base load (>7200 hours)	Total load	10.1	13.2	19.5		3.1	9.4
	Residual load	9.4	6.0	0.0		-3.4	-9.4
Total capacity needs	Total load	18.7	26.5	42.9		7.8	24.2
	Residual load	18.4	25.6	40.7		7.2	22.3

As noted, by comparing the load duration curves of **Figure 17**, a first impression is obtained from the necessary changes in capacity needs – including flexibility options – to meet different, varying levels of (residual) power load (see also **Table 7** and **Figure 18**). For instance, peak load is served by peak capacity, with a deployment of less than 1200 hours per year. **Figure 17** shows that in A2030 for total load the peak capacity needs amount to about 5 GW (for load levels above 22 GW up to the maximum hourly load of 27 GW). On the other hand, for residual load this need increases to approximately 9 GW (for residual load levels above 17 GW up to the maximum hourly residual load of 26 GW). In A2050, the increase in peak capacity need is even much higher, i.e. from approximately 9 GW (total load) to some 19 GW (residual load), resulting from the large increase in VRE power output between A2030 and A2050.

Figure 18: Capacity needs to meet power demand in different load periods in three scenario cases



	Total power demand			Residual power demand		
	R2015	A2030	A2050	R2015	A2030	A2050
Peak load (<1200 hours)	3.2	4.9	9.2	3.8	8.6	19.2
Mid load (1200-7200 h.)	5.4	8.4	14.2	5.2	11.0	21.5
Base load (>7200 hours)	10.1	13.2	19.5	9.4	6.0	0.0

The above findings indicate that, due to the increase in power supply from VRE sources, the need for residual peak load capacity increases substantially over time whereas the need for residual base load capacity decreases significantly (and even becomes zero in A2050; see **Figure 18**). The peak load capacity, however, has to be rather flexible as it covers less than 1200 hours per annum spread throughout the year. Note in particular that the number of peak hours with relatively high levels of residual load is relatively small in A2050 (and A2030), i.e. it is usually even much smaller than 1200 hours (see left side of **Figure 17**). Therefore, capacity investments in (flexible) power generation – or other (flexible) power supply options – to meet these high residual load levels have to be recovered in a relatively small number of running hours.

3.1.3 Residual load: VRE shortages versus surpluses

As observed above, for instance in **Figure 16** or **Figure 17**, besides hours with a 'positive residual load' ('VRE shortage') there may also be hours with a 'negative residual load' ('VRE surplus'), i.e. hours in which the output of power generation from VRE resources is larger than the total power load during these hours. In case the share of VRE generation in total load increases, both the number of hours with a VRE surplus and the size of this surplus tend to increase as well (as shown below). This raises both new challenges and opportunities in terms of flexibility demand and supply in the power system. For instance, the incidence and alternation of (large) hourly VRE shortages versus (large) VRE surpluses enhances the issue how to deal with these fluctuations in residual load (and the related fluctuations in hourly electricity prices). On the other hand, these fluctuations create also opportunities in terms of energy storage and demand response.[18]

[18] See also the report on phase 2 of the FLEXNET project, dealing with the supply of flexibility in the Dutch power system.

Table 8: Summary data on residual load, VRE shortages and VRE surpluses in all scenario cases, 2015-2050

		Reference scenario			Alternative scenario		
	Unit	2015	2023	2030	2023	2030	2050
Total power load	TWh	112.5	113.5	115.6	125.5	153.1	232.8
Total VRE output	TWh	8.6	40.0	55.5	40.0	55.5	186.0
Total residual load	TWh	103.8	73.6	60.2	85.6	97.6	46.8
VRE share in total load	%	8%	35%	48%	32%	36%	80%
Hours with a positive residual load ('VRE shortage')							
Total number of VRE shortage hours (p.a.)	Hrs	8760	8615	7887	8731	8640	5543
Maximum hourly VRE shortage	GW	18.4	17.9	18.4	20.1	25.6	40.7
Total hourly VRE shortage (p.a.)	TWh	103.8	73.7	62.0	85.6	97.8	81.9
Hours with a negative residual load ('VRE surplus')							
Total number of VRE surplus hours (p.a.)	Hrs	0	145	873	29	120	3217
Maximum number of consecutive VRE surplus hours	Hrs	0	10	21	8	10	61
Maximum hourly VRE surplus	GW	0	4.7	10.6	3.6	7.2	47.9
Total hourly VRE surplus (p.a.)	TWh	0	0.1	1.8	0.0	0.2	35.1

Table 8 provides some summary data on residual load, VRE shortages and VRE surpluses for all scenario cases. It shows, for instance, that in R2015 – with a share of VRE output in total annual load of approximately 8% – all hours of the year (8760) have a positive residual load and, hence, there is no VRE surplus during any hour of the year.

In R2023 and R2030, however, VRE power output has increased substantially, whereas total power demand has remained more or less the same (compared to R2015). Therefore, in R2023 and R2030 the VRE share in total load is much higher (than in R2015), i.e. 35% and 48%, respectively. As the hourly VRE output fluctuates heavily, however, there are on the one hand many hours with hardly or no VRE output and, on the other hand, several hours with a (substantial) VRE surplus. **Table 8** shows that the number of hours with a VRE surplus amounts to 145 in R2023 and increases to 873 in R2030, whereas the total VRE surplus accumulated over these hours increases from 0.1 TWh to 1.8 TWh, respectively.

In A2023 and A2030, VRE installed capacity and VRE output are assumed to be similar in R2023 and R2030, whereas the rate of electrification and, hence, total (additional) load are higher (see Chapter 2, **Table 5**). As a result, both (i) the VRE share in total load, (ii) the number of VRE surplus hours per annum, and (iii) the total VRE surplus accumulated over these hours are significantly lower in A2023 and A2030, compared to R2013 and R2030, respectively (see **Table 8**). On the other hand, in A2050 – due to the large increase in VRE output covering, on average, 80% of total power load – the number of VRE surplus hours jumps to 3217, i.e. about 37% of total annual hours, while the total (accumulated) hourly VRE surplus amounts to more than 35 TWh.

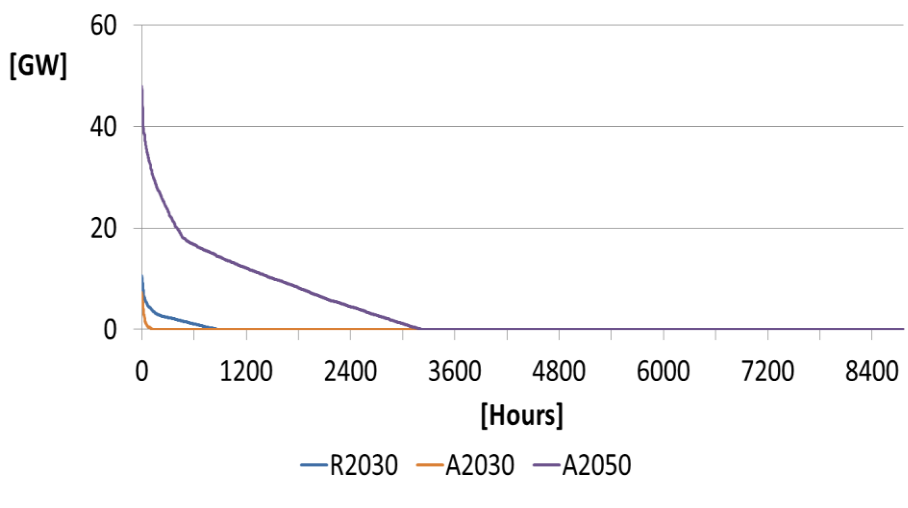
Note, however, that a total hourly VRE surplus in a certain scenario case – over a certain number of hours – does not imply that the total residual load in that case – over the year as a whole – is negative. On the contrary, the total hourly VRE surplus over a year refers only to those hours in which there is an actual surplus of power generation from VRE resources, compared to hourly load, and does not include those hours in which there is an actual 'positive' residual load (i.e. a 'VRE shortage'). As can be observed from **Table 8**, even in A2050 there is, on balance, a significant amount of total residual load (almost 47 TWh) over all annual hours (8760) despite a large VRE surplus (about 35 TWh) accumulated over 3217 hours of the year.

Table 8 also indicates the number of consecutive hours in which there is a VRE surplus. This is an indicator for the timing and, to some extent, the size of the VRE surplus issue and, hence, of the need for flexibility options to deal with this issue. **Table 8** shows that the number of consecutive hours increases from 8 in A2023 to 21 in R2030 and even to 61 – i.e. about 2.5 days in a row – in A2050.

VRE surplus duration curve

Figure 19 presents the VRE surplus duration curve for three scenario cases, i.e. for R2030, A2030 and A2050.[19] It shows, for instance, that in A2050 the maximum hourly VRE surplus amounts to about 48 GW and that the number of hours with a VRE surplus runs up to approximately 3200 hours. The surface between the VRE surplus duration curve and the X-axis represents the total VRE surplus over a whole year (for instance, about 35 TWh in 2050; see also **Table 8**, including more detailed VRE surplus data for all scenario cases).

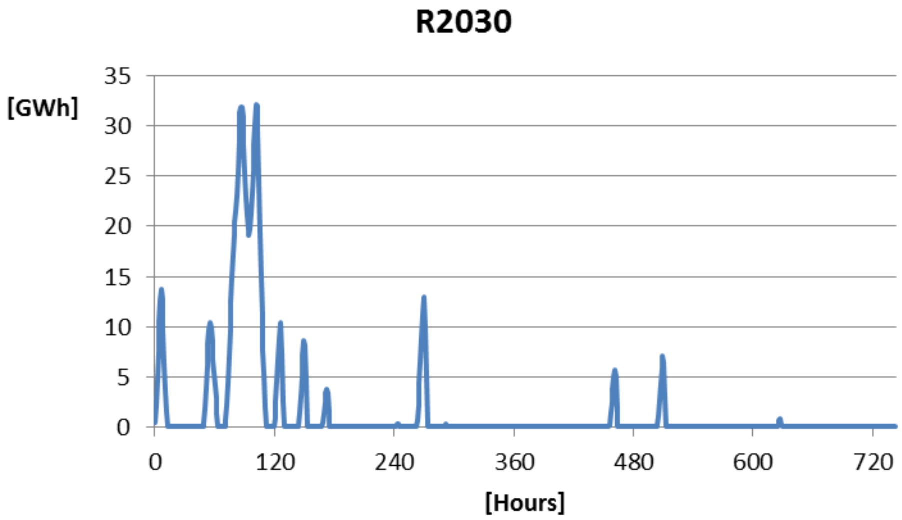
Figure 19: VRE surplus duration curve in three scenario cases, 2015-2050

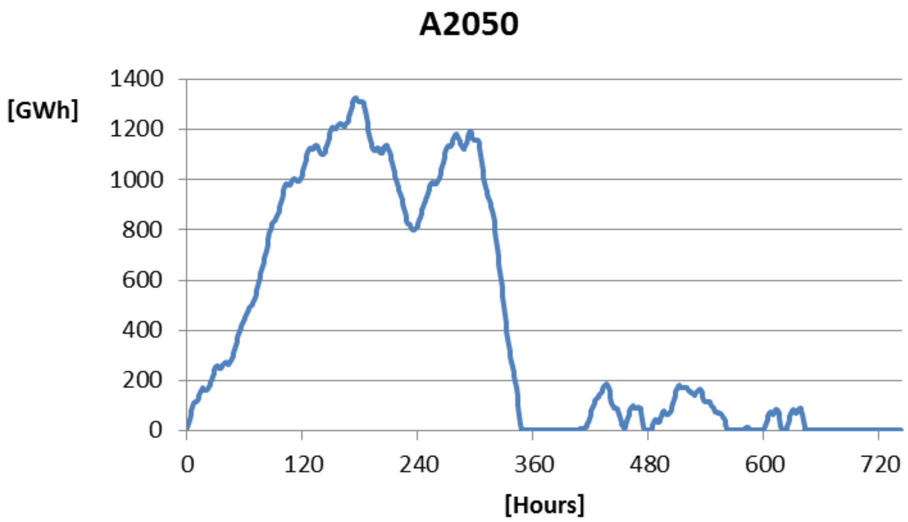


For illustrative purposes, **Figure 20** presents the cumulative demand for flexibility due to hourly VRE surpluses – e.g., in terms of the demand for flexible storage – during the first month of the year (January, 744 hour) in two scenario cases, i.e. R2030 and A2050, assuming that electricity is stored during those hours in which there is a VRE surplus

19 Note that the VRE surplus duration curve is the mirror image of the negative (part of the) residual load duration curve, as presented in the lower part of **Figure 16** (Section 3.1.2). In contrast to **Figure 16**, however, **Figure 19** includes scenario R2030 instead of R2015 as this latter (reference) scenario does not include any hourly VRE surplus at all (see also **Table 8**

Figure 20: Cumulative demand for flexibility ('storage') due to hourly VRE surpluses during the first month of the year (January, 744 hours) in scenario cases R2030 and A2050





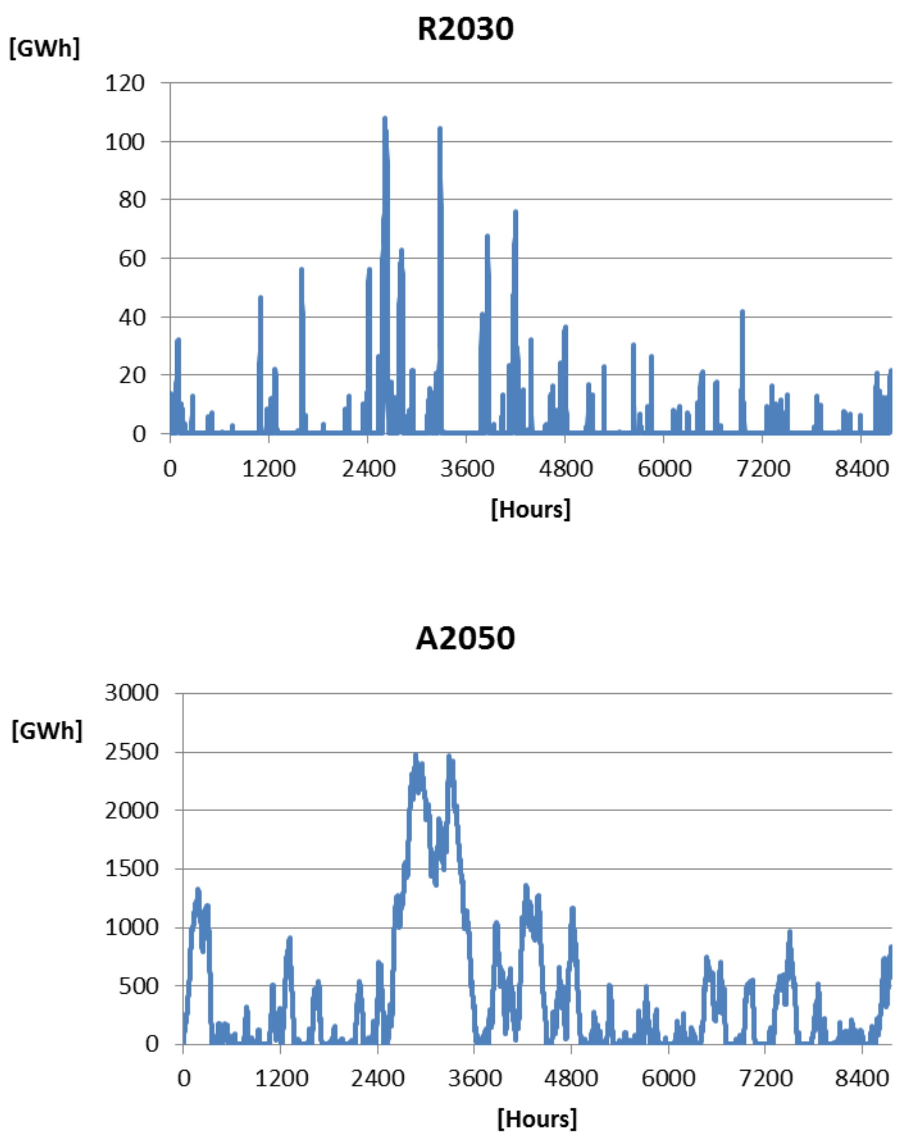
and used (discharged) in those hours in which there is no VRE surplus (i.e. to meet the residual load).[20] It shows, for instance, that during the first hours of January R2030 there is a VRE surplus in each hour resulting in a cumulative demand for flexible storage of almost 14 GWh (in hour 7). In the next few hours, however, there is no VRE surplus – i.e., there is a positive residual load – and the stored electricity is used (discharged) to meet this demand until the storage is empty (in hour 13). This patterns of electricity storage (in hours with a VRE surplus) and de-storage (in hours with a VRE shortage) until the storage is empty is repeated several times during the rest of January – and beyond – in R2030.

[20] Note that the scale on the Y-axis is different for the two scenario cases due to a large difference in the amounts of hourly VRE surpluses in R2030 versus A2050.

Due to the further, rapid increase in installed VRE generation capacity between R2030 and A2050 – whereas power load grows far less significantly between these two scenario years – the number of VRE surplus hours and the amounts of VRE surpluses involved increase rapidly over the years 2030-2050, resulting in a large, swiftly growing cumulative demand for flexible storage, as illustrated in the bottom part of **Figure 20** for the first month of A2050.

Figure 21 provides a similar picture of the cumulative demand for flexible storage due to hourly surpluses in R2030 and A2050 but this time for the year a whole. It shows, among others, that this need for flexibility is particularly high between hour 2400 (mid-April) and hour 3600 (late May). In A2050, the need for flexible storage due to hourly VRE surpluses even reaches a level of almost 2500 GWh during this period.

Figure 21: Cumulative demand for flexibility ('storage') due to hourly VRE surpluses during the whole year (8760 hours) in scenario cases R2030 and A2050



Some qualifications, however, have to be added to **Figure 20** and **Figure 21**, including the related observations made above. Firstly, these figures assume that the level of electricity storage is zero at the beginning of the year, while – in practice – there may already be some (substantial) electricity storage by that time. More importantly, these figures assume that an hourly VRE surplus needs to be (fully) stored, whereas there may be several other (cheaper) flexibility options to address a VRE surplus, such as VRE curtailment or more, flexible demand (including more power exports, less imports, demand response, etc.). Moreover, the figures assume that in case of a positive residual power load (i.e., no VRE surplus) this demand is (fully) met by discharging electricity storage, whereas there may be several other (cheaper) options to meet this (domestic) demand, such as more power imports, less exports or shifting power demand to other hours. Finally, these figures do not consider inflexible, non-VRE supply ('must run'), which enhances the issue of addressing the VRE surplus.[21]

Table 9 provides a summary overview of the demand for flexibility due to hourly VRE surpluses in all scenario cases. It shows, for instance, that for all indicators considered, this demand is zero in R2015. In addition, it indicates that, in capacity terms, the maximum hourly demand for flexibility due to a VRE surplus increases from 3.6 GW in A2023 to almost 48 GW in A2050, whereas – in energy terms – the maximum cumulative demand for flexibility (e.g., flexible storage) increases from 18 GWh in A2023 to almost 2500 GWh in A2050. In addition, **Table 9** shows that total annual demand for flexibility due to hourly VRE surpluses increases from almost zero in A2023 to more than 35 TWh in A2050.

Table 9: Summary overview of the demand for flexibility due to hourly surpluses of VRE output in all scenario cases, 2015-2050

	Reference scenario			Alternative scenario		
	2015	2023	2030	2023	2030	2050
Demand for flexibility due to VRE surplus						
Maximum hourly VRE surplus (in GW)	0	4.7	10.6	3.6	7.2	47.9
Maximum cumulative VRE surplus (in GWh)	0	27.7	108.1	18.2	46.1	2480.8
Total hourly VRE surplus (per annum; in TWh)	0	0.1	1.8	0.0	0.2	35.1

3.2 Trends in hourly variations of residual load and resulting flexibility needs

This section focusses more specifically on the trends in the hourly variations of the residual load in the Dutch power system up to 2050 and the resulting flexibility needs due to these variations. In brief, Section 3.2.1 presents some profiles of hourly load variations, Section 3.2.2 shows duration curves of hourly variations of the residual

[21] For a further analysis of non-VRE power supply, energy storage and other, alternative flexibility options, see the report on phase 2 of the FLEXNET project.

power load, Section 3.2.3 considers the link between hourly variations and levels of residual load, Section 3.2.4 discusses some indicators and trends of flexibility needs due to the hourly variations of the residual load and, finally, Section 3.2.5 analyses in some more detail the major drivers (determinants) of these flexibility needs.

3.2.1 Profiles of hourly load variations

Hourly load variations ('ramps') are defined as the difference between load in hour *t* and load in hour *t-1* (with t = 1,…..n). Following the analysis in Section 3.1.1, **Figure 22** presents profiles of the hourly variations in capacity terms (GW/h) for both conventional load, total load and residual load during the first day of week 4 in three scenario cases (R2015, A2030 and A2050).[22] In addition, for comparative reasons, **Figure 22** shows also the profile of the respective ramps during the first day of week 30 in A2030.[23] Note that for each scenario year different scales have been used on the Y-axis (in order to make the presentation and comparison of the respective ramps within a scenario year more meaningful) and that, therefore, the ramps in future scenario years – notably in A2050 – are substantially larger, in particular compared to R2015, than presented in **Figure 22**.

Hourly load variations ('ramps') can be either positive ('ramp-up') or negative ('ramp-down'). With regard to the residual load, they are one of the major indicators of the demand for flexibility, i.e. either upward flexibility or downward flexibility (see Section 2.1). As illustrated by **Figure 22**, hourly ramps are often significantly larger for residual load than for total load, implying that the demand for flexibility due to variation in residual load is often significantly higher than the demand for flexibility due to variation in total load.

In addition, over a certain period – for instance, a day, week or year – ramps are generally larger in cases with a higher total load and/or a higher supply of electricity from VRE sources in particular. For the first day of week 4 this is illustrated in **Figure 22** and quantified in **Table 10** for three scenario cases (R2015, A2030 and A2050). For instance, the maximum hourly ramp-up during this day increases from 2.6 GW in R2015 to 4.3 GW in A2030 and even to 7.2 GW in A2050, the average ramp-up increases from 0.8 GW to 2.0 GW and 3.7 GW, respectively, while the total hourly ramp-up increases from 9.0 GWh to 22 GWh and 52 GWh, respectively.[24]

For comparative reasons, both **Figure 22** and **Table 10** include also data on hourly ramps for the first day of week 30 in scenario A2030. They indicate that the comparative ramps in maximum, average and total aggregated terms are usually smaller in week 30 (summer) than in week 4 (winter). It should be noted, however, that these data are primarily indicative and that they may vary significantly by day/week.

[22] Note that the difference between the ramps of conventional load and total load represents the hourly variation in additional load (due to EVs, HPs and other means of electrification) and that the difference between the ramps of total load and residual load represents the hourly variation in VRE power generation.

[23] Obviously, both the level and variation of the respective ramps may be significant different during other days/weeks/scenario cases than presented in **Figure 22**.

[24] Total hourly ramp-up aggregates all hourly ramp-ups over a certain period (for instance, a day, week or year), while total hourly ramp-down aggregates all hourly ramp-downs over this period.

Figure 22: Hourly variations ('ramps') of conventional load, total load and residual load during the first day (Monday) of weeks 4 and 30 in selected scenario cases, 2015-2050

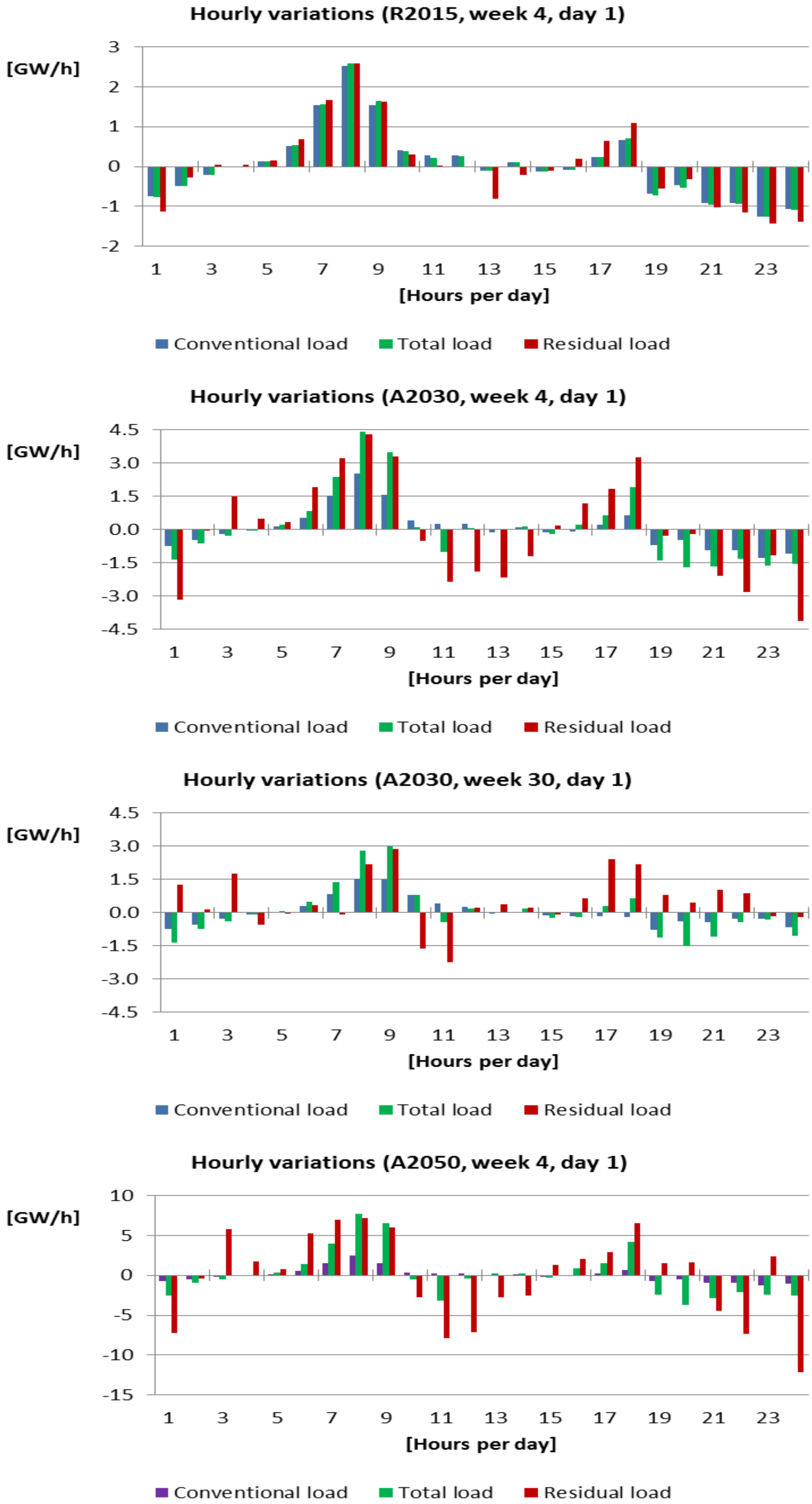


Table 10: Statistics on hourly variation ('ramps') of residual load during the first day (Monday) of week 4 and 30 in some scenario cases, 2015-2050

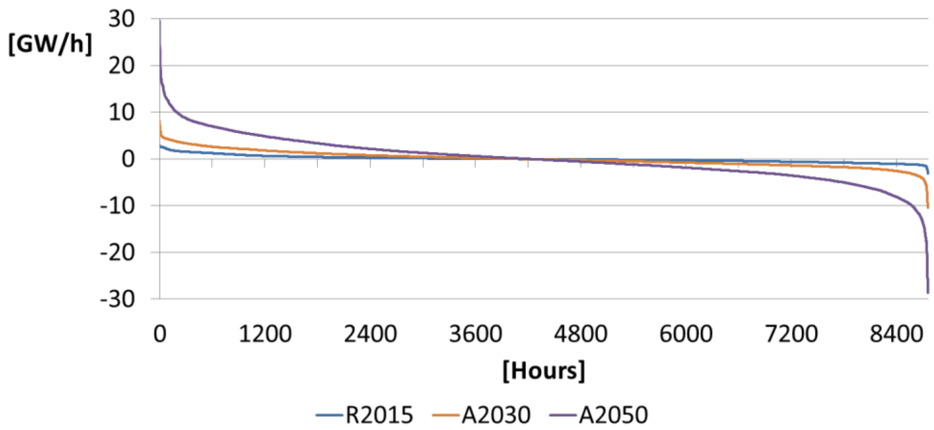
	R2015, week 4, day 1	A2030, week 4, day 1	A2030, week 30, day 1	A2050, week 4, day 1
Maximum hourly ramp-up (in GW/h)	2.6	4.3	4.0	7.2
Maximum hourly ramp-down (in GW/h)	1.4	4.1	3.2	12.1
Average hourly ramp-up (in GW/h)	0.8	2.0	1.2	3.7
Average hourly ramp-down (in GW/h)	0.7	1.7	0.9	5.5
Total hourly ramp-up (in GWh)	9.0	21.5	19.7	52.3
Total hourly ramp-down (in GWh)	8.4	22.1	6.8	54.7

3.2.2 Ramp duration curve

Figure 23 presents the ramp duration curve for three scenario cases, i.e. R2015, A2030 and A2050. This curve ranks the hourly variations of the residual load ('ramps'), i.e. the demand for flexibility due to the hourly changes of the residual load, either upwards ('ramp-up', i.e. in the left part of the figure, above the X-axis) or downwards ('ramp-down', i.e. in the right part of the figure, below the X-axis). It shows that both the size and the variation of the hourly ramps is significantly larger in A2050 compared to A2030 (and in A2030 compared to R2015). For instance, in A 2050 the hourly ramp varies between approximately 30 GW (maximum ramp-up) and -29 GW (maximum ramp-down), while in A2030 it ranges from about 8 to -10 GW (for specific data, including all other scenario cases, see below).

