Demand and supply of flexibility in the power system of the Netherlands, 2015-2050

Summary report of the FLEXNET project

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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 system in the **NET**herlands".

The current report presents a summary of the approach, main findings and key messages of the FLEXNET project, based on the summaries of the three extensive background reports of each phase of the project. In particular, these background reports include:

- *The demand for flexibility of the power system in the Netherlands, 2015-2050*, Report of phase 1 of the FLEXNET project;
- *The supply of flexibility for the power system in the Netherlands, 2015-2050*, Report of phase 2 of the FLEXNET project;
- *Societal framework to trade-off grid reinforcement and deployment of flexibility*, Report of phase 3 of the FLEXNET project (published in Dutch: '*Maatschappelijk afwegingskader voor de inzet van flexibiliteitsopties in elektriciteitsnetten*).

These reports can be downloaded for free at: https://www.ecn.nl/flexnet/

At ECN, FLEXNET is administered under project number 53626. For further information, you can contact the project leader: Jos Sijm (sijm@ecn.nl; tel.: +31 6 1048 4843).

Abstract

The current report presents a summary of the approach, main findings and key messages of the FLEXNET project. 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. The current report is based on the summaries of the three extensive background reports of FLEXNET, each covering one of the three phases of the project. These phases include (i) the demand for flexibility (phase 1), (ii) the supply of flexibility (phase 2), and (iii) societal framework to trade off grid reinforcements versus deployment of flexibility (phase 3).

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Summary of key messages

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 due to the increasing penetration of demand technologies such as electric vehicles (EVs), heat pumps (HPs), power-to-gas (P2G), etc., and – as a result of these two trends – (iii) a higher need for flexibility and system integration.

In this study we have developed several scenario cases up to 2050 which show the increase in flexibility needed in the electricity system (phase 1). We distinguish between three sources ('causes') of the demand for flexibility, i.e. due to (i) the variability of the residual load, (ii) the uncertainty ('forecast error') of the residual load, and (iii) the congestion (overloading) of the power grid (where residual load is defined as total power demand minus VRE power supply from sun and wind). The analyses in this study are based on hourly power demand and supply profiles for a 'normal' ('representative') year, although we also consider some extreme hours and some extreme situation in particular.

Subsequently, in phase 2 of the study, we have explored various options that can be used to provide flexibility such as, for example, storage, demand response or cross-border power trade. Our analysis provides insights in the importance of the different options in the future energy system, given their technical characteristics and economic costs. The analyses in phase 2 are conducted within an EU-wide power trade setting, assuming similar (correlated) weather patterns across EU countries.

Finally, in phase 3 of the study, we have described a societal framework that can be used to make well-informed decisions with regard to the trade-off between grid reinforcement and the deployment of flexibility options.

The study has been conducted at both the national level and the regional network level. The major key messages of the different phases of the study at the study at these levels are outlined below.

Phase 1: the demand for flexibility

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).

Phase 2: the supply of flexibility

National level

Cross-border trade becomes dominant flexibility option in future years but its size depends on available interconnection capacity as well as on the available potential and costs of alternative, domestic flexibility options.
In order to meet the rapidly growing demand for flexibility due to the variability of the residual load of the power system in the Netherlands up to 2050, cross-border power trade becomes the most important flexibility option in the coming years (decades), with shares ranging for this option from 65% to 74% of total annual flexibility needs in the period 2023-2050. As a result, power trade has a major impact on the business case of other, domestic options to meet the demand for flexibility by the Dutch power system, including the impact of (hourly variations in) power trade volumes and the related hourly fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly (depending on the available potential and costs of these options). This impact, however, depends in particular on the assumptions made with regard to the optimal interconnection capacities across European countries, notably between the Netherlands and its neighbouring countries. However, even under more (very) restrictive interconnection assumptions, however, the share of power trade in total annual flexibility demand still amounts to approximately 40-65% in 2050.

Non-VRE power generation becomes less important to meet future flexibility needs but gas-fired units may remain import as back-up capacity
In the current situation (scenario R2015), power generation from conventional, non-VRE sources is the most dominant flexibility option to meet total annual flexibility needs due to the variability of the residual load of the Dutch power system (estimated at 2.2 TWh, aggregated per annum), in particular by (hourly changes in) power generation from gas (49%) and coal (42%), while the remaining share of these needs is addressed by (hourly variations) in power trade (9%). In the coming years (decades), however, the

shares of these conventional power generation sources in the (rapidly growing) demand for flexibility declines steeply. Already in 2023, the share of gas falls to about 30% and of coal even to 5% (while the share of power trade increases to 65%). Under 'optimal' (i.e. 'least-cost') interconnection conditions, the share of gas in total annual flexibility needs in 2050 (estimated at about 15 TWh, aggregated per annum) declines further to less than 5% and of coal to less than 1% (while the share of power trade rises to 74%). Under very restrictive interconnection conditions, however, the share of gas becomes about 27% in 2050 and of coal some 2.4% (while the share of power trade becomes approximately 41%).

Curtailment of VRE power generation becomes a major flexibility option only far beyond 2030 depending to the availability of alternative options (in particular power trade and demand response)
Up to 2030, there is hardly or no curtailment of power generation from VRE sources (sun/wind) needed to balance (hourly) power demand and supply as the share of VRE output in total power demand is still manageable in almost all hours of the year. In 2050, however, - with a large share of potential VRE output in total power demand (80%) and a large number of hours (>3200) with a (large) VRE surplus – VRE curtailment becomes a major flexibility option. In that year, total VRE curtailment is estimated at about 26 TWh per annum, i.e. approximately 16-17% of total realised VRE power production. Under optimal (least-cost) interconnection conditions, the share of (hourly variations in) VRE curtailment in total annual flexibility needs due to the variability of the residual load amounts to some 20%, while under very restrictive interconnection conditions this share increases to approximately 28%.

Demand response has a large potential to meet future flexibility needs, but the role of demand curtailment is negligible
In general, there seems to a large potential to meet future flexibility needs of the Dutch power system by means of demand response, i.e. *shifting* part of (peak) power demand in a certain hour to another hour of the day, week, month, etc., either forwards or backwards. This applies in particular to (industrial) power demand functions that are expected to grow rapidly in the coming decades, such as power-to-gas (P2G), power-to-heat (P2H) or power-to-ammonia (P2A) but also to power demand by means of more smart (flexible) charging of electric vehicles (as all explored in the current study). In addition, there may be a substantial potential for demand response by other power demand functions in other sectors such as services or households (as explored at the regional network level; see below). This potential, however, may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. On the other hand, the role of *demand curtailment* – i.e. *limiting* (peak) power demand in a certain hour (and, hence, demand is lost) – as a flexibility option is negligible, at least in the present study in which the value of lost load (VOLL) is set at a relatively high level of 3000 €/MWh.

Energy storage plays generally a limited role in meeting future flexibility needs of the power system (due to its relatively high costs) but in specific cases it may be more significant
The role of energy storage is generally limited to meet future flexibility needs (or at least generally less than what is sometimes expected or suggested in the literature). This applies in particular to longer-term, single ('pure') storage functions to address flexibility needs due to the variability of the residual load on the day-ahead market or,

at the regional grid level, to using battery systems purely for congestion management reasons (see also below). The main reason is that the costs of these storage functions are generally high compared to alternative, amply available options such as power trade, demand response, VRE curtailment or – at the regional network level – grid reinforcement.

In specific cases, however, the role of energy storage to meet flexibility needs may be more significant. This applies, for instance, notably for providing short-cycle storage functions to meet flexibility/balancing needs due to the uncertainty ('forecast error') of the residual load on the intraday and balancing markets, in particular to provide primary/secondary power reserves (although on these markets storage also has to compete with alternative options while power reserve markets are usually relatively small, illiquid and/or uncertain).

In addition, energy storage becomes more attractive (profitable) if it is not the only – or primary – function of a technology and could be combined with providing other (more important) functions so that its costs can be shared or even covered primarily by these other functions and its benefits and revenues are broader and higher. Examples may include storage options such as power-to-gas (aimed primarily at reducing CO_2 emissions) or using EV batteries for storage functions (although the potential of these options to provide flexibility to the power system is likely higher through demand response than by energy storage).

Regional grid level

The net benefits of deploying large-scale flexibility options purely for congestion management in the Liander area are, *in general*, limited

In order to prevent overloads (congestion) in the Liander grid due to the increased deployment of sun PV, electric passenger vehicles (EVs) and household heat pumps (HPs) – as laid down in the FLEXNET scenario cases – *additional* investments in grid reinforcements are required of 2 to 5% per year up to 2030 and about 7% per year in the period from 2030 to 2050. Given current annual grid investments in the Liander service area of, on average, € 750 million in 2012-2016, this corresponds to a cumulative grid reinforcement investment of € 1.0-1.5 billion up to 2050 scenario.

In terms of capital investment savings (CAPEX), it is estimated that a mix of flexibility-based measures to mitigate grid overloads – notably deploying PV curtailment and demand response pricing mechanisms – can save up to about € 700 million (cumulative) in energy transition related grid investments up to 2050. This amount of € 700 million is an indication of the value of flexibility for network investment planning by Liander.

The amount of € 700 million mentioned above, however, does not yet include additional costs required to implement and operate the flexibility-based measures to mitigate grid overloads, such as lost PV revenues, additional grid losses, additional smart metering costs, higher risks, etc. Hence, the net benefits of deploying flexibility as an alternative for grid reinforcements are significantly lower. Moreover, flexibility could have a higher value for purposes such as portfolio and investment planning optimization or system balancing. Flexibility providers should be aware that generally flexibility has relatively a limited scope and limited net benefits for DSOs, implying no large payments for flexibility can be expected from network operators. Therefore, distribution systems operators (DSOs) should be cautious in claiming flexibility for congestion management purposes as, *in general*, the scope and benefits of deploying flexibility for congestion management seems to be limited.

It should be noted that the results have been calculated based on the current perspective on the future. Because of the many variables and assumptions, the rapid changing context and ever increasing complexity, modelling should become an integrated part of strategic decision making of the distribution system operators. This will enable a DSO to rapidly adjust their strategy based on the latest insights. In *specific* situations, however, deploying flexibility may offer a significant potential with a relatively high value and is therefore an important capability for any DSO

In specific situation (e.g., locally and/or temporarily), the deployment of flexibility measures to prevent or mitigate grid overloads – and, hence, to avoid or reduce investment costs in grid reinforcements – may offer a significant potential and relatively high value for DSOs, resulting in a concomitant high value of flexibility and associated benefits for flexibility providers. Other applications and opportunities besides congestion management which could be a reason for a DSO to deploy flexibility options include among others: local voltage support, system balancing, synergies groundwork with other infrastructural companies, black-out recovery. Moreover, a rough comparison of the Liander modelling results with modelling outcomes of DSO Stedin indicates more overloads in the Stedin service area and, therefore, a higher demand for flexibility in this area and, perhaps, a higher value (net benefits) of deploying flexibility as an alternative for grid reinforcements.

Energy storage: benefits of using battery system purely for congestion management do not outweigh costs
For energy storage at the regional grid level, the benefits of the use of a battery system for mitigating overloads do not outweigh the costs. Relatively large battery capacities are required to mitigate overloads of distribution transformers (DTs). Given (i) the accompanying cost of a battery system, (ii) the required operational expenditures (OPEX), (iii) the additional energy losses, and (iv) the added complexity and, therefore, the higher operational risks, it is safe to assume that the use of a battery system at the distribution transformer (DT) level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

Phase 3: Societal framework to trade-off grid reinforcement and deployment of flexibility

Societal framework essential
A societal framework for analysing the trade-off between grid reinforcement and the deployment of flexibility is essential due to the effects of such a trade-off on generators, consumers, network operators and other social actors.

Indices CBA or indicative CBA preferred
Depending on the size of the grid expansion investments that can be temporarily or permanently avoided through the deployment of flexibility and the available information to determine effects, the report shows that an indices or indicative CBA would be the most appropriate form.

Relevant factors in the decision to quantify an effect are the expected size of the effect, the required effort and the social support it generates

Modify requirement to only temporarily apply congestion management
Of course, to be able to devise an adequate societal framework for the trade-off between grid reinforcement and the deployment of flexibility, the legal and regulatory limitation (in the Electricity Act and the Grid Code) that congestion management may only be temporarily deployed will have to be removed.

Implementation of the societal framework in legislation and regulations will benefit uniformity
The aforementioned analysis steps can be used in the investment plans of network operators and be prescribed in a Ministerial Regulation, such as currently exists for Quality and Capacity Documents (KCDs). Policymakers will then be able to ensure more uniform implementation of the societal framework by the network operators.

The societal framework can also provide more insight into the social value of flexibility in specific situations
To better understand the value of flexibility for congestion management, it will be important to conduct further studies to analyse in which specific situations flexibility has the greatest value, for both network operators and society as a whole, by implementing the proposed societal framework in practice.

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 present a summary of the approach, main findings and key messages of the first phase of FLEXNET. It is based on the summaries of the three extensive background reports of each phase of the project.

Structure of report
Chapters 2 up to 4 provide a summary of the approach, main findings and key messages of phases 1 up to 3 of the FLEXNET project, respectively.

2

The demand for flexibility

This chapter provides a summary of the approach, main findings and key messages 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?

2.1 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.

2.2 Major results at the national level

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

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).

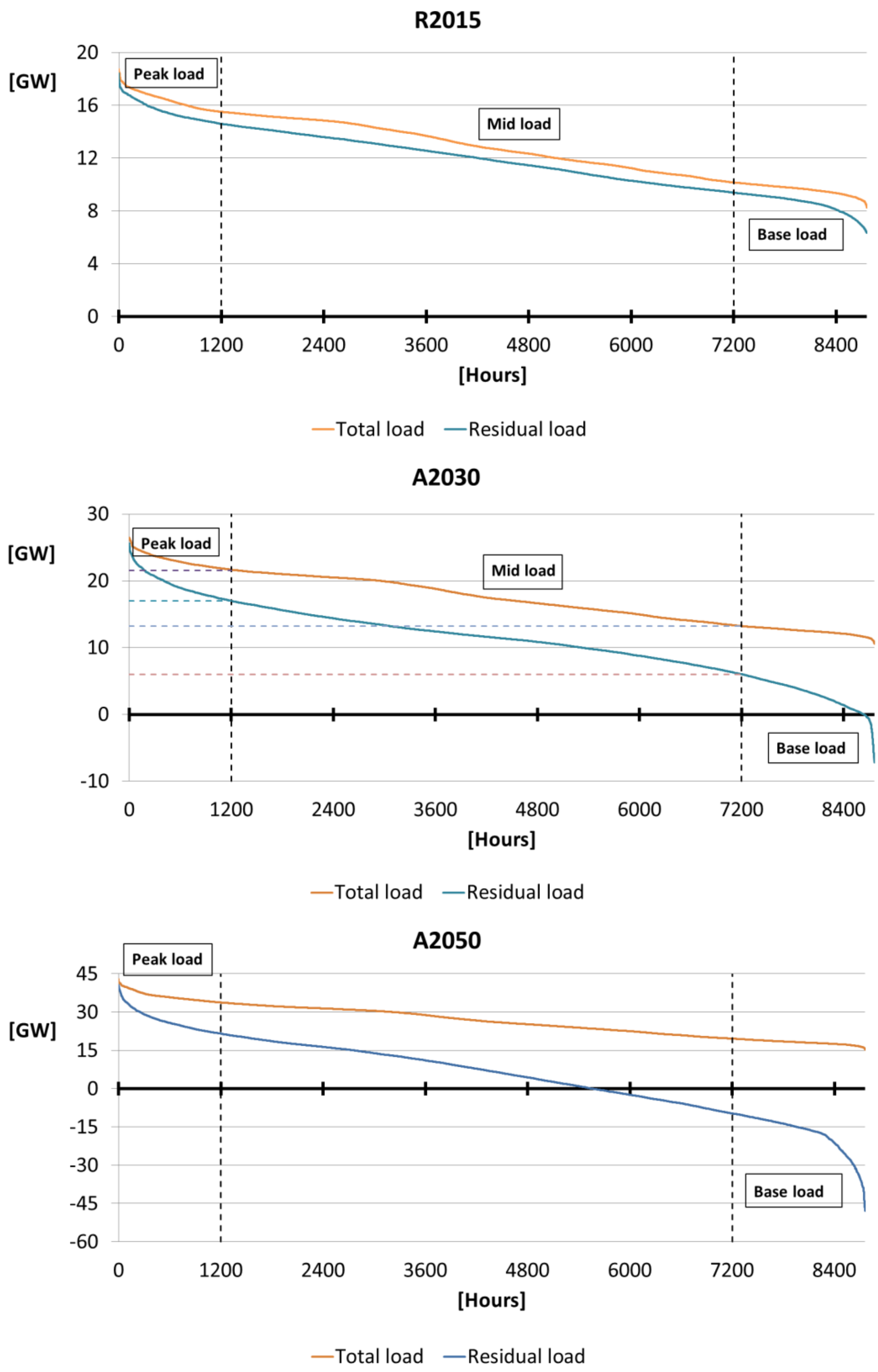
- *Power output from VRE sources (sun/wind)* increases substantially between 2015 and 2050. Hourly VRE output, however, is very volatile and fluctuates heavily over each period considered (day, week, month, etc.). Moreover, even in A2050, with a large share of VRE output in total annual power load (80%), 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.