The surface between the ramp duration curve and the X-axis represents the aggregated annual demand for hourly ramping (flexibility), either upwards (above the X-axis) or downwards (below the X-axis).

Figure 23: Ramp duration curve of the residual load in three scenario cases, 2015-2050



3.2.3 Link between residual load and hourly ramp

Figure 24 presents the relationship between hourly ramp and residual load in three scenario cases (R2015, A2030 and A2050) from two perspectives, i.e. (i) the link between residual load in hour X and ramp in the same hour (upper part of the figure) and (ii) the link between residual load in hour X and ramp in the next hour, X + 1 (lower part of the figure).[25] **Figure 24** confirms that (i) the variations of hourly ramps and residual load are in general significantly larger in A2030 than in R2015 while, in turn, they are much larger in A2050 than in A2030, (ii) in each scenario case, the total annual size/number of ramp-ups (i.e. above the X-axis) is generally equal to the total annual size/number of the ramp-downs (below the X-axis) as the sum of the ramp-ups and -downs over a year is close to zero, and (iii) the residual load is always positive in R2015 (i.e. on the right side of the Y-axis) whereas there are some hours in A2030 with a negative residual load ('VRE surplus') and even a lot of VRE surplus hours in A2050 (left side of the Y-axis).

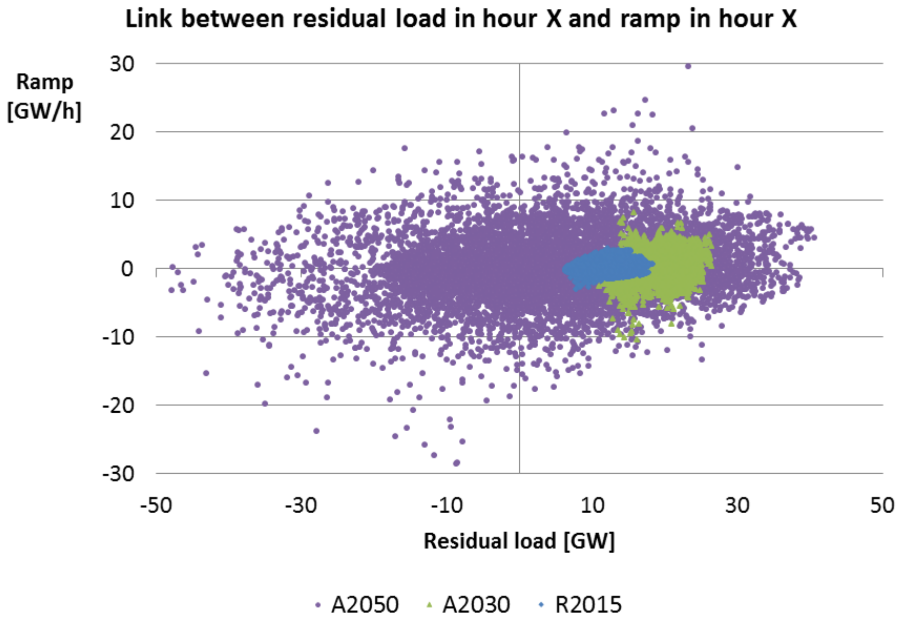
As said, the upper part of **Figure 24** presents the relationship between hourly ramp and residual load in the same hour. More specifically, it links the resulting residual load in hour X to the ramp in hour X, i.e. the change in residual load realised in hour X compared to the residual load in the previous hour, X – 1. For instance, the highest point in the upper-right quadrant of this figure, with coordinates 23 (X-axis) and 30 (Y-axis), indicates that in hour X the resulting residual load is 23 GW while the ramp – or change in residual load realised in that hour – amounts to 30 GW (ramp-up), implying that the residual load in the previous hour, X- 1, amounted to -7 GW. On the other hand, the lowest point in the bottom-left quadrant of the figure, with coordinates -9 and -29, indicates that in hour X the resulting residual load is -9 GW while the change in residual load realised in that hour amounts to -29 GW (ramp-down), implying that the residual load in the previous hour, X -1, amounted to 20 GW.

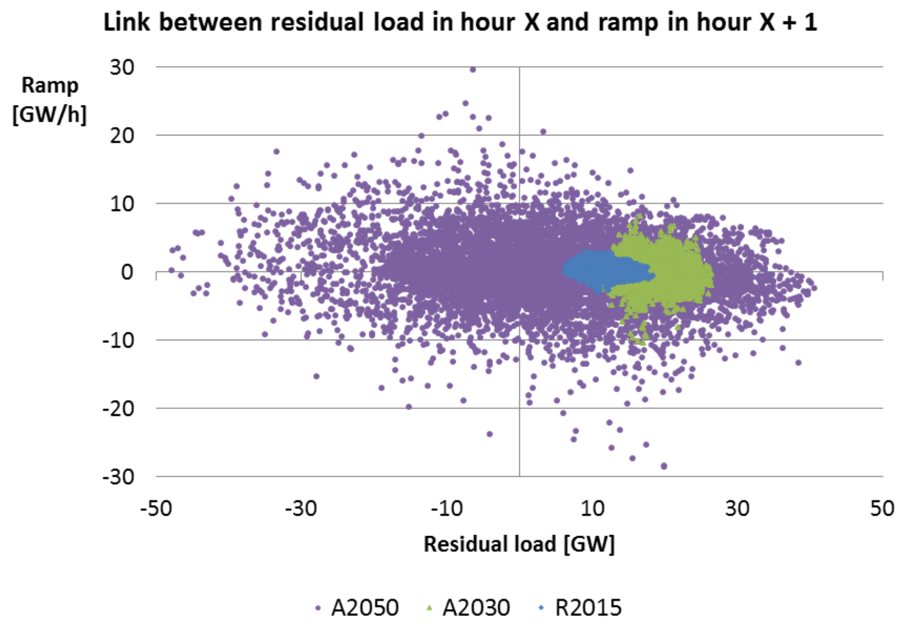
This information on the link between hourly ramp and residual load is both interesting and relevant as (i) the hourly ramp is a main indicator for both the size and the direction of the hourly demand for flexibility (either upwards or downwards), and (ii) the means or options to meet this demand for flexibility depend on the size and sign of the residual load in the previous hour. For instance, if the residual load in a specific hour is relatively high, the (gas) power plants dispatched to meet this load cannot be used to meet the upward ramping (flexibility) needs in the next hour, whereas they might be good options in case of downward flexibility needs in the next hour. On the other hand, if the residual load is relatively low in a specific hour, idle gas plants may be good options to meet upward ramping needs but cannot be used to meet a downward demand for flexibility.[26]

[25] Note that a part of A2030 is not visible in **Figure 24** as we have put R2015 in the upfront of the picture. This applies also for a part of A2050 as we have put this scenario case at the background of the figure.

[26] These and other (flexibility) supply issues are analysed and discussed in more detail in the report on the second phase of the FLEXNET project.

Figure 24: Hourly ramps versus residual load in three scenario cases, 2015-2050





From a flexibility or ramping need perspective, the lower part of **Figure 24** is probably more relevant as it links the residual load in hour X to the ramp in the next hour, X + 1, i.e. the change in residual load needed in hour X + 1 compared to the given residual load in hour X. For instance, the highest point in the upper-left quadrant of this figure, with coordinates -7 (X-axis) and 30 (Y-axis), indicates that in hour X the residual load is minus 7 GW while the ramp in the next hour, X + 1, amounts to 30 GW (ramp-up), implying that the residual load in that hour amounts to 23 GW. On the other hand, the lowest point in the bottom-right quadrant of the figure, with coordinates 20 and -29, indicates that in hour X the resulting residual load is 20 GW while the change in residual load needed in the next hour, X + 1, amounts to -29 GW (ramp-down), implying that the residual load in that hour amounts to -9 GW.

3.2.4 Indicators and trends of flexibility needs

In order to analyse the demand for flexibility due to the variability of the residual load, the following three specific indicators have been defined and applied:

- *Maximum hourly ramp*, in both directions (upwards and downwards), i.e. the maximum hourly variation in residual load over a year, expressed in capacity terms per hour (GW/h). As illustrated by **Figure 23**, the maximum ramp-up (or maximum hourly demand for upward flexibility) refers to the highest point in the upper left of the hourly ramp duration curve, whereas the maximum hourly ramp-down (or maximum hourly demand for upward flexibility) refers to the lowest point in the bottom right of the hourly ramp duration curve. The maximum hourly ramp is an indicator for the maximum hourly capacity need for flexibility in a year.

- *Maximum cumulative ramp,* in both directions (upwards and downwards). As illustrated in **Figure 22** above, hourly ramps vary widely and alternate continuously between ramp-ups and ramp-downs. During some consecutive hours, however, ramps may move into one direction, either upwards or downwards. This implies that over these hours the cumulative ramp – and, hence, the capacity need for flexibility, either upwards or downwards – is significantly higher than during one of these single hours. The maximum cumulative ramp, expressed in capacity terms over the number (#) of the respective consecutive hours (GW/#h), refers to the maximum ramp (i.e. the maximum variation in residual load, either upwards or downwards) during some consecutive hours in a year and is, hence, an indicator for the maximum capacity needs for flexibility in a year.

- *Total hourly ramps,* in both directions (upwards and downwards), i.e. the total annual amount of hourly ramps – either up or down – aggregated over a year, expressed in energy terms (TWh). As illustrated in **Figure 23**, the surface between the hourly ramp duration curve and the X-axis represents the total annual amount of hourly ramps, either upwards – i.e. in the left part of the figure, above the X-axis – or downwards, i.e. in the right part of the figure, below the X-axis.

Maximum hourly ramp
Figure 25 presents an overview of the hourly demand for flexibility due to the hourly variation of residual load, either upward ('ramp-up') or downwards ('ramp-down'), in terms of the maximum hourly ramping capacity needed in all scenario cases. It shows that the capacity need for maximum hourly ramp-up increases from 3.0 GW in R2015 to almost 30 GW in A2050, while the need for maximum hourly ramp-down increases from 3.1 to almost 29 GW, respectively.

Maximum cumulative ramp
Figure 26 presents an overview of the maximum cumulative ramps in all scenario cases. It shows that the capacity need for maximum cumulative ramping in both directions (up and down) increases from about 10 GW in R2015 to approximately 65-66 GW in A2050. In addition, **Table 11** provides data on the number of consecutive hours in which the maximum cumulative ramps are achieved. For instance, in A2050 the maximum cumulative ramp-up of 66 GW is reached in 10 consecutive hours, while the maximum cumulative ramp-down of 65 GW is achieved in 17 hours.

Figure 25: Need for maximum hourly ramps ('flexibility') in all scenario cases, 2015-2050

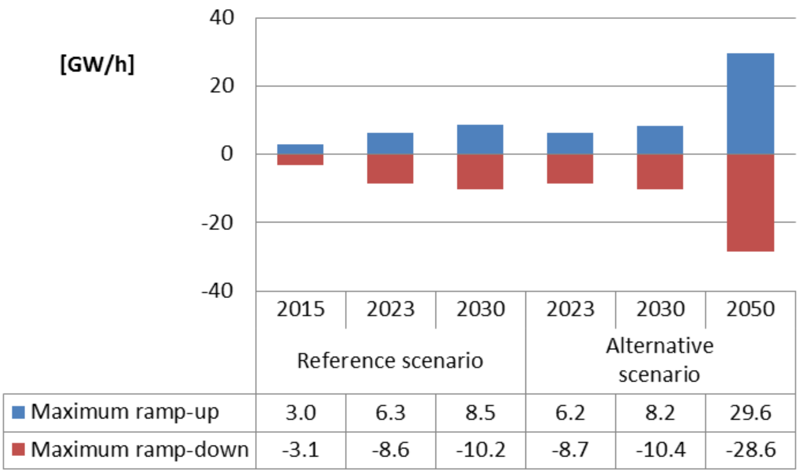


Figure 26: Need for maximum cumulative ramp ('flexibility') in all scenario cases, 2015-2050

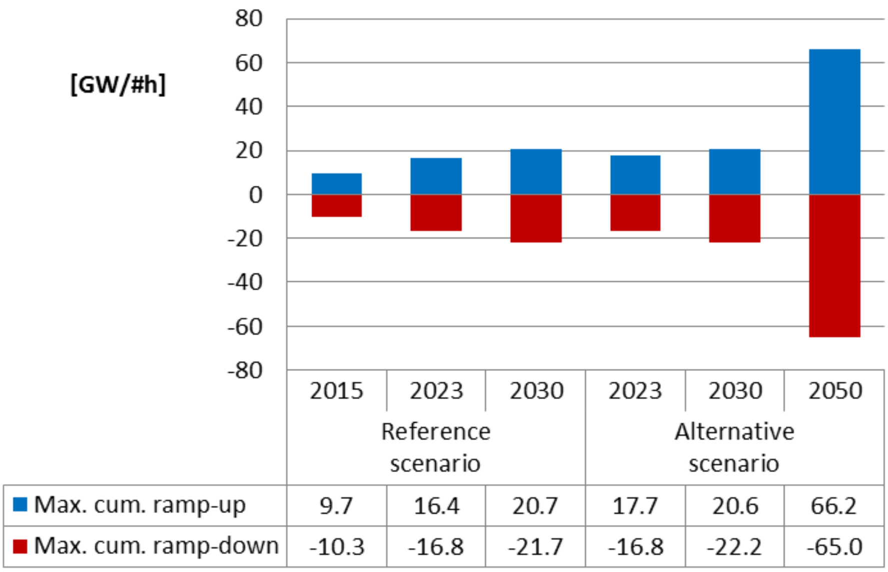


Table 11: Number of consecutive hours of maximum hourly ramps in all scenario cases, 2015-2050

	Reference scenario			Alternative scenario		
	2015	2023	2030	2023	2030	2050
Maximum cumulative ramp-up (in GW/#h)	9.7	16.4	20.7	17.7	20.6	66.2
• *Number of consecutive ramp-up hours*	*14*	*14*	*9*	*14*	*9*	*10*
Maximum cumulative ramp-down (in GW/#h)	10.3	16.8	21.7	16.8	22.2	65.0
• *Number of consecutive ramp-down hours*	*10*	*17*	*17*	*19*	*17*	*17*

Figure 27: Illustration of maximum cumulative ramp-up in mid-May of A2050 (hours 3277-3290)

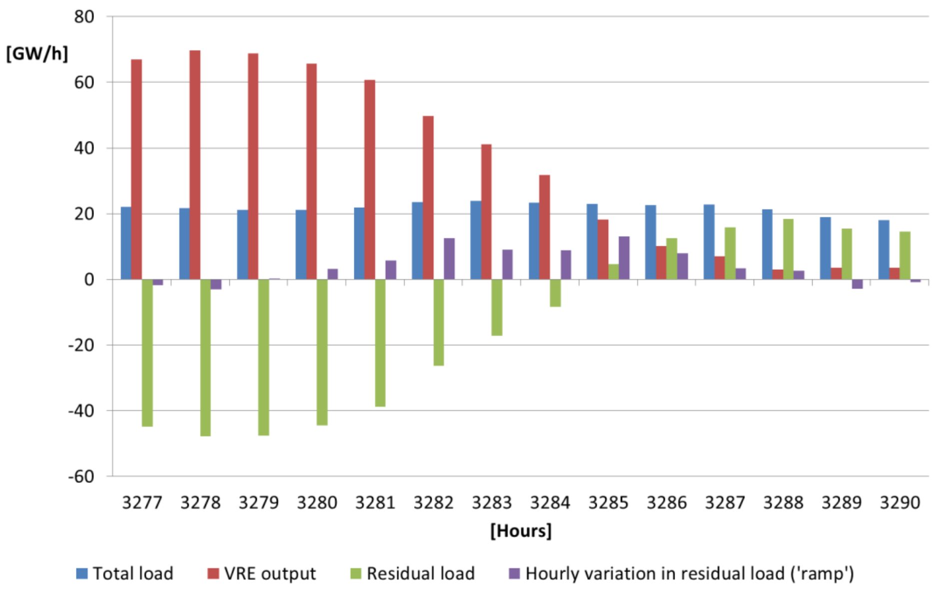


Figure 27 illustrates the case of the maximum cumulative ramp-up of 66 GW in A2050, which takes place over the hours 3279-3288 (i.e. somewhere in mid-May). **Figure 27** shows that over these hours total power demand is rather stable at a level of 22 GW. VRE output, however, declines steadily from almost 70 GW in hour 3278 to 3 GW in hour 3288. As a result, residual load increases steadily from -48 GW in hour 3278 to +18 GW in hour 3288, i.e. equal to a cumulative ramp-up of 66 GW over these hours. This amount is equal to the sum of the hourly variations of the residual load ('ramps') over the hours 3278-3288 (i.e. the sums of the purple bars in **Figure 27**).

Total hourly ramps

Figure 28 provides an overview of the total annual demand for flexibility due to the hourly variation of the residual load, aggregated in energy terms (TWh) for either all hourly ramp-ups or all hourly ramp-downs during a year in each of the six scenario cases. It shows that this demand for flexibility increases from 2.2 TWh in R2015 to more than 15 TWh in A2050. In addition, it indicates that the demand for total annual ramp-down in each scenario case is exactly similar to the demand for total annual ramp-up. This is due to the fact that the cumulative values of all hourly ramps amount to zero by the end of the year as it is assumed in our scenario analysis that the residual load during the first hour of a scenario case is exactly similar to the residual load during the first hour of the next year.

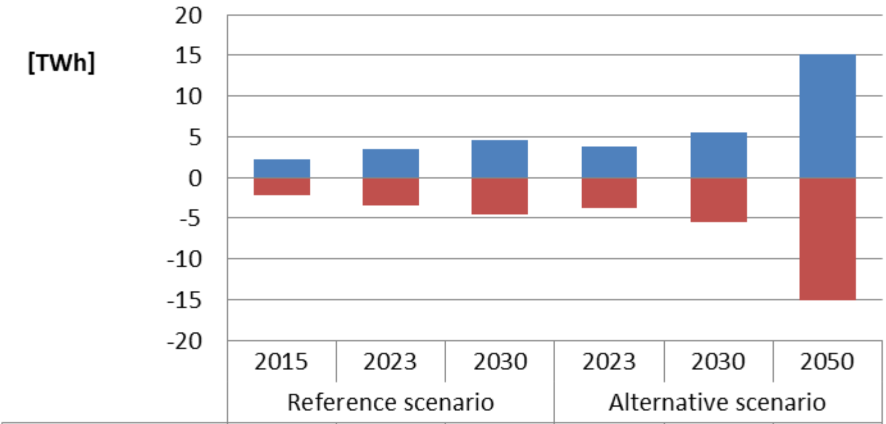
Table 12 presents a summary overview of the demand for flexibility due to the hourly variation in residual load ('ramps') in all scenario cases. This demand is expressed in capacity terms (GW/h) for both maximum single and cumulative hourly ramp-ups and ramp-downs, as well as in energy terms (TWh) for total annual ramp-ups and ramp-downs. In addition, it is expressed in both absolute terms, absolute changes (compared to 2015) and in relative changes (i.e. in %, compared to 2015).

Table 12: Summary overview of the demand for flexibility due to hourly variations in residual load ('ramps') in all scenario cases, 2015-2050

	Reference scenario			Alternative scenario		
	2015	**2023**	**2030**	**2023**	**2030**	**2050**
Demand for flexibility						
Maximum hourly ramp-up (in GW/h)	3.0	6.3	8.5	6.2	8.2	29.6
Maximum hourly ramp-down (in GW/h)	3.1	8.6	10.2	8.7	10.4	28.6
Maximum cumulative ramp-up (in GW/h)	9.7	16.4	20.7	17.7	20.6	66.2
• *Number of consecutive ramp-up hours*	14	14	9	14	9	10
Maximum cumulative ramp-down (in GW/h)	10.3	16.8	21.7	16.8	22.2	65.0
• *Number of consecutive ramp-down hours*	10	17	17	19	17	17
Total hourly ramp-up (p.a.; in TWh)	2.2	3.5	4.6	3.8	5.5	15.2
Total hourly ramp-down (p.a.; in TWh)	2.2	3.5	4.6	3.8	5.5	15.2
Absolute change in demand for flexibility (compared to 2015)						
Maximum hourly ramp-up (in GW/h)		3.3	5.5	3.1	5.2	26.6
Maximum hourly ramp-down (in GW/h)		5.5	7.1	5.6	7.3	25.6
Maximum cumulative ramp-up (in GW/h)		6.7	11.0	8.0	10.9	56.5
Maximum cumulative ramp-down (in GW/h)		6.5	11.4	6.5	11.9	54.7
Total hourly ramp-up (p.a.; in TWh)		1.3	2.3	1.5	3.3	12.9
Total hourly ramp-down (p.a.; in TWh)		1.3	2.3	1.5	3.3	12.9
Relative change in demand for flexibility (compared to 2015)						
Maximum hourly ramp-up (in %)		108	183	105	174	884
Maximum hourly ramp-down (in %)		181	232	184	240	836
Maximum cumulative ramp-up (in %)		69	113	82	112	581
Maximum cumulative ramp-down (in %)		63	110	63	116	530
Total hourly ramp-up (p.a.; in %)		57	106	70	148	582
Total hourly ramp-down (p.a.; in %)		57	106	70	148	582

Table 12 shows, among others, that in R2030 the need for maximum hourly ramping-up capacity is 183% higher than in R2015, while the need for maximum hourly ramping-down capacity increases by 232% over this period. In terms of maximum cumulative ramping capacity, these comparative figures are 113% and 110%, respectively, while in total annual energy terms the increase in the demand for both total annual ramp-ups and total annual ramp-downs amounts to 106%.

Figure 28: Need for total annual hourly ramps ('flexibility') in all scenario cases, 2015-2050



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Total ramp-up	2.2	3.5	4.6	3.8	5.5	15.2
Total ramp-down	-2.2	-3.5	-4.6	-3.8	-5.5	-15.2

In A2030, the relative changes in the demand for flexibility are largely similar than in R2030, although the increase in the total annual ramp-ups and ramp-downs (148%) are somewhat higher in A2030 than in R2030. Finally, in A2050 the demand for flexibility due to hourly variations in residual load is many times higher than in R2015. For instance, the need for maximum hourly ramp-up in A2050 is almost 10 times higher in A2050 than in R2015. The need for total annual ramp-up/down, however, is almost seven times higher in A2050, compared to R2015 (see last column of **Table 12**).

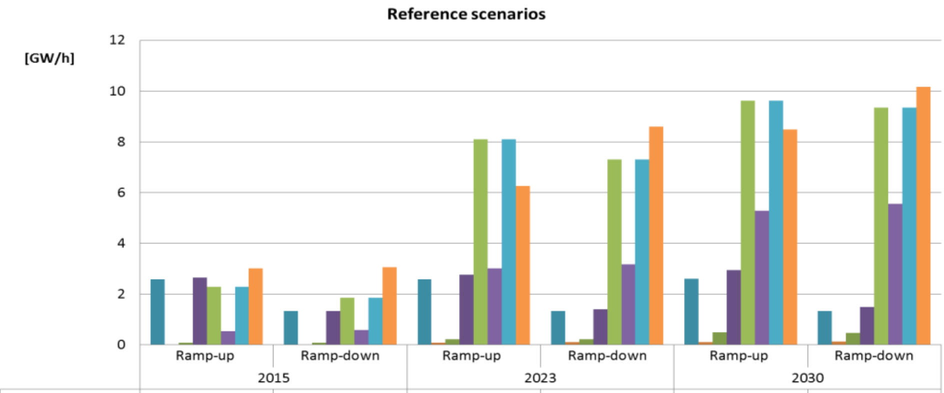
The large (absolute) increase in the demand for flexibility in the years 2030-2050, compared to the period 2015-2030, is largely due to the following two reasons:

- The increase in total power load – due to additional electrification by means of EVs, HPs , etc. – is relatively modest up to 2030 (i.e. from 113 TWh in R2015 to 153 TWh in A2030), but becomes more significant in the period 2030-2050 (i.e. from 153 TWh in A2030 to 233 TWh in A2050 (see Section 2.2; **Table 5**).
- More importantly, the increase in VRE power generation between 2015 and 2030 is very high in relative terms (from 8.6 TWh to 56 TWh, respectively) but it is far more substantial in absolute terms between 2030 and 2050 (from 56 TWh to 186 TWh, respectively; see Section 2.2; **Table 5**).

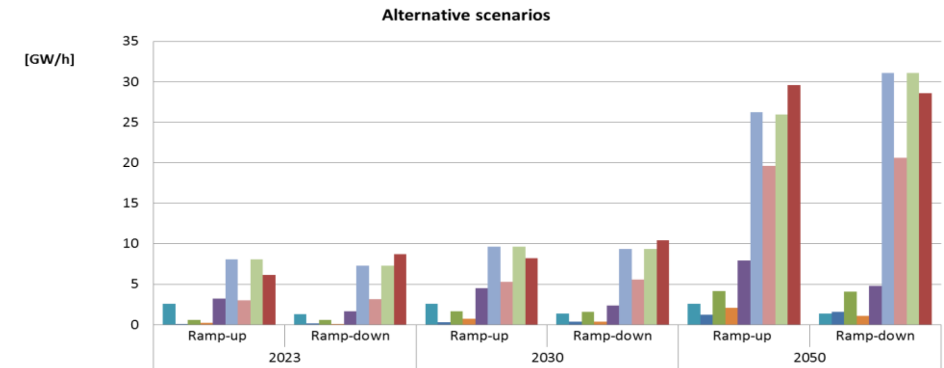
3.2.5 Determinants of hourly variations in residual load

In order to analyse roughly the major determinants of the need for flexibility due to the hourly variations in residual load, **Figure 29** presents the maximum hourly variations for different constituent components of the residual load in all scenario cases. The upper part of **Figure 29** shows the outcomes for the three reference scenario cases (R2015, R2023 and R2030) while the lower part provides the results for the three alternative scenarios cases (A2023, A2030 and R2050). Note that the alternative scenario cases also include additional load for 'other electrification'(besides load for household HPs and passenger EVs), and that, for visibility reasons, the scale size of the lower part of **Figure 29** is more than three times larger than the upper part.

Figure 29: Maximum hourly variations (ramp-ups/downs) for different components of residual load in all scenario cases, 2015-2030



	2015 Ramp-up	2015 Ramp-down	2023 Ramp-up	2023 Ramp-down	2030 Ramp-up	2030 Ramp-down
Conventional load	2.6	1.3	2.6	1.3	2.6	1.3
HP load	0.0	0.0	0.1	0.1	0.1	0.1
EV load	0.1	0.1	0.2	0.2	0.5	0.5
Total load	2.6	1.3	2.8	1.4	3.0	1.5
Wind	2.3	1.8	8.1	7.3	9.6	9.4
Sun PV	0.5	0.6	3.0	3.2	5.3	5.6
Total VRE	2.3	1.8	8.1	7.3	9.6	9.4
Residual load	3.0	3.1	6.3	8.6	8.5	10.2



	2023 Ramp-up	2023 Ramp-down	2030 Ramp-up	2030 Ramp-down	2050 Ramp-up	2050 Ramp-down
Conventional load	2.6	1.3	2.6	1.3	2.6	1.3
HP load	0.1	0.1	0.3	0.4	1.2	1.6
EV load	0.6	0.6	1.6	1.6	4.2	4.1
Other electrification	0.2	0.1	0.7	0.4	2.1	1.1
Total load	3.2	1.7	4.5	2.3	7.9	4.8
Wind total	8.1	7.3	9.6	9.4	26.3	31.1
Sun PV	3.0	3.2	5.3	5.6	19.6	20.6
Total VRE	8.1	7.3	9.6	9.4	26.0	31.1
Residual load	6.2	8.7	8.2	10.4	29.6	28.6

Figure 29 enables to make a comparative analyses both vertically, i.e. across different components of residual load, and horizontally, i.e. across different scenario cases, for either ramp-ups or ramp-downs. Horizontally, **Figure 29** confirms that the need for maximum hourly ramp-ups – due to hourly variations of residual load – increases substantially from 3.0 GW in R2015 to almost 30 GW in A2050 (see the bottom line of **Figure 29** in comparison to the upper line of **Table 12**). However, when looking at the hourly variation of conventional load only – i.e. ignoring the impact of additional load and VRE output – the need for maximum hourly ramp-up remains more or less stable across the scenario cases at a level of about 2.6 GW.

In terms of hourly variations of total load, i.e. including additional load but excluding VRE output, the need for maximum hourly ramp-up rises from 2.6 GW in R2015 to 7.9 GW in A2050. This increase is significantly higher than the comparative increase in the maximum hourly ramp-up due to the hourly variation of conventional load – which is actually zero – but substantially lower than the increase in the maximum hourly ramp-up due to the hourly variation of residual load. Hence, the difference between the need for maximum hourly ramp-ups (and ramp-downs) due to hourly variations in conventional load versus residual load seems to result primarily from the hourly variation in VRE output and less from the hourly variation in additional load.

In turn, the difference between the need for maximum hourly ramp-ups/downs due to hourly variations in conventional load versus total load seems to result primarily from (the hourly variations in) the additional load for passenger EVs and less from the additional load for household HPs and other means of electrifications (see the upper lines of the tables included in **Figure 29**).[27] Apart from the higher volume of the additional load for EVs compared to HPs, this results mainly from the fact that the hourly load for EVs varies more widely, with actually two outspoken peak periods per working day, whereas the hourly load for HPs is far more flat over the days of a week (as explained in Section 3.1). In addition, the hourly load for EVs varies also more widely than the hourly profile of the additional load for other means of electrification (which is assumed to be the same as the hourly profile for conventional load, as explained in Section 2.3).[28]

Finally, the difference between the need for maximum hourly ramp-ups/downs due to hourly variations in total load versus residual load seems to result primarily from (the hourly variation in) VRE output generated by means of wind energy and less from VRE output due to sun PV (see the bottom lines of the tables included in **Figure 29**). This results mainly from both the large volumes and the high variations in hourly VRE output from wind (on sea) compared to the VRE output from sun PV (See also Section 3.3 below for a more detailed sensitivity analysis of the impact of specific variables on the demand for flexibility due to the variation of residual load).

Figure 30 presents a similar comparative analysis of the total annual hourly ramp-ups for different components of residual load in all scenario cases.[29] This figure largely confirms the above findings based on **Figure 29**, i.e. the need for total annual hourly ramp-ups – i.e. the total annual demand for flexibility (in TWh) due to the hourly variation in residual load – is (i) substantially higher for residual load than conventional load, mainly due to the hourly variations in VRE power output (rather than in additional load), (ii) higher for total load than for conventional load, largely due to the hourly variations in additional load for passenger EVs rather than in additional load for household HPs or other means of electrification, and (iii) higher for residual load than for total load, mainly due to the hourly variations in VRE output from wind (on sea), rather than from sun PV.[30]

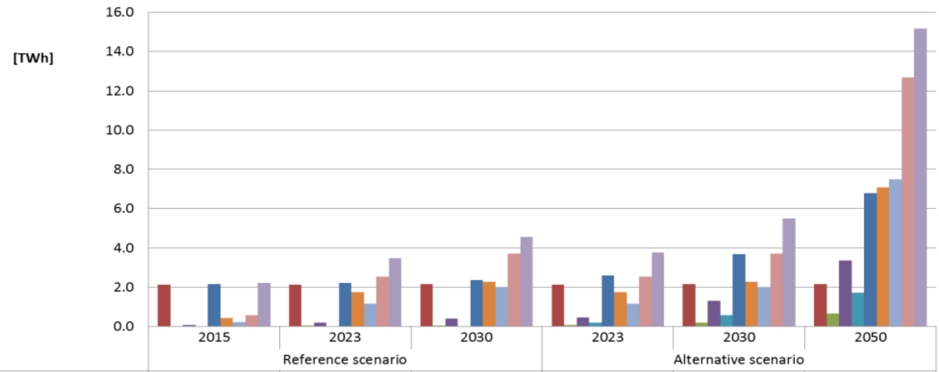
[27] Note that the maximum ramp-ups (or ramp-downs) of the different components of total load (residual load) cannot be simply added up to get the ramp-up of total load (residual load) as the maximum ramp-ups of the different components occur in different hours (while a specific hour may even show a ramp-up for one component and a ramp-down for another component).

[28] See also Section 3.3 below for a more detailed sensitivity analysis of the impact of specific, individual components of residual load on the demand for flexibility due to the hourly variation of residual load.

[29] We have only included ramp-ups in **Figure 30** as the need for total annual ramp-ups – due to variations in residual load – is similar to the need for total annual ramp-downs.

[30] Note, however, that the impact of VRE output from sun PV is larger in energy terms (i.e. in TWh, see **Figure 30**) than in capacity terms (i.e. in GW, see **Figure 29**).

Figure 30: Total annual hourly ramp-ups for different components of residual load in all scenario cases, 2015-2050



	Reference scenario			Alternative scenario		
	2015	2023	2030	2023	2030	2050
Conventional load	2.1	2.1	2.1	2.1	2.1	2.1
HP load	0.0	0.0	0.1	0.1	0.2	0.7
EV load	0.1	0.2	0.4	0.5	1.3	3.4
Other electrification	0.0	0.0	0.0	0.2	0.6	1.7
Total load	2.2	2.2	2.4	2.6	3.7	6.8
Wind total	0.4	1.8	2.3	1.8	2.3	7.1
Sun PV	0.2	1.2	2.0	1.2	2.0	7.5
Total VRE	0.6	2.5	3.7	2.5	3.7	12.7
Residual load	2.2	3.5	4.6	3.8	5.5	15.2

3.3 Sensitivity analyses

In order to get an idea of the sensitivity of the demand for flexibility for some of the underlying scenario assumptions, in particular for changes in some input variables, we have conducted a number of sensitivity analyses. More specifically, the following two sets or 'runs' of sensitivity analyses have been performed (with each run consisting of a set of six separate sensitivity analyses for six separate input variables):

- *Run A*. In this run, the hourly and total annual volume of six input variables has been increased individually for each variable by a fixed percentage of 20% compared to their respective values in the reference scenario for 2030 (R2030) in order to assess the impact of such a change on the demand for flexibility. These six variables consist of three load variables – i.e., conventional load, additional load for passenger electric vehicles (EVs), and additional load for household heating pumps (HPs) – as well as three VRE power generation variables, i.e. electricity output from wind on land, wind on sea and sun PV.

- *Run B.* This run is largely similar to run A. The only difference is that in this run the total annual volume of the six variables mentioned above has been increased individually for each variable by a fixed amount of 8 TWh – compared to their respective values in R2030 – which has been proportionally distributed and added to the hourly profiles of these variables, respectively.[31]

[31] We did not include 'other additional load' as a separate variable to our sensitivity analyses. However, as the hourly profile of this variable is assumed to be similar to the hourly profile of conventional load, the impact of an absolute change in this variable on the demand for flexibility is similar to the same change in conventional load.

For each of the six input variables, the impact has been assessed individually on the demand for flexibility by means of the two indicators defined in Section 3.2.4, i.e. (i) maximum hourly ramp, and (ii) total hourly ramp (per annum).

The major findings of the sensitivity analyses include:

- If the volume of the respective input variables is changed individually by the same percentage (20%), the resulting change in the required maximum hourly capacity for ramp-up (or ramp-down) is relatively low – i.e., varying between -1.2% and 0.9% – for variables such as conventional load, EV load and HP load, while it is significantly higher – ranging between 8.4% and 14% – for the variables wind on land and wind on sea. However, for the other VRE variable – sun PV – the resulting change in the required maximum hourly capacity for either upward or downward flexibility is zero.
- The change in total annual demand for either hourly ramp-ups or ramp-downs is relatively highest for a 20% change in variables such as sun PV (+6.8%) or conventional load (+5.5%) and relatively lowest for EV load (+0.9%) and HP load (+0.1%), with a middle position for wind on land (+3.2%) and wind on sea (+4.0%).
- If the volume of the respective scenario input variables is changed individually by the same amount (8 TWh), the resulting change in the required maximum hourly capacity for ramp-up (or ramp-down) is again relatively lowest – varying from -1.7% to +1.4% – for conventional load, EV load and HP load, while it is relatively highest – ranging between 14% and 23% - for wind on land and wind on sea. For sun PV, the resulting change in the required maximum hourly capacity to meet the demand for flexibility amounts to +0.7 GW (+8%) for ramping up and zero for ramping down.
- If the volume of the respective variables is changed by the same amount (8 TWh), the resulting change in the total annual demand for flexibility (either upward or downward) is relatively highest for sun PV (+23%) and EV (+16%) and relatively lowest for conventional load (+2%) and HP (+5%), with a middle position for wind on land and wind on sea (both approximately +7%).

The above findings imply that if the demand for electricity is enhanced by a certain amount (e.g., by 8 TWh) due to an increased use of either EVs or HPs, the resulting change in the demand for total annual ramp-ups/downs will be significantly higher in the case of electrification by means of EVs than HPs. Hence, the demand for total annual ramp-ups/downs is more sensitive to a similar (absolute) change in electricity use for EVs than for HPs. This is due to the fact that the hourly profile of the demand for electricity is relatively more variable for EVs than for HPs (see Section 3.1).

Another implication of the above findings is that if the supply of electricity from VRE resources is enhanced by the same amount (e.g., 8 TWh) for either wind energy or solar PV, the resulting capacity needs for flexibility in terms of maximum hourly ramp-up/down is significantly higher in the case of electricity supply from wind energy than from solar energy. On the other hand, the resulting (energy) need for flexibility in terms of total hourly ramp-ups/downs is significantly higher in the case of electricity supply from solar PV than from wind energy.

The latter (total energy) result is (most likely) due to the fact that, on average, over a year electricity from solar PV is apparently relatively more volatile and focussed in a smaller number of output hours than electricity from wind energy. The former (maximum capacity) result is a bit more difficult to explain as it may be due to coincidental factors in the sense that the additional output variability of electricity from wind energy may be focused and added to those hours where the capacity demand for ramp-up/down is already high – or even at its maximum – while the additional output availability of electricity for sun PV may be focussed and added to those hours where the capacity demand for ramp-up/down is relatively low.

More details of the sensitivity analyses are provided in Appendix C (see particularly **Table 21** up to **Table 24**).

3.4 Extreme situations

In the sections above, the variability of the residual load and the resulting demand for flexibility has been analysed for so-called '*normal situations*', i.e. for scenario cases based on electricity demand and VRE supply profiles for 'normal' ('representative', 'middle-of-the-road') years, as outlined in Section 2.3. In addition, we have analysed the impact of two '*extreme situations*' on some constituent components of residual load and some indicators of the demand for flexibility. These two extreme situations include:

- A '*long cold winter'*, i.e. a winter with, on average, relatively low temperatures and hardly or no power generation from VRE sources (sun/wind) during the whole month of January.
- A '*long hot summer'*, i.e. a summer with, on average, relatively high temperatures and a very lot of VRE power generation during the whole month of July.

Approach

In order to simulate the extreme situations mentioned above, we have assumed that only the VRE output profiles and the load profile for heat pumps (HPs) changes – compared to the normal situation – and, hence, that the hourly profiles for the other input variables (conventional load, EV load and additional load of 'other electrification') do not change. More specifically, in order to simulate the 'long cold winter' case, the approach used includes the following three steps:

- *Step A*. In this step only the hourly load profile for household heat pumps has changed. In particular, a HP load profile has been designed, based on hourly temperature data for 1987, i.e. a relatively very cold year.[32] As a result, HP electricity use in this 1987 profile is higher than in the 'normal' profile – based on the year 2012 – notably during the winter period.
- *Step B*. In this step only the hourly profiles for power generation from VRE sources have changed. In particular, hourly profiles for sun PV, onshore wind and offshore wind on the day with the lowest VRE output in a 'normal' situation – i.e. day 15 – have been copied 31 times for all days of the month January (whereas the VRE profiles for the other months are similar to those of the 'normal' situation).
- *Step C*. This step is a combination of steps A and B.

Similarly, in order to simulate and analyse the 'long hot summer' case, the approach used include the following steps:

[32] The respective HP load profiles – for both the 'normal' and 'extreme' situations – have been designed by Robert de Smidt of the ECN unit Energy Efficiency. For details on these profiles, see Appendix A.

- *Step D*. In this step only the hourly load profile for household heat pumps has changed. In particular, we have assumed that air/ground-source heat pumps in highly insulated houses can also be used for cooling. Consequently, an hourly load profile for HP cooling has been designed for the months June-September – based on hourly temperature data for 2003, i.e. a year with a relatively very warm summer period – and added to the HP load profile in the 'normal' situation (2012).
- *Step E*. In this step only the hourly profiles for power generation from VRE sources have changed. In particular, hourly profiles for sun PV, onshore wind and offshore wind on the day with the highest VRE output in a 'normal' situation – i.e. day 161 – have been copied 31 times for all days of the month July (whereas the VRE profiles for the other months are similar to those of the 'normal' situation).
- *Step F*. This step is a combination of steps D and E.

Major results
The results for both extreme situations have been calculated for two scenario cases, i.e. for R2030 and A2050. **Table 13** presents the major results for R2030 and **Table 14** for A2050, both in absolute outcomes, in absolute differences (compared to the 'normal' situation) and in relative differences (i.e. in %, compared to the 'normal' situation).

For example, some major results for the two extreme situations in A2050 include (**Table 14**):

- Compared to the normal situation in A2050, power load for household HPs increases by 1.1 TWh (+12%) in the extreme cold case (due to the additional heating needs in the winter period), and by 1.0 TWh (+11%) in the extreme hot case (due to the additional cooling needs in the summer period);
- Total VRE supply declines by 17 TWh (-9%) in the extreme cold situation, whereas it rises by 19 TWh (+10%) in the extreme hot situation;
- The share of VRE output – as a percentage of total load – amounts to72% in the extreme cold case and to 88% in the extreme hot case, compared to 80% in the normal situation;
- The annual residual load amounts to 65 TWh (+39%) in the extreme cold situation and to 28 TWh (-39%) in the extreme cold case, compared to 47 TWh in the normal situation of A2050;
- The number of hours with a VRE surplus amounts to 2889 (-10%) in the extreme cold situation and to 3663 (+14%) in the extreme hot situation, compared to 3217 hours in the normal situation;
- The total VRE surplus – covering all VRE surplus hours in a year – amounts to 32 TWh (-8%) in the extreme cold case and to 47 TWh (+35%) in the extreme hot case, compared to 35 TWh in the normal situation;
- As outlined in Section 3.2.4 above, the demand for flexibility due to the hourly variations of the residual load can be expressed by means of three indicators, i.e. (i) maximum hourly ramps, (ii) maximum cumulative ramps, and (iii) total hourly ramps (per annum). In terms of maximum hourly ramps, the need for flexibility increases by almost 5% in the extreme cold case of A2050, whereas it decreases by 17% in the extreme hot case. In terms of the other two indicators, however, the difference in the demand for flexibility in extreme situations is much smaller (i.e. <3%; see bottom lines of **Table 14**).

Table 13: Extreme situations – major results for scenario R2030

			Extreme situations [A2030]						Extreme situations [A2030]						Extreme situations [A2030]					
			Long cold winter			Long hot summer			Long cold winter			Long hot summer			Long cold winter			Long hot summer		
		Normal situation [A2030]	Additional HP load [A]	Lower RES-E [B]	Total impact [A+B]	Additional HP load [C]	Higher RES-E [D]	Total impact [C+D]	Additional HP load [A]	Lower RES-E [B]	Total impact [A+B]	Additional HP load [C]	Higher RES-E [D]	Total impact [C+D]	Additional HP load [A]	Lower RES-E [B]	Total impact [A+B]	Additional HP load [C]	Higher RES-E [D]	Total impact [C+D]
		Absolute outcomes							Absolute differences (compared to normal situation)						Relative differences [in %]					
Power load																				
Total per annum	[TWh]	115.6	115.7	115.6	115.7	115.7	115.6	115.7	0.1	0.0	0.1	0.1	0.0	0.1	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
HP load	[TWh]	0.9	1.0	0.9	1.0	1.0	0.9	1.0	0.1	0.0	0.1	0.1	0.0	0.1	9.9%	0.0%	9.9%	9.7%	0.0%	9.7%
VRE Power generation																				
Wind onshore	[TWh]	18.1	18.1	15.7	15.7	18.1	21.3	21.3	0.0	-2.4	-2.4	0.0	3.2	3.2	0.0%	-13.2%	-13.2%	0.0%	17.4%	17.4%
Wind offshore	[TWh]	25.0	25.0	22.1	22.1	25.0	27.7	27.7	0.0	-2.9	-2.9	0.0	2.7	2.7	0.0%	-11.4%	-11.4%	0.0%	10.9%	10.9%
Sun PV	[TWh]	12.4	12.4	12.2	12.2	12.4	13.3	13.3	0.0	-0.2	-0.2	0.0	0.8	0.8	0.0%	-1.4%	-1.4%	0.0%	6.8%	6.8%
Total VRE output	[TWh]	55.5	55.5	50.1	50.1	55.5	62.2	62.2	0.0	-5.4	-5.4	0.0	6.7	6.7	0.0%	-9.8%	-9.8%	0.0%	12.1%	12.1%
As % of total load	[%]	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.1	0.1	-0.1%	-9.8%	-9.9%	-0.1%	12.1%	12.0%
Residual load																				
Total per annum	[TWh]	60.2	60.3	65.6	65.7	60.2	53.4	53.5	0.1	5.4	5.5	0.1	-6.7	-6.6	0.1%	9.0%	9.2%	0.1%	-11.2%	-11.0%
VRE surplus generation																				
Total per annum	[TWh]	1.8	1.8	1.7	1.7	1.8	3.9	3.9	0.0	-0.1	-0.1	0.0	2.0	2.0	0.2%	-6.5%	-6.1%	-0.8%	111.4%	109.6%
# VRE surplus hours	[hour]	873	873	793	793	871	1390	1389	0	-80	-80	-2	517	516	0.0%	-9.2%	-9.2%	-0.2%	59.2%	59.1%
VRE surplus as % of total load	[%]	1.6%	1.6%	1.5%	1.49%	1.6%	3.4%	3.3%	0.0%	-0.1%	-0.1%	0.0%	1.8%	1.7%	0.1%	-6.5%	-6.2%	-0.9%	111.4%	109.5%
Demand for flexibility due to variability of residual load																				
Maximum hourly ramp-up	[GW/h]	8.5	8.5	11.1	11.1	8.5	8.2	8.2	0.0	2.6	2.6	0.0	-0.3	-0.3	0.0%	31.1%	30.9%	0.0%	-3.3%	-3.3%
Maximum hourly ramp-down	[GW/h]	-10.2	-10.2	-10.2	-10.2	-10.2	-9.2	-9.2	0.0	0.0	0.0	0.0	0.9	0.9	0.0%	0.0%	0.0%	0.0%	-9.1%	-9.1%
Max. cumulative ramp-up	[GW/h]	20.7	20.8	20.7	20.8	20.7	20.7	20.7	0.0	0.0	0.0	0.0	0.0	0.0	0.2%	0.0%	0.2%	0.0%	0.0%	0.0%
Max. cumulative ramp-down	[GW/h]	-21.7	-21.8	-21.7	-21.8	-21.7	-21.7	-21.7	-0.2	0.0	-0.2	0.0	0.0	0.0	0.7%	0.0%	0.7%	0.0%	0.0%	0.0%
Total hourly ramp-up (p.a.)	[TWh]	-4.6	-4.6	-4.5	-4.5	-4.6	-4.7	-4.7	0.0	0.1	0.1	0.0	-0.1	-0.1	0.1%	-1.9%	-1.8%	-0.1%	2.1%	2.0%
Total hourly ramp-down (p.a.)	[TWh]	4.6	4.6	4.5	4.5	4.6	4.7	4.7	0.0	-0.1	-0.1	0.0	0.1	0.1	0.1%	-1.9%	-1.8%	-0.1%	2.1%	2.0%

Table 14: Extreme situations – major results for scenario A2050

			Extreme situations [A2030]						Extreme situations [A2030]						Extreme situations [A2030]					
			Long cold winter			Long hot summer			Long cold winter			Long hot summer			Long cold winter			Long hot summer		
		Normal situation [A2030]	Additional HP load [A]	Lower RES-E [B]	Total impact [A+B]	Additional HP load [C]	Higher RES-E [D]	Total impact [C+D]	Additional HP load [A]	Lower RES-E [B]	Total impact [A+B]	Additional HP load [C]	Higher RES-E [D]	Total impact [C+D]	Additional HP load [A]	Lower RES-E [B]	Total impact [A+B]	Additional HP load [C]	Higher RES-E [D]	Total impact [C+D]
		Absolute outcomes							Absolute differences (compared to normal situation)						Relative differences [in %]					
Power load																				
Total per annum	[TWh]	232.8	233.9	232.8	233.9	233.8	232.8	233.8	1.1	0.0	1.1	1.0	0.0	1.0	0.5%	0.0%	0.5%	0.4%	0.0%	0.4%
HP load	[TWh]	9.3	10.3	9.3	10.3	10.3	9.3	10.3	1.1	0.0	1.1	1.0	0.0	1.0	11.6%	0.0%	11.6%	10.8%	0.0%	10.8%
VRE Power generation																				
Wind onshore	[TWh]	19.7	19.7	17.1	17.1	19.7	23.1	23.1	0.0	-2.6	-2.6	0.0	3.4	3.4	0.0%	-13.1%	-13.1%	0.0%	17.1%	17.1%
Wind offshore	[TWh]	120.2	120.2	106.5	106.5	120.2	133.1	133.1	0.0	-13.7	-13.7	0.0	12.9	12.9	0.0%	-11.4%	-11.4%	0.0%	10.7%	10.7%
Sun PV	[TWh]	46.0	46.0	45.4	45.4	46.0	49.2	49.2	0.0	-0.7	-0.7	0.0	3.1	3.1	0.0%	-1.4%	-1.4%	0.0%	6.8%	6.8%
Total VRE output	[TWh]	186.0	186.0	169.0	169.0	186.0	205.4	205.4	0.0	-17.0	-17.0	0.0	19.4	19.4	0.0%	-9.1%	-9.1%	0.0%	10.4%	10.4%
As % of total load	[%]	79.9%	79.5%	72.6%	72.3%	79.5%	88.2%	87.8%	-0.4%	-7.3%	-7.6%	-0.3%	8.3%	8.0%	-0.5%	-9.1%	-9.5%	-0.4%	10.4%	10.0%
Residual load																				
Total per annum	[TWh]	46.8	47.9	63.8	64.9	47.8	27.4	28.4	1.1	17.0	18.0	1.0	-19.4	-18.4	2.3%	36.2%	38.5%	2.1%	-41.5%	-39.3%
VRE surplus generation																				
Total per annum	[TWh]	35.1	34.9	32.4	32.4	34.6	47.9	47.2	-0.2	-2.7	-2.7	-0.5	12.8	12.1	-0.6%	-7.6%	-7.7%	-1.5%	36.4%	34.6%
# VRE surplus hours	[hour]	3217	3193	2901	2889	3194	3677	3663	-24	-316	-328	-23	460	446	-0.7%	-9.8%	-10.2%	-0.7%	14.3%	13.9%
VRE surplus as % of total load	[%]	15.1%	14.9%	13.9%	13.9%	14.8%	20.6%	20.2%	-0.2%	-1.1%	-1.2%	-0.3%	5.5%	5.1%	-1.1%	-7.6%	-8.1%	-1.9%	36.4%	34.0%
Demand for flexibility due to variability of residual load																				
Maximum hourly ramp-up	[GW/h]	29.6	29.6	31.0	31.0	29.6	24.6	24.6	0.0	1.5	1.4	0.0	-4.9	-4.9	0.0%	4.9%	4.8%	0.0%	-16.7%	-16.7%
Maximum hourly ramp-down	[GW/h]	-28.6	-28.7	-28.6	-28.7	-28.6	-28.6	-28.6	0.0	0.0	0.0	0.0	0.0	0.0	0.2%	0.0%	0.2%	0.0%	0.0%	0.0%
Max. cumulative ramp-up	[GW/h]	66.2	66.4	66.2	66.4	66.2	66.2	66.2	0.2	0.0	0.2	0.0	0.0	0.0	0.3%	0.0%	0.3%	0.0%	0.0%	0.0%
Max. cumulative ramp-down	[GW/h]	-65.0	-66.8	-65.0	-66.8	-65.0	-65.0	-65.0	-1.8	0.0	-1.8	0.0	0.0	0.0	2.8%	0.0%	2.8%	0.0%	0.0%	0.0%
Total hourly ramp-up (p.a.)	[TWh]	-15.2	-15.2	-14.9	-14.9	-15.1	-15.3	-15.3	0.0	0.3	0.3	0.1	-0.2	-0.1	0.2%	-2.0%	-1.8%	-0.4%	1.1%	0.7%
Total hourly ramp-down (p.a.)	[TWh]	15.2	15.2	14.9	14.9	15.1	15.3	15.3	0.0	-0.3	-0.3	-0.1	0.2	0.1	0.2%	-2.0%	-1.8%	-0.4%	1.1%	0.7%

3.5 Summary and conclusions

This chapter has analysed the demand for flexibility due to the variability of the residual load in the Dutch power system at the national level up to 2050. The major findings of this analysis include:

- *Total (hourly) power load* increases substantially between 2015 and 2050 and becomes much more volatile, mainly due to the additional electrification of the energy system through the increase in electric vehicles (EVs), heat pumps (HPs) and other means of electrification such as power-to-gas (P2G), power-to-heat (P2H), power-to-ammonia (P2A) or power-to-other-products (P2X).

- *Power output from VRE sources (sun/wind)* increases substantially between 2015 and 2050. Hourly VRE output, however, is very volatile and fluctuates heavily over each period considered (day, week, month, etc.). Moreover, even in A2050, with a large share of VRE output in total annual power load (80%), there is still a large number of hours (1600-2600) in which VRE output is relatively low, covering only a small part of power demand (10-20%). This implies that during these hours power demand has to be met largely (80-90%) by other supply sources besides VRE output, including other means of power generation (gas, coal, nuclear) or by flexibility options such as power imports, demand response or using electricity stored during other, surplus hours.

- As a result of the two trends mentioned above, *hourly residual power load* becomes much more volatile (variable) over time. In A2050, it varies even between *minus* 48 GW (i.e., actually, a large *VRE surplus*) and *plus* 41 GW (a large *VRE shortage*), compared to plus 6 GW and 18 GW in R2015, respectively.

- A growing share of power production from sun and wind leads, hence, to a growing variability and an increase in extreme values of residual load, implying a higher need for flexibility to deal with these VRE-induced characteristics of the residual load.

- More specifically, due to the increase in power supply from VRE sources, the need for residual peak load capacity increases substantially over time, whereas the need for residual base load capacity decreases significantly (and even becomes zero in A2050). Peak load capacity, however, has to be rather flexible as it covers less than 1200 hours per annum spread throughout the year. Notably, the number of peak hours with relatively high levels of residual load is relatively small in A2050 (and A2030), i.e. it is usually even much smaller than 1200. Therefore, capacity investments in (flexible) power generation – or other (flexible) power supply options – to meet these high residual load levels have to be recovered in a relatively small number of running hours.

- In case the share of VRE generation in total load increases, both (i) the number of hours with a VRE surplus (i.e. a ‘negative residual load’), (ii) the maximum hourly

VRE surplus, (iii) the total hourly VRE surplus per annum, and (iv) the maximum number of consecutive VRE surplus hours tend to increase as well. This raises both new challenges and opportunities in terms of flexibility demand and supply in the power system. For instance, the incidence and alternation of (large) hourly VRE shortages versus (large) VRE surpluses enhances the issue how to deal with these fluctuations in residual load (and the related fluctuations in hourly electricity prices). On the other hand, these fluctuations create also opportunities in terms of energy storage and demand response.

- The hourly variations of the *total power load* – including load for EVs, HPs and other means of additional electrification – are generally larger than the hourly variations of the *conventional load* whereas, in turn, the hourly variations of the *residual load* – due to the additional, strong variability of VRE output – are usually (significantly) larger than the hourly variations of *total load*.

- The hourly variations of total load and, particularly, of the residual load increase substantially over time, i.e. from R2015 to A2050, due to the increase in total load and, notably, in total VRE output over this period. This implies that the need for hourly ramping (flexibility) increases significantly over time.

- Ramping needs alternate regularly between hours of upwards versus downward ramping. Occasionally, however, ramping needs may move in the same direction – either upwards or downwards – during several consecutive hours. Therefore, the (maximum) cumulative need for either ramping-up or ramping-down of the power system during these consecutive hours is larger than the (maximum) ramping need during a single hour.

- Regardless of the indicator used, the demand for flexibility due to the hourly variation of the residual load increases rapidly up to 2030 (+110-240%) and, in particular, up to 2050 (+530-880%), compared to 2015.

- The large (absolute) increase in the demand for flexibility in the years 2030-2050, compared to the period 2015-2030, is due to the relatively large (absolute) increase in total power load - notably due to the additional electrification by means of EVs, HPs, etc. – and, more importantly, the relatively large (absolute) increase in VRE power generation between 2030 and 2050.

- The main driver of the demand for flexibility is the increase in electricity production from VRE power sources, in particular from wind (on sea) and – to a lesser extent – from sun PV.

- Another, less important driver – at least in a direct sense – is the increase in the additional load due to the further electrification of the energy system, notably due to the hourly variations in the additional load for passenger EVs rather than in the additional for household HPs or other means of electrification.

- In an indirect sense, however, the increase in electrification is an important driver of the demand for flexibility if it is assumed that the resulting additional load is largely met by electricity from VRE power sources.

4

The demand for flexibility due to the uncertainty of the residual load

As outlined in Section 2.1, in addition to the flexibility needs due to the variability of the residual load – expressed predominantly on the day-ahead market (DAM) – there are also flexibility needs due to the *uncertainty* of the residual load, expressed on the intraday/balancing market (ID/BM). A major part of this ID/BM-based demand for flexibility concerns the need to accommodate the power system for so-called '*forecast errors'* of electricity production from VRE sources (sun/wind), i.e. the differences between forecasted (or expected) VRE generation – as traded on the day-ahead market – and actually realised VRE output. Because of these forecast errors, VRE producers – or the balancing responsible party (BRP) which has assumed responsibility for supplying the expected VRE output – will need to compensate the differences. Or, alternatively, the TSO (TenneT) will have to contract reserve power to meet the imbalances. This will generate additional demand for flexibility on the intraday/balancing market (see Koutstaal et al., 2014, and references cited there).[33]

As an illustration, **Figure 31** presents the estimate of the hourly wind forecast error in 2030, covering both scenario R2030 and A2030 as it is assumed that the respective wind profiles and the installed wind capacity are similar in these scenario cases (Section 2.2). This estimate is based on the difference between the forecasted and actual hourly wind output data for 2012 multiplied by the installed wind capacity in 2030 (assuming that this difference – or forecast error – will remain the same per unit installed wind capacity as actually measured in 2012).[34]

[33] Actually, continuous updates of VRE output projections are addressed on the intraday market (IDM) until this market closes and the balancing market (BM) takes over. In this chapter, however, we treat the intraday/balancing market (ID/BM) as a single market.