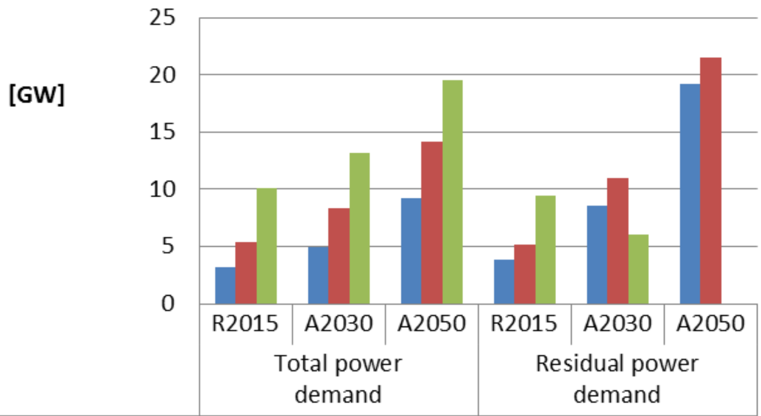
- More specifically, due to the increase in power supply from VRE sources, the need for residual *peak* load capacity increases substantially over time, whereas the need for residual *base* load capacity decreases significantly (and even becomes zero in A2050; see **Figure 1** and **Figure 2**). Peak 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 R2015	Total power demand A2030	Total power demand A2050	Residual power demand R2015	Residual power demand A2030	Residual power demand 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.

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).

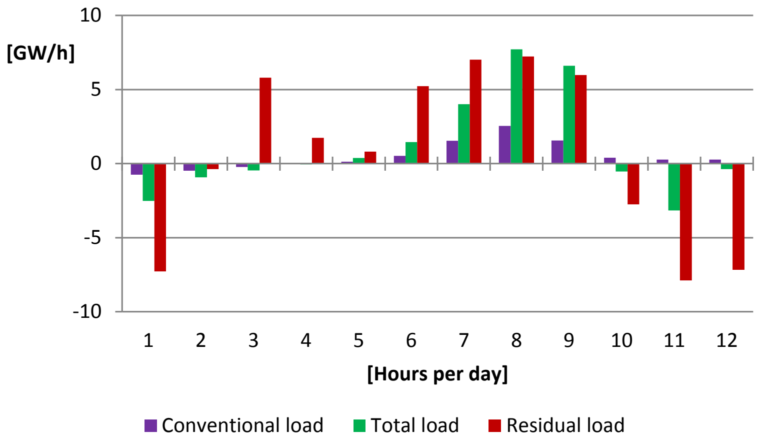
- Ramping needs alternate regularly between hours of upwards versus downward ramping. Occasionally, however, ramping needs may move in the same direction – either upwards or downwards – during several consecutive hours (**Figure 3**). Therefore, the (maximum) cumulative need for either ramping-up or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

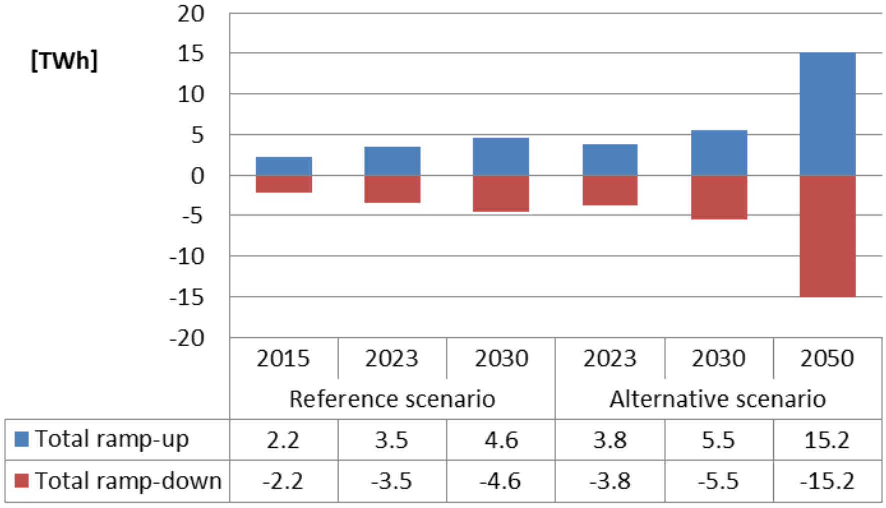
Major drivers (determinants) of the demand for hourly ramping
A comparative analysis of the flexibility ('ramping') needs for different constituent components of the residual load (conventional load, additional load, VRE power generation) shows that the demand for flexibility due to the hourly variation 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%).

2.2.2 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.

2.3 Major results at the regional Liander network distribution level

2.3.1 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.

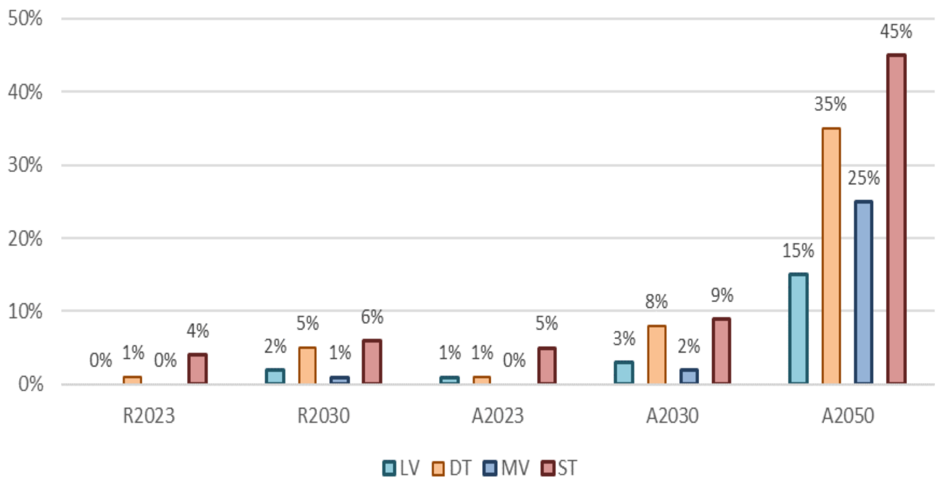
The regional grid assessment shows that the load profiles are expected to alter considerably due to the adoption of sun PV, EVs and HPs over the next decades. The loads on all the assets of the distribution network are observed to become much more volatile. Furthermore, the winter load peaks intensify 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).

2.4 Key messages

2.4.1 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.

2.4.2 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).

3

The supply of flexibility

This chapter provides a summary of the approach, main findings and key messages 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 second phase of the FLEXNET project regarding these two levels include:

- What are the major options to meet the demand for flexibility due to the variability and uncertainty of the residual load of the power system in the Netherlands over the period 2015-2050)?
- What are the options and (net) economic benefits of deploying flexibility for congestion management rather than the traditional solution of grid reinforcement for mitigating network overloads, in particular at the Liander distribution network level up to 2050?

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

3.1 Approach

Definition and scope of flexibility supply options

In order to meet the demand for flexibility, the following supply options have been considered in the present study:

- *Power generation from (flexible) non-VRE sources*, including conventional sources – in particular (flexible) gas-fired power plants but also, to some extent, other conventional units (coal, nuclear) – as well as 'other RES-E' sources (i.e. besides sun/wind) such as hydro or biomass;
- *VRE curtailment*, i.e. limitation of peak power generation from VRE sources;
- *Demand curtailment*, i.e. limitation of peak power demand;

- *Demand response*, i.e. part of total demand in a certain hour is shifted to another hour of the day, week, month, etc., either forward or backwards.
- *Energy storage*, such as batteries, hydro pumped storage (HPS) or compressed air energy storage (CAES), including energy conversion/storage technologies such as power-to-gas (P2G), power-to-ammonia (P2A), etc.;
- *Power trade*, i.e. hourly variations in (net) imports/exports of electricity.

In principle, all flexibility supply options have been considered throughout the study. Some options, however, turned out to more important (and, hence, have received more attention), while other options appeared to be less or hardly important or even not viable (and, hence, have received less or hardly any attention). Moreover, some options turned out to be more relevant at the national level but less relevant at the regional grid level (or vice versa). In addition, some flexibility options are included and analysed more specifically by some of the models used, while other options are not or hardly analysed by these models (or taken as given; see below).

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

In phase 1 of the FLEXNET project, we have distinguished between three main sources ('causes') of the need for flexibility of the power sector (see Section 2.1):

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 (notably decentralised sun PV).

During phase 2, we have considered and analysed the supply options to meet the three different types of flexibility demand. Similar to phase 1, however, phase 2 was also predominantly focussed on modelling and analysing the first and third type of flexibility and hardly on the second type. In particular, the following general approaches and tools have been used to analyse the supply options to meet the three different types of flexibility demand:

1. Options to meet flexibility needs due to the variability of the residual load have been analysed extensively at the national level of the Dutch power system over the period 2015-2050 by means of two models developed by ECN, i.e. COMPETES (an EU28+ electricity market model) and OPERA (an NL energy system model);
2. Options to meet flexibility needs due to the uncertainty of the residual load have been considered briefly by means of a review of available literature;
3. Options to meet flexibility needs due to the congestion of the power grid have been analysed thoroughly at the regional Liander distribution level by means of the Liander network model ANDES.

In order to determine and analyse supply options to meet flexibility needs due to the variability of the residual load at the national level, the two models concerned have been used successively. First of all, the EU28+ electricity market model COMPETES has been used to determine and analyse the supply of some specific flexibility options in particular, notably the cross-border option of power trade and the domestic option of power generation from non-VRE sources (while ignoring the domestic option of demand response). Subsequently, the NL energy system model OPERA has taken the power trade option as given and has focussed more specifically on analysing some domestic flexibility options (in particular demand response).

Scenario cases
During phase 1 of the FLEXNET project, we have defined six scenario case, i.e. two scenarios – the reference scenario and the alternative scenario – each with three focal years (see Section 2.1). As part of phase 2, we have defined two additional 2050 scenario cases, i.e. besides the A2050 case mentioned above. More specifically, as part of the COMPETES modelling outcomes, the A2050 turned out to be characterised by a large ('optimal') interconnection capacity across all European countries covered by the model (including a large expansion of this capacity since A2030). As this variable appeared to be a key variable for almost all other modelling outcomes (and may be overestimated), we have defined two additional 2050 scenario cases labelled as '*B2050*' and '*C2050*'. Both cases are similar to A2050, but in B2050 we have assumed that the expansion of the interconnection capacity since A2030 is only 50% of the ('optimal') expansion in A2050, whereas in C2050 we have assumed that this expansion is 0%. Hence, in C2050 the interconnection capacity across European countries is assumed to be similar to the capacity in A2030 (for details, see below).

3.2 Major results at the national level

3.2.1 Options to meet the demand for flexibility due to the variability of the residual power load

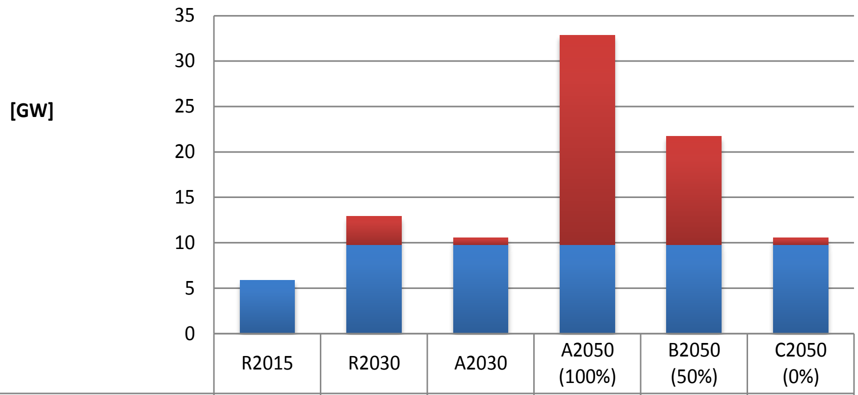
Competes modelling results

Trends in residual power supply
By means of the COMPETES model, we have first of all analysed the trends in the so-called '*residual power supply*' – and its constituent components – of the Dutch power system in the FLEXNET scenario cases up to 2050 (where residual supply – as opposed to 'residual load' – is defined at total power supply minus VRE power generation). The major findings of this analysis include:

- According to the COMPETES modelling outcomes, the optimal ('least-cost') interconnection capacity across all EU28+ countries increases from 62 GW in R2015 to 121 GW in A2030 and to 241 in A2050. For the Netherlands only, the respective capacity figures amount to 6 GW, 11 GW and 33 GW (see **Figure 6**).

- In B2050 (50% interconnection expansion beyond A2030), the cross-border transmission capacity amounts to 181 GW in the EU28+ as a whole and 22 GW in the Netherlands only. In C2050 (0% interconnection expansion) these figures amount to 121 GW and 11 GW, respectively (i.e. similar to the capacity levels in A2030).

Figure 6: Total interconnection capacity in the Netherlands, 2015-2050



	R2015	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
New transmission capacity	0.0	3.1	0.7	23.1	11.9	0.7
Baseline capacity (TYNDP2016)	5.9	9.8	9.8	9.8	9.8	9.8

- The installed VRE capacity (sun/wind) in the Netherlands increases from almost 5 GW in R2015 to approximately 92 GW in A2050. On the other hand, the conventional capacity (gas/coal/nuclear) declines from 25 GW to 9 GW, respectively (see **Figure 7**). In the 2050 scenario cases, however, gas-fired capacity increases rapidly from 6 GW in A2050 to almost 18 GW in B2050 and even to about 32 GW in C2050 (due to the similar decrease in interconnection capacity over these cases mentioned above). This increase refers particularly to central gas turbines (GTs, +14 GW) and combined cycle gas turbines (CCGTs) with carbon capture and storage (CCS, +12 GW).

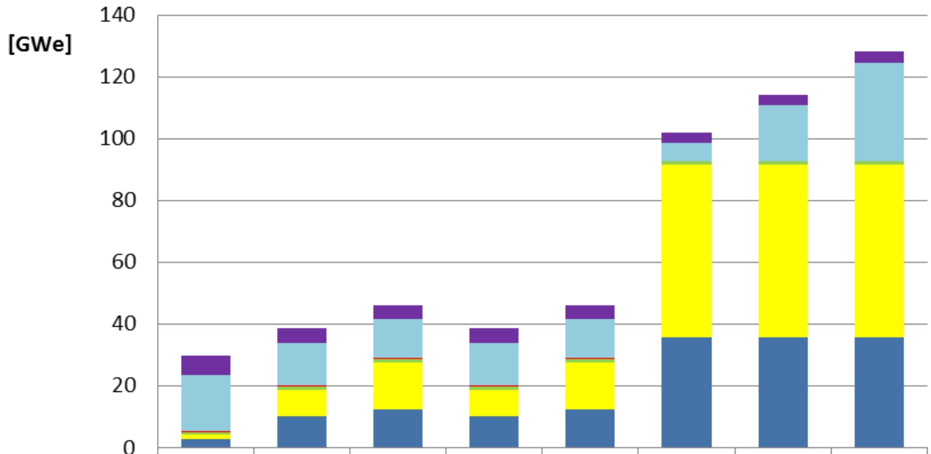
- In the Netherlands, total electricity production doubles in absolute terms from 96 TWh in R2015 to 185 TWh in A2050 (see **Figure 8**). The share of sun and wind in total output increases from 9% to 87%, respectively. On the other hand, for nuclear the share in total power generation declines from 4% in R2015 to zero in A2050, for coal from 31% to 0.2% and for gas from 51% to 12%, respectively.