[34] The 'Normalised Root Mean Square Error' (NRMSE) of the wind forecast error in the Netherlands, based on the 2012 data, amount to 7%. For an explanation of this measure of accuracy, see Wikipedia (2017).

Figure 31: Estimate of wind forecast error in 2030

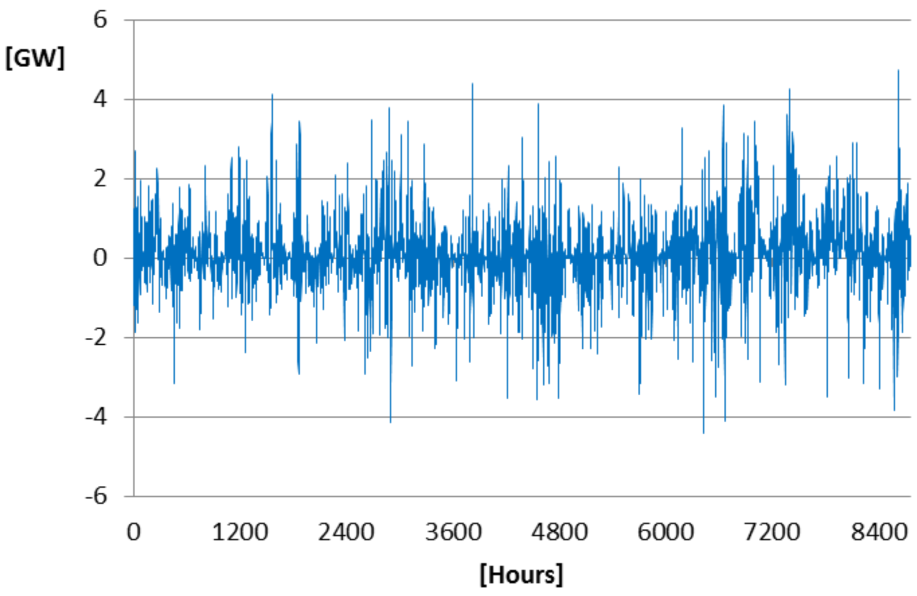


Figure 32 presents the duration curve of the hourly wind forecast error in 2030, i.e. the duration curve of the need for hourly ramping (flexibility) of the power system due to the estimated wind forecast error in 2030. It shows that this need varies from a maximum hourly ramp-up of about 4.7 GW to a maximum ramp-down of approximately 4.4 GW.

The surface between the duration curve and the X-axis in **Figure 32** represents the total annual demand for flexibility due to the wind forecast error, either for upward flexibility (above the X-axis) or for downward flexibility (below the X-axis). In 2030, the total demand for ramp-up flexibility amounts to 3.0 TWh and for ramp-down flexibility to 1.8 TWh.

Figure 32: Duration curve of wind forecast error in 2030

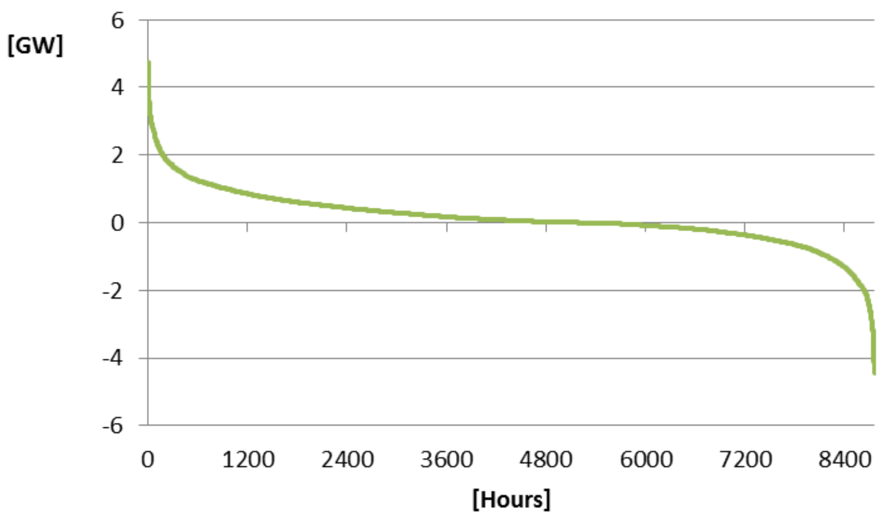


Table 15: Demand for flexibility on the intraday/balancing market due to the forecast error of wind generation in all scenarios cases, 2015-2050

		Reference scenarios			Alternative scenarios		
	Unit	**2015**	**2023**	**2030**	**2023**	**2030**	**2050**
Maximum hourly ramp-up	GW/h	1.1	3.9	4.7	3.9	4.7	13.7
Maximum hourly ramp-down	GW/h	1.1	3.6	4.4	3.6	4.4	12.8
Total hourly ramp-up (p.a.)	TWh	0.7	2.4	3.0	2.4	3.0	8.5
Total hourly ramp-down (p.a.)	TWh	0.4	1.5	1.8	1.5	1.8	5.3

Table 15 provides estimates of the demand for flexibility on the intraday/balancing market due to the wind forecast error for all scenario cases over the period 2015-2050. It shows, for instance, that over this period the maximum need for hourly ramp-up increases from 1.1 GW in R2015 to almost 14 GW in A2050, while the total annual demand for ramp-down rises even from 0.4 TWh to 5.3 TWh, respectively.

It should be stressed, however, that the estimates of the flexibility needs indicted in **Table 15** are based on the assumption that the wind forecast error over this period will remain the same per unit installed wind capacity as actually measured in 2012. If, on the contrary, it is assumed that over time, the weather-based forecast of wind generation will improve significantly – and, hence, the wind forecast error will decline substantially – the need for flexibility due to the wind forecast error will decrease accordingly (although overall it may still grow significantly in absolute terms due to the increase in total VRE output from wind over time). For instance, if the wind forecast error improves by, say, 3% per annum, the maximum ramp-up due to this error increases only from 1.1 GW in 2015 to 4.7 GW in 2050, while the total annual demand for hourly ramp-ups rises only from 0.7 TWh to 2.9 TWh, respectively.

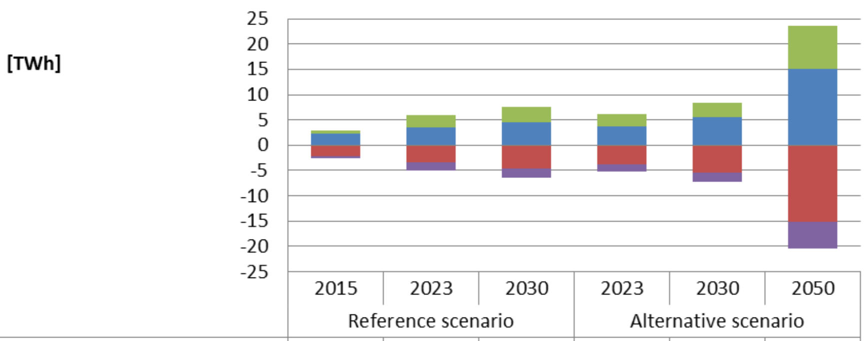
On the other hand, it should be realised that **Table 15** includes only the need for flexibility due to the wind forecast error, but ignores the demand for flexibility of the power system due to the sun forecast error or to other uncertainties such as the uncertainty of power demand or the uncertainty of power supply from conventional installations (for instance, due to a sudden, unplanned breakdown of a coal plant). Including these variables – notably the fast-growing power supply from sun PV – will significantly enhance the demand for flexibility due to the uncertainty of the residual load.

Table 16 provides a comparative overview of both the total annual demand for flexibility on the *day-ahead market (DAM)*, i.e. the demand for flexibility due to the *variability* of the residual power load, and the total annual demand for flexibility on the *intraday/balancing market (ID/BM)*, i.e. the demand for flexibility due to the *uncertainty* of the residual load, in particular due to the *forecast error* of power generation from wind energy. It shows, for instance, that the total annual demand for hourly ramp-ups increases from 2.2 TWh in R2015 to 15 TWh in A2050 on the day-ahead market and from 0.7 TWh to 8.5 TWh on the intraday/balancing market (see also **Figure 33**).

Table 16: Total annual demand for flexibility on the day-ahead and intraday/balancing markets in all scenarios, 2015-2050

	Reference scenarios			Alternative scenarios		
[TWh]	**2015**	**2023**	**2030**	**2023**	**2030**	**2050**
Day-ahead market (DAM):						
- Annual demand for ramp-up	2.2	3.5	4.6	3.8	5.5	15.2
- Annual demand for ramp-down	2.2	3.5	4.6	3.8	5.5	15.2
Intraday/balancing market (ID/BM):						
- Annual demand for ramp-up	0.7	2.4	3.0	2.4	3.0	8.5
- Annual demand for ramp-down	0.4	1.5	1.8	1.5	1.8	5.3
Total (DAM + ID/BM)						
- Annual demand for ramp-up	2.9	5.9	7.5	6.2	8.5	23.7
- Annual demand for ramp-down	2.7	5.0	6.4	5.3	7.3	20.4
- Total hourly ramps (p.a.)	5.6	10.9	13.9	11.5	15.8	44.1
- Index (2015 = 100)	100	194	249	205	282	788
- % of total final power load	5.0%	9.6%	12.0%	9.1%	10.3%	18.9%

Figure 33: Total annual demand for flexibility on the day-ahead market (DAM) and the intraday/balancing market (ID/BM) in all scenarios, 2015-2050



	2015	2023	2030	2023	2030	2050
Total hourly ramp-up (ID/BM)	0.7	2.4	3.0	2.4	3.0	8.5
Total hourly ramp-up (DAM)	2.2	3.5	4.6	3.8	5.5	15.2
Total hourly ramp-down (ID/BM)	-0.4	-1.5	-1.8	-1.5	-1.8	-5.3
Total hourly ramp-down (DAM)	-2.2	-3.5	-4.6	-3.8	-5.5	-15.2

Overall, the total annual demand for flexibility on both the DAM and ID/BM, including the need for both hourly ramp-ups and hourly ramp-downs, increases from 5.6 TWh in R2015 to 44 TWh in A2050. In terms of an index, this corresponds to an increase from 100 in R2015 to 788 in A2050, i.e. an increase by 688 percent over this period as a whole. While a significant share of this increase – i.e., about one-fourth – is realised in the period 2015-2030, the main part, however, will be effectuated over the years 2030-2050. This implies that the increase in the demand for flexibility over the period 2015-2030 is indeed significant but still relatively modest (compared to the period 2030-

2050) and that the main increase in the demand for flexibility – in both absolute and relative terms – will be effectuated in the years 2030-2050.

Due to the expected, further electrification of the energy system, the total demand for electricity is assumed to grow significantly over the years 2015-2050, notably in the alternative scenario cases (see Section 2.2., in particular **Table 5**). Therefore, expressed as a percentage of total final load, the increase in the total annual demand for flexibility on both the day-ahead market and the intraday market, including both hourly ramp-ups and ramp-downs, is less outspoken than in absolute terms, although still significant. The bottom line of **Table 16** shows that, expressed likewise, this rate increases from 5% in R2015 to almost 19% in A2050.

Conclusion
The demand for flexibility due to the *uncertainty* of the residual load is also expected to increase rapidly up to 2050, in particular due to (i) the uncertainty – or lower predictability ('forecast error') – of power from wind, in combination with (ii) the large (dominant) increase in installed wind capacity over the years 2015-2050. The size of this type of flexibility demand, however, depends highly on the extent to which improvements in reducing the forecast error will be effectuated up to 2050.

5

The demand for flexibility due to congestion of the power grid

The previous chapters have discussed the impact of the FLEXNET scenario cases on the demand for flexibility by the Dutch power sector at the national level (due to the variability and uncertainty of the residual power load). Based on the same scenario cases as used for the national analysis, a regional grid analysis was performed to investigate first of all the impact of the scenario cases on the load profile of the regional Liander grid network in the Netherlands in order to identify the need for flexibility due to possible overloads of this network (phase 1 of FLEXNET) and, subsequently, the degree to which flexibility can offer a solution to mitigate congestion and necessary reinforcements of the grid (phase 2 of the project).

The regional analysis distinguishes itself by the scale and resolution of the study. As part of the project, the implications of the FLEXNET scenario cases have been assessed for the load profile of the Liander distribution grid, with over 80,000 km of power cable and over 36,000 transformers.[35] For all these power cables and transformers, a power load time series has been constructed with a 15 minutes' resolution for all scenario cases in order to assess which assets of the Liander distribution grid are expected to be overloaded, and where and when these overloads are expected to concur. The results form the basis for phase 2 of the FLEXNET project, in which potential flexibility options to overcome grid congestion problems have been analysed.

Power flows in the distribution network are significantly altered due to the increasing adoption of new technologies such as photovoltaics (sun PV), heat pumps (HPs), electric vehicles (EVs) and wind power. High local penetration of these technologies will lead to increased peak loading and higher volatility of power flows, potentially causing congestion and power quality issues.

[35] Liander is the largest DSO in the Netherlands, supplying about one third of the Dutch households with electricity.

The impact of these new technologies will not be uniformly distributed over the power grid and will differ based on demographic differences. These developments make long term planning for distribution system operators (DSOs), such as Liander, a serious challenge, since their assets have a typical operating life time well beyond 40 years.

The main research question for phase 1 of the regional analysis is: *Based on the scenario cases as defined in Chapter 2 of this report, which parts of the total asset base of the Liander distribution grid are expected to be overloaded, and where and when are these overloads expected to occur?*

This chapter presents the impact of the FLEXNET scenario cases, notably of the adoption of the emerging new power sector technologies (sun PV, wind, EVs and HPs) on the load profile of the Liander distribution grid. Firstly, the bottom-up calculation methodology is discussed in Section 5.1, followed by the results of the regional analysis. In line with the calculation method, the results are discussed in a bottom-up manner, starting in Section 5.2 with the outcomes of the dispersion model and the expected regional adoption of EVs, HPs and sun PV for the Liander service area. In Section 5.3 examples of load profiles are shown at different levels of the network topology to illustrate the impact of the transition scenarios on the distribution grid. In Section 5.4 the expected congestion (number of overloaded assets) for the considered scenario cases is discussed at different levels of the network topology.

Section 5.5 compares the main findings of the present study for the Liander grid distribution network with the outcomes of a similar study for the regional network of another distribution system operator (DSO) in the Netherlands, i.e. Stedin. Subsequently, Section 5.6 presents the major outcome of an assessment conducted by TenneT on the implications of the FLEXNET scenarios – and the findings of the Liander regional analyses in particular – for TenneT's transmission grid assets in the north-western part of the Netherlands (i.e. in the province of North-Holland). Finally, the conclusions of phase 1 on the regional network analysis of FLEXNET are presented in Section 5.7.

5.1 Methodology

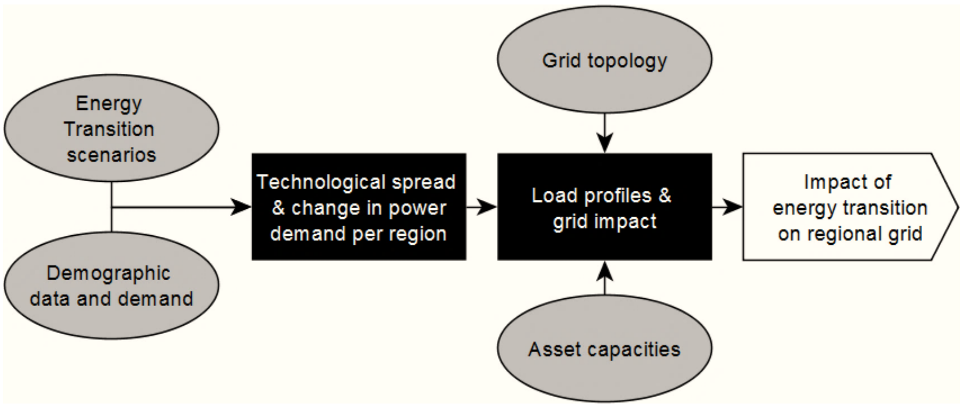
The regional grid analysis has been performed by means of the Liander ANDES model. This model has been developed by Liander to determine the impact of the energy transition on the Liander distribution grid.

In phase 1, the ANDES model is used to generate load profiles at different levels of the grid (high voltage, medium voltage, and low voltage) for the different FLEXNET scenario cases (see **Table 5** in Chapter 2). Based on the calculation results, the model determines where and when overload will occur for each scenario case.

5.1.1 Modelling approach

The ANDES model is based on a bottom-up methodology. It uses analytical methods to predict the adoption of photovoltaics (sun PV), electric vehicles (EVs) and heat pumps (HPs) at a granular local level (i.e. at the 6-digit zip code level). In this way, the model is able to construct a load profile for each customer (including prosumers) based on the expected local adoption of these technologies. Using load flow calculations, the impact of the changes in load profiles is calculated at each level of the grid up to the substation level. **Figure 34** shows a conceptual overview of the calculation method.

Figure 34: Conceptual overview of the calculation of load profiles for different assets in the regional grid



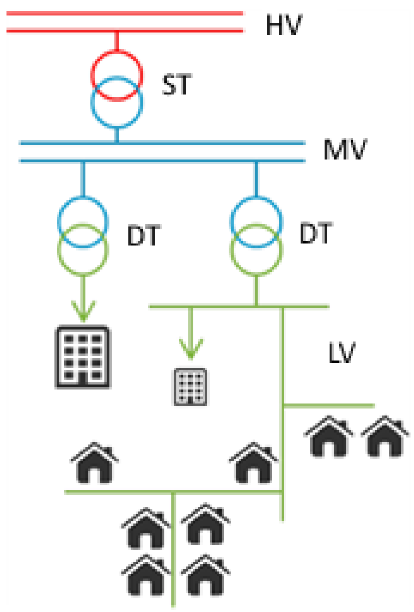
The first step in the load profile calculation is to convert the forecasted adoption of EVs, HPs and sun PV at the national level to an estimation of the adoption per scenario case at the regional level. To achieve this, a statistical dispersion model applies various regression methods to historic and demographical data to determine the probability of households adopting a certain technology. Historic data is mainly obtained from Liander internal data sources, while the demographic data is obtained from external data sources such as the Dutch Department of Transportation, the Chamber of Commerce, the Central Bureau of Statistics (CBS) and the European Data Management (EDM), i.e. a commercial supplier of marketing and customer intelligence data.

Based on the determined probabilities, the ANDES dispersion model uses a Monte Carlo simulation to determine absolute adoption numbers at 6-digit zip code level (comparable to street level). The absolute numbers of technology adoption are converted into 15-minute load profiles for the various technologies at customer level.

In addition to the load profiles for the various technologies, the base load for each customer is required to calculate the residual load. The base load per customer is assumed to be equal to the 2015 load profile of each customer. As the adoption of the emerging power sector technologies in 2015 is still very low, the 2015 load is taken as the conventional load. If available, the conventional load is equal to measured, telemetric data (smart meter data; 15-minute average; base year 2015). In the Netherlands this data is available for all large industrial customers and most small and medium enterprise (SME) customers. If no measured data is available, the conventional load profile is based on average household load profiles[36] and average industry segment load profiles[37] scaled with the known 2015 yearly energy usage. The residual load is equal to the summation of the conventional load profile and the load profiles of the adopted new technologies per customer.

The predicted residual loads are then coupled to the grid based on grid topology and aggregated at each level of the network to determine the load on each asset. A schematic overview of the network topology is shown in **Figure 35**. The model calculates the load profiles for all assets up to and including the HV/LV transformers in the Liander substations, which form the connection points of the distribution system to the national transmission system. In total, calculations are made for more than 80,000 km of power cables and 36,000 transformers.

Figure 35: Schematic overview of the grid topology from low voltage (LV) to medium voltage (MV) and high voltage (HV)



Note: ST stands for Substation Transformer and DT for Distribution Transformer.

Development plans for additional housing, industry and large scale electricity generation by wind for the coming 10 years are added to the model and again converted to load profiles for each type. These load profiles are aggregated at the substation level under the assumption that these loads will be part of grid expansion and directly connected to a substation.

The last step is to determine the impact on the distribution grid per scenario case in terms of grid congestion. This can easily be done by comparing the predicted load profiles per asset with the asset's load capacity.

[36] Average household load profiles are made available by the Energy Data Services in the Netherlands (EDSN). Due to privacy restrictions, DSOs in the Netherlands are only allowed to use aggregated household smart meter data.

[37] Average industry segment profiles are provided by the Dutch Chamber of Commerce.

5.1.2 Assumptions and inputs

Table 17 provides some detail on the major assumptions and input values for all scenario cases as used in the regional analysis. The input is based on the same assumptions as for the national level, but has been adjusted as the Liander service area covers only one third of the Netherlands. The installed capacity of wind on land is based on the report '*Monitor Wind on Land'* (RVO, 2015) and Liander internal research. Only already planned wind capacity is taken into account, because the location of additional wind capacity and its impact on the regional power grid is too uncertain.

Table 17: Major assumptions and input values of all scenario cases, 2023-2050, for the regional analysis

		Reference scenario			Alternative scenario		
	Unit	2015	2023	2030	2023	2030	2050
Electrification							
Share of EVs in total passenger cars	[%]	2.0%	4.7%	9.6%	12.0%	32.0%	74.0%
Share of HPs in total households	[%]	2.1%	6.5%	7.9%	8.0%	20.0%	69.0%
Installed capacity of VRE sources							
• Wind on land	[MWe]	1329	1938	1961	1938	1961	1961
• Sun PV	[MWe]	530	2,970	5,180	2,970	5,180	20,039

For the determination of congestion, the following assumptions are applied:

- In the case of medium voltage transformers, the maximum capacity is set at 110% of the rated capacity of the transformer. The capacity of the transformer is mainly limited by the allowed temperature of the transformer. Therefore, transformers are allowed to be overloaded for short periods of time as the rated capacity is based on continuous loading.

- For the cables, medium and low voltage, the type of cable/material is taken into account. For paper insulated cables, the maximum capacity is set at 70% of the rated capacity to account for higher degradation of these cables above 70% loading. For cables with insulation made of cross-linked polyethylene (XLPE) the capacity is set at 100% of the rated capacity. Both assumptions are in accordance with current Liander policy.

- The medium voltage grid is designed in ring structures with sufficient capacity to supply all load in case of a single fault or maintenance situation. To account for the N-1 redundancy requirement of the medium voltage grid, the allowed loading of the medium voltage cables is reduced to 0.7 of the above mentioned maximum capacity. The factor 0.7 was chosen instead of 0.5 because the medium voltage grid usually consists of multiple interconnected rings, giving the operator more than one option for reconfiguring the grid connections during a fault or maintenance situation. A factor 0.5 would therefore be too stringent.

- Substations capacity is also based on their redundant N-1 capacity, which in theory means that in the case of maintenance or failure of one of the components in the substation, for instance a transformer, the entire load can still be supplied. In practice, however, substation loading is allowed to surpass the N-1 capacity for a limited amount of hours during the year. Investment decisions for reinforcement are based on a risk assessment and only performed if the risk (probability x impact) is considered high according to the Liander risk matrix. Again, this is in line with current Liander policy.

5.2 Regional technology adoption

In this section the results of the ANDES dispersion model are discussed. Sections 5.2.1 to 5.2.3 dive into some more detail regarding the prediction of the regional adoption for each of the considered technologies sun PV, EVs, and HPs. Section 5.2.4 presents the results of the dispersion model using a geographic representation for both the reference and the alternative scenario cases.

5.2.1 Regional adoption of PV systems

For residential PV a logistic regression model has been built based on the currently known PV-population in the Liander service area (around 40,000 PV installations in early 2014). The predictive power of a number of demographic variables regarding PV-ownership has been assessed, resulting in a model with the eight most significant demographic variables. The variables are displayed in **Table 18**. Both open data and commercial data were used.

Table 18: Input variables for logistic regression model for PV-ownership with the highest prediction value

Customer variables	Example categories
House type	Apartment, detached house
Year of construction of house	1990-1994, 1995-2000
House volume	250-325 m^3, 325-375 m^3
Living area	80-100 m^2, 100-120 m^2
Ownership	Owned, rented
Life phase	Families with children, elderly singles
Social class	Combination of education level and income
Lifestyle type	Intellectual/cultural, trend followers

The regression model has delivered a probability per household for becoming a PV owner. The number of PV systems according to the national scenario is sampled, using the probabilities as weights, to assign each PV system to one of the households in the Liander service area. This process is repeated 100 times and the results are averaged. The simulations have a resolution of zip code level, which in the Liander area has an average of 16.6 households. The final result is a predicted average number of PV installations per zip code per year up to 2050 for each scenario case.

5.2.2 Regional adoption of passenger EVs

The impact of passenger EVs on the power grid is the combination of residential and non-residential charging actions per day.

For determining the location of *residential* EV charging the model of Eising et al. (2014) has been used. Eising et al. predict the geographical distribution of EVs by dividing zip codes into adoption categories based on income, second car ownership and urbanization. Based on this, a similar regression model is applied as was developed for PV installations. Using these adoption categories and the adoption scenarios, EVs are assigned to households. Of the total EV energy demand, 53% is assumed to be charged at or near home.

The number of *non-residential* EV charging actions up to 2050 has been estimated for three types of non-residential customers:

1. The number of EVs at *corporate buildings* was estimated by multiplying the number of company employees with estimated car usage per employee (Chamber of Commerce, 2016; CBS, 2015). These cars are then 'electrified' using the adoption scenarios. Estimated car use of employees ranged from 40% in the highest urbanization areas to 72% in the lowest urbanization areas (CBS, 2013). About 29% of the total energy demand of EV is assumed to be charged at work.
2. For EV charging at a *public parking garage*, the number of car spaces in each public parking garage was multiplied with the EV penetration percentage. This resulted in a number of EVs per public parking garage with a corresponding load profile. About 5% of the total EV energy demand is assumed to be charged at a public parking garage.
3. Fast charging locations are based on the location of current *gas stations* in the Liander service area. About 13% of the total EV energy demand is assumed to be charged at fast charging locations. 50% of the energy demand is uniformly distributed over gas stations located next to a highway and 50% over the other locations.

Per category, a load profile is constructed based on the method discussed in the Movares EV charging strategy report (Movares, 2013).

5.2.3 Regional adoption of residential HPs

Since there is no central instance that registers the location of residential heat pumps (HPs), only limited data was available to create the dispersion model for this technology. Since installing a HP is relatively expensive and requires some serious modifications to the building, it was assumed that the most likely moment for a household to acquire a HP is a renovation. The two predictors for renovations that were used are the type of house occupancy and the building year of the houses.

Using this data, for the location of heat pumps a regression model has been developed that predicts the number of heat pumps per zip code. First a segmentation was made of houses in ownership and social rental houses and private rental houses. Each segment was given a different maximum adoption rate and a different geographical distribution.

5.2.4 Results

The results of the logistical regression can be observed in **Figure 36** and **Figure 37**. These figures depict the spread of the technologies across the service area of the Liander distribution grid.

It can be observed that the penetration of PV and EV is relatively low in the city centres, even in the alternative 2050 scenario. For PV this is mainly caused by the fact that power consumption density is relatively high, while the amount of space that is available for PV installations is limited. Not everyone living in a flat will have access to a rooftop on which PV can be installed. For EV the story is similar. People living in cities are less likely to own a car and hence are also less likely to acquire an electric vehicle.

5.3 Impact of adoption of new technologies on load profiles

The adoption of new technologies such as sun PV, EVs, and HPs will have a significant impact on the power load profiles of customers in the distribution grid. At high penetration rates, these changes will become visible at all levels of the grid.

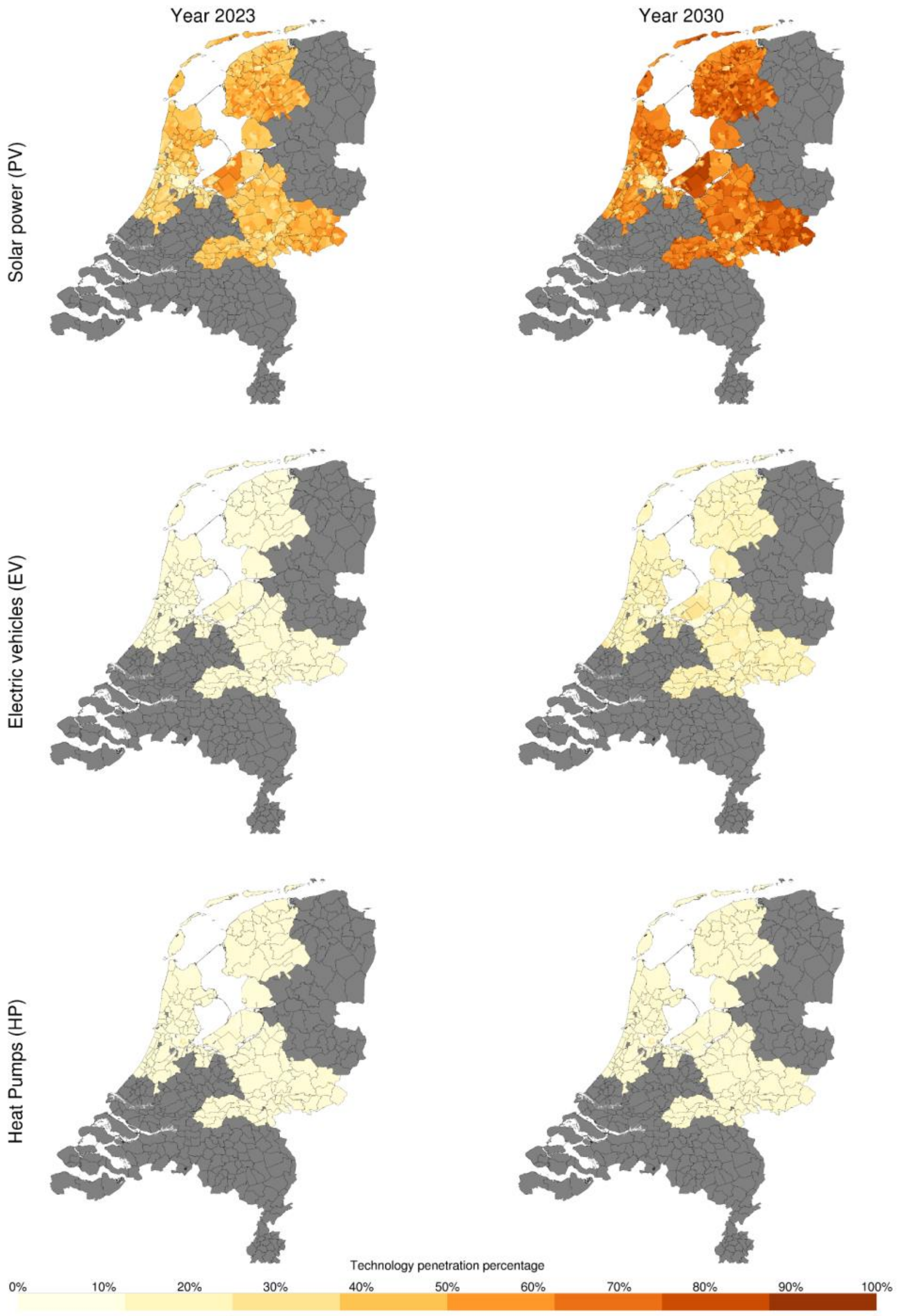
Currently, the chance that all power customers use their peak load at the same time is very low. Since the worst case peak load is very unlikely, the assets are usually dimensioned for a smaller peak load. The main issue with PV, EV and HP is not only the increased supply and demand of electricity in the distribution grid, but also the fact that these installations usually are active at the same time on a local level, leading to high peak loads on the grid in both directions (demand and feed-in).

The coincidence factor, also known as the simultaneity factor, is generally used to describe this effect. It is the ratio between the peak load and the total installed capacity. PV systems for instance have a very high coincidence factor of more than 0.8 on a clear-sky summer day, as the peak generation occurs around midday for all systems. The coincidence factor of PV is slightly reduced by, among others, the variation in orientation towards the sun and the influence of the temperature on the PV panel efficiency.

For EVs the coincidence factor is high due to similar arrival times of EV users (arriving at work in the morning or at home in the evening) in combination with relative long charging times. This will cause a high peak load which, unfavourably, also coincides with the peak of an average household load profile.

Lastly, the coincidence factor of heat pumps will approach 1.0 during a cold winter's day. High local penetration of these technologies will potentially lead to congestion and power quality issues.

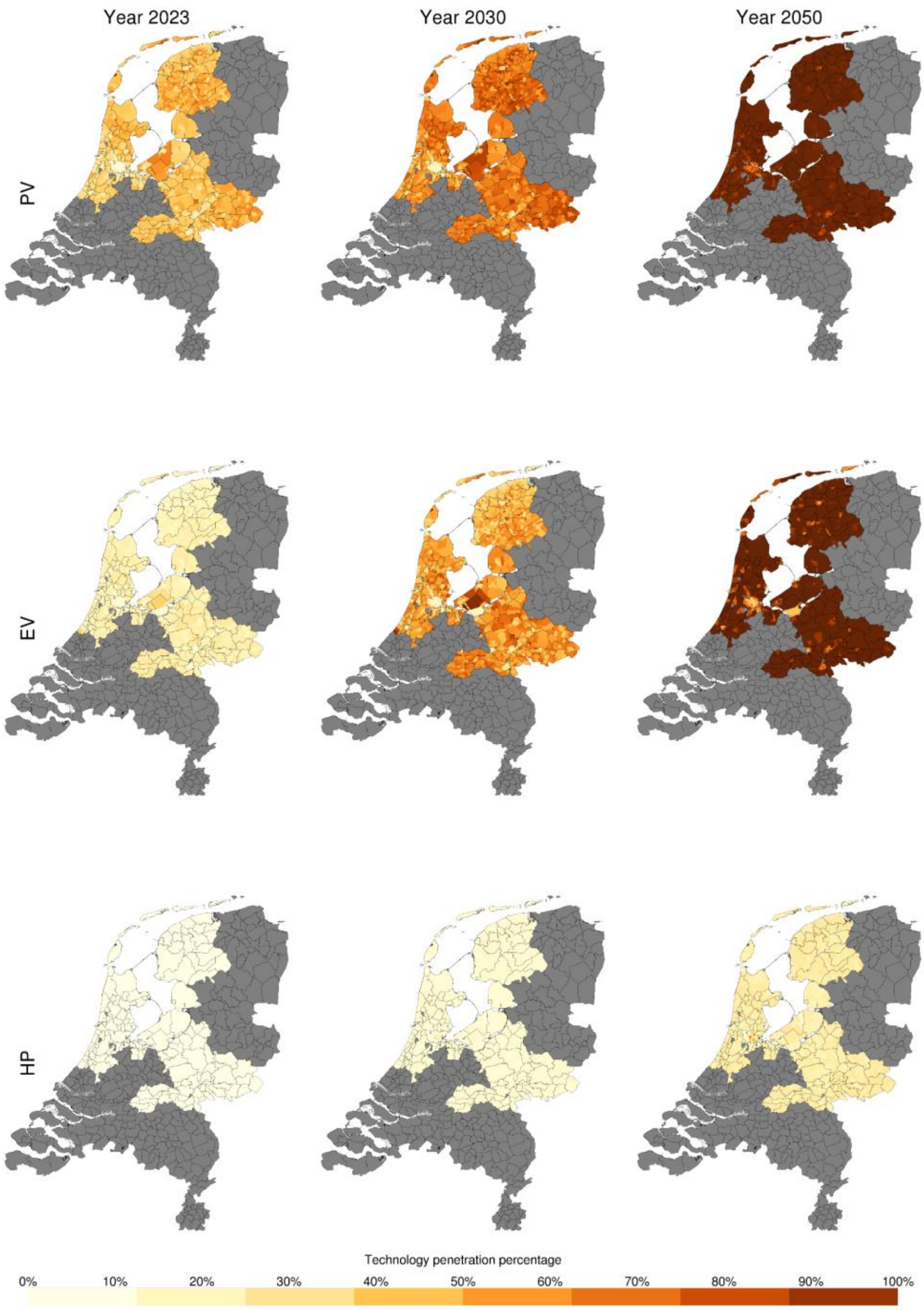
Figure 36: Geographic representation of the technology penetration for the FLEXNET reference scenario on district level resolution



Notes:

- The grey borders are the municipalities of the Netherlands.
- The model takes into account the limited availability of useful roof surface by restricting the maximum kWp per household to the current yearly energy use.
- The part of the solar capacity that cannot be assigned to households is distributed over SME and large-scale consumers based on yearly energy usage.

Figure 37: Geographic representation of the technology penetration for the FLEXNET alternative scenario on district level resolution



Notes:

- The grey borders are the municipalities of the Netherlands.
- The total installed capacity of PV increases by a factor 4 between 2030 and 2050 according to the FLEXNET scenarios. This leads to a PV adoption of almost 100%.
- In the alternative scenario in 2050, over 90% of the households have at least one electric car, as can be seen in the picture. However, since many households own more than one car, only 74% of all cars are electric in 2050 in the alternative scenario.

In the section below, the impact of the penetration of new technologies (PV, EV, and HP) on the distribution grid is illustrated. In line with the methodology, the results are shown in a bottom-up manner starting with an example of a household load profile. Next, the results for the load profile of a distribution transformer is shown, which is an aggregated load profile of the connected customers. Lastly, the load profile at one of the Liander substations (Zaltbommel) is presented.

5.3.1 Load profile of a household

Figure 38 shows an example of a load profile for a household for a winter and summer week for all scenario cases. This particular household is equipped with a heat pump and solar panels. Furthermore, the household owns an electric vehicle.

The residual load profile (see bottom two graphs of **Figure 38**), is the summation of four separate load profiles as illustrated in the top two graphs. In these graphs, the load profiles are divided into a demand profile and a supply profile (only solar generation in this case). The four load profiles are:

1. The conventional load (blue area) represents the average load profile of a household in the Netherland in 2015, scaled by the household's yearly energy usage of 3.300 kWh.
2. Stacked on top of the conventional load, the red area represents the heat pump's load profile.
3. Lastly, the load profile of the electric vehicle charging is added to the demand profile (green area).
4. On the supply side (below the X-axis) the load profile of the installed VRE capacity is shown (yellow area). For household it is assumed that only sun PV will have a (significant) contribution to this profile.[38]

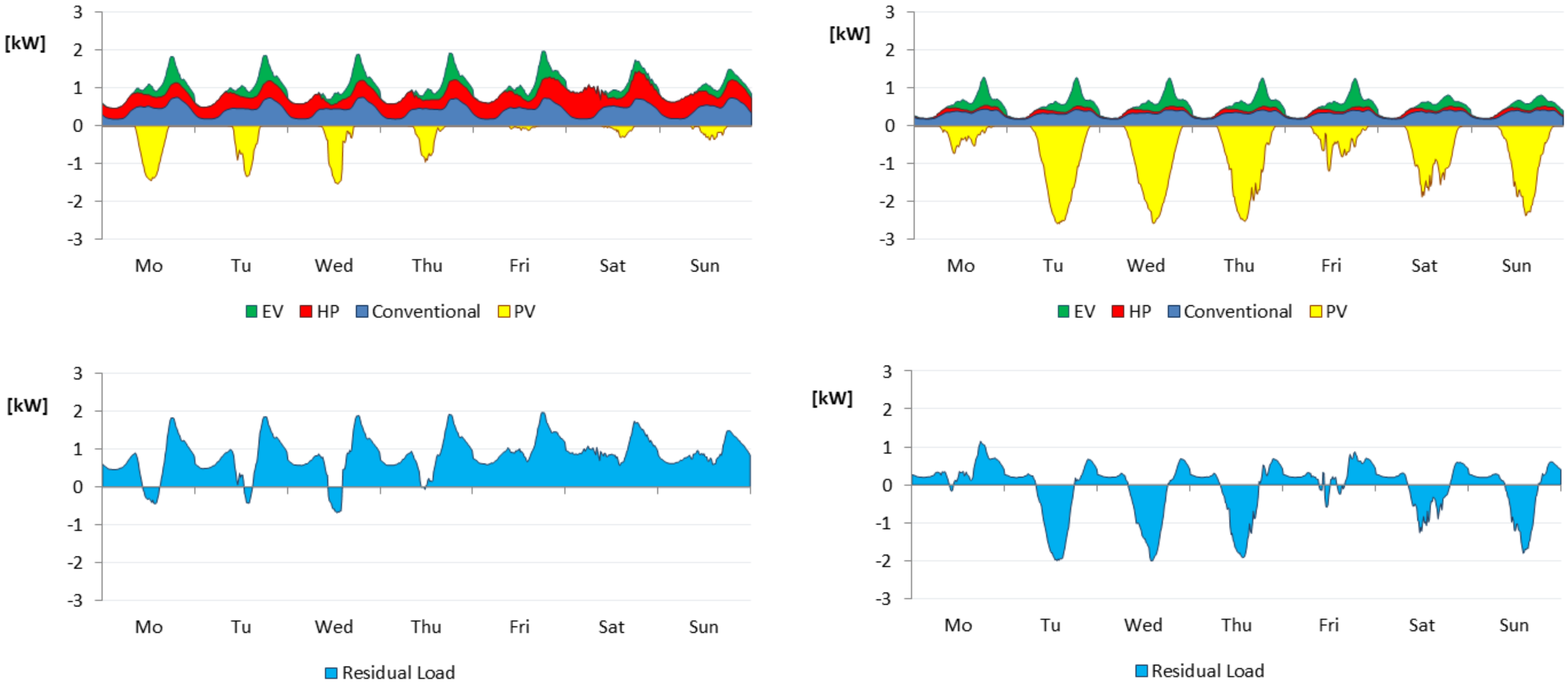
All load profiles are average load profiles under the assumption that the load profiles are aggregated on the distribution grid.

The first effect that can be observed from **Figure 38** is the change in volatility of the residual load between a household without HP, EV and PV (represented by the conventional load profile) and a household with these technologies (lower two graphs). Changes in load of about 3 kW can be seen on multiple days, which is a factor 5 higher than in a conventional load profile.

As can be expected, a clear difference can be noted in the residual load between winter and summer due to the seasonal differences. In winter, the contribution of heat pumps to total power load is significant. It must be noted, however, that in the presented week 6, the temperature drops down to a minimum of -19°C in the night from Friday to Saturday. This is rather extreme for the Netherlands. During this time, the heat pump's combined load becomes twice as high as the average for this relatively cold week. During the day, the temperature rises again, reducing the heat pump's load.

[38] PV profile is based on the output data of more than 80 different PV systems. Due to the different orientations of these PV systems, the maximum output power is about 30% lower than the rated capacity (2.8kW vs 4kWp in this example).

Figure 38: Demand & supply profiles and residual load for a winter and summer week for a single household in the reference scenario case 2015 (R2015)



Power load winter (week 6)

Power load summer (week 30)

The highest demand peak occurs in winter between 18:00 and 18:30 at the time people arrive home from work due to the fact that the EV charging peak coincides with the evening household peak. This in combination with the HP load leads to demand peaks of 2.5 times the conventional load peak in this relatively extreme winter week.

The highest absolute peak, however, occurs in summer due to the energy generation of the PV system. The solar system in this example is about 4 kWp. As mentioned before, the model uses an average load profile, which is based on the output data of more than 80 different PV systems. Due to the different orientations of these PV systems, the maximum output power is lower than the above mentioned 4 kWp at about 2.8 kW. This leads to a maximum negative peak of about -2.5 kW in this example, which is still more than 3 times higher than the highest peak of the conventional load.

In short it can be concluded that the adoption of sun PV, EVs, and HPs will completely alter the load profile of a household. With high adoption degrees these changes will become visible on all connected assets higher up in the network topology.

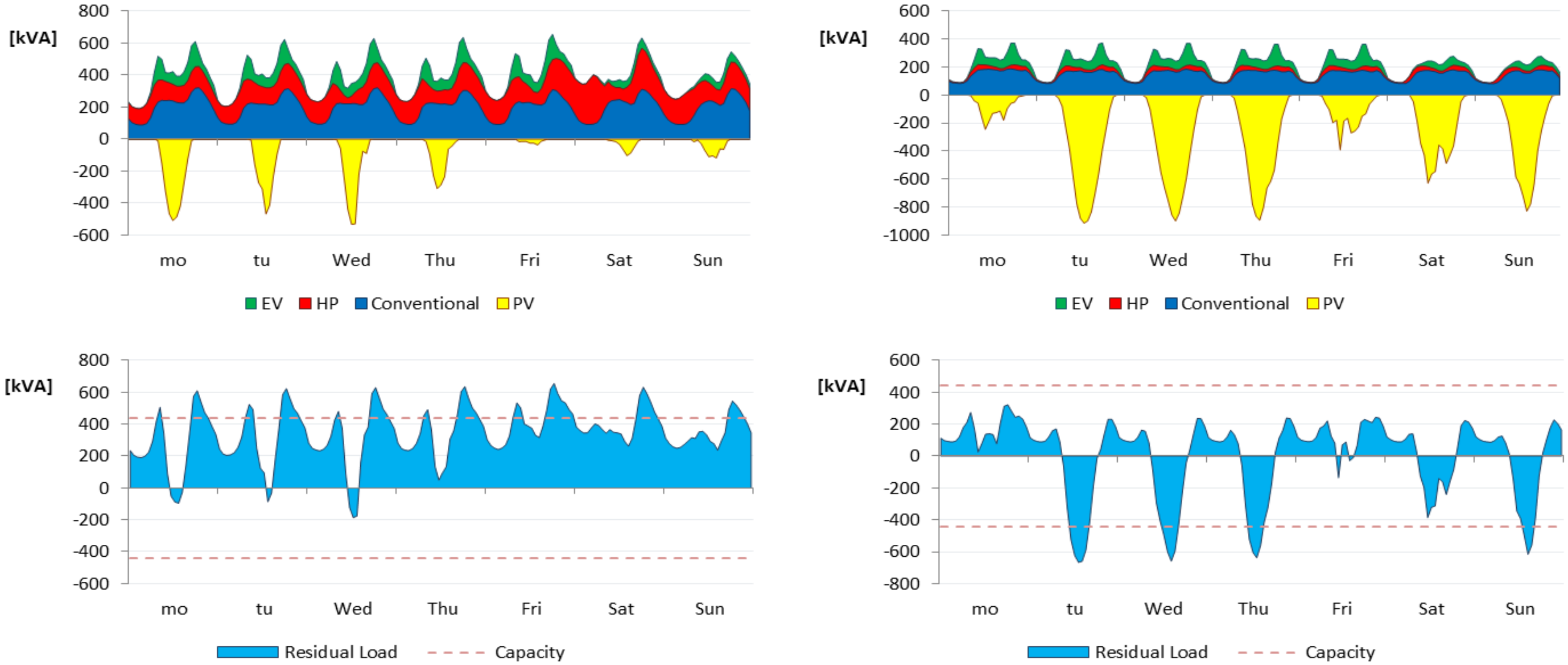
5.3.2 Load profile of a distribution transformer

Figure 39 shows an example of the load profile of one of the distribution transformers for the 2050 alternative scenario. This particular transformer is supplied by the Zaltbommel MV/LV substation and has a rated capacity of 400 kVA. The distribution transformers connect the medium voltage grid to the low voltage grid. The low voltage grid mainly supplies household consumers and some small-scale enterprises. Large-scale consumers are generally connected at the medium voltage level. The considered distribution transformer supplies 257 small-scale customers with a connection capacity of maximum 3x80 amperes and 5 large-scale customers with a connection capacity larger than 3x80 amperes. The load profile for the distribution transformer is constructed by aggregating the load profiles of the supplied customers. Whether a particular customer has adopted one of the technologies (HP, EV, PV) is determined by the dispersion model.

As for the household profile, the conventional load (blue area) has exactly the same pattern as the load in 2015. For 2050, however, the total yearly energy usage is scaled 10% downward to take into account energy efficiency improvements of the conventional load. Comparing the conventional load pattern to the residual load pattern in the lower two graphs, it can be seen that the profile becomes much more volatile, especially during a clear winter’s day, with a load differences of more than 800 kVA in about 5 hours.

In the lower two residual load graphs, the dotted lines represent the maximum capacity of the transformer. The capacity of the transformer is mainly limited by the allowed temperature of the transformer. Therefore, transformers are allowed to be overloaded, compared to the rated capacity (continuous loading), for short periods of time. To take this fact into consideration, the transformers are only assumed to be overloaded if the peak load is more than 110% of the rated capacity, which in this case is + or -400 kVA.

Figure 39: Demand & supply profiles and residual load for a winter and summer week at a MV/LV distribution transformer in the alternative scenario case 2050 (A2050)



Power load winter (week 6)

Power load summer (week 30)

Looking at the residual load graphs, it is clear to see that this particular transformer is overloaded once or twice a day in the considered weeks in the 2050 alternative scenario. The characteristics of the overload are, however, different. During the winter overload is mainly caused by demand, while in summer overload is caused by PV feed-in.

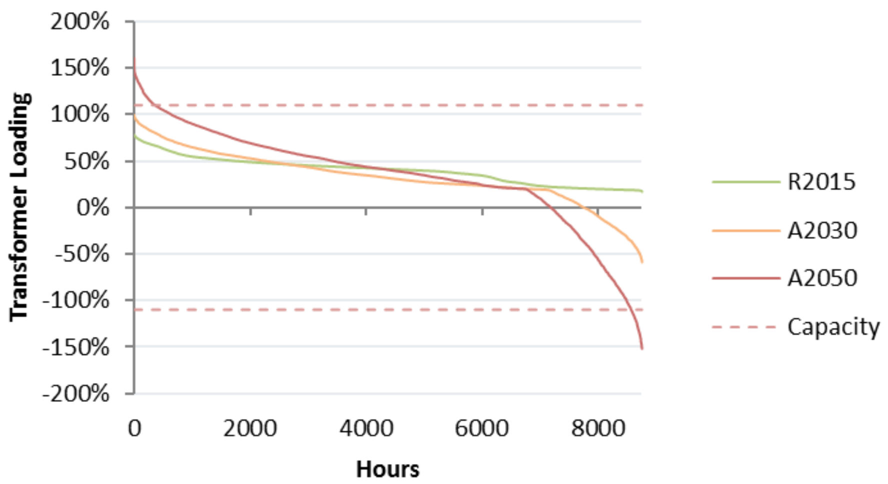
The EV load profile shows, besides the peak in the evening, a peak in the morning. This is due to the presence of some business activity in the area and coincides with the time people arrive at work.

As a conclusion, it can be said that due to the high adoption rates in the alternative 2050 scenario case, the changes in load profile for households and small-scale enterprises as illustrated in the previous section propagate to the higher assets in the network topology, in this case the distribution transformer. As a result, the load profile becomes much more volatile with significantly increased peak loading.

A load duration curve can be used to observe how the asset load is distributed. It shows, for instance, whether an asset is loaded with a high but short-lived peak, or whether the peaks are relatively low but more long-standing. This is useful for determining the appropriate solution for the overload problem as a high but short-lived overload might be easier to mitigate than a lower but long-standing overload.

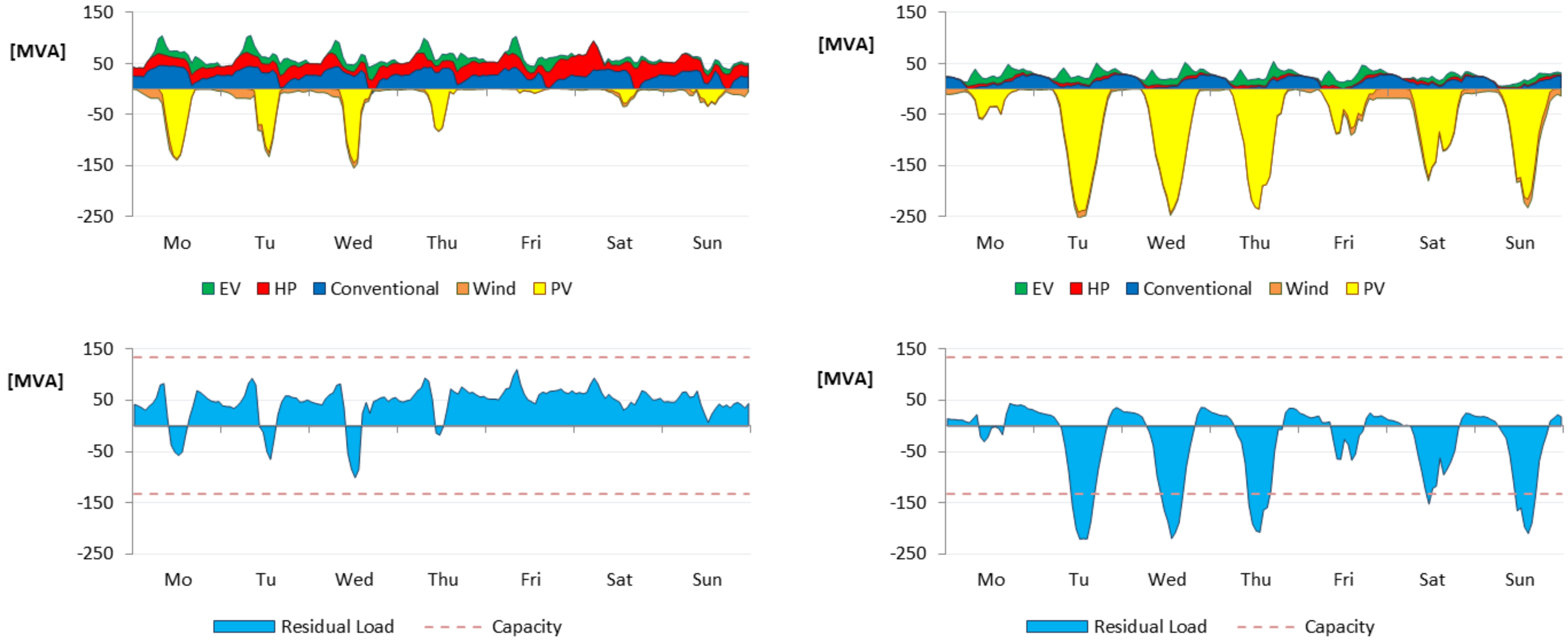
Figure 40 presents a load during curve at a MV/LV distribution transformer for three scenario cases (R2015, A2030 and A2050). The change in transformer loading is most significant on the right side of the graph due to the feed-in of sun PV.

Figure 40: Load duration curve at a MV/LV distribution transformer for some selected scenarios



As can be seen from **Figure 40**, the change in loading does not directly lead to overloading. For this particular transformer, no overload is to be expected up to at least 2030. Whether congestion occurs is very much dependent on the local situation (e.g. current load ratio, type of customers). Most distribution transformers have a relative high margin and overload only occurs at relatively high adoption rates of EVs, sun PV and HPs.

Figure 41: Demand & supply profiles and residual load for a winter and summer week at the Zaltbommel substation in the alternative scenario case 2050 (A2050)



Power load winter (week 6)

Power load summer (week 30)

5.3.3 Load profile of a high voltage substation

To illustrate the effect of the energy transition on the loading of a Liander substation, **Figure 41** shows the load profile for the Zaltbommel substation for the 2050 alternative scenario. In general, it can be said that the Liander high voltage substations connect the transmissions system of TenneT to the distribution grid of Liander.

The load profile at the substation is again an aggregation of the load profiles of the consumers in the substation's service area. Large-scale consumers (and large-scale prosumers) are connected to the medium voltage grid or directly to the substation. Wind is also connected to the medium voltage grid and larger wind-on-land parks are connected directly to the substation. As a result, the load profile of a high voltage substation looks much less like a typical household profile.

The Zaltbommel substation has recently been reinforced/expanded. The capacity is therefore relatively large compared to the current load. Despite this, the installed capacity of PV assumed in the 2050 scenario causes an overload as a result of the amount of sun PV feed-in. The maximum feed-in peak is about twice as high as the maximum demand peak for this particular area, as illustrated in **Figure 42**.

Figure 42: Load duration curve at Substation Zaltbommel for some selected scenario cases

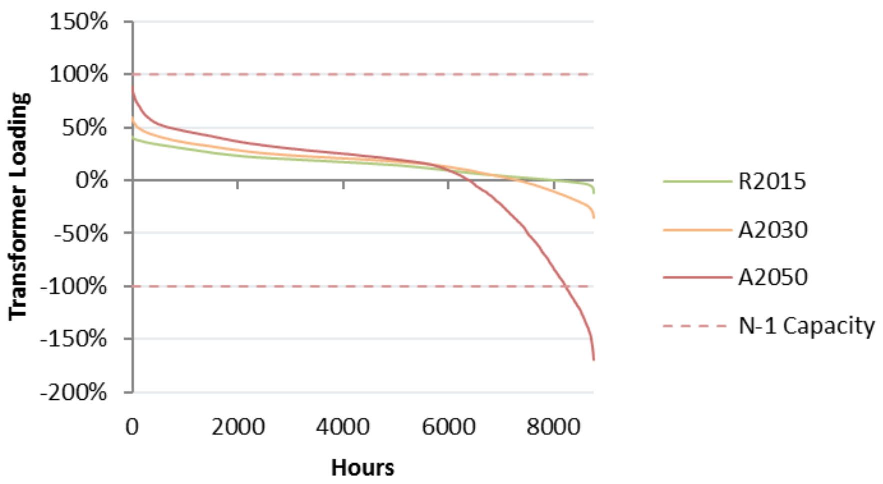


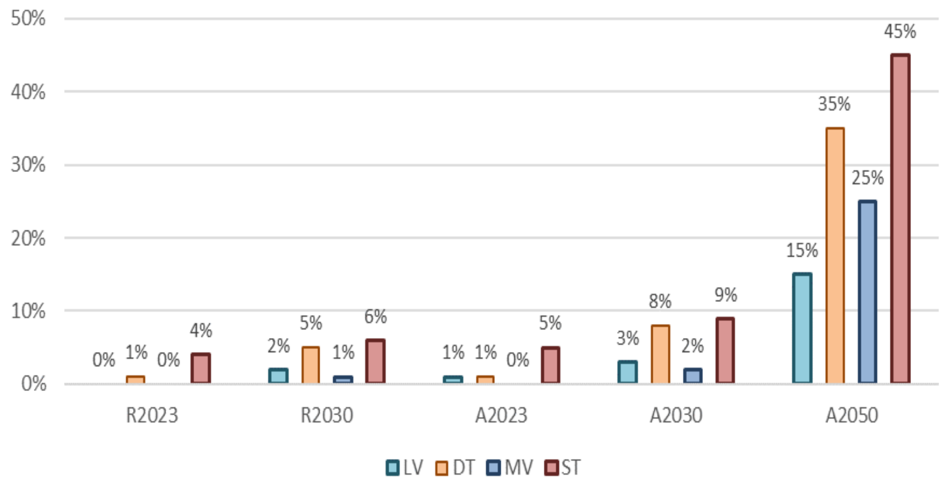
Figure 42 shows the load duration curve for the Zaltbommel substation for three scenario cases (R2015, A2030 and A2050). Most notable is the difference in feed-in peak load at the substation between the 2030 and 2050 scenario. This difference is even more distinctly than in the load duration curve of the distribution transformer (**Figure 40**).