- In C2050 (0% interconnection expansion), electricity production in the Netherlands is significantly higher (222 TWh) than in A2050 (185 TWh). This increase in total output (+37 TWh) is almost fully met by an increase in gas-fired generation only, which rises steeply from 22 TWh in A2050 to 58 TWh in C2050 (i.e. by 36 TWh; see **Figure 8**). As a result, the share of gas in total electricity production increases from 12% in A2050 to 26% in C2050.

- The increase in total gas-fired power generation by 36 TWh in C2050, compared to A2050, is almost fully met by the newly installed CCGT CCS capacity, i.e. by 32 TWh, and to a lesser extent by the increased GT capacity (by 2 TWh).

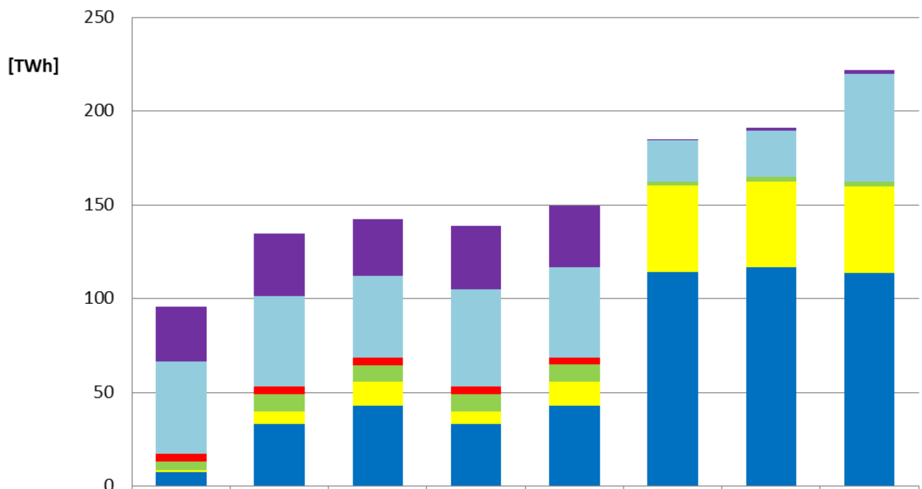
- There is a clear trade-off between the availability (and use) of cross-border interconnection capacity and the deployment of (domestic) gas-fired capacity. In A2050, with a relatively large interconnection capacity for the Netherlands (i.e. 33 GW), the need for and deployment of gas-fired generation capacity is relatively low and stable, implying that, on average, a predominant share of this capacity is deployed for a large number of running hours. On the other hand, in C2050 – with a

Figure 7: Installed power generation capacity in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	6.6	4.6	4.6	4.6	4.6	3.4	3.4	3.4
Gas	17.8	13.7	12.4	13.7	12.4	5.6	17.9	31.8
Nuclear	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
Other RES-E	0.6	1.2	1.2	1.2	1.2	1.1	1.1	1.1
Solar	1.5	8.6	15.1	8.6	15.1	56.1	56.1	56.1
Wind	3.0	10.1	12.4	10.1	12.4	35.7	35.7	35.7

Figure 8: Power generation mix in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	29	33	30	34	33	0	2	2
Gas	49	48	43	52	48	22	24	58
Nuclear	4	4	4	4	4	0	0	0
Other RES-E	5	9	9	9	9	2	2	3
Sun	1	7	12	7	12	46	46	46
Wind	7	33	43	33	43	114	116	114

relatively small interconnection capacity (i.e. 11 GW) – the need for, and deployment of peak and upper mid-load gas-fired capacity is relatively high and declines steeply, implying that, on average, a major share of this capacity is deployed for a small number of running hours.

- Up to 2030, there is no curtailment of VRE power generation as the share of VRE output in total power demand is still manageable (i.e. less than 50%). In A2050 – with a share of 80% of (uncurtailed) VRE output in total power demand and a large interconnection capacity (33 GW) – the curtailment of power generation from sun PV is still zero, but from wind it amounts to almost 26 TWh, i.e. 22% of realised (curtailed) wind production, 16% of total VRE output and 14% of total electricity generation by the Dutch power system in A2050.

- In C2050 – also with a share of 80% of VRE output in total demand but with a small interconnection capacity (11 GW) – curtailment of sun PV amounts to 0.1 TWh and of wind to more than 26 TWh, i.e. together almost 17% of total VRE production.

- Curtailment of power demand – as a flexibility option to balance electricity demand and supply – is restricted to the alternative scenario cases of 2030 and 2050 only, while it is limited to a few hours per year (≤ 6 hours) and, in general, to a small amount per hour, varying from 1 GW in A2050 to 10 GW in C2050.

- Energy storage, by means of compressed air energy storage (CAES) or hydro pumped storage (HPS), does not appear as a viable flexibility option for the Netherlands in the FLEXNET-COMPETES modelling scenarios up to 2050 (although indirectly the Netherlands may benefit from HPS as a flexibility option at the EU28+ level through its power trade relations with other, neighbouring EU28+ countries, including Norway, Germany and France).

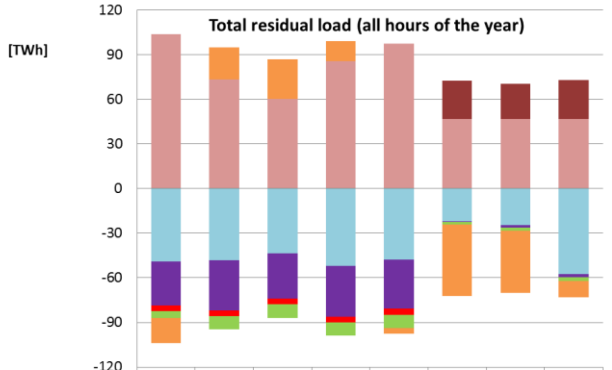
- At an aggregated (annual) level, power trade by the Netherlands over the period 2015-2030 varies widely from large net imports in R2015 (17 TWh) to large net exports in R2023 (21 TWh) and R2030 (27 TWh). In the alternative scenario cases, however, the Netherlands becomes a major net importer of electricity again, varying from 11 TWh in C2050 (small interconnection capacity) to 48 TWh in A2050 (large interconnection capacity).

- Moreover, within the focal years considered, *hourly* power trade is even more volatile, i.e. varying between the interconnection capacities of the Netherlands in the respective scenario cases. For instance, in A2050 net hourly power trade varies between +33 GW (imports) to -33 GW (exports) whereas in C2050 it varies between +11 GW and -11 GW, respectively.

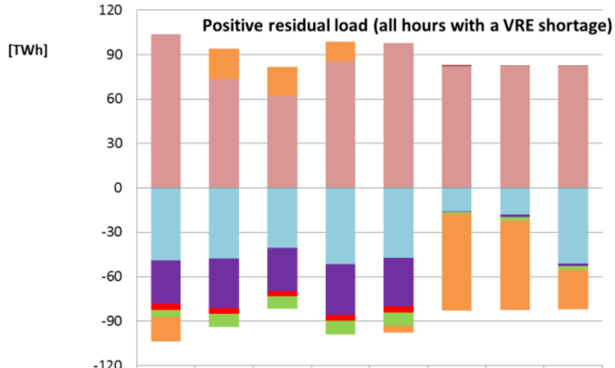
- Aggregated over all hours of the year, the (domestic, uncurtailed) residual load declines in the reference scenario from 104 TWh in 2015 to 60 TWh in 2030 and in the alternative scenario from 86 TWh in 2023 to 47 TWh in 2050 (see upper part of **Figure 9**). In some cases, this (domestic, uncurtailed) residual load is enhanced by net exports – notably in R2023, R2030 and A2023 – and/or by VRE curtailment, in particular in the alternative 2050 scenario cases (A2050, B2050 and C2050).

- In the reference scenario cases R2015-R2030, the (national, curtailed) residual power demand is met primarily by domestic non-VRE power generation, in particular from fossil fuels (coal, gas) and, to a lesser extent, from nuclear and other RES-E. In addition, in R2015 a minor part of this residual power demand is covered by net imports (**Figure 9**).

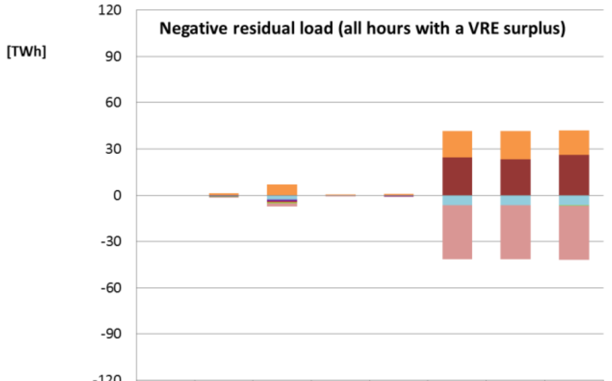
Figure 9: Net residual power balance of the Netherlands, including a distinction between hours with a positive and negative residual load, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	-16.7	21.3	26.7	13.5	-3.6	-48.2	-41.7	-11.0
VRE curtailment	0.0	0.0	0.0	0.0	0.0	25.5	23.5	26.4
Residual load (uncurtailed)	103.8	73.6	60.2	85.6	97.6	46.8	46.8	46.8
Other RES-E	-4.6	-9.0	-9.0	-9.0	-9.2	-1.7	-2.3	-2.6
Nuclear	-4.1	-4.0	-4.0	-4.0	-4.0	0.0	0.0	0.0
Coal	-29.4	-33.4	-30.4	-34.2	-32.9	-0.4	-1.7	-1.9
Gas	-49.0	-48.4	-43.5	-51.8	-47.8	-22.1	-24.5	-57.7



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	-16.7	20.2	19.6	13.2	-4.6	-65.0	-60.2	-26.6
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.9	0.3	0.1
Residual load (uncurtailed)	103.8	73.7	62.0	85.6	97.8	81.9	81.9	81.9
Other RES-E	-4.6	-8.9	-8.3	-9.0	-9.1	-1.6	-2.1	-2.4
Nuclear	-4.1	-4.0	-3.6	-4.0	-4.0	0.0	0.0	0.0
Coal	-29.4	-33.2	-29.2	-34.1	-32.7	-0.4	-1.7	-1.9
Gas	-49.0	-47.8	-40.5	-51.7	-47.4	-15.8	-18.2	-51.0



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	0.0	1.1	7.1	0.2	1.0	16.8	18.5	15.6
VRE curtailment	0.0	0.0	0.0	0.0	0.0	24.7	23.1	26.2
Residual load (uncurtailed)	0.0	-0.1	-1.8	0.0	-0.2	-35.1	-35.1	-35.1
Other RES-E	0.0	-0.1	-0.7	0.0	-0.1	-0.1	-0.2	-0.2
Nuclear	0.0	-0.1	-0.4	0.0	-0.1	0.0	0.0	0.0
Coal	0.0	-0.3	-1.2	0.0	-0.2	0.0	0.0	0.0
Gas	0.0	-0.5	-3.0	-0.1	-0.4	-6.3	-6.3	-6.6

- In the alternative scenario cases A2023 and A2030, the residual supply side shows a similar picture: residual power demand is primarily met by non-VRE power generation, while in A2030 an additional, small part is covered by net imports.

- In the alternative 2050 cases, however, the situation is quite different. Notably in A2050, about two-thirds of the (national, curtailed) residual power demand is covered by net imports while the remaining part is addressed by domestic, non-VRE generation (**Figure 9**).

- On the other hand, in C2050 (0% interconnection expansion), the residual supply side is quite different compared to A2050 (100% interconnection expansion). Due to the interconnection restriction, the contribution of net imports to total supply falls from 48 TWh in A2050 to 11 TWh in C2050, whereas the contribution of gas-fired power generation to meet electricity demand increases from 22 TWh to 58 TWh, respectively. As a result, gas becomes by far the most dominant source of total (national) residual power supply in C2050.

- However, in the 2050 scenario cases – with a large VRE surplus over a large number of hours – the residual supply situation is quite different in the hours with a VRE surplus compared to the hours with a VRE shortage (see middle versus lower part of **Figure 9**).).The VRE supply surplus is usually enhanced by non-VRE generation – notably from gas and, to a lesser extent, from other RES-E – because of 'must-run' production considerations and/or ample export opportunities in certain hours. The resulting domestic surplus of power supply is predominantly met by VRE curtailment and, to a lesser extent, by net exports

Trends in hourly variations of residual load and resulting flexibility needs
Following hourly variations in residual load (as defined and analysed in the phase 1 report), we have defined hourly variations ('ramps') in residual supply as the difference between residual supply in hour t and residual supply in hour t-1 (with t = 1,…..n). These variations can be either positive ('ramp-up') or negative ('ramp-down').

In order to analyse the demand for flexibility due to the variability of the residual load during phase 1 of FLEXNET, we have defined and applied the following three specific indicators of flexibility needs resulting from the hourly variations of the residual load:

- *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);
- *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).

As part of the second phase of FLEXNET, we have estimated and analysed the supply options to meet the demand for flexibility according to the three indicators mentioned above by means of the EU28+ electricity market model COMPETES. The major results of this effort include:

- In R2015, the need for maximum hourly ramp-up (3.0 GW/h) is still solely met by power generation from fossil fuels, in particular from gas (2.9 GW/h) and, to a lesser extent, from coal (1.3 GW/h), whereas the ramp of net imports is still relatively small and even moves in the other direction (-1.2 GW/h).

- In almost all scenario cases the need for both *maximum hourly ramp-up and maximum hourly ramp-down* is predominantly (60-100%) met by hourly changes in net power trade. The only exceptions include the need for upward flexibility in R2015 (as noted above) and the need for downward flexibility in B2050 and C2050. In particular, in C2050 (0% interconnection expansion), only a minor share of the maximum need for hourly ramp-down (-29 GW/h) is met by net imports (-6 GW/h), whereas major shares are addressed by VRE curtailment (-11 GW/h) and gas-fired generation (-11 GW/h) and a small share by other RES-E (<1 GW/h; see **Figure 10**).

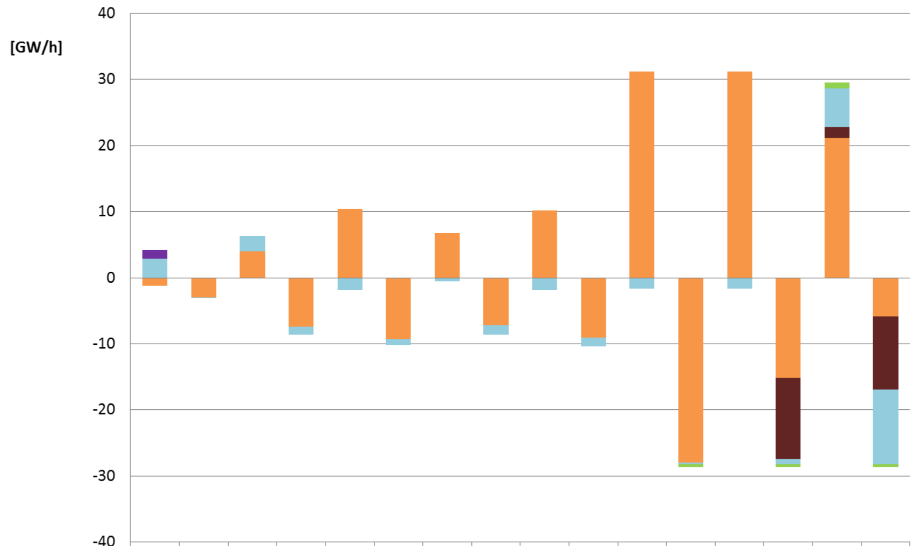
- Hourly variations in power generation from fossil fuels (coal, gas) play a more important role as flexibility options to meet flexibility needs in terms of the *maximum cumulative ramps* up to A2030, notably from coal to meet downward cumulative flexibility needs. In the 2050 scenario cases, the role of (hourly variations in) VRE curtailment in meeting maximum cumulative ramps is more important, whereas the role of (hourly variations in) power trade is less important (compared to meeting maximum hourly ramps, discussed above). More specifically, the share of VRE curtailment in addressing cumulative upward flexibility needs amounts to 44% in A2050 and increases to almost 60% in C2050, whereas the share of power trade is 56% in A2050 and drops to 31% in C2050; see **Figure 11**).