The relatively large difference between A2030 and A2050 can partly be explained by looking at **Table 17** (Section 5.1). The assumed installed capacity of PV in the Liander service area increases by about a factor 4 between A2030 and A2050.

5.4 Overload caused by technology adoption in the Liander regional power grid

Given the energy technology adoption scenarios and the Liander network topology, the overloaded assets in the Liander regional distribution grid have been calculated. The results are presented in **Figure 43**, **Figure 44** and **Figure 45**.

Figure 43: Percentage of overloaded assets per scenario case at different levels of the distribution grid

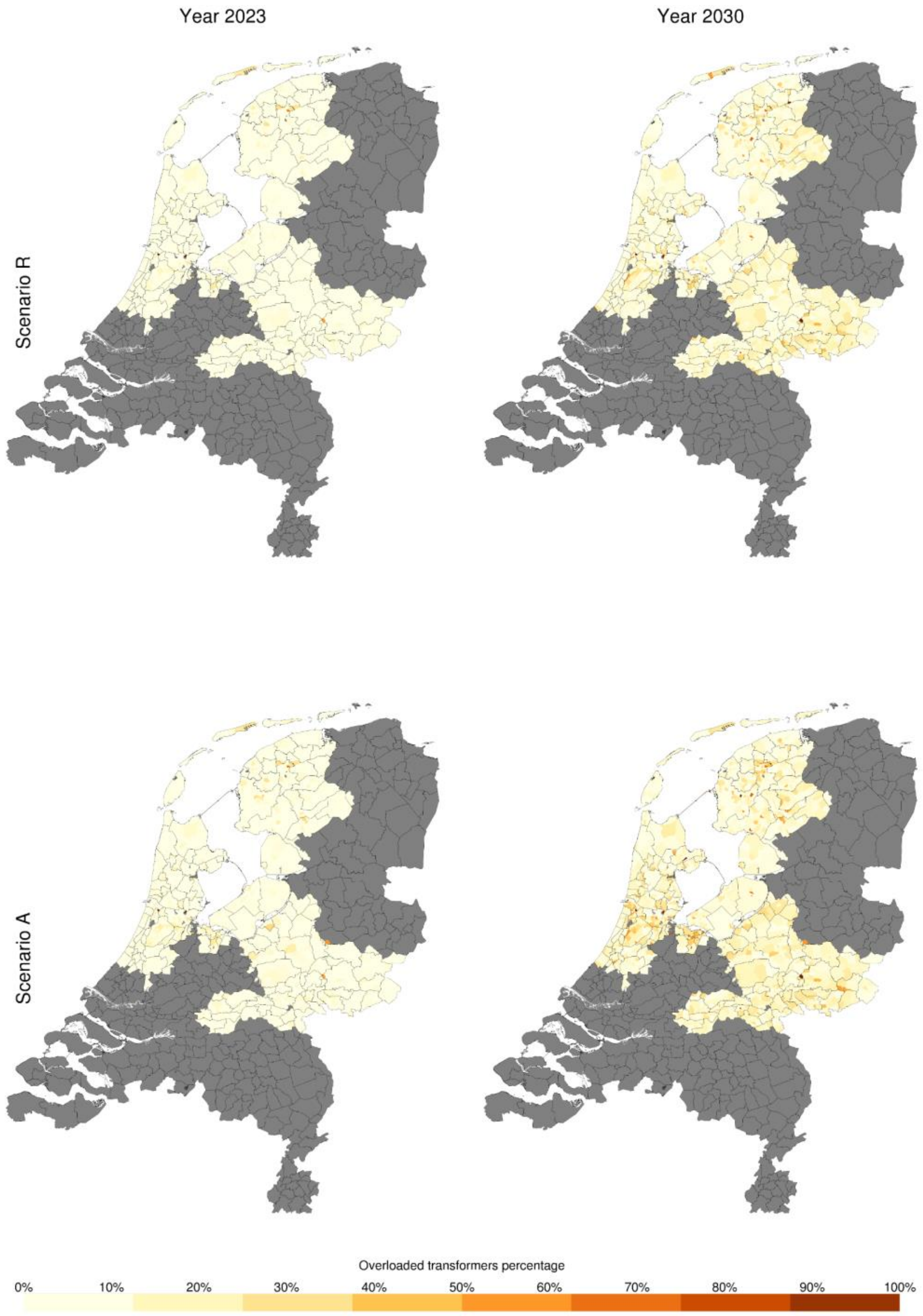


Note: LV = Low voltage cable; DT = Distribution transformer; MV = Medium voltage cable; ST = Substation transformer

It can be concluded from **Figure 43** that the expected number of overloaded assets is relatively low compared to the numbers predicted by previous studies on Dutch power distribution grids performed with real asset data (Veldman, 2013; Veldman et al., 2013). The main cause of this difference seems to be the fact that these studies assume an autonomous load growth of 1% per year until 2050 (additional to the growth that results from the increasing penetration of EV and HP). ANDES predicts a load growth of over 1% per year as well, but that is primarily based on the increasing adoption of EV and HP (and is not on top of an autonomous growth of 1%). Another important difference with other studies, is that they often focus on the medium voltage grid, while ANDES focuses on low voltage assets as well. A final difference is that the present study uses more precise data and predictions than previous studies, as this is one of the first studies which simulates the impact of emerging power sector technologies on distribution grid assets at the local, granular level using a stepwise, bottom-up methodology, detailed datasets and specific technology dispersion scenarios.

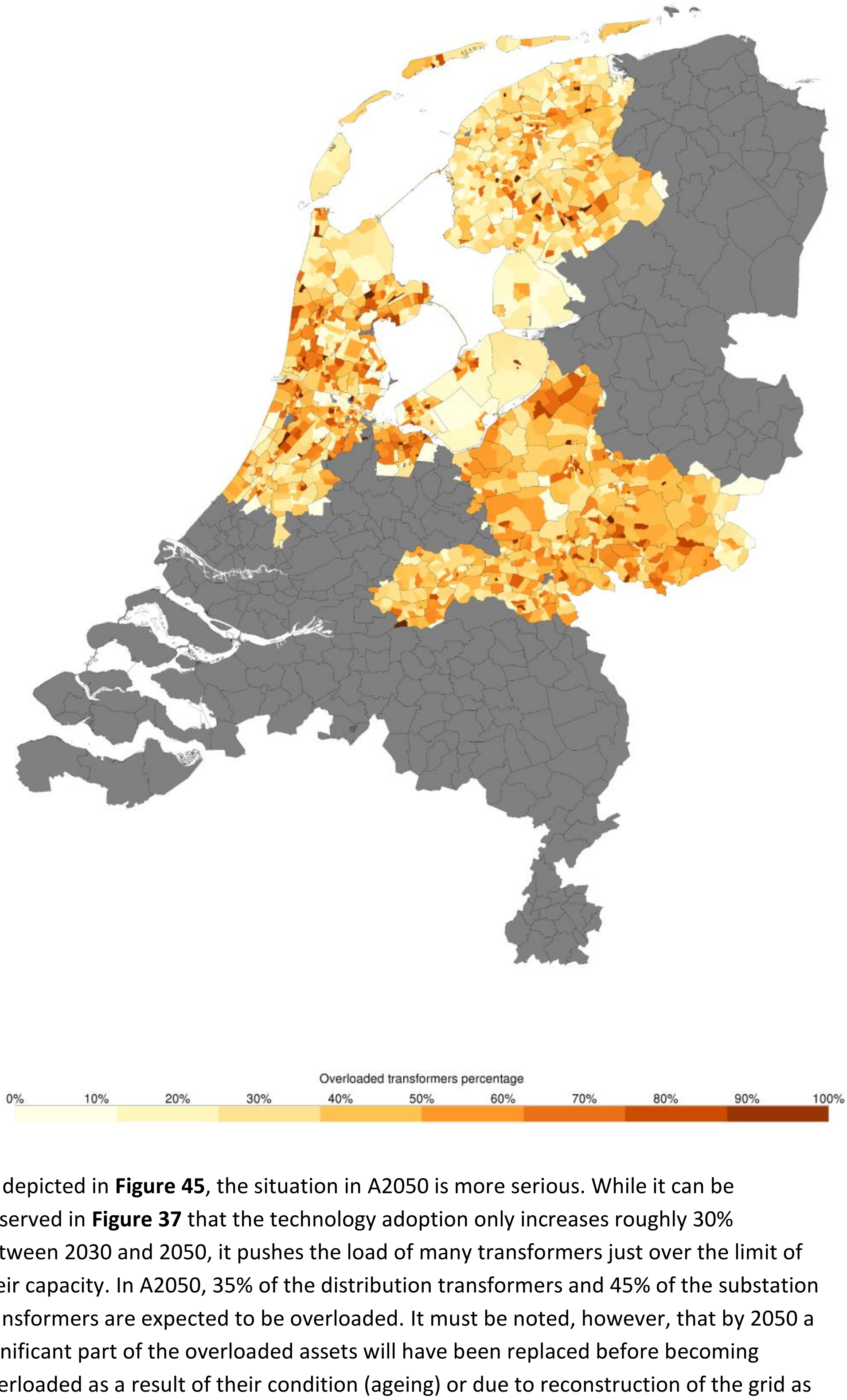
The geographic distribution of the overloaded transformers is displayed in **Figure 44** and **Figure 45**. For convenience, these figures only display the percentage of overloaded medium voltage transformers. The predicted regional impact of the overloaded cables is geographically similar to that of the medium voltage transformers, making visualizations of the cable overload distribution redundant.

Figure 44: Geographic representation of the percentage of overloaded distribution transformers per postal code for the years 2023 and 2030 in both the reference (R) scenario and the alternative (A) scenario



It can be concluded from **Figure 44** that the number of overloads due to the new energy technologies is limited until 2030, even in the alternative scenario case. Only 8% of the distribution transformers and 9% of the substation transformers are expected to be overloaded in A2030. Apart from some city centres, the transformers have sufficient capacity to transport the extra load. This is one of the major conclusions of this study. Most likely, new energy technologies such as PV, EV and HP can be accommodated relatively easily the next few decades.

Figure 45: Geographic representation of the percentage of overloaded distribution transformers per postal code in the alternative scenario for the year 2050 (A2050)



As depicted in **Figure 45**, the situation in A2050 is more serious. While it can be observed in **Figure 37** that the technology adoption only increases roughly 30% between 2030 and 2050, it pushes the load of many transformers just over the limit of their capacity. In A2050, 35% of the distribution transformers and 45% of the substation transformers are expected to be overloaded. It must be noted, however, that by 2050 a significant part of the overloaded assets will have been replaced before becoming overloaded as a result of their condition (ageing) or due to reconstruction of the grid as a result of for instance the construction of a new road or residential area.

5.5 Comparing results of Liander versus Stedin

In order to validate the Liander results on network loading discussed above, the regional analysis conducted by Liander has been compared with a similar recent study by another distribution system operator (DSO) in the Netherlands, i.e. Stedin.[39]

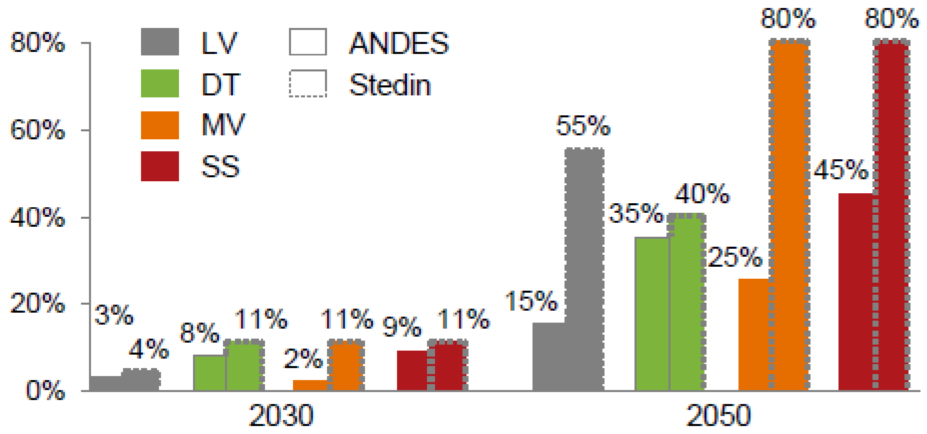
Figure 46: Service areas of regional network operators in the Netherlands

In general, compared to Liander, the Stedin approach results in similar outcomes on grid congestion in 2030 but in a higher expected number of overloads in 2050 (see Stedin, 2017a and 2017b). More specifically, comparing the respective assessments of the incidence of overloads in the Liander and Stedin networks in 2030 and 2050 results in the following findings (see also **Figure 47**):

- For 2030, Stedin models predict overloads of 4% for low voltage (LV) cables and 11% for distribution transformers (DT), where ANDES predicts 3% and 8%, respectively;
- For 2050, Stedin models predict overloads of 55% for LV and 40% for DT, where ANDES predicts 15% and 35%, respectively;
- For medium voltage (MV) cables and substation (SS) transformers, outcomes are hard to compare as Stedin has different definitions of assets belonging to MV and SS. Nevertheless, although hard to compare, Stedin estimates for overloads of MV and SS seem to be much higher (~80%) than the Liander numbers for 2050 (~25-45%).

39 Stedin is the third largest DSO in the Netherlands (after Liander and Enexis), covering more than two million households connected to the power grid (about 25% of all household connections). The service area of Stedin is located mainly in the provinces of South Holland and Utrecht (see **Figure 46**). The contribution of Stedin to Section 5.5 was delivered by Jan Pellis.

Figure 47: Comparison of expected incidence of overloads in the Liander and Stedin power distribution networks in 2030 and 2050



These differences in outcomes between Liander and Stedin are due to underlying differences in modelling approaches applied by these DSOs as well as differences in the current structure and capacity of their distribution networks. These input differences include in particular the following factors:

- Stedin has included 'other electrification' (besides EV and HP) for half in the MV network, whereas Liander – i.e. the ANDES model – did not include this additional load at all.[40]
- Stedin applied 100% of the installed PV capacity on house roof tops, resulting in peak loads (per house) of 2.5 kW in 2030 and 5 kW (urban) and 9 kW (rural) in 2050. ANDES assumes current standardised annual usage per household as a limit, resulting in peak loads of 3 kW per house.[41]
- Stedin uses a less complex allocation mechanism for predicting the adoption of technologies (EV, HP and PV). ANDES uses detailed regression models, resulting in a geographically more differentiated technology adoption.
- The grid topology of Stedin differs from Liander. Stedin seems to have connected more customers per LV cable, resulting in quicker overloading of its assets.
- Stedin applies different assumptions on energy usage profiles. For large consumers, ANDES uses LV profiles derived from telemetry measurements, while Stedin only uses EDSN profiles. For EV loading, Stedin uses sliding pointer meter measurements on distribution transformers as indication for current peak loads in the LV grid, where ANDES uses nominal capacity of assets as starting point.
- The peak loads for aggregated profiles are slightly different. For EV, Stedin assumes peak loads of 0.9 kW, where ANDES assumes 0.8 kW. For HP, Stedin assumes peak loads of 1.8 kW, where ANDES assumes 2.1 kW.

The comparison of the results on overloaded assets between Liander and Stedin shows that the Liander outcomes are not fully representative for all distribution networks in the Netherlands. This applies particularly for the year 2050 in which the predicted

[40] For the definition of 'other electrification' and its size in FLEXNET scenario cases, see Section 2.2.

[41] The part of PV capacity in the FLEXNET scenarios that is not installed on house roof tops is taken into account in ANDES in the form of solar fields and in the form of installation on roof tops of non-residential buildings.

incidence of asset overloads is significantly higher in the Stedin network (whereas the results for 2030 are largely similar in the two respective power grids). This difference in outcomes is mainly due to underlying differences in modelling inputs, including particularly differences in energy usage profiles and in translating future scenario assumptions to local developments.

5.6 Implications for HV transmission assets

The datasets and results of the ANDES model for the Liander distribution network have been used by the Dutch Transmission System Operator (TSO), TenneT, to assess roughly the implications of the FLEXNET scenarios A2030 and A2050 for some of its high voltage (HV) grid assets in the north-western part of the Netherlands, i.e. in the province of North Holland.

A major finding of TenneT's assessment is that only a rapid growth in further electrification can lead to significant additional loading of the HV grid by 2030. The growth in VRE power generation in any FLEXNET scenario up to 2030 is not big enough such that it could lead to additional bottlenecks on the HV grid by 2030. However, if by 2050 the penetration of PV becomes as big as predicted in the A2050 scenario, the HV grid as it is now will be overloaded significantly during the mid-day PV peak on sunny summer days.

More specifically, TenneT's load flow calculations show that high levels of additional electrification can load the 150 kV grid beyond its limits, especially when there is low production in the area as well. This is entirely possible with low VRE generation in the future, when the conventional plants in the area have been decommissioned or mothballed, and power has to be imported from the 380 kV grid.

The grid is also not designed to drain the projected amount of decentralised generation (DG), notably sun PV, from the area in high production situations. When the load is low and production by DG is very high, 150-380 kV transformers become heavily loaded, which could jeopardise redundancy. Important to note here is that a failure of one of those transformers would in principle not lead to an outage. While not desirable, VRE generation can be curtailed to reduce the load level of components. When curtailment is required often, significant spillage of VRE generation will occur. This would be the case in the A2050 scenario where lines get overloaded even when there is no contingency situation.

The need for weighing network reinforcement versus deployment of flexibility options is apparent, notably in the period beyond 2030. It was shown by Liander that increased electrification and VRE generation results in overloading of their assets, but also increases the load on TenneT's substations. To drain all the power from VRE on low load moments in the future, the current grid does not suffice. By 2050, the penetration of PV could become so large that it completely overloads the 150 kV grid in its undisturbed state. To avoid the spillage of VRE surpluses, power will have to be either curtailed or transported across large distances towards areas that require more power than is generated locally. Alternative measures are to temporarily store the energy locally or to shift (local) demand over time. It will depend on the specific situation what solution is most desirable (as analysed further during both the second and third phase of the FLEXNET project).

For more details on the methodology and major findings of Tennet's assessment of the implications of the FLEXNET scenarios on its HV transmission assets, notably in North Holland, see Appendix D.

5.7 Summary and conclusions

This chapter has assessed the implications of the FLEXNET scenario cases – in particular of the assumed adoption rates of the emerging power sector technologies in these cases (EVs, HPs, sun PV and wind energy) – for the load profiles of the Liander distribution network. Over 80,000 km of power cables and 36,000 transformers have been evaluated as part of this assessment. Many data sources have been combined to predict and evaluate grid loading up to 2050 on a very granular, local level. By means of the Liander bottom-up network model ANDES, the FLEXNET scenario cases have been converted into power load time series with a 15-minute interval. Using these detailed load profiles, the impact of the adoption of sun PV, EVs and HPs on the Liander regional distribution grid has been evaluated.

The regional grid assessment shows that load profiles are expected to alter considerably due to the adoption of sun PV, EVs and HPs over the next decades. The loads on all the assets of the distribution network are observed to become much more volatile. Furthermore, the winter load peaks intensify due to electrical heating while in the summer many areas have an energy surplus caused by the penetration of sun PV.

The ANDES modelling analysis indicates that the percentage of overloaded assets due to increasing adoption of PV, EV and HP is limited, at least until 2030 (<10%). In A2030, about 8% of the distribution transformers and 9% of the substation transformers will be overloaded. The percentage of overloaded cables is even lower (2-3%). As a conclusion it can be said that most assets of the network, especially cables, will have sufficient capacity to facilitate the increased loads for at least the next 15 years.

In A2050, 35% of the distribution transformers and 45% of the substation transformers are expected to be overloaded. Although these overload percentages are significant, they are not alarming. Due to asset ageing, many of the assets indicated as overloaded in 2050 will most likely have been replaced before 2050. With bigger capacities, the additional costs of these bigger capacities are marginal, as most of the costs are caused by the required work, not the material. Moreover, several 'smart solutions' are expected to become available within this time span. Therefore, the actual number of grid overloads is likely lower than indicated by the ANDES modelling results.

Geographically, most overloads are expected to arise in city centres, because of relatively old networks. The fact that the adoption of PV, EV and HP is lower in the city centres is offset by the density of the urban population, resulting in a larger increase of power load in urban areas than in non-urban areas.

The expected number of overloaded assets is relatively low compared to the numbers predicted by previous studies on Dutch power distribution grids performed with real asset data. The main causes of this difference are that (i) these previous studies assume a higher autonomous load growth than the present Liander analysis, (ii) these other studies focus on the medium voltage grid, while the Liander-ANDES assessment focuses on low voltage assets as well, and (iii) the present Liander study uses more precise data and predictions than previous studies, as this is one of the first studies which simulates the impact of emerging power sector technologies on distribution grid assets at the local, granular level using a stepwise, bottom-up methodology, detailed datasets and specific technology dispersion scenarios.

Comparing Liander and Stedin results

Comparing the major outcomes of the Liander regional grid analyses with the major findings of a similar recent assessment by Stedin shows that the Stedin approach results in similar outcomes on grid congestion in 2030 but in a higher expected number of overloads in 2050. The differences in outcomes between Stedin and Liander for the year 2050 are due to differences in the current structure and capacity of their distribution networks as well as to differences in modelling approaches and inputs, including particularly differences in energy usage profiles and in translating future scenario assumptions to local developments.

Impact on HV transmission assets

The datasets and results of the Liander analysis have been used by TenneT to assess roughly the implications of the FLEXNET scenarios A2030 and A2050 for some of its high voltage (HV) grid assets in the north-western part of the Netherlands, i.e. in the province of North Holland. A major finding of this assessment is that only a rapid growth in further electrification can lead to significant additional loading of the HV grid by 2030. The growth in VRE power generation in any FLEXNET scenario up to 2030 is not big enough such that it could lead to additional bottlenecks on the HV grid by 2030. If by 2050, however, the penetration of PV becomes as big as predicted in the A2050 scenario, the HV grid as it is now will be overloaded significantly during the mid-day PV peak on sunny summer days.

The need for weighing network reinforcement versus deployment of flexibility options is apparent, notably in the period beyond 2030. To avoid the spillage of VRE surpluses in case of grid overloads, power will have to be either curtailed or transported across large distances towards areas that require more power than is generated locally. Alternative measures are to temporarily store the energy locally or to shift (local) demand over time. It will depend on the specific situation what solution is most desirable (as analysed further during both the second and third phase of the FLEXNET project).

6

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Appendix A. Electricity demand and VRE supply profiles

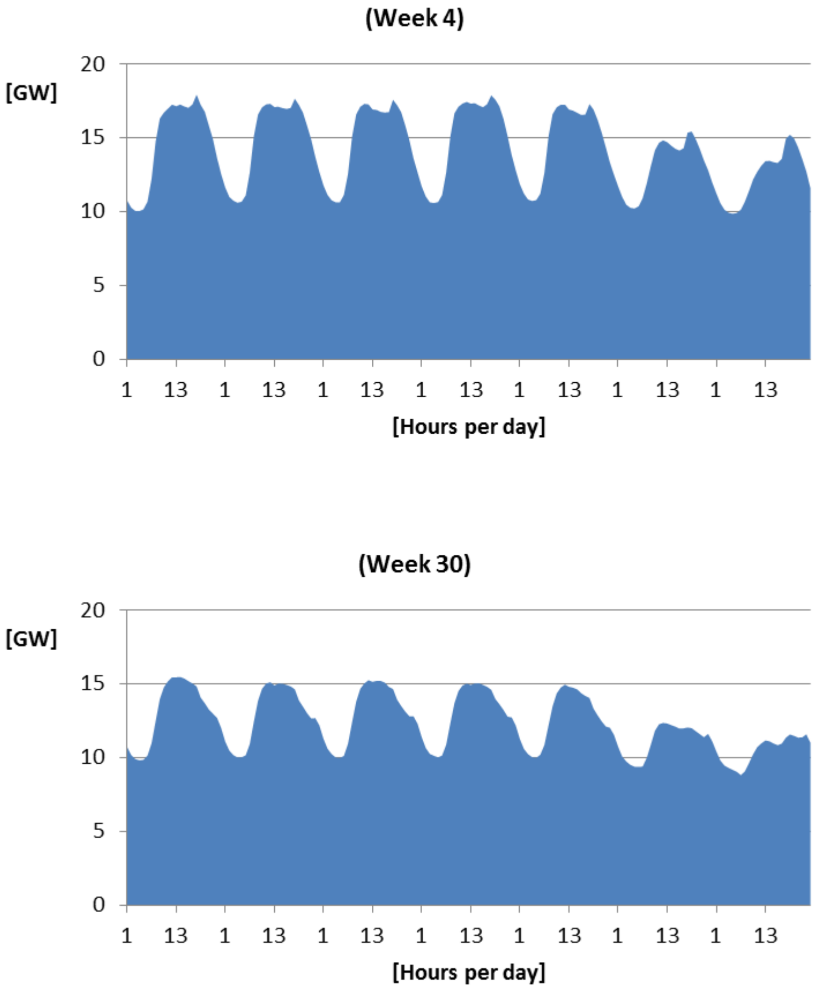
In order to analyse the trends and hourly variations in the residual load – and the resulting flexibility needs – of the Dutch power sector over the years 2015-2050 at the national and regional level, hourly profiles of electricity demand and VRE power supply have been developed by the project partners or obtained from available, external sources. In particular, hourly profiles of recent 'representative' ('middle-of-the-road') years have been developed/obtained for three variables at the demand side of the electricity balance – i.e. conventional load, additional load for passenger EVs, and additional load for household HPs – as well as for three variables at the VRE supply side (i.e. wind on land, wind on sea and sun PV). Subsequently, these profiles have been normalised to standard units, for instance per MWh power demand or MWe installed VRE capacity. Finally, the normalised profiles have been multiplied by the volumes – or input values – of the respective scenario cases (see Chapter 2, **Table 5**).

Table 6 (Section 2.3) provides a summary overview of the electricity demand and VRE supply profiles used during phase 1 of the FLEXNET project to analyse the hourly variation in residual load. These profiles are explained briefly below and illustrated at the national level for two weeks in scenario A2030, i.e. for week 4 (a winter 'working' week) and week 30 (a summer 'holiday' week).

A.1. Conventional load profile

At the national level, the hourly profile of conventional load – realised in 2014 – was obtained from ENTSO-E (2016a), whereas at the regional Liander grid level it was constructed by Alliander using its internal data sources, including data from telemetrics and the Energy Data Services in the Netherlands (EDSN). **Figure 48** presents the hourly profile of conventional load at the national level during weeks 4 and 30 in A2030, based on an assumed total annual conventional load of 112 TWh in 2030 (Chapter 2, **Table 5**). It shows that hourly conventional load varies significantly over the day from base load, during hours 3-4 at night, to peak load, during hours 8-9 in the morning and, particularly, hours 18-19 in the evening. In addition, it shows that conventional demand is generally higher during working days than in the weekend (i.e. the last two days of **Figure 48**). Moreover, conventional demand is also generally higher during the winter (week 4) than in the summer (week 30).

Figure 48: Hourly profile of conventional load at the national level during week 4 and week 30 in A2030



A.2. Load profile for household heat pumps

ECN has designed hourly load profiles for three different types of electrical household heat pumps (HPs) – air-source HPs, ground-source HPs and hybrid HPs (i.e. both gas and electric) – in order to meet the heat demand for space heating and hot tap water of an average house, distinguished by two different levels of house insulation, i.e. medium (energy label B) and high ('net-zero-energy-use'). Overall, six different HP load profiles have been developed (i.e. for three types of HP technologies times two levels of house insulation). These profiles have been developed for a 'normal' ('representative', 'middle-of-the-road' year), i.e. 2012, based on the hourly temperatures and modelled household heat demand in that year.[42]

[42] These profiles have been developed by Robert de Smidt of the ECN unit Energy Efficiency. In addition to the profiles for a 'normal' year, he has also developed HP load profiles for two 'extreme situations' (see Section 3.4). For more details on the different types of HP technologies and the development of the related HP load profiles, see Ecofys (2015).