- Flexibility needs in terms of *total annual for demand for upward/downward flexibility* (due to the hourly variations of the residual load) increase from 2.2 TWh in R2015 to more than 15 TWh in the 2050 scenario cases (see **Figure 12**). In R2015, these needs are predominantly met by (hourly) increases in power generation from gas (49%) and coal (42%), while the remaining part is covered by increases in net imports (9%).

- In R2023, the total annual demand for upward flexibility increases to 3.5 TWh. However, already in this scenario case the share of power trade (net imports) increases to 65%, whereas the shares of gas and coal drop to 30% and 5%, respectively (**Figure 12**).

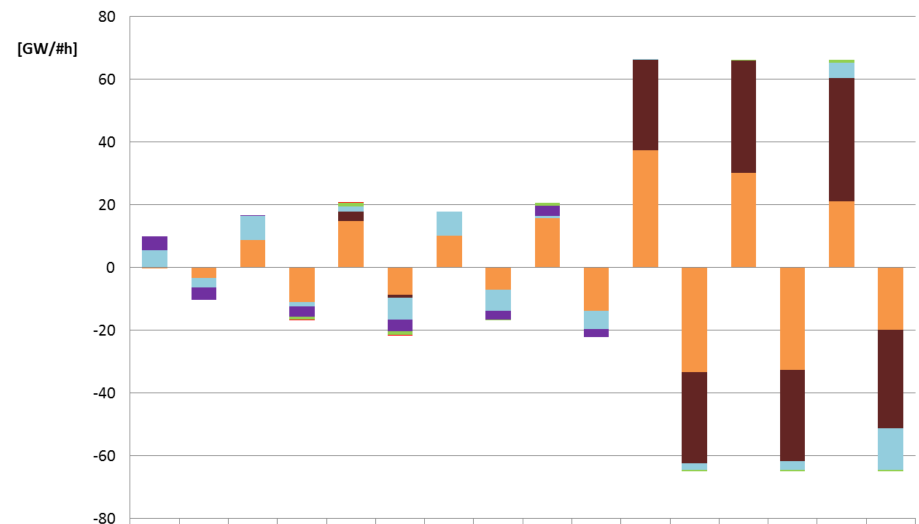
- In the scenario cases A2023 up to A2050, the share of power trade in total flexibility demand (upwards/downwards) is significantly higher, whereas the share of fossil fuels is lower accordingly. In A2050, the share of net power imports in total annual flexibility demand/supply amounts even to almost 74%, whereas the share of gas and coal amounts to only 4.6% and 0.6%, respectively. The remaining part is largely accounted for by (hourly changes in) VRE curtailment (20%) and, to a lesser extent, by generation from other RES-E (1%).

Figure 10: Flexibility options to meet flexibility needs in terms of maximum hourly ramps, 2015-2050



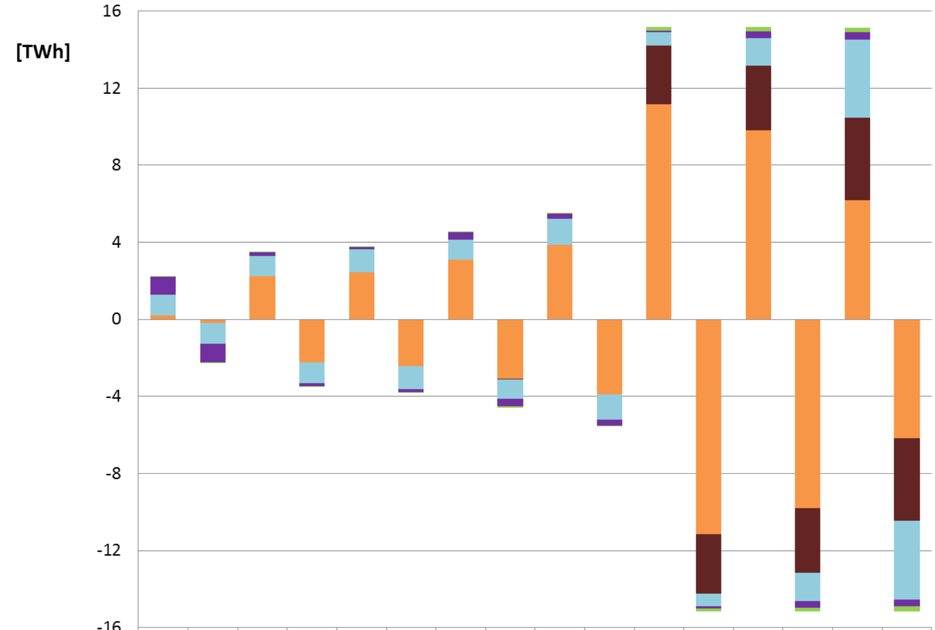
	R2015		R2023		R2030		A2023		A2030		A2050 (100%)		B2050 (50%)		C2050 (0%)	
	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down
Other RES-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.4	0.0	-0.4	0.9	-0.4
Coal	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	2.9	-0.1	2.2	-1.2	-1.9	-0.8	-0.6	-1.5	-1.9	-1.4	-1.7	-0.3	-1.7	-0.9	5.8	-11.3
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-12.2	1.7	-11.1
Net imports	-1.2	-3.0	4.0	-7.4	10.4	-9.3	6.7	-7.2	10.1	-9.0	31.2	-28.0	31.2	-15.1	21.1	-5.8

Figure 11: Flexibility options to meet flexibility needs in terms of maximum cumulative ramps, 2015-2050

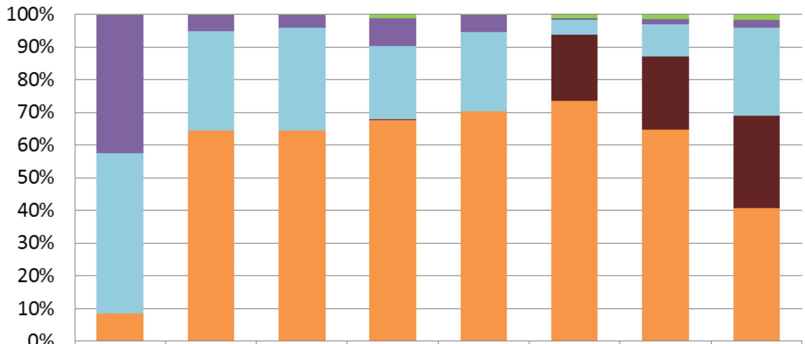


	R2015		R2023		R2030		A2023		A2030		A2050 (100%)		B2050 (50%)		C2050 (0%)	
	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down
Nuclear	0.0	0.0	0.0	-0.1	0.2	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other RES-E	0.0	0.0	0.0	-1.0	1.0	-1.0	0.0	-0.3	1.0	0.0	0.0	-0.4	0.4	-0.4	0.9	-0.4
Coal	4.5	-3.9	0.0	-3.1	0.1	-3.7	0.0	-2.7	3.1	-2.5	0.0	0.0	0.0	0.0	0.0	0.0
Gas	5.4	-3.0	7.6	-1.5	1.5	-7.1	7.7	-6.8	0.8	-5.9	0.0	-2.3	0.0	-2.9	5.0	-13.4
VRE curtailment	0.0	0.0	0.0	0.0	3.1	-0.8	0.0	0.0	0.0	0.0	28.9	-28.9	35.7	-28.9	39.1	-31.4
Net imports	-0.3	-3.4	8.8	-11.1	14.7	-8.8	10.1	-7.0	15.7	-13.8	37.3	-33.4	30.1	-32.8	21.1	-19.8

Figure 12: Total annual supply of flexibility options to meet total annual demand of flexibility, either upwards or downwards, in all scenario cases, 2015-2050



	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Other RES-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	-0.2	0.2	-0.2	0.3	-0.3
Coal	0.9	-0.9	0.2	-0.2	0.2	-0.2	0.4	-0.4	0.3	-0.3	0.1	-0.1	0.3	-0.3	0.4	-0.4
Gas	1.1	-1.1	1.1	-1.1	1.2	-1.2	1.0	-1.0	1.3	-1.3	0.7	-0.7	1.4	-1.4	4.1	-4.1
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	-3.1	3.4	-3.4	4.3	-4.3
Net imports	0.2	-0.2	2.2	-2.2	2.4	-2.4	3.1	-3.1	3.9	-3.9	11.1	-11.1	9.8	-9.8	6.2	-6.2



	R2015	R2023	A2023	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
Other RES-E	0.2%	0.1%	0.0%	1.1%	0.0%	1.1%	1.4%	1.7%
Coal	42.4%	5.0%	4.0%	8.6%	5.4%	0.6%	1.7%	2.4%
Gas	48.9%	30.4%	31.5%	22.2%	24.2%	4.6%	9.8%	26.8%
V-RES curtailment	0.0%	0.0%	0.0%	0.3%	0.0%	20.2%	22.1%	28.2%
Net imports	8.5%	64.5%	64.5%	67.7%	70.4%	73.5%	64.6%	40.8%

- In the two other 2050 scenario cases – with significantly lower interconnection capacities – the share of power trade in total upward/downward flexibility is significantly lower, while the shares of the other flexibility options are higher accordingly. More specifically, in C2050 (% interconnection expansion), the share of gas-fired generation in total annual flexibility needs increases to 27% (compared to less than 5% in A2050) while the share of VRE curtailment rises from 20% in A2050 to 28% in C2050. In C2050 , however, power trade still accounts for the largest share of all flexibility options (41%), while in B2050 (50% interconnection expansion), the share of net imports in total flexibility needs, however, even amounts to 65% (**Figure 12**).

- To conclude, in R2015 hourly changes in the power generation from non-VRE sources – notably from gas, coal and, to a lesser extent, other RES-E (biomass, hydro) – are the main supply options to meet the demand for upward/downward flexibility due to the (hourly) variability of the residual load, regardless of the indicator used to express and quantify this type of flexibility demand. In all scenario cases over the period 2023-2050, however, hourly changes in power trade become the most important (dominant) supply option to address the demand for flexibility due to the variability of the residual load.

- Our analysis shows, however, that the role of the different supply options to meet the need for flexibility depends highly on the assumptions made with regard to the expansion of the interconnection capacities across the EU28+ countries in general and between the Netherlands and its neighbouring (interconnected) countries in particular. For instance, in A2050, the shares of the three main supply categories in addressing total annual flexibility demand – i.e. power trade, VRE curtailment and power generation from non-VRE resources – amount to 74%, 20% and 6%, respectively.

- On the other hand, in C2050, these shares amount to 41%, 28% and 31%, respectively. In particular, the share of gas-fired power generation increases from 4.6% in A2050 to almost 27% in C2050 (**Figure 12**).

The role of power trade versus other, domestic flexibility options
As observed above, in the coming decades (hourly variations in) power trade plays a major (usually dominant) role in meeting (hourly variations in) residual load (and resulting flexibility needs). Additional analysis of this role has resulted in the following findings:

- Even in hours in which the EU28+ countries as a whole and the Netherlands in particular faces an 'extreme' high level of either a large positive residual load (VRE shortage) or a large negative residual load (VRE surplus), these countries are able to address these situations by a mix of (hourly variations in) non-VRE power generation, VRE curtailment, demand curtailment, energy storage and, in particular, power trade between countries with, on balance, a domestic power surplus (net exports) and countries with a domestic power deficit (net imports).

- Power trade as a flexibility option has a major impact on the business case of other, domestic options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050, including the impact of (hourly variations in) power trade volumes and the related hourly fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly. This impact, however, depends significantly on the assumptions the Netherlands and its neighbouring countries.

Electricity prices and power system costs

In addition, we have analysed hourly electricity prices and (total, annual) power system costs in the FLEXNET scenario cases up to 2050 by means of the COMPETES model. The major findings in this regard include:

- Over the period R2015- A2030, the (weighted average, annual) electricity price increases significantly (mainly due to the higher fuel and CO_2 prices for the marginal units setting the power price over this period). Compared to A2030, however, the electricity price drops substantially in A2050 (due to the large share in total power production by VRE sources with low marginal costs). In C2050, on the other hand, the electricity price is significantly (60%) higher than in A2050 (due to the lower interconnection capacity and the resulting number of hours in which electricity end-users can benefit less from lower-priced electricity imports).

- Over the period 2015-2050, *hourly* electricity prices fluctuate heavily (see **Figure 13** as well as **Figure 14**). Moreover, this price volatility increases over time, mainly due to both the increasing share of VRE sources – with low marginal costs – in total power production, setting the price during a growing number of hours, as well as the decreasing share of gas-fired generation – with high marginal costs, setting the price during a diminishing number of (peak load) hours (i.e. hours with a relatively high VRE shortage). In addition, electricity price volatility increases in B2050 and C2050, compared to A2050, due to the lower interconnection capacities in these scenario cases, (implying that power trade flows play a smaller role in stabilising domestic electricity prices).

Figure 13: Illustration of hourly electricity price levels and fluctuations during the mid of the year (hours 3900-4500) in some selected scenario cases, 2015-2050

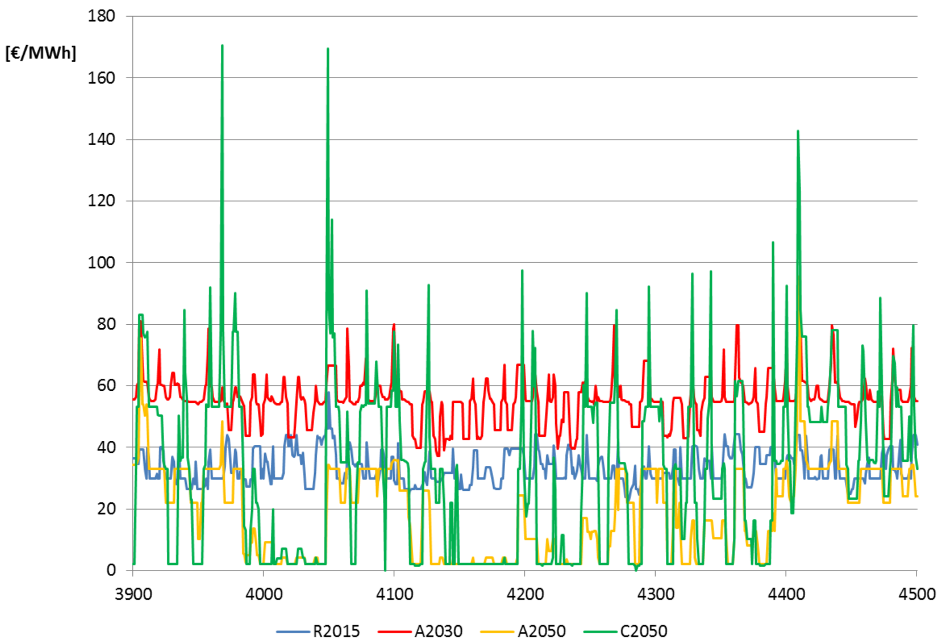
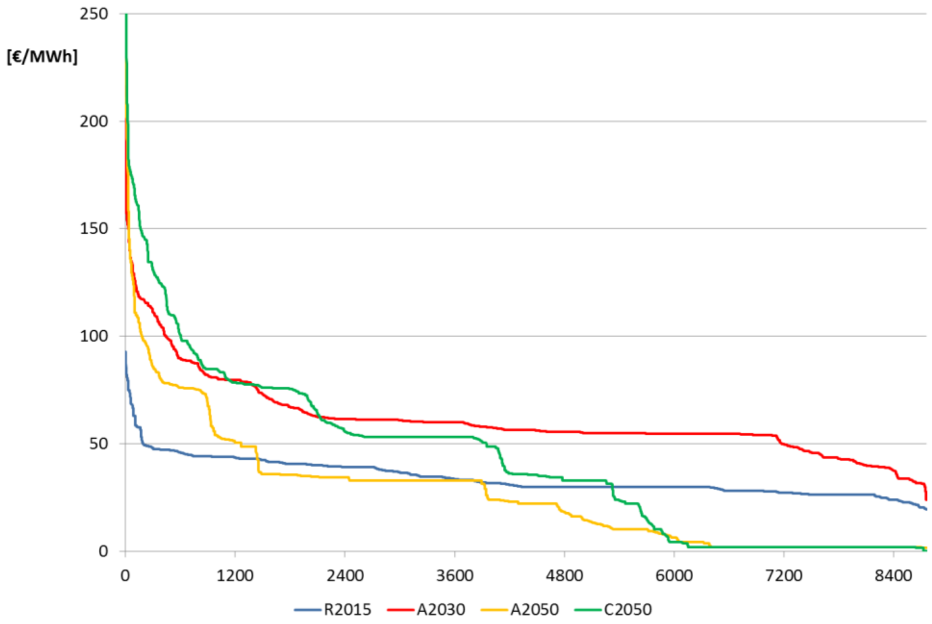


Figure 14: Duration curves of hourly electricity prices in some selected scenario cases, 2015-2050



- ➢ Compared to A2050, total power system costs in the EU28+ as a whole are approximately € 2.2 billion (8%) higher in B2050 and about € 10 billion (38%) in C2050. In the Netherlands only, total power system costs are about € 1.9 billion (43%) higher in B2050 and approximately € 2.4 billion (54%) in C2050. These higher costs result, on balance, from lower (annualised) interconnection capacity investments on the one hand and higher costs for (gas-fired) generation capacity investments and (variable) power generation costs on the other hand.