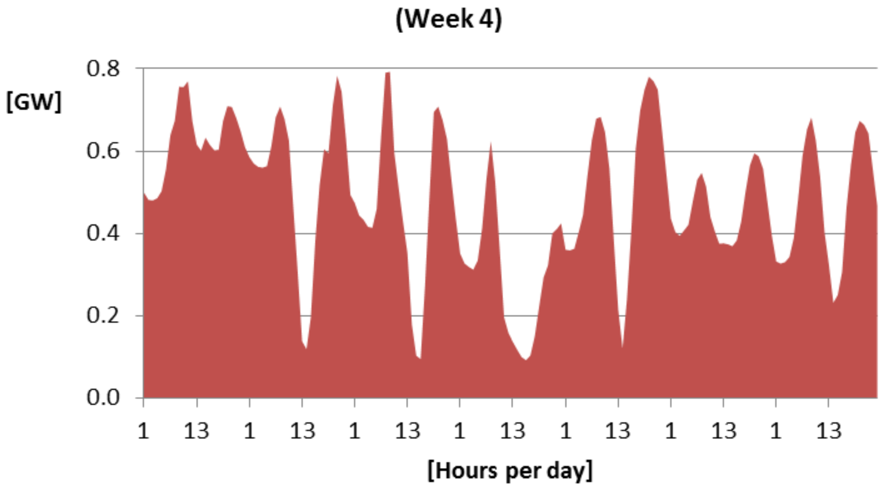
Table 19: Major assumptions underlying the hourly load profile for household heat pumps

		Reference scenario			Alternative scenario		
		R2015	**R2023**	**A2023**	**R2030**	**A2030**	**R2050**
HP penetration:							
as % of all households		2%	6%	8%	8%	20%	69%
# of households (x 1000)		149	496	612	630	1,587	5,727
Mix of HP technologies (in %)							
Level of insulation	*HP technology*						
Medium	Air-source HP	-	-	-	-	-	-
	Ground-source HP	-	-	-	-	-	-
	Hybrid HP	-	-	*10%*	-	*15%*	*15%*
High	Air-source HP	-	*20%*	*20%*	*25%*	*25%*	*35%*
	Ground-source HP	*30%*	*35%*	*30%*	*35%*	*40%*	*50%*
	Hybrid HP	*70%*	*45%*	*40%*	*40%*	*20%*	-
Total		*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Mix of HP technologies (in # of households x 1000)							
Level of insulation	*HP technology*						
Medium	Air-source HP	-	-	-	-	-	-
	Ground-source HP	-	-	-	-	-	-
	Hybrid HP	-	-	*61*	-	*238*	*859*
High	Air-source HP	-	*99*	*122*	*157*	*397*	*2,004*
	Ground-source HP	*45*	*174*	*184*	*220*	*635*	*2,864*
	Hybrid HP	*105*	*223*	*245*	*252*	*317*	-
Total		*149*	*496*	*612*	*630*	*1,587*	*5,727*
Electricity use per HP technology (in kWh)[a]							
Level of insulation	*HP technology*						
Medium	Air-source HP	*4344*	*4344*	*4344*	*3910*	*3910*	*3475*
	Ground-source HP	*4237*	*4237*	*4237*	*3814*	*3814*	*3390*
	Hybrid HP	*1303*	*1303*	*1303*	*1173*	*1173*	*1042*
High	Air-source HP	*2549*	*2549*	*2549*	*2294*	*2294*	*2039*
	Ground-source HP	*1861*	*1861*	*1861*	*1675*	*1675*	*1489*
	Hybrid HP	*784*	*784*	*784*	*705*	*705*	*627*
Weighted average HP electricity use (in kWh)		*1,109*	*1,516*	*1,514*	*1,444*	*1,563*	*1,617*

a) The energy efficiency improvement factor for all types of HPs is assumed to be 0.9 in 2030 and 0.8 in 2050.

In order to obtain the (aggregated, weighted-average) HP load profile at the national level for each scenario case, the six individual (normalised) HP load profiles have been multiplied by the HP proliferation mix and the electricity use per HP technology and level of house insulation in each scenario case. **Table 19** provides the major assumptions with regard to these variables in each scenario case.

Figure 49: Hourly load profile for household heat pumps at the national level during week 4 and week 30 in A2030



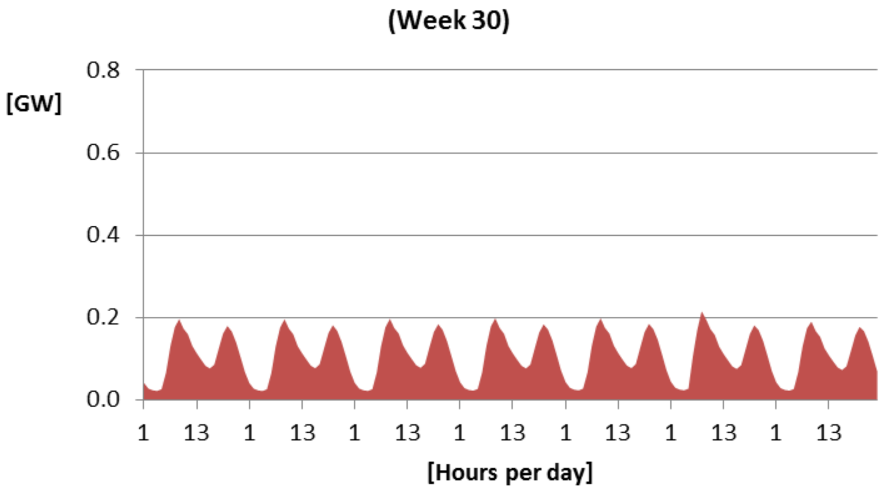


Figure 49 presents the national hourly load profile for household HPs during week 4 and week 30 in A2030, based on the following assumptions: (i) a HP penetration rate in the household sector of 20% in A2030 (i.e. almost 1.6 million household HPs), and (ii) a weighted-average HP electricity use of almost 1.6 MWh per annum, resulting in a total annual HP load of approximately 2.5 TWh in A2030.

Figure 49 shows that during the winter period (week 4) the hourly HP load profile varies heavily, depending on the variation of hourly temperatures and household activities. In general, however, there is one base load period during the day, i.e. in the afternoon (hour 13-15), and two peak load periods, i.e. in the morning (hour 7-9), when people wake up and take a shower or start heating their houses, and in the evening (hour 18-20), when people come back from their work, start (re)heating their homes, prepare a meal, do the dishes, etc.

During the summer period (week 30), the average HP power demand is much lower than in the winter period as the household HP is used only for heating tap water but not for space heating. The hourly HP load profile, however, still varies widely over a single day, although this pattern is rather stable across all days of week 30 (see bottom part of **Figure 49**). In general, there are two base load periods during a summer day, i.e. at night (hour 3-4) and in the afternoon (hour 14-16), and two peak load periods, i.e. in the morning (hour 7-9) and in the evening (hour 18-20).

A.1. Load profile for electric passenger cars

The hourly load profile for electric vehicles (EVs) – or, more precisely, for electric passenger cars – used in the FLEXNET project has been developed by Liander by means of the database '*Onderzoek Verplaatsingen in Nederland*' (OViN; CBS, 2013) and the study '*Laadstrategie Elektrisch Vervoer*' (Movares, 2015). By means of this information, four EV profiles have been constructed for four charging locations, i.e. a profile for EV charging (i) at home, (ii) at work, (iii) at public parking garages, and (iv) at fast charging locations (see **Figure 50**). The shares of these charging locations in total EV charging by passenger cars amount to 53%, 29%, 5% and 13%, respectively. Based on these shares and the bottom-up profiles of the four charging locations, an aggregated, weighted-average profile for EV charging by passenger cars has been designed on both an hour and a quarter (15 minutes) basis.[43]

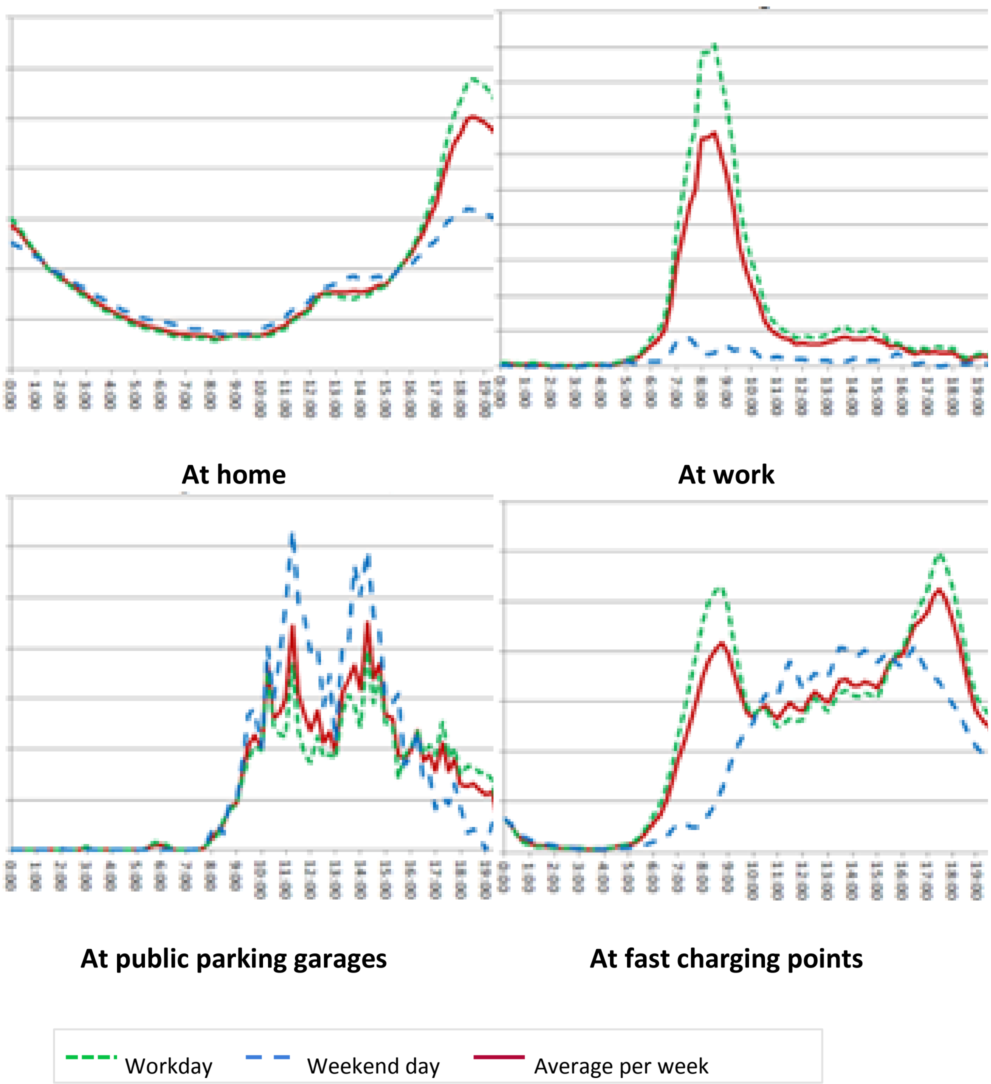
Figure 51 presents the national hourly load profile for EV charging by passenger cars during week 4 and week 30 in A2030, based on the following assumptions: (i) an EV penetration rate in total passenger cars of about 32% in A2030 (i.e. almost 2.8 million EV passenger cars), and (ii) an average electricity use per EV of 3 MWh – i.e., on average, 15.000 km per EV times 0.2 kWh per km – resulting in a total EV load of approximately 8.4 TWh in A2030.

Figure 51 shows that at the national, aggregated level the hourly EV load profile has actually two outspoken peak periods per day, notably during working days, i.e. around 9 AM and 6 PM. This is largely due to the fact that during working days a large amount of passenger EVs is assumed to be uploaded immediately when people have arrived at their working station (9 AM) and, subsequently, when they come back home (6 PM).

So, the EV load profile for A2030 – and, similarly, for the other FLEXNET scenario cases – is based on rather 'dumb' EV charging assumptions, i.e. EVs are uploaded immediately when people have arrived at their work place and, subsequently, when they come back home. During the second phase of the project, however, we assume also a more 'smart' ('flexible') EV charging profile and analyse the implications of such a profile for both demand and supply of flexibility by the Dutch power sector (Sijm et al., 2017).

[43] For more details on the EV charging profiles and the assumed trends in EV adoption across the Liander service area, see Liander (2015a and 2015b) and Section 5.2.2.

Figure 50: Hourly profiles of daily EV charging at different charging points



Source: Movares (2013) and Liander (2015a).

A.2. Hourly profile of power output from wind

Normalised profiles of power generation from both wind onshore and wind offshore (per MWe installed capacity) have been derived from the Hirlam database of the ECN unit Wind, including data on both projected (forecasted) and realised wind power output in 2012. In order to obtain the hourly wind profiles at the national level in each scenario case, these normalised profiles have been multiplied by the assumed installed capacities of onshore and offshore wind in each scenario case, respectively, and corrected for the assumed improvement in full load hours (see Section 2.2, **Table 5**).

Figure 51: Hourly EV load profile at the national level during week 4 and week 30 in A2030

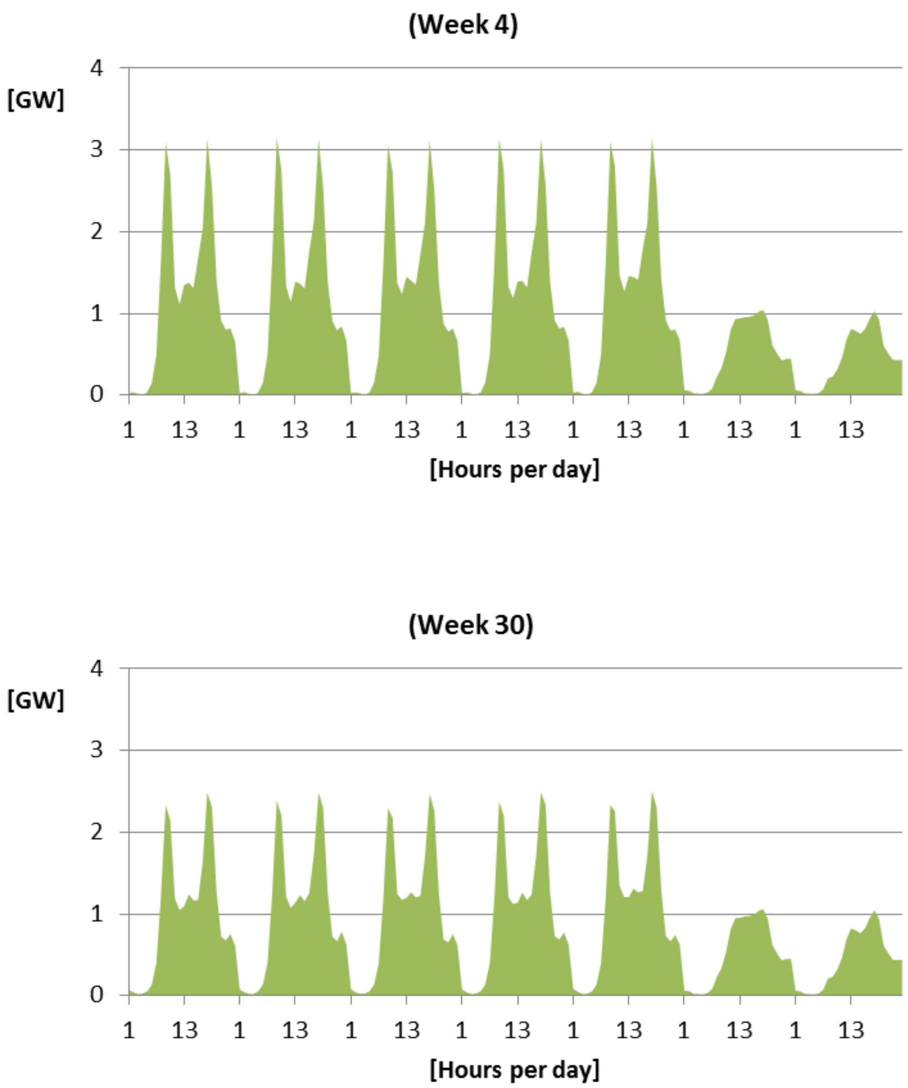
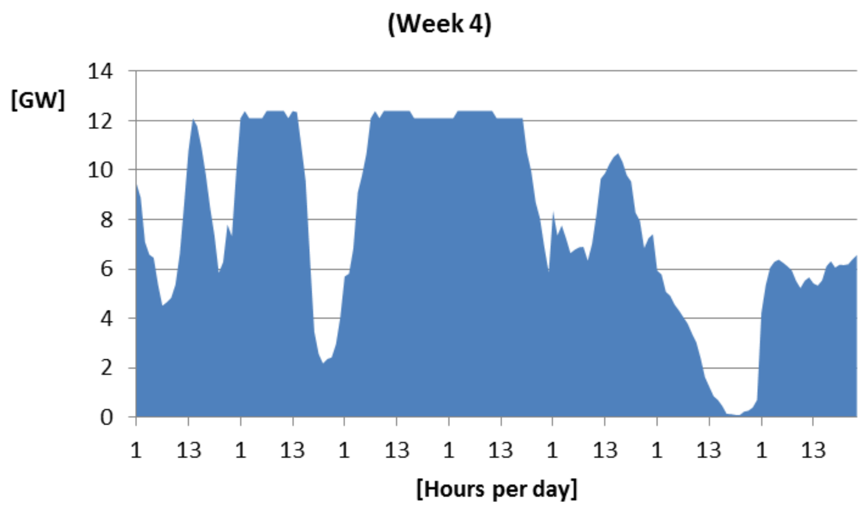
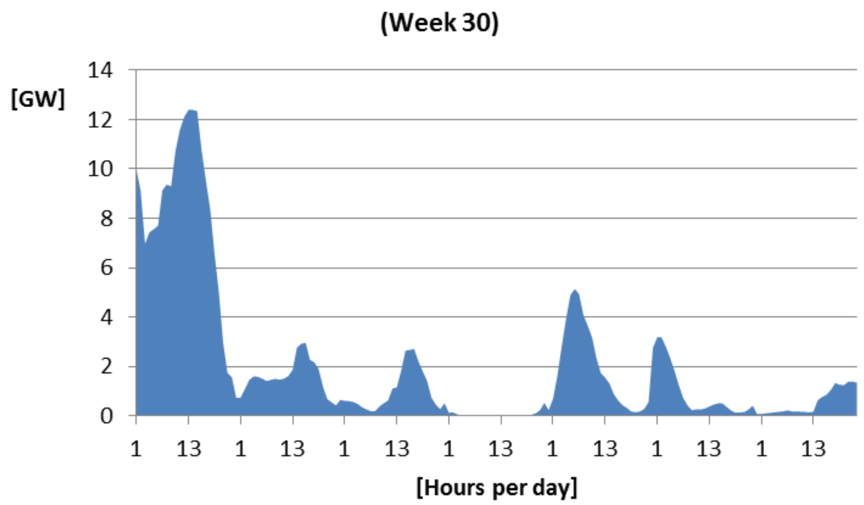


Figure 52 presents the national hourly profile of power generation from wind, including both wind onshore and offshore, during week 4 and week 30 in A2030.[44] It shows that this profile is characterised by a rather irregular pattern, varying strongly per day and week, fluctuating heavily from almost zero in some hours to the maximum output capacity of 12.4 GW in other hours. In addition, it shows that the total/average power generation from wind is much higher in week 4 (winter) than in week 30 (summer), although it should be realised that, as noted, power generation varies strongly per week throughout the year.

44 At the regional (Liander grid distribution) level, the wind profile includes only wind onshore.

Figure 52: Hourly profile of power supply from wind at the national level during week 4 and week 30 in A2030





A.1. Hourly profile of power output from sun PV

The national hourly profile of (forecasted) power generation from sun PV in 2015 has been downloaded from the transparency platform of ENTSO-E (2016b) and, subsequently, normalised per unit installed sun PV. In order to obtain the national hourly sun PV output profile for each scenario case, the normalised profile has been multiplied by the assumed installed capacity of sun PV in each scenario case (see Section 2.2, **Table 5**).[45]

[45] At the regional (Liander grid distribution) level, the sun PV profile was based on regional data of realised power output from sun PV in 2014.

Figure 53: Hourly profile of power supply from sun PV at the national level during week 4 and week 30 in A2030

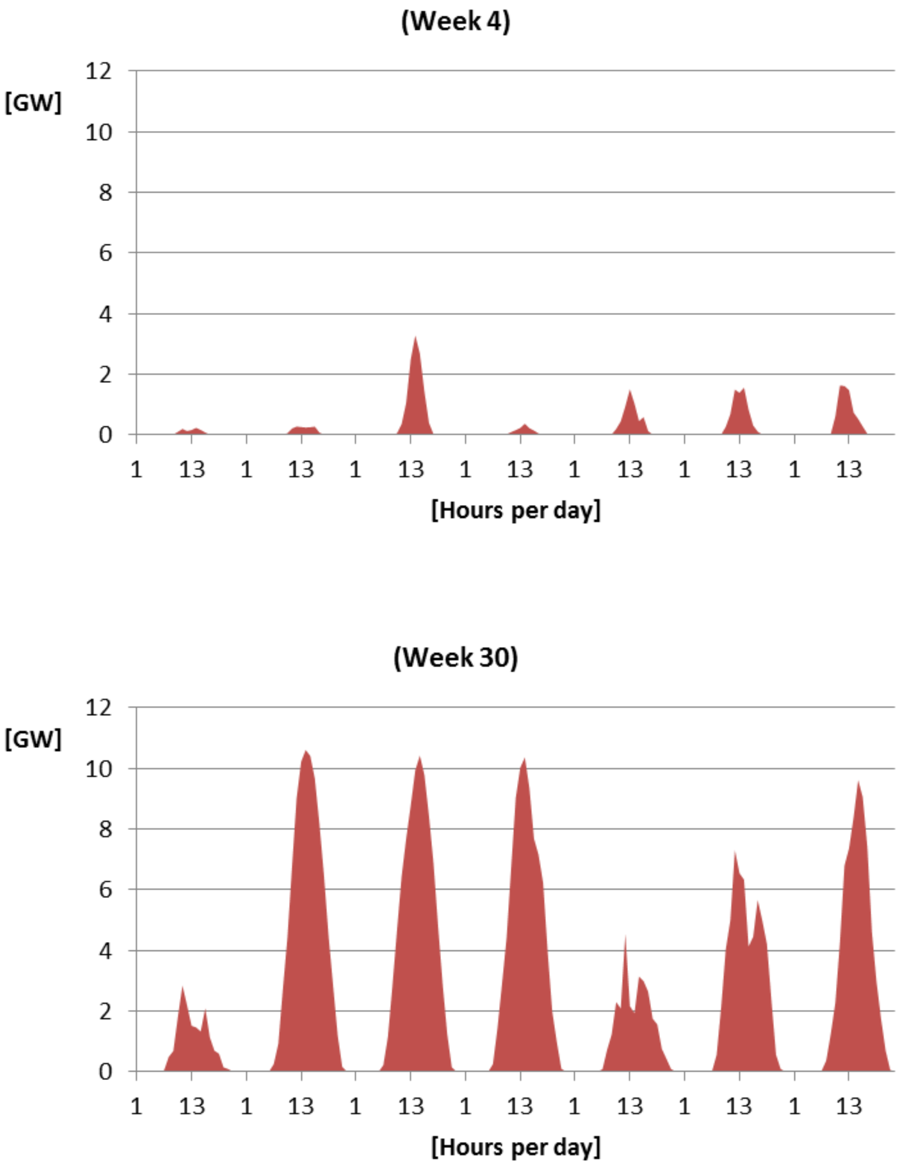
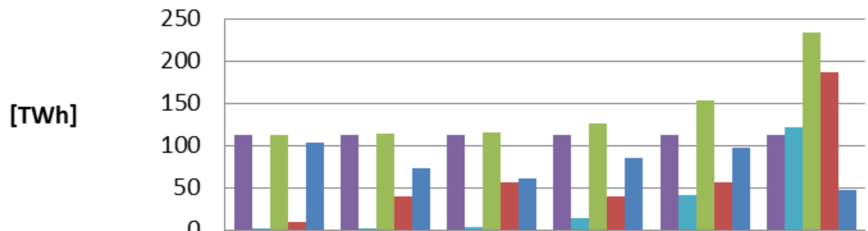


Figure 53 presents the national hourly profile of power generation from sun PV during week 4 and week 30 in A2030, based on an assumed installed PV capacity of approximately 15 GWe. It shows that hourly power output from sun PV varies widely per day and week but has a more regular daily pattern than electricity generation from wind, i.e. PV output peaks usually at hour 13 of the day, whereas it is zero during the evening hours and at night. In addition, as expected, power generation from sun PV is generally substantially higher – during more daily hours – in the summer period (week 30) than in the winter (week 4).

Appendix B. Data on annual power load and VRE generation

This appendix provides some data on annual power load and VRE electricity generation in all scenario cases analysed. **Figure 54** presents data on annual residual load, including its major constituent components. *Conventional load* is assumed to remain more or less stable over the years 2015-2030 at a level of approximately 112 TWh.

Figure 54: Total annual power load and VRE electricity generation in all scenario cases, 2015-2050

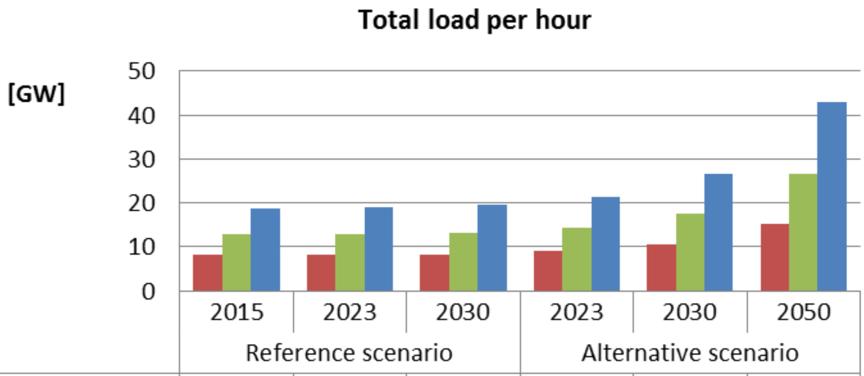


	Reference scenario			Alternative scenario		
	2015	2023	2030	2023	2030	2050
Conventional load	111.8	111.6	112.2	111.6	112.2	112.0
Additional load	0.6	1.9	3.4	13.9	40.9	120.8
Total load	112.5	113.5	115.6	125.5	153.1	232.8
Total VRE output	8.6	40.0	55.5	40.0	55.5	186.0
Total residual load	103.8	73.6	60.2	85.6	97.6	46.8

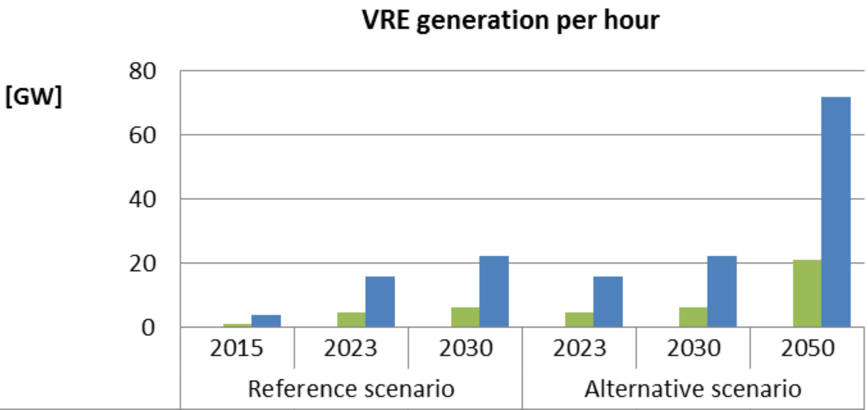
The *additional load* for passenger EVs and household HPs increases modestly in the reference scenarios (R2015-2030) but more rapidly in the alternative scenarios (A2023-2050), in particular due to the additional load for other means of electrification in these alternative scenarios (in order to meet the 85% GHG-reduction by 2050). As a result, *total load* increases only modestly in R2015-R2030 (from 113 TWh to 116 TWh) but more rapidly in A2023-A2050 (from 126 to 233 TWh).

Total power generation from VRE resources, on the contrary, increases rapidly in R2015-R2030, i.e. from 9 TWh in R2015 to almost 56 TWh in R2030. Since the (growth of) installed VRE capacity is assumed to be similar in the reference scenario as in the reference scenario for the years 2023 and 2030, the VRE output is also similar in both scenario cases for these respective years (see **Figure 54** and Section 2.2, **Table 5**). For A2050, however, it is assumed that VRE capacity expands rapidly and, hence, VRE power output increases accordingly to about 186 TWh in A2050.

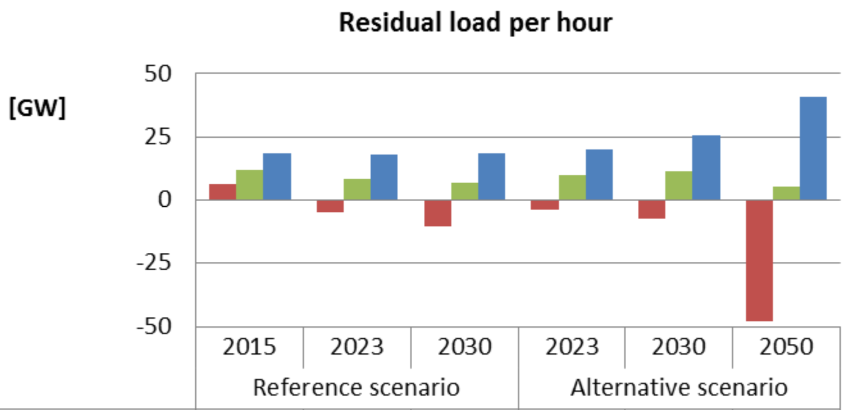
Figure 55: Minimum, maximum and average values of hourly power load, VRE generation and residual load per hour in all scenario cases, 2015-2050



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Minimum load	8.2	8.3	8.3	9.0	10.6	15.3
Average load	12.8	13.0	13.2	14.3	17.5	26.6
Maximum load	18.7	19.0	19.5	21.2	26.5	42.9



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Minimum VRE	0.0	0.0	0.0	0.0	0.0	0.0
Average VRE	1.0	4.6	6.3	4.6	6.3	21.2
Maximum VRE	4.0	15.7	22.2	15.7	22.2	71.9



	Reference scenario 2015	Reference scenario 2023	Reference scenario 2030	Alternative scenario 2023	Alternative scenario 2030	Alternative scenario 2050
Min. residual load	6.3	-4.7	-10.6	-3.6	-7.2	-47.9
Av. residual load	11.9	8.4	6.9	9.8	11.1	5.3
Max. residual load	18.4	17.9	18.4	20.1	25.6	40.7

Figure 55 provides some comparative statistics of the minimum, maximum and average values of hourly power load, VRE generation and residual load in all scenario cases. It shows, for instance, that the minimum (base) load increases from 8.2 GW (per hour) in R2015 to 15.3 GW in A2050, while the maximum (peak) load rises from 19 to 43 GW, respectively. On average, however, hourly power load increases from almost 13 GW in R2015 to approximately 27 GW in A2050. This increase in minimum, maximum and average power load is due to the increase in electrification (EVs, HPs, other) across the respective scenario cases.