Opera modelling results

To some extent, the OPERA modelling results are additional, complementary to the COMPETES modelling findings – as discussed above – in the sense that the power trade results of COMPETES are used as given input into OPERA and that, subsequently, OPERA focusses specifically on analysing some domestic flexibility options, in particular on demand response and energy storage (which are not – or to a lesser extent – covered by COMPETES). The major findings of the OPERA modelling analyses – including, where possible and relevant, a comparison with the COMPETES modelling results – are summarised below.

Demand response
As part of the OPERA modelling analyses, we have particularly investigated the potential of demand response by some selected power demand technologies as an option to address flexibility needs of the Dutch power system up to 2050. These technologies include electric passenger vehicles (EVs) as well as three energy conversion technologies, i.e. power-to-gas (P2G), power-to-heat (P2H) and power-to-ammonia (P2A).

At present, the power demand by these technologies is still (negligible) small but it is expected that it will grow rapidly in the coming decades and that it offers, in principle, a large potential for demand response as a flexibility option for the Dutch power system, perhaps already – to some extent – in the period up to 2030 but notably in the years beyond 2030.

The major OPERA modelling findings with regard to the role of demand response by the four selected technologies include:

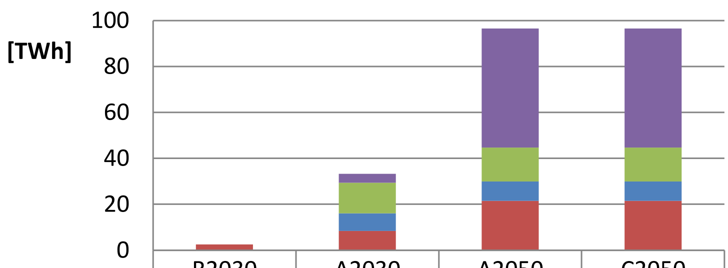
- Total power demand by the four selected technologies increases from almost zero in R2015 to about 33 TWh in A2030 and to 97 TWh in both A2050 and C2050, i.e. more than 40% of total power load in the 2050 scenario cases (**Figure 15**).

- The total annual *upward* demand response of the four technologies considered increases from zero in R2030 to 4.4 TWh in A2030, to 18 TWh in A2050 and even to 25 TWh in C2050 (where the total *downward* demand response shows similar amounts in these scenario cases). As a share of total annual power demand by these four technologies, this corresponds to 13% in A2030, 19% in A2050 and 26% in C2050 (**Figure 16**).

- As expected, the total annual demand response in the 2050 scenario cases is, on balance, significantly negative in all hours with a VRE shortage (i.e. generally a *downward* demand response in hours with a *positive* residual load and, hence, relatively *high* electricity prices) and significantly positive in all hours with a VRE surplus (i.e. generally an *upward* demand response in hours with a *negative* residual load and, therefore, relatively *low* electricity prices).

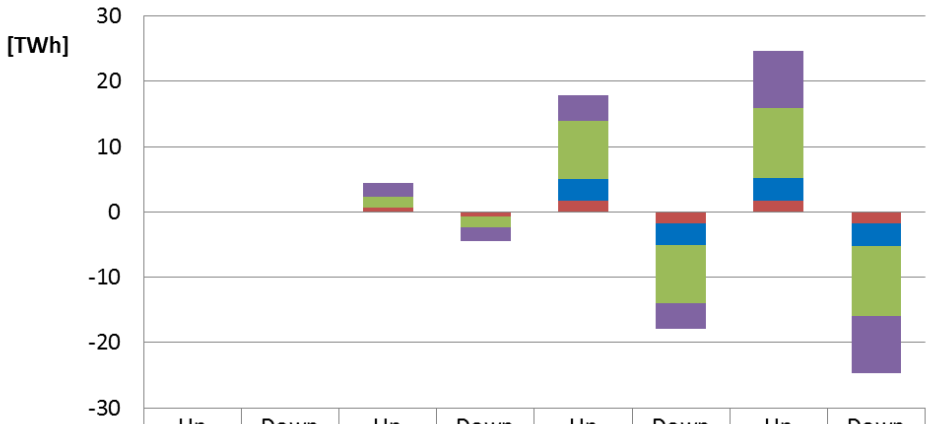
- The total annual flexibility – either upwards or downwards – offered by all demand-response technologies considered amounts to 1.8 TWh in A2050 and to 4.8 TWh in C2050. As a percentage of total annual flexibility needs due to the hourly variations of the residual load this corresponds to 12% and 32%, respectively (see **Figure 20** below).

Figure 15: Annual power load of selected demand-responsive technologies in selected FLEXNET scenario cases, 2030-2050



	R2030	A2030	A2050	C2050
P2G	0.0	3.9	51.8	51.8
P2H	0.0	13.3	14.7	14.7
P2A	0.0	7.6	8.5	8.5
EV	2.5	8.4	21.5	21.5

Figure 16: Total annual demand response per technology, either upwards or downwards, in selected scenario cases, 2030-2050



	Up	Down	Up	Down	Up	Down	Up	Down
	R2030		A2030		A2050		C2050	
P2G	0.0	0.0	2.0	-2.0	3.9	-3.9	8.7	-8.7
P2H	0.0	0.0	1.7	-1.7	8.9	-8.9	10.6	-10.6
P2A	0.0	0.0	0.0	0.0	3.2	-3.2	3.5	-3.5
EV	0.0	0.0	0.7	-0.7	1.8	-1.8	1.8	-1.8

Overall, there seems to be a large potential to meet future flexibility needs of the Dutch power system by means of demand response. This applies in particular to (industrial) power demand activities that are expected to grow rapidly in the coming decades such as power-to-gas, power-to-heat or power-to-ammonia, but also to power demand by means of more smart (flexible) charging of electric vehicles (as analysed above).

Moreover, there may be a large, additional potential for demand response by other power demand activities in other (household/service) sectors, although – to some extent – this potential may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. This potential has not been explored in the current study at the national level, but our analyses at the regional Liander network level show that there is a significant potential of demand response at the local (household) level by means of direct load control (DLC) and various pricing mechanisms (see Section 3.3 below).

Energy storage

In addition to the demand response technologies discussed above – of which some can, in principle, also be regarded as energy storage technologies (notably P2G and P2A) – the OPER model includes a wide variety of other, 'pure' electricity storage technologies such as compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and several types of batteries (conventional, sodium sulphur, lithium ion, flow batteries, etc.). As part of the FLEXNET project, OPERA has analysed the role of these storage technologies as a flexibility option to address the changes and variations of the (hourly) residual load of the Dutch power system in the FLEXNET scenario cases up to 2050.

A major finding of the FLEXNET-OPERA modelling analyses is that the role of 'pure' electricity storage technologies as a flexibility option to address hourly variations of the residual load of the Dutch power sector is low, i.e. nearly zero, up to 2030 and rather limited beyond 2030.More specifically, the major OPERA modelling results on energy storage include:

- The total charging-discharging activities, excluding storage losses, amount to almost 0.25 TWh in A2050 and 0.21 TWh in C2050, whereas the storage losses amount to 0.11 TWh and 0.09 TWh, respectively. All these activities result from one single technology only, i.e. CAES. As a percentage of residual load, these storage activities are generally rather limited, i.e. (far) less than 1%.

- The total annual supply of flexibility offered by energy storage (CAES) in order to meet the flexibility needs of the Dutch power system due to the hourly variation of the residual load in A2050 and C2050 amounts to approximately 0.1 TWh in both scenario cases, corresponding to less than 1% of total annual flexibility needs in these cases (see **Figure 20** below).

As the role of energy storage as a flexibility option turned out to be relatively limited (compared to previous expectations and to what is often suggested by other studies), we have conducted some sensitivity analyses by means of the OPERA model for the scenario case C2050 (which includes the largest part of domestic flexibility options).

In particular, we have reduced the annualised investment costs and the fixed operation and maintenance (O&M) costs of three storage technologies by a factor 10 in C2050, i.e. in the sensitivity runs these costs have been set at 10% of their original, baseline level. These three technologies include (i) compressed air energy storage (CAES), (ii) li-ion batteries, and (iii) superconducting magnetic energy storage (SMES).

The sensitivity analyses show that even in the case of fixed (O&M and investment) costs of the technologies considered have been reduced by 90%, their shares in (residual) power demand and flexibility supply remain relatively limited. For instance, the storage activities by these technologies offer flexibility to the power system by an amount varying between 0.15 TWh and 0.75 TWh per annum, i.e. approximately 1-5% of the annual flexibility needs due to the hourly variation of the residual load.

Explanation of the limited role of energy storage
Why is the role of energy storage in meeting future flexibility needs relatively limited (compared to what is generally expected or usually suggested in the literature), even if it is assumed that the cost of energy storage are reduced substantially (by a factor 10)?

The basic answer is rather simple, i.e. there is a large potential of other, alternative flexibility options that are (much) cheaper to meet these needs, in particular flexibility offered through options such as power trade and demand response, but also – notably in hours with a VRE surplus – by means of VRE curtailment. Besides their volume effect, these options reduce the business case of energy storage technologies through the related price effects in the sense that they reduce the volatility of the electricity price and, hence, reduce the price margin to cover the cost of offering flexibility. This applies particularly for 'pure' electricity storage technologies, such as CAES, SMES or batteries, which have to cover their costs primarily – or even solely – from the price margin earned by this single activity.

Some qualifications, however, may be added to the above observation. Firstly, there are some technologies that – besides their primary function(s) in a more sustainable, low-carbon energy system – can offer flexibility by means of an additional function (energy storage) at relatively low costs to the energy system in general and, to some extent, the power system in particular. This applies notably to energy conversion technologies such as power-to-gas (P2G) and power-to-ammonia (P2A). The power demand by these technologies is expected to grow rapidly in the coming decades as part of the transition to a more sustainable energy system, in particular to meet ambitious carbon reduction targets. As a result, these technologies become more necessary in the future energy system anyhow and, consequently, they can cover the main part of their costs by meeting these primary energy function(s). In addition, they may offer flexibility by means of energy storage functions to the energy system as a whole – and, in specific cases, to the power system as well – at relatively low marginal costs. The current study, however, indicates that the potential of the energy conversion technologies, such as P2G or P2A, to offer flexibility to the power system lies primarily in the option to provide demand response rather than electricity storage (as the costs of supplying electricity by means of these technologies are relatively high).

In addition, the above-mentioned qualification applies to some extent also for batteries of electric vehicles (EVs) that may be used to store electricity in order to discharge electricity to the power system again at a later stage. As the costs of this technology are covered predominantly by its primary functions (transport, comfort, etc.), the additional, marginal cost of offering flexibility through electricity storage by this technology are likely low while the benefits may be relatively high. Due to a variety of practical, techno-economic constraints, however, energy storage potential of EVs may be hard to realise while, on the other hand, the potential of this technology to provide flexibility to the power system by means of demand response – through smart charging – seems to be substantial (as analysed in the present study). Therefore, also for this technology the potential to offer flexibility to the power system may be more significant for the option of demand response rather than of energy storage.

A second qualification is that in the OPERA modelling analyses, i.e. in the current chapter, we have focussed our attention on exploring the role of energy storage as an option to meet flexibility needs due to the (hourly) variability of the residual load. Energy storage, however, may be an attractive option to meet other flexibility needs. Although the role and net benefits of energy (battery) storage to address network congestion seems to be limited – and even negative (see Section 3.3 below), energy storage may be an attractive, cost-effective option to address short-term power system balancing issues – e.g. due to the uncertainty ('forecast error') of VRE power generation – notably if this function can be combined with other, additional ('ancillary') services such as voltage support, frequency control or resilience/back up power (see below).

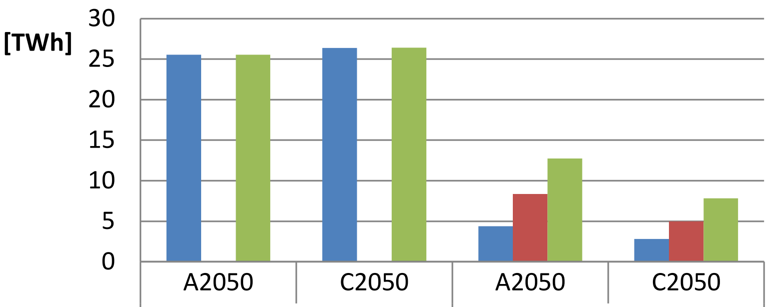
Finally, for geographical reasons hydro pumped storage (HPS) is not a cost-effective flexibility option in the Netherlands. In most EU28+ countries, however, HPS is a major, attractive flexibility options. Hence, as noted, indirectly the Netherland may benefit from HPS as a flexibility option at the EU28+ level through its power trade relations with neighbouring countries, including Norway, Germany and France.

Curtailment of VRE power generation
Comparing the role of VRE curtailment as a flexibility option in the OPERA versus COMPETES modelling results lead to the following major findings (**Figure 17**):

- Total VRE curtailment in OPERA is significantly lower in both A2050 and C2050 than in COMPETES. This is largely due to the fact that OPERA generates a large amount of upward demand response as a flexibility option – which reduces the need for VRE curtailment, notably in VRE surplus hours – whereas COMPETES does not include demand response as a potential flexibility option into the model and, hence, the contribution of (upward) demand response in offering flexibility – and, hence, in reducing the need for VRE curtailment – is consequently zero in COMPETES.

- In COMPETES the curtailment of power generation from sun PV is nearly zero, whereas in OPERA it is quite substantial (and even bigger than VRE curtailment from wind). This is due to different modelling assumptions regarding future network capacities, i.e. no domestic network restrictions – 'copper plate' – in COMPETES versus local (low-voltage) grid restrictions in particular hours (with high PV output) in OPERA.

Figure 17: Comparison of COMPETES versus OPERA modelling results on VRE curtailment in A2050 and C2050

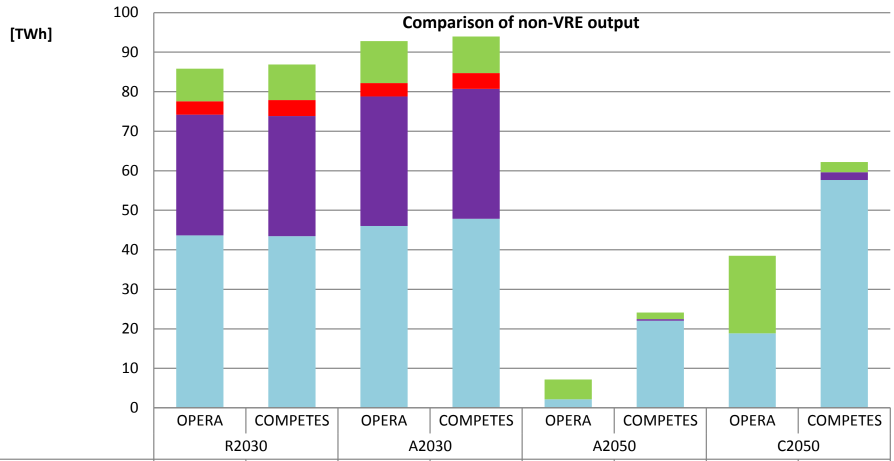


	COMPETES A2050	COMPETES C2050	OPERA A2050	OPERA C2050
Wind	25.5	26.4	4.4	2.8
Sun PV	0.0	0.1	8.3	5.0
Total	25.5	26.4	12.7	7.8

Non-VRE power generation
Comparing the role of power generation from non-VRE sources (coal, gas, nuclear, biomass, etc.) as a flexibility option in the OPERA versus COMPETES modelling results lead to the following major findings (**Figure 18**):

- Compared to OPERA, the non-VRE output level of COMPETES is much higher in both A2050 and C2050. Moreover, the output mix of COMPETES in these scenario cases is quite different in the sense that gas output is much higher whereas the output from other non-VRE sources is much lower than in OPERA, notably in C2050.

Figure 18: Comparison of OPERA versus COMPETES modelling results on non-VRE power mix in selected scenario cases, 2030-2050



	R2030		A2030		A2050		C2050	
	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES
Other non-VRE supply	8.2	9.0	10.6	9.2	5.0	1.7	19.6	2.6
Nuclear	3.4	4.0	3.4	4.0	0.0	0.0	0.0	0.0
Coal	30.6	30.4	32.8	32.9	0.0	0.4	0.0	1.9
Gas	43.6	43.5	46.0	47.8	2.2	22.1	18.9	57.7

- These differences in non-VRE output generation between the two models result in particular from the large amount of demand response in the OPERA modelling outcomes in the 2050 scenario cases, especially in C2050, whereas COMPETES does not include demand response as a flexibility option. As a result, the level of VRE curtailment is much lower in OPERA than in COMPETES, notably due to the upward demand response in hours with a major VRE surplus.

- Hence, in these hours – and over the year as a whole – more VRE output becomes available. In addition, due to the downward demand response – notably in hours with a large VRE shortage – less non-VRE output is needed in these hours and, therefore, over the year as a whole.

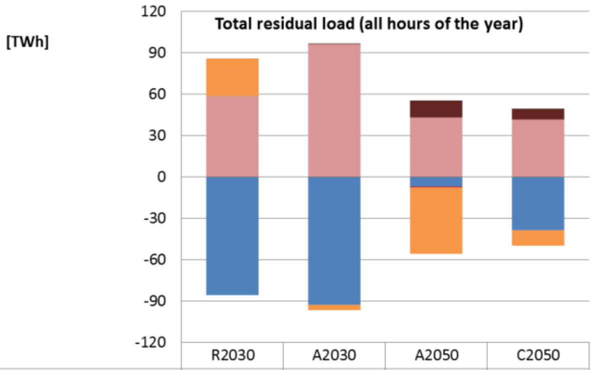
- Moreover, due to both the upward and downward demand response, the residual load duration curve becomes much flatter in OPERA than in COMPETES. As a result, there is less need for peak load installations (with relatively high variable costs) – such as gas-fired plants – and more need for mid or base load units (with relatively high investment costs), such as biomass, waste or geothermal installations.

Net residual power balances

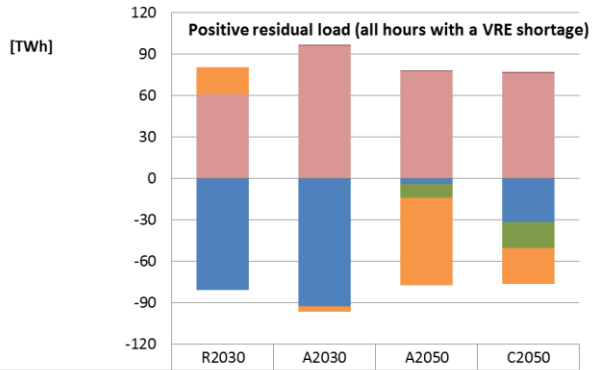
Figure 19 presents the net residual power balances in some selected scenario cases over the years 2030-2050, including a distinction between all hours over the year with a positive residual load (VRE shortage) and all hours with a negative residual load (VRE surplus), according to the OPERA modelling results. This figure resembles a similar set of graphs above, i.e. **Figure 9**, which presents similar net residual power balances for all FLEXNET scenario cases according to the COMPETES modelling results.

Overall, the differences in the net residual power balances of **Figure 9** (COMPETES) and **Figure 19** (OPERA) are generally small for the respective 2030 scenario cases. In the 2050 scenario cases, however, the differences between the two models are quite substantial. As outlined above, these differences are primarily due to the fact that the

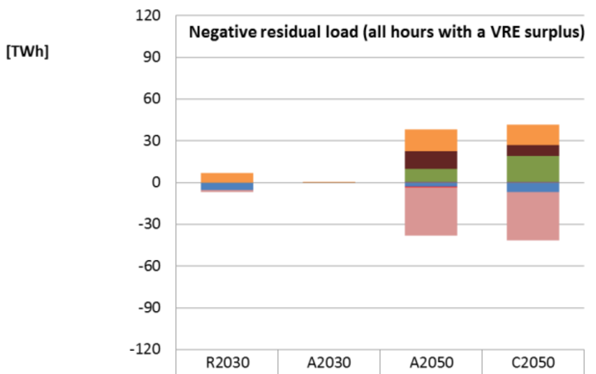
Figure 19: Net residual power balances in some selected scenario cases, 2030-2050, including a distinction between hours with a positive residual load (VRE shortage) and a negative residual load (VRE surplus), according to the OPERA modelling results



	R2030	A2030	A2050	C2050
Net exports	26.7	-3.6	-48.2	-11.0
VRE curtailment	0.1	0.1	12.7	7.8
Residual load (uncurtailed)	59.0	96.4	42.5	41.6
Demand response - total	0.0	0.0	0.0	0.0
Storage - charge (incl. losses)	0.0	0.0	0.4	0.3
Storage - discharge	0.0	0.0	-0.2	-0.2
Non-VRE supply	-85.8	-92.8	-7.2	-38.5

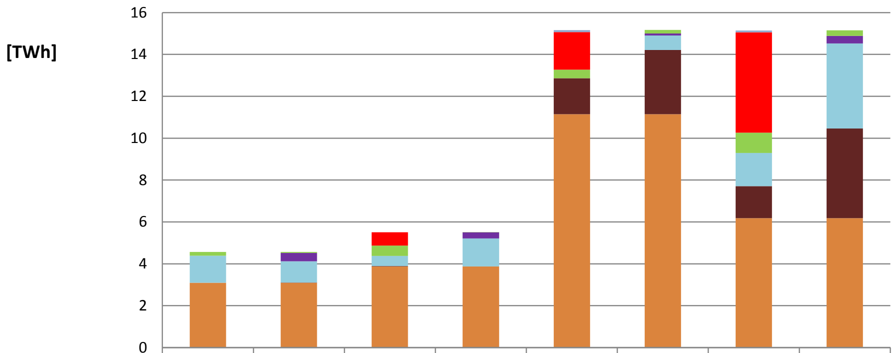


	R2030	A2030	A2050	C2050
Net exports	19.8	-3.8	-63.8	-26.0
VRE curtailment	0.1	0.0	0.0	0.0
Residual load (uncurtailed)	60.7	96.4	77.4	76.4
Demand response - total	0.0	0.0	-9.5	-18.6
Storage - charge (incl. losses)	0.0	0.0	0.1	0.0
Storage - discharge	0.0	0.0	-0.1	-0.1
Non-VRE supply	-80.5	-92.6	-4.1	-31.7

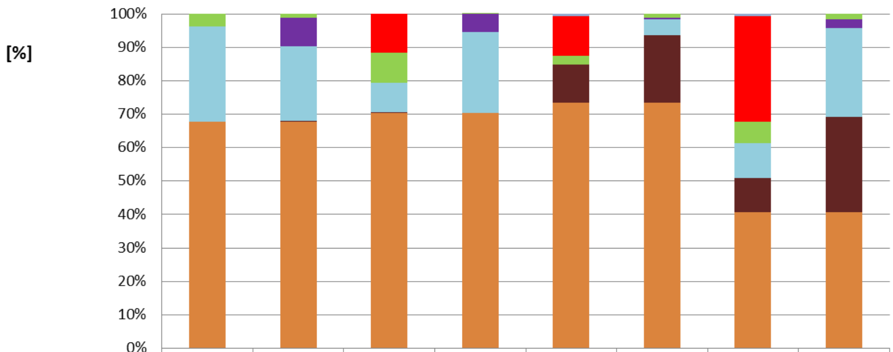


	R2030	A2030	A2050	C2050
Net exports	6.9	0.2	15.7	15.0
VRE curtailment	0.0	0.0	12.7	7.8
Residual load (uncurtailed)	-1.7	0.0	-34.9	-34.8
Demand response - total	0.0	0.0	9.5	18.6
Storage - charge (incl. losses)	0.0	0.0	0.3	0.3
Storage - discharge	0.0	0.0	-0.1	-0.1
Non-VRE supply	-5.3	-0.2	-3.1	-6.7

Figure 20: Comparison of OPERA versus COMPETES modelling results on the total annual supply of upward flexibility options to meet total annual demand of upward flexibility due to the hourly variations ('ramps') of the residual load in selected scenario cases, 2030-2050



	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES
	R2030		A2030		A2050		C2050	
Storage	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0
Total demand response	0.0	0.0	0.6	0.0	1.8	0.0	4.8	0.0
Other non-VRE supply	0.2	0.0	0.5	0.0	0.4	0.2	1.0	0.3
Coal	0.0	0.4	0.0	0.3	0.0	0.1	0.0	0.4
Gas	1.3	1.0	0.5	1.3	0.0	0.7	1.6	4.1
VRE curtailment	0.0	0.0	0.0	0.0	1.7	3.1	1.5	4.3
Net imports	3.1	3.1	3.9	3.9	11.1	11.1	6.2	6.2



	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES
	R2030		A2030		A2050		C2050	
Storage	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.6%	0.0%
Total demand response	0.0%	0.0%	11.5%	0.0%	11.8%	0.0%	31.7%	0.0%
Other non-VRE supply	3.8%	1.1%	9.1%	0.0%	2.7%	1.1%	6.4%	1.7%
Coal	0.0%	8.6%	0.0%	5.4%	0.0%	0.6%	0.0%	2.4%
Gas	28.4%	22.3%	8.7%	24.2%	0.0%	4.6%	10.4%	26.8%
VRE curtailment	0.0%	0.3%	0.3%	0.0%	11.3%	20.2%	10.1%	28.3%
Net imports	67.8%	67.8%	70.4%	70.4%	73.6%	73.5%	40.8%	40.8%

OPERA modelling results include a large amount of (upward and downward) demand response, whereas this flexibility option is not covered by COMPETES. As a result, VRE curtailment is much lower in OPERA than in COMPETES – notably in hours with a VRE surplus and an upward demand response – while non-VRE output is also much lower in OPERA than in COMPETES, in particular in hours with a VRE shortage and a downward demand response.

Flexibility options to meet hourly variations of the residual load
Finally, **Figure 20** presents a comparison between the (corrected) OPERA and COMPETES modelling results with regard to the total annual supply of upward flexibility options due to the hourly variations of the residual load of the Dutch power system in

four selected scenario cases over the years 2030-2050.[2] Similar to the comparison of the modelling results on VRE curtailment and non-VRE power generation in the sections above, it shows that the differences in modelling outcomes are generally relatively small in the 2030 scenario cases, notably in R2030.

On the other hand, in the 2050 scenario cases – and particularly in C2050 – the differences in domestic flexibility options are quite substantial. For instance, in C2050 the flexibility offered by means of the hourly variations in total demand response amounts to 4.8 TWh in the OPERA modelling results, corresponding to almost 32% of total annual flexibility demand/supply – and being the most dominant 'domestic' flexibility option in C2050 – whereas it amounts to zero in the COMPETES modelling results (as this option is not covered by this model).

In addition, **Figure 20** shows that in C2050 the flexibility offered by (hourly variations in) VRE curtailment and gas-fired power generation are significantly lower in the OPERA modelling results than in the COMPETES modelling outcomes (due to the difference in modelling results on demand response mentioned above). For instance, in C2050 the share of VRE curtailment in total annual flexibility supply amounts to 10% in the OPERA results and to 28% in the COMPETES outcomes. For gas-fired power generation, these figures amount to 10% and 27%, respectively (see the last two columns in the lower part of **Figure 20**).

3.2.1 Options to meet the demand for flexibility due to the uncertainty of the residual power load

In addition to the need for flexibility due to the variability of the residual load (expressed on the day-ahead market), there is also the demand for flexibility resulting from the uncertainty of the residual load, in particular due to the forecast error of VRE power generation (expressed on the intraday/balancing market). Due to modelling, time and budget constraints we have not been able to model and analyse quantitatively the options to meet the demand for flexibility due to the uncertainty of the residual load up to 2050 as part of the present study. Rather we have reviewed a previous ECN study on flexibility on the intraday/-balancing market as well as some other recent, medium-term studies (usually up to 2023) that have considered potential options to meet flexibility needs resulting from the uncertainty of the residual power load in general and the wind forecast error in particular. Some of the major findings of these studies include:

- The total annual demand for upward flexibility on the intraday/balancing market is estimated to increase from 0.6 TWh in 2012 to 3.2 TWh is 2023. Most of (the increase in) this demand by 2023 can be met by incumbent, conventional generators (gas, coal) but there is also some room (0.8 TWh) – and even a business case – for new entrants such as conventional generators (notably CCGTs) or storage, in particular compressed air energy storage (CAES; see Koutstaal et al., 2014 as well as Özdemir et al., 2015).

[2] The OPERA results have been corrected for the so-called 'time slice effect' as explained in Section 3.7 of the FLEXNET phase 2 report. Note that **Figure 20** shows only a comparison of the *upward* flexibility demand/supply as the downward flexibility demand/supply levels are exactly similar to the upward levels.

- Under the condition that the comfort of living should remain equal, only a limited number of devices in households are suitable for balancing purposes, including in particular freezers, refrigerators, electric water heaters, heat pumps and air conditioners. The potential of these devices for both up and down balancing, however, was found to be relatively large, i.e. there is 100 MW of down regulation and 200 MW up regulation available in the Netherlands while the current (2013) absolute imbalance is around 110 MW (Bal, 2013).

- Realising the household balancing potential by means of demand response would result in a decrease in imbalance costs of approximately € 30 million annually. This is, on average, € 40 per household annually, which provides a relatively low incentive for the implementation of smart household appliances for balancing purposes. Moreover, the balancing market – which was expected to increase due to increased imbalance resulting from growing VRE generation shares – will likely decrease in the next years because a large part of total imbalance will be settled within the International Grid Control Cooperation (IGCC) between Germany, the Netherlands and some other north-western European countries (or by other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area). This provides a lower incentive to realise the household balancing potential by means of demand response. Finally, this potential may also be harder to realise due to the competition by other, alternative balancing options such as providing balancing services through energy storage or by VRE generators themselves, which increasingly are technically well suited for being ramped down quickly – when generating electricity – or even to ramp up, when producing below potential output such that some VRE generation is constantly curtailed. (Bal, 2013; Hirth and Ziegenhagen, 2015).

- The development of the balancing market up to 2030 is highly uncertain. Compared to the day-ahead/intraday markets, imbalance prices show wider fluctuations – with peak prices running up to 600 €/MWh – although they occur less often. Moreover, the volume of the balancing market is limited, implying that energy storage will meet swiftly competition from other flexibility/balancing options (Berenschot, et al., 2015).

- Due to the higher price differences and the number of peak prices per day, the perspectives for some storage technologies are better on the Dutch balancing market than on the Dutch spot market (where variations in electricity prices are not sufficient in 2030 to make longer-term storage attractive). Current regulation, however, may be a potential barrier for storage activities on the balancing market (Berenschot, et al., 2015).

- With regard to the market for regulation and reserve power, it is noticed in (international) practice that – besides conventional generators – also energy storage is deployed for offering services on this market, notably by technologies such as flywheels and li-ion batteries that meet the required specifications for these services. Economic analysis shows that with the current price levels and costs for some technologies (flywheels), there is a positive business case for offering primary reserve services. In addition, market consultations show that commercial parties are interested to become active with li-ion batteries in this field (Berenschot, et al., 2015).

- In general, the available capacity for upward and downward balancing seems to be sufficient to meet balancing needs up to 2023. It should be realised, however, that the balancing needs to correct VRE forecast errors are usually highest during situations of high VRE output levels. During these situations, the availability of conventional options to meet these needs – i.e. gas-fired spinning reserves – will become under increasing pressure. This likely creates the need for the availability of other options such as storage or demand response (CE Delft, 2016).