In addition, **Figure 55** indicates that hourly VRE power generation in R2015 varies from zero (minimum) to 4.0 GW (maximum). Due to the rapid increase in the deployment of VRE installed capacity up to A2050, the maximum VRE electricity output per hour increases to almost 72 GW in A2050, although the minimum output is still zero in this scenario case. On average, however, hourly VRE generation increases from 1.0 GW in R2015 to more than 21 GW in A2050.

Finally, **Figure 55** indicates that the hourly residual load in R2015 ranges from 6.3 GW (minimum) to 18 GW (maximum). In A2050, however, the minimum residual load amounts to -48 GW, i.e. a large VRE surplus, whereas the maximum residual load amounts to 41 GW. Hence, the *variation* between minimum and maximum residual load increases significantly over the years R2015-A2050, mainly due to the large increase in VRE power generation over this period and partly due to the substantial increase in total (additional) load, in particular in the alternative scenario cases.

On the other hand, despite the significant increase in average total load between R2015 and A2050, the *average* hourly residual load *declines* substantially from almost 12 GW in R2015 to approximately 5.3 GW in A2050. This is solely due to the large increase in VRE power generation across these scenario cases.

Appendix C. Sensitivity analyses

In order to get an idea of the sensitivity of the demand for flexibility for some of the underlying scenario assumptions, in particular for changes in some input variables, we have conducted a number of sensitivity analyses. More specifically, the following two sets or 'runs' of sensitivity analyses have been performed (with each run consisting of a set of six separate sensitivity analyses for six separate input variables):

- *Run A*. In this run, the hourly and total annual volume of six input variables has been increased individually for each variable by a fixed percentage of 20% compared to their respective values in the reference scenario for 2030 (R2030) in order to assess the impact of such a change on the demand for flexibility. These six variables consist of three load variables – i.e., conventional load, additional load for passenger electric vehicles (EVs), and additional load for household heating pumps (HPs) – as well as three VRE power generation variables, i.e. electricity output from wind on land, wind on sea and sun PV.
- *Run B.* This run is largely similar to run A. The only difference is that in this run the total annual volume of the six variables mentioned above has been increased individually for each variable by a fixed amount of 8 TWh – compared to their respective values in R2030 – which has been proportionally distributed and added to the hourly profiles of these variables, respectively.[46]

Hence, overall we have conducted 12 separate sensitivity analyses in two different runs, labelled from A1 to A6 and from B1 to B6. **Table 20** provides an overview of these sensitivity analyses. The third column of this table shows the size – or volume – of the six variables considered in runs A and B. The fourth column indicates the change in this volume by a fixed percentage (i.e., by 20%; Run A), while the fifth column indicates the change in the size of the variable by a fixed amount (i.e. 8 TWh; Run B).

Table 20: Overview of the number of sensitivity analyses conducted for R2030

			SA Run A:	SA Run B:
SA Run	Variable	Size in R2030	Change in fixed %	Change in fixed volume
[#]		[in TWh]	[+20%; in TWh]	[in TWh]
1	Conventional load	112.2	22.4	8.0
2	EV load	2.5	0.5	8.0
3	HP load	0.9	0.2	8.0
4	Wind on land	18.1	3.6	8.0
5	Wind on sea	25.0	5.0	8.0
6	Sun PV	12.4	2.5	8.0

46 We did not include 'other additional load' as a separate variable to our sensitivity analyses. However, as the hourly profile of this variable is assumed to be similar to the hourly profile of conventional load, the impact of an absolute change in this variable on the demand for flexibility is similar to the same change in conventional load.

Table 21: Summary overview of sensitivity analyses, Run A (+20%): impact on the main components of residual load in reference scenario 2030 (R2030)

	R2030	R2030 A1 (CL)[a]	R2030 A2 (EV)	R2030 A3 (HP)	R2030 A4 (WoL)	R2030 A5 (WoS)	R2030 A6 (PV)
Residual load (in GWh)							
Conventional load	112.2	134.6	112.2	112.2	112.2	112.2	112.2
Additional load ('electrification')	3.4	3.4	3.9	3.6	3.4	3.4	3.4
Total load	115.6	138.1	116.1	115.8	115.6	115.6	115.6
VRE generation	55.5	55.5	55.5	55.5	59.1	60.5	58.0
Residual load	60.2	82.6	60.7	60.3	56.5	55.2	57.7
Change in residual load (compared to 2015, in GWh)							
Conventional load		22.4	0.0	0.0	0.0	0.0	0.0
Additional load ('electrification')		0.0	0.5	0.2	0.0	0.0	0.0
Total load		22.4	0.5	0.2	0.0	0.0	0.0
VRE generation		0.0	0.0	0.0	3.6	5.0	2.5
Residual load		22.4	0.5	0.2	-3.6	-5.0	-2.5
% change in residual load (compared to 2015, in %)							
Conventional load		20.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Additional load ('electrification')		0.0%	14.7%	5.3%	0.0%	0.0%	0.0%
Total load		19.4%	0.4%	0.2%	0.0%	0.0%	0.0%
VRE generation		0.0%	0.0%	0.0%	6.5%	9.0%	4.5%
Residual load		37.3%	0.8%	0.3%	-6.0%	-8.3%	-4.1%

a) CL = Conventional Load; EV = Electric Vehicles; HP = Heat Pumps; WoL = Wind on Land; WoS = Wind on Sea; PV = Sun PV.

Table 21 presents a summary overview of the major results of run A of the sensitivity analysis in terms of the impact on the main components of residual load in R2030, whereas **Table 22** provides similar result for run B. **Table 21**, for instance, shows that in sensitivity run A1 the total annual residual load in R2030 increases by 22.4 TWh (+37%) due to an increase in conventional load by the same amount, while in A5 it decreases by 5 TWh (-8%) due to an increase in VRE power generation (from wind on sea) by the same amount. On the other hand, in B1 the total annual residual load increases by 8 TWh (+13%), while in B5 it decreases by 8 TWh due to a change by the same amount of the respective, underlying variables of these sensitivity runs (**Table 22**).

As noted, the total annual change in the input variables underlying the sensitivity runs – as well as the resulting output variable of residual power load – have been distributed and added proportionally to the hourly profiles of the variables. Based on the changes in these variables, **Table 23** presents a summary overview of the major results of run A of the sensitivity analyses in terms of the impact on the demand for flexibility by means of the indicators defined in Section 3.2.4, i.e. in terms of (i) maximum hourly ramp and (ii) total hourly ramp. **Table 24** provides similar results for run B.

Table 22: Summary overview of sensitivity analyses, Run B (+8 TWh): impact on the main components of residual load in reference scenario 2030 (R2030)

	R2030	R2030 B1 (CL)[a]	R2030 B2 (EV)	R2030 B3 (HP)	R2030 B4 (WoL)	R2030 B5 (WoS)	R2030 B6 (PV)
Residual load (in GWh)							
Conventional load	112.2	120.2	112.2	112.2	112.2	112.2	112.2
Additional load ('electrification')	3.4	3.4	11.4	11.4	3.4	3.4	3.4
Total load	115.6	123.6	123.6	123.6	115.6	115.6	115.6
VRE generation	55.5	55.5	55.5	55.5	63.5	63.5	63.5
Residual load	60.2	68.2	68.2	68.2	52.2	52.2	52.2
Change in residual load (compared to 2015, in GWh)							
Conventional load		8.0	0.0	0.0	0.0	0.0	0.0
Additional load ('electrification')		0.0	8.0	8.0	0.0	0.0	0.0
Total load		8.0	8.0	8.0	0.0	0.0	0.0
VRE generation		0.0	0.0	0.0	8.0	8.0	8.0
Residual load		8.0	8.0	8.0	-8.0	-8.0	-8.0
% change in residual load (compared to 2015, in %)							
Conventional load		7.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Additional load ('electrification')		0.0%	233.0%	233.0%	0.0%	0.0%	0.0%
Total load		6.9%	6.9%	6.9%	0.0%	0.0%	0.0%
VRE generation		0.0%	0.0%	0.0%	14.4%	14.4%	14.4%
Residual load		13.3%	13.3%	13.3%	-13.3%	-13.3%	-13.3%

a) CL = Conventional Load; EV = Electric Vehicles; HP = Heat Pumps; WoL = Wind on Land; WoS = Wind on Sea; PV = Sun PV.

Table 23 shows that if the volume of the respective input variables is changed individually by the same percentage (20%), the resulting change in the required maximum hourly capacity for ramp-up (or ramp-down) is relatively low – i.e., varying between -1.2% and 0.9% – for variables such as conventional load (CL; A1), EV load (A2) and HP load (A3), while it is significantly higher – ranging between 8.4% and 14% – for the variables wind on land (A4) and wind on sea (A5). However, for the other VRE variable – sun PV – the resulting change in the required maximum hourly capacity for either upward or downward flexibility is zero (A6).

On the other hand, **Table 23** illustrates also that, in energy trading terms, the change in total annual demand for either hourly ramp-ups or ramp-downs is relatively highest for a 20% change in variables such as sun PV (+6.8%) or conventional load (+5.5%) and relatively lowest for EV load (+0.9%) and HP load (+0.1%), with a middle position for wind on land (+3.2%) and wind on sea (+4.0%).

Table 23: Summary overview of sensitivity analyses, Run A (+20%): impact on the demand for flexibility in reference scenario 2030 (R2030)

	R2030	R2030 A1 (CL)[a]	R2030 A2 (EV)	R2030 A3 (HP)	R2030 A4 (WoL)	R2030 A5 (WoS)	R2030 A6 (PV)
Demand for flexibility							
Maximum hourly ramp-up (GW/h)	8.5	8.4	8.5	8.5	9.2	9.6	8.5
Maximum hourly ramp-down (GW/h)	-10.2	-10.2	-10.2	-10.2	-11.2	-11.0	-10.2
Total hourly ramp-ups (GWh)	4569	4824	4609	4573	4717	4752	4881
Total hourly ramp-downs (GWh)	4569	4824	4609	4573	4717	4752	4881
Change in demand for flexibility (compared to 2015)							
Maximum hourly ramp-up (GW/h)		-0.1	0.0	0.0	0.7	1.1	0.0
Maximum hourly ramp-down (GW/h)		-0.1	0.0	0.0	-1.1	-0.9	0.0
Total hourly ramp-ups (GWh)		255	40	4	148	183	313
Total hourly ramp-downs (GWh)		255	40	4	148	183	313
% change in demand for flexibility (compared to 2015, in %)							
Maximum hourly ramp-up		-1.2%	-0.1%	0.0%	8.4%	13.5%	0.0%
Maximum hourly ramp-down		0.9%	0.1%	0.0%	10.5%	8.4%	0.0%
Total hourly ramp-ups		5.6%	0.9%	0.1%	3.2%	4.0%	6.8%
Total hourly ramp-downs		5.6%	0.9%	0.1%	3.2%	4.0%	6.8%

a) CL = Conventional Load; EV = Electric Vehicles; HP = Heat Pumps; WoL = Wind on Land; WoS = Wind on Sea; PV = Sun PV.

Table 24 shows that if the volume of the respective scenario input variables is changed individually by the same amount (8 TWh), the resulting change in the required maximum hourly capacity for ramp-up (or ramp-down) is again relatively lowest – varying from -1.7% to +1.4% – for conventional load (B1), EV load (B2) and HP load (B3), while it is relatively highest – ranging between 14% and 23% - for wind on land (B4) and wind on sea (B5). For sun PV (B6), the resulting change in the required maximum hourly capacity to meet the demand for flexibility amounts to +0.7 GW (+8%) for ramping up and zero for ramping down.

On the other hand, **Table 24** also illustrates that if the volume of the respective variables is changed by the same amount (8 TWh), the resulting change in the total annual demand for flexibility (either upward or downward) is relatively highest for sun PV (+23%) and EV (+16%) and relatively lowest for conventional load (+2%) and HP (+5%), with a middle position for wind on land and wind on sea (both approximately +7%).

Table 24: Summary overview of sensitivity analyses, Run B (+8 TWh): impact on the demand for flexibility in reference scenario 2030 (R2030)

	R2030	R2030 B1 (CL)[a]	R2030 B2 (EV)	R2030 B3 (HP)	R2030 B4 (WoL)	R2030 B5 (WoS)	R2030 B6 (PV)
Demand for flexibility							
Maximum hourly ramp-up (GW/h)	8.5	8.5	8.4	8.4	10.4	10.3	9.2
Maximum hourly ramp-down (GW/h)	10.2	10.2	10.3	10.3	12.5	11.5	10.2
Total hourly ramp-ups (GWh)	4569	4658	5316	4790	4903	4866	5634
Total hourly ramp-downs (GWh)	4569	4658	5316	4789	4903	4866	5634
Change in demand for flexibility (compared to 2015)							
Maximum hourly ramp-up (GW/h)		0.0	-0.1	-0.1	1.9	1.8	0.7
Maximum hourly ramp-down (GW/h)		0.0	0.1	0.1	2.4	1.4	0.0
Total hourly ramp-ups (GWh)		89	747	221	334	297	1065
Total hourly ramp-downs (GWh)		89	747	221	334	297	1065
% change in demand for flexibility (compared to 2015, in %)							
Maximum hourly ramp-up		-0.4%	-1.7%	-1.4%	22.6%	21.7%	8.0%
Maximum hourly ramp-down		0.3%	1.4%	1.2%	23.2%	13.5%	0.0%
Total hourly ramp-ups		1.9%	16.3%	4.8%	7.3%	6.5%	23.3%
Total hourly ramp-downs		1.9%	16.3%	4.8%	7.3%	6.5%	23.3%

a) CL = Conventional Load; EV = Electric Vehicles; HP = Heat Pumps; WoL = Wind on Land; WoS = Wind on Sea; PV = Sun PV.

The above findings imply that if the demand for electricity is enhanced by a certain amount (e.g., by 8 TWh) due to an increased use of either EVs or HPs, the resulting change in the demand for total annual ramp-ups/downs will be significantly higher in the case of electrification by means of EVs than HPs. Hence, the demand for total annual ramp-ups/downs is more sensitive to a similar (absolute) change in electricity use for EVs than for HPs.[47] This is due to the fact that the hourly profile of the demand for electricity is relatively more variable for EVs than for HPs (see Section 3.1).[48]

Another implication of the above findings is that if the supply of electricity from VRE resources is enhanced by the same amount (e.g., 8 TWh) for either wind energy or solar PV, the resulting capacity needs for flexibility in terms of maximum hourly ramp-

47 Note that in capacity terms of maximum hourly ramp-up/down the change in the need for flexibility is more or less similar for the variables EV and HP (**Table 24**).

48 As outlined in Section 3.1, as part of phase 1 of the FLEXNET project, the hourly demand profile for EVs is rather 'dumb' with two outspoken peak periods per day – notably during working days, i.e. around 9 AM and 6 PM – whereas the hourly demand profile for HPs is rather flat. However, if a more 'smart' or 'flexible' demand profile for EVs is assumed, the resulting demand for flexibility will be lower (see also phase 2 of the project in which we will analyse and discuss flexible demand options).

up/down is significantly higher in the case of electricity supply from wind energy than from solar energy. On the other hand, the resulting (energy) need for flexibility in terms of total hourly ramp-ups/downs is significantly higher in the case of electricity supply from solar PV than from wind energy.

The latter (total energy) result is (most likely) due to the fact that, on average, over a year electricity from solar PV is apparently relatively more volatile and focussed in a smaller number of output hours than electricity from wind energy. The former (maximum capacity) result is a bit more difficult to explain as it may be due to coincidental factors in the sense that the additional output variability of electricity from wind energy may be focused and added to those hours where the capacity demand for ramp-up/down is already high – or even at its maximum – while the additional output availability of electricity for sun PV may be focussed and added to those hours where the capacity demand for ramp-up/down is relatively low.

Appendix D. Implications of FLEXNET scenarios for high voltage grid assets in North Holland

Abstract[49]

High degrees of further electrification and distributed generation (DG), notably from variable renewable energy (VRE) such as wind of sun PV, will not only have major implications for loading in the medium voltage (MV) electricity grid but can also affect flows on the high voltage (HV) grid. The exchange between HV and the lower grids (on a substation level) is characterized by the maximum and minimum load, of which the latter can be negative. This indicates a net flow from MV up to HV caused by DG.

With detailed information per substation from the regional grid analyses conducted by Liander for the FLEXNET project (see Chapter 5), a rough estimation of worst-case grid states was made. To do this, the hourly FLEXNET data was matched with the hourly data for TenneT's most recent Quality and capacity document (KCD). In particular, a load flow calculation was conducted for the HV sub-grid in the north-western part of the Netherlands, i.e. in the province of North Holland(NH).

Two worst-case hours from the KCD calculations were matched with similar FLEXNET situations for two extreme calculations: High load low DG and low load high DG.

The low load situation shows little difference with the reference for the FLEXNET 2030 scenarios. Differently distributed loads and generation are responsible for most of the difference. The A2050 scenario includes a huge surplus in renewable generation, and causes several lines to become overloaded. Especially the flow away from the northern part of NH, where there's much wind, is clearly visible.

The high load hour shows a similar picture, but with a power flow the other way around. Again, the R2030 scenario produces results very similar to the base run, but the A2030 scenario already shows the impact of electrification. We see more components above 50% load, and two connections loaded to around 100%, so this would already be a critical situation. The A2050 scenario exaggerates this situation: we see overloading to

[49] As part of the FLEXNET project, this appendix has been drafted by TenneT. It includes a brief description of the methodology and major results of an assessment by TenneT of the implications of some FLEXNET scenarios on its HV transmission grid assets in the Dutch province of North Holland, based on input from the regional grid analysis by Liander (see Chapter 5).

120% on the same two lines and 80-100% load on five more connections. At this level of net inflow of power to the NH sub-grid we start to see the 380-150kV transformers approach their limits, at around 80% load.

With this, we can conclude that only a rapid growth in further electrification can lead to significant additional loading of the HV grid by 2030. The growth in power generation from variable renewable energy (VRE) in any FLEXNET scenario up to 2030 is not big enough such that it could lead to additional bottlenecks on the HV grid by 2030. However, if by 2050 the penetration of PV becomes as big as predicted in the A2050 scenario, the HV grid as it is now will be overloaded significantly during the mid-day PV peak on sunny summer days.

D.1 Introduction

In order to get an overview of the impact of further electrification and high VRE penetration in the lower power grids (MV, LV), load flow calculations have been made on the HV level. This was done with the regional FLEXNET-ANDES data provided by Liander (see Chapter 5). On a substation level, electricity demand and generation was mapped by Liander for their entire distribution area. The FLEXNET-ANDES data were compared against the data used for TenneT's most recent Quality and capacity document (KCD). This KCD data comprises the expected peak load and installed distributed generation (DG) capacity per substation as provided by the distribution network operators.

The KCD data only includes maximum powers; a scaling profile is therefore applied by TenneT for doing load flow calculations. The ANDES tool that produced the regional FLEXNET data provides much more detailed breakdown of all load and generation categories based on demographics. This is used to predict the adoption of electric vehicles (EV), heat pumps (HP) and VRE generation. Furthermore, the data spans an entire year, and demand predictions for every single hour.

D.2 Method

The validity of the data was checked by comparing the values of peak load to the values used for the previous KCD calculations. Several stations had inexplicable deviations in peak value and some stations were missing altogether. The most complete and valid dataset was that of the North Holland (NH) sub-grid (150 kV). Liander operates the distribution grid in the entire province of North Holland, so there is data for every substation in the area. Therefore, it was decided to simulate the load flows in this area. A comprehensive map of the grid is shown in **Figure 56**.

An additional advantage of this sub-grid is its relatively isolated position in the national grid. In normal operation, its three interconnection lines to other sub-grids are opened. It does have three coupling points with the 380 kV grid at this moment, but four of the eight transformers are located at Diemen, which makes it the main coupling point. With the completion of Randstad 380 kV North ring however, four more transformers will become available at a total of four substations. What the grid structure will be when this ring is completed is shown in **Figure 57**. The grid will then also be opened at more points within the sub-grid to create load pockets; smaller portions of the sub-grid that exchange power with the 380 kV grid, to make sure that the large power transports are on the 380 kV grid.

Figure 56: Current structure of the 150 KV grid in North Holland

Source: TenneT (2016)

The load flows have been simulated for the entire country, and the exchange with the neighbouring countries was predefined as well. The results are however only analysed on the HV grid of North Holland. A surplus or shortage of power in this sub-grid will be exchanged with the 380 kV grid. Because the other sub-grids were not altered, the flows on the 380 kV grid are not representative. The power exchange through the coupling transformers, however, is representative.

Figure 57: Projected route of the Randstad 380 kV North Ring

Note: Red lines concern the 380 kV links
Source: TenneT (2017)

D.2.1. Hour selection

Hour selection
Because of the many factors that influence a substation's net load, it is not easy to select an hour from the FLEXNET data that matches with the KCD data that originates from a market simulation. The profiles produced by the market simulations are completely different from the FLEXNET profiles, because the two datasets (KCD and FLEXNET) have both used a different input for the simulations. The market simulation on which the KCD is based produces dispatch of power plants and the output of solar-PV and wind power based on climate data, among other parameters, but the climate is by far the most important one. The hours have to be carefully selected in order to get a good match, and this was done using multiple Matlab scripts and manual verification. Matching the peak load is especially difficult, since the peak could be obscured by high DG, of which only a part is separated from the load.

Two extremes were explored: High load, low production and low load, high production. These two extremes give the maximum loading of the power grid for either a net up- or downstream power flow (from MV->HV and HV->MV respectively). Large amounts of power will have to be exchanged on the coupling points with the 380 kV grid in these extremes.

Production in the KCD scenarios depends heavily on wind power in the prognosis, which is more than 1000 MW in NH at its peak. FLEXNET has only little onshore wind production but a huge growth in solar PV (and offshore wind).

In the end, two hours were compared to FLEXNET, and this was done using the R2030, A2030 and A2050 scenarios. The earlier scenarios do not differ enough from the KCD to get a significant change in load flow. Even the results from the R2030 scenario vary little from the KCD results. The 2050 scenario however, differs strongly from the KCD results. It gives a global perspective of what to expect when the degree of electrification and decentral (renewable) becomes very large. Only in this scenario decentral generation becomes so large that its peak power generation is larger than the load at that moment. It is even so large that the load flow is bigger in this case than during the maximum load peak during the winter.

Hour 8297
This hour from the KCD simulations has very high load but only limited DG, due to low wind production. A winter hour with high load and low DG was easily found. This occurs during the evening peak, which is increased in magnitude by electrification, especially in the later FLEXNET scenarios. As can be derived from the research, the KCD case for 2025 is more in tune with the A2030 scenario, judging from the total load.

Hour 2401
This hour is characterised by low load and high generation, thus a flow away from the MV grid, up to HV and eventually EHV, 380 kV. The difference between the KCD hour and the FLEXNET hour is the source of DG. A perfect match with FLEXNET was not found; the load in the FLEXNET scenarios is still medium to high, but the peak is reduced by the large VRE production in this hour. In the case of FLEXNET, this is the middle day peak of solar PV, whereas the source of DG is predominantly wind in the KCD calculations.

D.2.2. PowerFactory model

Digsilent PowerFactory was used to simulate and calculate load flows. The PowerFactory model used for the KCD 2016 calculations is used to compare with the FLEXNET data; this is a schematic grid model. The model for North Holland includes the various study hours that were selected based on the DC calculations. The grid model consists of all 150 kV substations and the lines that interconnect them, as well as couplings to the 380 kV grid. A legend is used to identify the load level of lines and transformer.

D.3 Results

D.3.1 Load flow hour 2401

Base run
The base model in this hour has low load overall, but maximum wind production with low conventional production. The results of the load flow calculation show the following: There is a net outflow of power to the 380 kV grid, but with the main flow directed towards one substation. High production combined with high load would lead

to overloading of the 150-380 transformers at this substation without the new 150-380 substations. Tap adjusters keep the 150 kV stations within the voltage limits, but this does result in an overvoltage at the substation at hand.

FLEXNET runs
A perfect match with FLEXNET was not found; the load in the FLEXNET scenarios is still medium to high, but the peak is reduced by the large generation on this hour. This leads to the reduction of load in the 2030 scenarios, but to a net negative load in the NH area for the A2050 scenario. The loading of the grid itself would be higher if the stations were loaded less, so this is not a worst-case scenario.

R2030 run
The results show little difference from the base run. It shows a little more load in the lines that connect one substation to the 380 kV grid, and the previous substation does not have overvoltage.

A2030 run
The A2030 scenario includes the same number of VRE as R2030, but it does have higher loading due to electrification. That extra load helps to drain some of the VRE generation with slightly lower loadings than in the R2030 run.

A2050, altered model with low conventional production
To get a more accurate picture and make the load flow converge, conventional thermal power plants were shut down. These wouldn't be producing power given the surplus of solar power, but it does mitigate the loading of the transformers. The most heavily overloaded line remains the same, but apart from that there is only one overloaded connection. The largest flow is on the line that connects the on station connecting the North of the province to the rest of the grid, so all DG surpluses from that area will come together in this node. The North happens to have large wind farms planned, these are for a large part responsible for the power flows directed south. From the connecting station, it is distributed between two other substations in the area. Other than that, only the city of Amsterdam is connected to this coupling, and large cities in FLEXNET have a relatively low PV penetration.

D.3.2 Load flow hour 8297

Base run
As expected, the lines towards the 380 kV stations get congested, but not overloaded. A load of 50-100% is observed for many components.

FLEXNET runs
Because this high load hour occurs during the evening peak, the impact of electrification will become clear in these runs.

R2030 run
The R2030 load flow does not differ all that much from the reference, as expected from the input. The heaviest loaded line is now a little less loaded; the rest remained about the same.

A2030 run
In this scenario, the load is distributed differently from the base case, which leads to heavier loading of two lines, while another line in the same area is loaded less. No overloading occurs; line loading remains limited to 80%.

A2050 run
The effect of electrification in the evening peak becomes clear in this run. More than half of the lines are loaded to over 50%, with many of the 380-150 kV transformers also at around 70% load. Overloads happen on two lines (about 120%). This is due to a high load flow from the 380 kV grid to the NH 150 kV grid.

D.3.3 N-1 results

In addition to these load flow calculations, N-1 calculations were done as well. For the high load case, hour 8297, the existing bottlenecks just got worse, but some new bottlenecks appeared as well. The most interesting result is the A2050 run in the low load case, because this one is not guided by the load distribution but rather the DG distribution. As a result, other bottlenecks will arise than the ones determined by high load rather than high production. As explained before, the largest amount of DG is installed in the north of the province, and that is also where the biggest problems will occur.

D.4 Developments in the grid

These calculations were made without taking into account possible future developments that aim to strengthen the grid. Not all developments are in the grid model, only those that are already under construction.

There is no FLEXNET data for new 150 kV stations, of which several are planned. These substations will mainly be used for connecting wind power. Thus, the data FLEXNET has for wind power on a certain station would have to be transferred to another substation or distributed across multiple substations, but how it should be distributed is beyond the scope of this study. Therefore, the power exchange of the new stations was not changed (zero load). The expansions do not only include new substations, but also new connections. The new situation can be compared against the 2020 configuration. The 2020 grid configuration contains all expansions projects that are already in implementation, chiefly the Randstad 380 kV North ring. Because this project was present in all variations in the grid model, the projected load pockets had already been implemented.

The effect of the new 150 kV links has been investigated with two load flows: The A2030 situation was calculated for both hours. In the low load hour run, there were no notable differences. The power from the north of NH still converges at one substation, so the high power flow from that station towards two others in the area is still there.

Result of grid expansion

The flow towards the North of North Holland still has to be fed from one specific substation, and as a result the lines that feed this substation are still loaded quite heavily. A solution to this, which was not implemented in the model, is the construction of a new 380 kV station at the location of the current substation. It will be of vital importance if vast amounts of new onshore wind is connected in the North of the province. The strengthened link between two stations has mitigated the high loading of the link between these two substations. This measure is instrumental to the creation of load pockets and maintaining the N-1 criterion.

The low load, high production case for A2030 had little differences from the run without the expansions. As mentioned before, the connection to the northern part of the province has not been strengthened in these expansions, and it is this particular area that is home to the most (wind) production.

D.5 Conclusion

With these load flow calculations, it has been shown that high levels of additional electrification can load the 150 kV grid beyond its limits, especially when there is low production in the area as well. This is entirely possible with low VRE generation in the future, when the conventional plants in the area have been decommissioned or mothballed, and power has to be imported from the 380 kV grid.

The grid is also not designed to drain the projected amount of DG from the area in high production situations. When the load is low and production by DG is very high, 150-380 kV transformers become heavily loaded, which could jeopardise redundancy. Important to note here is that a failure of one of those transformers would in principle not lead to an outage. While not desirable, VRE generation can be curtailed to reduce the load level of components. When curtailment is required often, significant spillage of VRE generation will occur. This would be the case in the A2050 scenario where lines get overloaded even when there is no contingency situation.

The need for weighing flexibility versus network reinforcement is apparent, notably in the period beyond 2030. It was shown by Liander that increased electrification and VRE generation results in overloading of their assets, but also increases the load on TenneT's substations. To drain all the power from VRE on low load moments in the future, the current grid does not suffice. By 2050, the penetration of PV could become so large that it completely overloads the 150 kV grid in its undisturbed state. To avoid the spillage of VRE surpluses, the power will have to be either curtailed or transported across large distances towards areas that require more power than is generated locally. Alternative measures are to temporarily store the energy locally or to shift (local) demand over time. It will depend on the specific situation what solution is most desirable (as analysed further during the second phase of the FLEXNET project).

D.6 References

TenneT (2016): Kwaliteits- en capaciteitsdocument (KCD).

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