- The business case of a windmill and energy storage for balancing purposes can be positive if some conditions are met, notably if a certain size of the storage is met – for instance, a cooperative storage system that connects several smaller windmills – and if it is used for several purposes, including (i) avoiding imbalance and, hence, avoiding the imbalance costs that windmill owners have to pay, (ii) trading on the balancing market by providing secondary reserve power, and (iii) using part of the electricity from storage for own consumption and, hence, reducing grid connection costs (DNV GL, 2017).

Overall, it can be concluded that in the coming years the increasing demand for flexibility on the intraday/balancing market due to the increasing share of VRE power generation – and, hence, the increasing uncertainty (forecast error) of the residual load – can be met by incumbent, conventional generators (notably gas) as well as by new entrants, including flexible conventional gas units (particularly CCGTs) but also new, additional flexibility options such as storage, demand response or providing balancing services by VRE generators themselves.

The perspectives of the balancing market in the Netherlands, however, are rather uncertain. In particular, the market for activated control power may grow slowly – or even decline – because a major part of total imbalance may be settled by means of the International Grid Control Cooperation (IGCC) or by other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area.

Moreover, it should be realised that most of the studies reviewed cover only a short to medium term period (e.g., up to 2023) and consider usually a single option to address the demand for flexibility on the intraday/balancing market resulting from the forecast error of VRE power production rather than to determine the optimal mix of a set of supply options in the long run. Therefore, it is hard to say which mix and size of supply options will meet the demand for flexibility on the intraday/balancing market due to the uncertainty of the residual load in either the medium or long run.

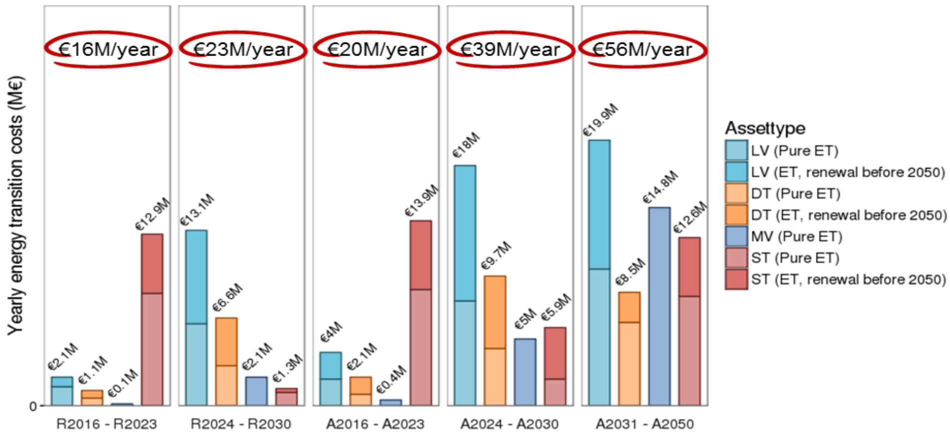
3.3 Major results at the regional Liander network distribution level

3.3.1 Options to meet the demand for flexibility due to the congestion of the power grid

The Liander regional grid analysis has assessed the potential benefits of addressing predicted grid congestion by deploying flexibility options rather than by network expansions. The major findings of this assessment are summarised below.

Benefits of deployment of flexibility as alternative for grid reinforcements
Based on the results of the ANDES model and the FLEXNET scenario cases, it is estimated that additional investments in grid reinforcements of 2 to 5% per year up to 2030 and about 7% per year in the period from 2030 to 2050 are required to prevent overloads in the Liander grid due to the increased deployment of sun PV, electric passenger vehicles (EVs) and household heat pumps (HPs). Given current annual grid investments in the Liander service area of, on average, € 750 million in 2012-2016, this corresponds to a cumulative grid reinforcement investment of € 1.0-1.5 billion up to 2050 (alternative scenario; see **Figure 21**).

Figure 21: Increase of average network investments due to the energy transition (phase 1 results)



In order to limit the required additional grid investments, a number of promising, flexibility-based overload mitigation measures is selected and assessed. In particular, five different types of *demand response* measures to mitigate grid overloads (congestion) have been analysed:

1. *Direct Load control (DLC)* i.e. energy management of EV and HP (e.g. smart charging) through a third party (e.g. the network operator or aggregator).
2. *Critical Peak Pricing (CPP)*. During high wholesale market prices or power system emergency conditions, the price for electricity is substantially raised for a specified time period.

3. *Time of Use Pricing (TOU)*. Typically this measure applies to usage over broad blocks of hours where the price for each period is predetermined and constant.
4. *Real Time Pricing (RTP)*. Pricing rates generally apply to usage on an hourly basis.
5. *Critical Peak Rebate (CPR)*. Similar to CPP, the price for electricity during these time periods remains the same but the customer is refunded at a predetermined value for any reduction in consumption.

In addition to demand response, other flexibility options analysed as the regional level to mitigate grid overloads include VRE curtailment – notably decentralised PV curtailment – and energy storage, in particular by means of (lithium ion) batteries at the household level or the distribution transformer (DT) level.

Grid overloads can be addresses by either flexibility-based mitigation measures or grid reinforcements (or a mix of both options). Overload mitigation measures can substantially reduce the capital expenditures (CAPEX) i.e. investments in grid reinforcements. In terms of CAPEX reduction, it is estimated that PV curtailment (assuming a 30% peak reduction in PV production) or time-of-use (TOU) pricing (assuming a 16% peak demand reduction) alone can save up to about € 250 million (cumulative) in energy transition related grid investments up to 2050 (in the alternative scenario). A combination of curtailment and TOU pricing can save up to € 700 million of these types of grid investments up to 2050 (see **Figure 22**). This € 700 million is an indication of the value of flexibility for network investment planning by Liander.

The effectiveness of PV curtailment versus demand response depends on the adoption levels of sun PV versus EVs and HPs. In the reference scenario (up to 2030), PV curtailment is more effective in reducing reinforcement costs than demand response, due to the fact that in this specific scenario, PV production creates more congestion problems than the adoption of EV and HP. The alternative scenario shows that the higher adoption of EV and HP increases the effectiveness of demand response significantly.

Net benefits of deployment of flexibility as alternative for grid reinforcements

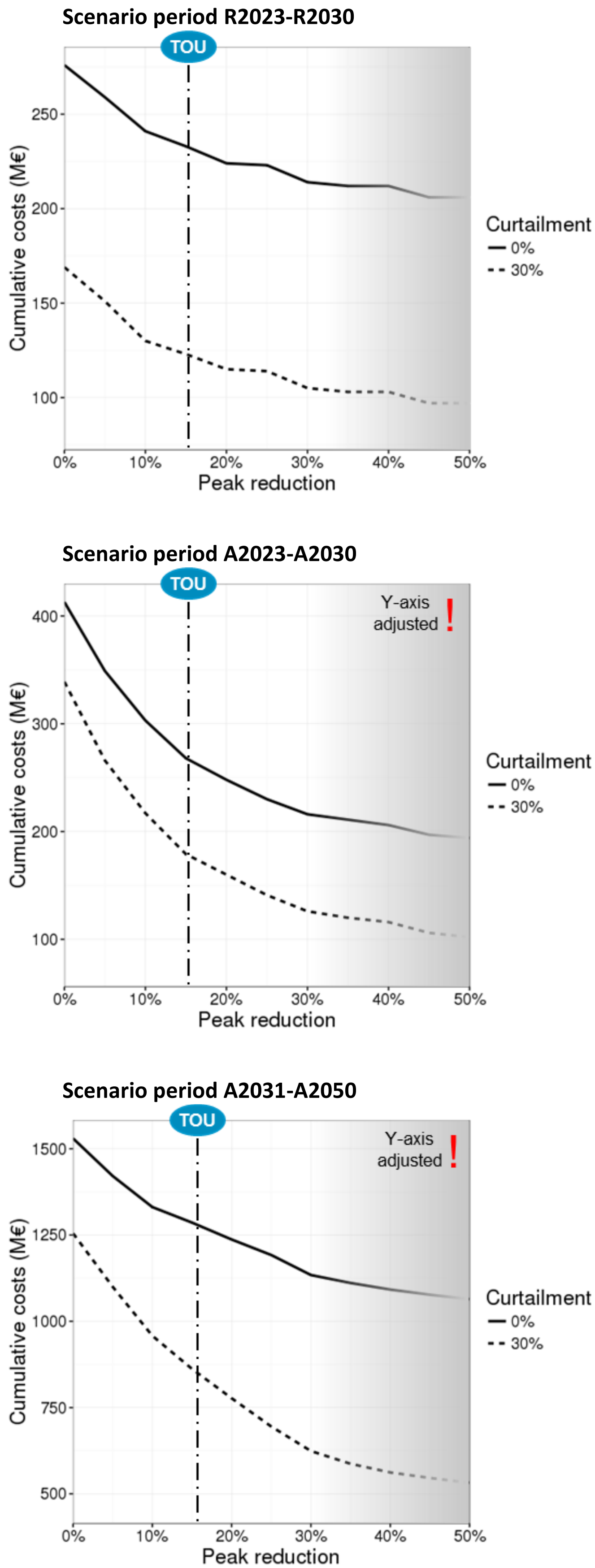
The numbers provided above do not yet include additional costs required to implement and operate each of the selected mitigation measures. The net benefits of deployment of flexibility as an alternative for grid reinforcements are therefore significantly lower. Given estimates for additional costs, net benefits for PV curtailment, direct load control, and pricing mechanisms have been determined, as discussed below.

PV curtailment

The benefits of PV curtailment consist of an estimated 20% avoided ET grid reinforcement investments for the A2050 case i.e. € 300 million, but when taking into account the cost of 30% PV curtailment in terms of lost revenue, the net benefit is about half of this amount i.e. € 150 million.

The lost revenue on the wholesale market is calculated by estimating the lost energy in the A2050 scenario and multiplying this amount by the corresponding hourly APX price. Subsequently, the total lost revenue up to 2050 is obtained by linear interpolation between scenario cases. Similar to other overload mitigation measures, these amounts do not take into account additional grid losses as a result of deferred or avoided investments (which are estimated at € 55 million in A2050).

Figure 22: Reduction of cumulative grid investment costs during different scenario periods



Direct load control

Direct load control (DLC) can potentially avoid 13-30% of grid reinforcement investments in the alternative scenario i.e. € 200 million alone and € 450 million when combined with PV curtailment respectively. Assuming a linear development in cost (rough estimation), the total costs of implementation and operation will be about € 70 million without PV curtailment and about € 150 million with PV curtailment for the A2050 scenario. The net result of DLC would be about € 130 million without curtailment and about € 300 million with curtailment (including lost PV revenue) up to 2050 for the Liander service area at most. This is, on average, around 1% per year of the total grid investments in the Liander service area up to 2050.

These costs figures do not include a possible penalty for DSOs for not meeting contractual capacity (kW) agreements as well as costs of additional grid losses. Furthermore, the assumption is made that no additional investments are required in grid digitization/measurements besides the smart meter. On the other hand, since restoring power after an outage in a region with a high adoption of HPs and/or EVs can lead to high currents and overloads, investments in DLC might already be made for power restoration reasons, decreasing required DLC investments for congestion management purposes.

Pricing mechanisms

Pricing mechanisms (CPP, TOU, RTP, CPR) alone can potentially avoid up to 18% of grid reinforcement investments in the alternative scenario, while the combination with PV curtailment may result in savings of 48% of grid reinforcement investments. In absolute terms this amounts to € 275 million and € 725 million, respectively. For several reasons, however, the net savings of pricing mechanisms are likely to be smaller.

First of all, research shows that the percentage of peak reductions used in this analysis can only be achieved if local devices such as, for instance, washing machines can be automatically controlled. This requires investments from either consumers in home automation or from market participants in an IT platform, which controls devices in a certain area. Although part of the cost may be attributed to deployment of flexibility for portfolio optimization and balancing purposes, assuming pricing mechanisms do not levy any costs on deployment of flexibility for congestion management is a strong assumption.

Furthermore, the grid operator should have sufficient insight in the (near) real-time load in the controlled area to effectively use pricing mechanisms for congestion management. Smart metering may fulfil this requirement, although additional investments in grid digitization or measurements might be required.

In addition, grid losses which are expected to be higher for pricing mechanisms compared to grid reinforcement, have not been taken into account. According to Liander estimates, these grid losses may result in additional operational costs of € 55 million per year in the A2050 scenario.

Besides, the unpredictable behaviour of customers makes it unlikely that the indicated net benefits can be achieved in practice as grid operators will need some security margin in their grid design. Especially at the lower grid levels, the number of controlled devices will be limited and the risk of relying on pricing mechanisms to prevent overloads for DSOs is higher.

Considering the above, the net result of pricing mechanisms is estimated to be less than 1% per year of the total grid investments in the Liander service area.

Energy storage (batteries)
For energy storage, the benefits of the use of a battery system for mitigating overloads do not outweigh the costs. Relatively large battery capacities are required to mitigate overloads of distribution transformers (DTs). Given (i) the accompanying cost of a battery system, (ii) the required operational expenditures (OPEX), (iii) the additional energy losses, and (iv) the added complexity and, therefore, the higher operational risks, it is safe to assume that the use of a battery system at the distribution transformer (DT) level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

Overall conclusions
In contrast with some earlier studies and expectations beforehand, based upon a comprehensive quantitative analysis the current study shows limited net benefits of deployment of flexibility solutions by DSO Liander in order to prevent traditional grid reinforcements. However, a rough comparison of the ANDES modelling results of Liander with modelling outcomes of DSO Stedin indicates more overloads in 2050 in the Stedin service area and, therefore, a higher demand for flexibility in this area. This difference in regional outcomes is partially due to differences in regional network topology, differences in input assumptions, notably on the allocation of technology adoption rates to grid levels, as well as to differences in regional/local load profiles.

Given the Liander analysis, some policy recommendations can be inferred. DSOs should be cautious in claiming flexibility for congestion management purposes as, *in general*, the scope and benefits of deploying flexibility for congestion management seems to be limited. Moreover, flexibility could have a higher value for purposes such as portfolio optimization or system balancing. Flexibility providers should be aware that generally flexibility has relatively a limited scope and limited net benefits for DSOs, implying no large payments for flexibility can be expected from network operators.

At the same time it should be noted that in *specific* (local) situations deploying flexibility for congestion management may offer a significant potential and relatively high net benefits for DSOs, resulting in a concomitant high value of flexibility and associated benefits for flexibility providers. In which type of situations and how frequently these situations could occur is a subject for further research.[3]

[3] See also the report of phase 3 of the FLEXNET project, focusing on the development of a societal framework for the trade-off between grid reinforcement versus deployment of flexibility for congestion management.

3.4 Key messages

3.4.1 National level

Cross-border trade becomes dominant flexibility option in future years but its size depends on available interconnection capacity as well as on the available potential and costs of alternative, domestic flexibility options.

In order to meet the rapidly growing demand for flexibility due to the variability of the residual load of the power system in the Netherlands up to 2050, cross-border power trade becomes the most important flexibility option in the coming years (decades), with shares ranging for this option from 65% to 74% of total annual flexibility needs in the period 2023-2050. As a result, power trade has a major impact on the business case of other, domestic options to meet the demand for flexibility by the Dutch power system, including the impact of (hourly variations in) power trade volumes and the related hourly fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly (depending on the available potential and costs of these options). This impact, however, depends in particular on the assumptions made with regard to the optimal interconnection capacities across European countries, notably between the Netherlands and its neighbouring countries. However, even under more (very) restrictive interconnection assumptions, however, the share of power trade in total annual flexibility demand still amounts to approximately 40-65% in 2050.

Non-VRE power generation becomes less important to meet future flexibility needs but gas-fired units may remain import as back-up capacity

In the current situation (scenario R2015), power generation from conventional, non-VRE sources is the most dominant flexibility option to meet total annual flexibility needs due to the variability of the residual load of the Dutch power system (estimated at 2.2 TWh, aggregated per annum), in particular by (hourly changes in) power generation from gas (49%) and coal (42%), while the remaining share of these needs is addressed by (hourly variations) in power trade (9%). In the coming years (decades), however, the shares of these conventional power generation sources in the (rapidly growing) demand for flexibility declines steeply. Already in 2023, the share of gas falls to about 30% and of coal even to 5% (while the share of power trade increases to 65%). Under 'optimal' (i.e. 'least-cost') interconnection conditions, the share of gas in total annual flexibility needs in 2050 (estimated at about 15 TWh, aggregated per annum) declines further to less than 5% and of coal to less than 1% (while the share of power trade rises to 74%). Under very restrictive interconnection conditions, however, the share of gas becomes about 27% in 2050 and of coal some 2.4% (while the share of power trade becomes approximately 41%).

Curtailment of VRE power generation becomes a major flexibility option only far beyond 2030 depending to the availability of alternative options (in particular power trade and demand response)

Up to 2030, there is hardly or no curtailment of power generation from VRE sources (sun/wind) needed to balance (hourly) power demand and supply as the share of VRE output in total power demand is still manageable in almost all hours of the year. In

2050, however, - with a large share of potential VRE output in total power demand (80%) and a large number of hours (>3200) with a (large) VRE surplus – VRE curtailment becomes a major flexibility option. In that year, total VRE curtailment is estimated at about 26 TWh per annum, i.e. approximately 16-17% of total realised VRE power production. Under optimal (least-cost) interconnection conditions, the share of (hourly variations in) VRE curtailment in total annual flexibility needs due to the variability of the residual load amounts to some 20%, while under very restrictive interconnection conditions this share increases to approximately 28%.

Demand response has a large potential to meet future flexibility needs, but the role of demand curtailment is negligible
In general, there seems to a large potential to meet future flexibility needs of the Dutch power system by means of demand response, i.e. *shifting* part of (peak) power demand in a certain hour to another hour of the day, week, month, etc., either forwards or backwards. This applies in particular to (industrial) power demand functions that are expected to grow rapidly in the coming decades, such as power-to-gas (P2G), power-to-heat (P2H) or power-to-ammonia (P2A) but also to power demand by means of more smart (flexible) charging of electric vehicles (as all explored in the current study). In addition, there may be a substantial potential for demand response by other power demand functions in other sectors such as services or households (as explored at the regional network level; see below). This potential, however, may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. On the other hand, the role of *demand curtailment* – i.e. *limiting* (peak) power demand in a certain hour (and, hence, demand is lost) – as a flexibility option is negligible, at least in the present study in which the value of lost load (VOLL) is set at a relatively high level of 3000 €/MWh.

Energy storage plays generally a limited role in meeting future flexibility needs of the power system (due to its relatively high costs) but in specific cases it may be more significant
The role of energy storage is generally limited to meet future flexibility needs (or at least generally less than what is sometimes expected or suggested in the literature). This applies in particular to longer-term, single ('pure') storage functions to address flexibility needs due to the variability of the residual load on the day-ahead market or, at the regional grid level, to using battery systems purely for congestion management reasons (see also below). The main reason is that the costs of these storage functions are generally high compared to alternative, amply available options such as power trade, demand response, VRE curtailment or – at the regional network level – grid reinforcement.

In specific cases, however, the role of energy storage to meet flexibility needs may be more significant. This applies, for instance, notably for providing short-cycle storage functions to meet flexibility/balancing needs due to the uncertainty ('forecast error') of the residual load on the intraday and balancing markets, in particular to provide primary/secondary power reserves (although on these markets storage also has to compete with alternative options while power reserve markets are usually relatively small, illiquid and/or uncertain).

In addition, energy storage becomes more attractive (profitable) if it is not the only – or primary – function of a technology and could be combined with providing other (more important) functions so that its costs can be shared or even covered primarily by these other functions and its benefits and revenues are broader and higher. Examples may include storage options such as power-to-gas (aimed primarily at reducing CO_2 emissions) or using EV batteries for storage functions (although the potential of these options to provide flexibility to the power system is likely higher through demand response than by energy storage).

3.4.2 Regional grid level

The net benefits of deploying large-scale flexibility options purely for congestion management in the Liander area are, *in general*, limited
In order to prevent overloads (congestion) in the Liander grid due to the increased deployment of sun PV, electric passenger vehicles (EVs) and household heat pumps (HPs) – as laid down in the FLEXNET scenario cases – *additional* investments in grid reinforcements are required of 2 to 5% per year up to 2030 and about 7% per year in the period from 2030 to 2050. Given current annual grid investments in the Liander service area of, on average, € 750 million in 2012-2016, this corresponds to a cumulative grid reinforcement investment of € 1.0-1.5 billion up to 2050 scenario.

In terms of capital investment savings (CAPEX), it is estimated that a mix of flexibility-based measures to mitigate grid overloads – notably deploying PV curtailment and demand response pricing mechanisms – can save up to about € 700 million (cumulative) in energy transition related grid investments up to 2050. This amount of € 700 million is an indication of the value of flexibility for network investment planning by Liander.

The amount of € 700 million mentioned above, however, does not yet include additional costs required to implement and operate the flexibility-based measures to mitigate grid overloads, such as lost PV revenues, additional grid losses, additional smart metering costs, higher risks, etc. Hence, the net benefits of deploying flexibility as an alternative for grid reinforcements are significantly lower. Moreover, flexibility could have a higher value for purposes such as portfolio and investment planning optimization or system balancing. Flexibility providers should be aware that generally flexibility has relatively a limited scope and limited net benefits for DSOs, implying no large payments for flexibility can be expected from network operators. Therefore, distribution systems operators (DSOs) should be cautious in claiming flexibility for congestion management purposes as, *in general*, the scope and benefits of deploying flexibility for congestion management seems to be limited.

It should be noted that the results have been calculated based on the current perspective on the future. Because of the many variables and assumptions, the rapid changing context and ever increasing complexity, modelling should become an integrated part of strategic decision making of the distribution system operators. This will enable a DSO to rapidly adjust their strategy based on the latest insights. In *specific* situations, however, deploying flexibility may offer a significant potential with a relatively high value and is therefore an important capability for any DSO

In specific situation (e.g., locally and/or temporarily), the deployment of flexibility measures to prevent or mitigate grid overloads – and, hence, to avoid or reduce investment costs in grid reinforcements – may offer a significant potential and relatively high value for DSOs, resulting in a concomitant high value of flexibility and associated benefits for flexibility providers. Other applications and opportunities besides congestion management which could be a reason for a DSO to deploy flexibility options include among others: local voltage support, system balancing, synergies groundwork with other infrastructural companies, black-out recovery. Moreover, a rough comparison of the Liander modelling results with modelling outcomes of DSO Stedin indicates more overloads in the Stedin service area and, therefore, a higher demand for flexibility in this area and, perhaps, a higher value (net benefits) of deploying flexibility as an alternative for grid reinforcements.

Energy storage: benefits of using battery system purely for congestion management do not outweigh costs

For energy storage at the regional grid level, the benefits of the use of a battery system for mitigating overloads do not outweigh the costs. Relatively large battery capacities are required to mitigate overloads of distribution transformers (DTs). Given (i) the accompanying cost of a battery system, (ii) the required operational expenditures (OPEX), (iii) the additional energy losses, and (iv) the added complexity and, therefore, the higher operational risks, it is safe to assume that the use of a battery system at the distribution transformer (DT) level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

4

Societal framework to trade-off grid reinforcement and deployment of flexibility

This chapter provides a summary of the main findings and key messages of the third phase of the FLEXNET project. This phase is focussed on elaborating a societal framework for the trade-off between grid reinforcement and deployment of flexibility options for congestion management at the regional network level. The main purpose of this framework is to be used in follow-up studies, notably in cost-benefit analyses, in order to address the question in which situation the deployment of flexibility is a better, more attractive option from a societal perspective than reinforcement of the grid.

4.1 Main findings

Societal framework essential
Phase 3 of the FLEXNET project has developed a societal framework to trade-off grid reinforcement versus deployment of flexibility options. A societal framework is essential due to the effects of such decisions on generators, consumers, network operators and other social actors. For example, the framework will influence generators' ability to sell electricity and deploy flexibility. The design of the framework will also have an impact on the network costs that are passed on to consumers through the network tariffs. Moreover, a measure that obliges market participants to include a location component in their tenders will influence the business models of the balancing responsible parties. The report reveals that the concept of the social cost-benefit analysis can be applied to structure decision-making, identify likely solutions and determine which empirical information will be required later in the decision-making process. This could help to achieve social consensus on an appropriate analysis framework before policy measures are assessed for their usefulness and necessity by

quantifying and monetising them. The focus lies mainly on the distribution networks, since flexibility can already be deployed in transmission networks.

Indices CBA or indicative CBA preferred
Various analysis methods can be used for such a societal framework, including various types of CBAs (cost-benefit analyses) such as social CBAs, indices CBAs and indicative CBAs. A flow diagram is available to decide which analysis method is most suitable. Depending on the size of the grid expansion investments that can be temporarily or permanently avoided through the deployment of flexibility as well as the amount of available information to determine effects, the report shows that an indices or indicative CBA would be most appropriate. To reduce the analysis load, it is recommended to analyse only entire investment portfolios, because little can be learned from analysing various small and unrelated investments. Nor is it worthwhile subjecting investments that have little promise to an indices or indicative CBA. Investments should be filtered by technical and economic boundary conditions before they are subjected to one of these analyses. These conditions could include the presence of electricity distribution and control equipment (or the option to install these in the short term) and the presence of sufficient potential providers of significant amounts of flexibility.

Example of the application of the CBA for deployment of flexibility for network management
In view of the aforementioned preference, the following steps in a CBA can be applied when deciding between grid expansion investments and deployment of flexibility:

Step 1 of every CBA is the problem analysis. A bottleneck occurs when there are multiple situations of infrequent/non-structural congestion for which grid reinforcement is not an effective solution (in the short term). At the same time, there are technical, legal and economic limitations to the deployment of flexibility. The policy issue under investigation is the most effective trade-off between grid expansion investments and the purchase of flexibility. This issue will have the greatest effect on the policy objectives of affordability and reliability.

Step 2 describes the baseline alternatives. The baseline alternatives offer little policy leeway, i.e. it is not possible to deploy flexibility options as an alternative to grid reinforcement. The necessity of analysing multiple realistic scenarios with different transmission demands means there are various baseline alternatives. We have established 2030 and 2050 as our time horizons. The 2030 horizon is useful for assessing whether policy alternatives will achieve results in the foreseeable future, while the 2050 horizon indicates the robustness of the investments and hence the value of the deployment of flexibility.

Step 3 describes the policy alternatives. To ensure affordability, the deployment of flexibility could be achieved by requiring DSOs to apply market restrictions, by applying system redispatch more widely, or by implementing price zones with auctions. These policy alternatives result in varying cost-benefit trade-offs. To ensure reliability, market participants may improve their compliance with existing legal and regulatory requirements of transmission forecasts, network operators may introduce financial incentives, or market participants may be required to include a location component in their tenders. Six policy alternatives were defined based on the measures for achieving the policy objectives of affordability and reliability:

1. Apply market restrictions to DSOs and ensure more compliance with the current legal and regulatory requirements for transport prognoses.
2. Apply market restrictions to DSOs and financial incentives for complying with transport prognoses.
3. Wider application of system redispatch and ensure more compliance with the current legal and regulatory requirements for transport prognoses.
4. Wider application of system redispatch and compulsory location component in tenders of market participants.
5. Introduction of price zones with implicit auctions and ensure more compliance with the current legal and regulatory requirements of transport prognoses.
6. Introduction of price zones with implicit auctions and compulsory location component in tenders of market participants.

Step 4 consists of identifying, quantifying and valuing the effects of the policy alternatives involving the deployment of flexibility in comparison with the baseline alternatives involving grid reinforcements. The following key effects were identified:

- Investment in network capacity: extra income for network operators from delays/cancellation of grid reinforcement.
- National congestion and competition:
  - Loss of income for generators due to avoided grid reinforcement (because grid reinforcement can open new markets and thus result in higher production revenues).
  - Conversely, avoiding grid reinforcement could also result in higher revenues for generators in the form of sales of flexibility to network operators.
- Investment in generation capacity: incentives for generators to consider alternative locations, thereby achieving higher system efficiency.
- Security and quality of supply:
  - The policy alternatives could lead to better and more location-specific information so that network operators can manage congestion more effectively.
  - Frequency and duration of power outages: if the deployment of flexibility for congestion management results in higher operational risks for network operators, and this risk is not mitigated in their operational practices, this could lead to longer power outages. The social costs of power outages are higher than the network operator's costs.
  - Voltage quality: it is unclear whether voltage quality issues will occur more frequently if congestion management is applied.
- Renewable energy: the application of congestion management could marginally increase curtailment of RES, although the most economically efficient option is to curtail generators with high marginal costs (e.g. fuel costs), if such generators exist in the relevant grid section. Here too, the social costs are higher than the costs for the generators.
- Environment and landscape:
  - Higher emissions of harmful substances such as NO_x, SO_2, PM_{10}, NH_3 and CO_2. Congestion management entails less efficient deployment of power plants and hence an alternative generation mix and higher emissions of harmful substances. Again, the associated social costs are higher than the costs for the generators. These harmful substances can be given a social value; in the case of CO_2, this is already partly included in the ETS price that is taken into account when

determining the producer surplus. Based on the WLO scenarios, a surcharge will also be applied to the ETS price for CO_2.

- Limiting the impact of electricity infrastructure on the landscape by deploying congestion management.

These welfare and distributional effects are summarised in a table with costs and benefits on the y-axis and the involved actors on the x-axis. The above overview is not exhaustive; other types of effects are also conceivable.

Relevant factors in the decision to quantify an effect are the expected size of the effect, the required effort and the social support it generates
Some effects are easier to quantify and monetise than others. If a milder form of CBA is chosen, such as an indices or indicative CBA, then the following three questions may play a role in the decision to quantify:

- What is the expected size of the effect – and hence the significance of the effect – for overall welfare or redistribution of welfare between actors?
- What effort is required (in time and resources) to quantify or monetise the effect?
- To what degree does the choice of effect contribute to increasing social support for the deployment of flexibility for congestion management? Have the effects on the various stakeholders been identified?

If the investor anticipates a substantial effect and the analysis load (in the form of a CBA) is limited, then it would be worthwhile quantifying the effect. This also applies if the net effect is limited but the impact of distributing costs and benefits is substantial (because unequal distribution of net benefits could lead to social resistance to a policy alternative and hence impede its implementation). If the expected effects are limited, there is a large analysis load, and little social support is expected, then such an analysis will serve no purpose.

Remove requirement to only temporarily apply congestion management
Of course, to be able to devise an adequate societal framework for the trade-off between grid reinforcement and the deployment of flexibility, the legal and regulatory limitation (in the Electricity Act and the Grid Code) that congestion management may only be temporarily deployed will have to be removed.

Implementation of the societal framework in legislation and regulations will benefit uniformity
The aforementioned analysis steps can be used in the investment plans of network operators and be prescribed in a Ministerial Order, such as currently exists for Quality and Capacity Documents (KCDs) (*Ministeriële Regeling kwaliteitsaspecten netbeheer elektriciteit en gas* (Ministerial Regulation on quality aspects of grid operation for electricity and gas)). Policymakers will then be able to ensure more uniform implementation of the societal framework by the network operators.

The societal framework can also provide more insight into the social value of flexibility in specific situations
Finally, this study focussed on the trade-off between the deployment of flexibility for congestion management and grid reinforcement in light of the FLEXNET phase 2 study into the average value of flexibility in the entire Liander grid. To better understand the value of flexibility for congestion management, it will be important to conduct further

studies to analyse in which specific situations flexibility has the greatest value, for both network operators and society as a whole, by implementing the proposed societal framework in practice.

4.2 Key messages

Societal framework essential
A societal framework for analysing the trade-off between grid reinforcement and the deployment of flexibility is essential due to the effects of such a trade-off on generators, consumers, network operators and other social actors.

Indices CBA or indicative CBA preferred
Depending on the size of the grid expansion investments that can be temporarily or permanently avoided through the deployment of flexibility and the available information to determine effects, the report shows that an indices or indicative CBA would be the most appropriate form.

Relevant factors in the decision to quantify an effect are the expected size of the effect, the required effort and the social support it generates

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The societal framework can also provide more insight into the social value of flexibility in specific situations
To better understand the value of flexibility for congestion management, it will be important to conduct further studies to analyse in which specific situations flexibility has the greatest value, for both network operators and society as a whole, by implementing the proposed societal framework in practice.

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