KIVI Elektrotechniek

Design of a Dutch carbon-free energy system

EnergyNL2050

A detailed follow-up study

with system simulations and

a financial analysis

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Design of a Dutch carbon-free energy system

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20/07/2020: final version
16/10/2020: correction on pg. 25 Appendix A: block Backup Fuel cell Powerplant *33 GW*

Summary

From 2013 till 2017 we organized several KIVI seminars in Utrecht where more than 50 Dutch professionals presented their views on the energy challenge for the Netherlands in the future. Based on this particularly useful information we devised an energy plan for 2050 and published it beginning 2018.
The plan describes the EnergyNL2050 energy system which is CO_2 neutral. The system generates more than 85% of the nationally needed energy and needs at most 15% import from abroad. Although positive feedback was received, we recognized that a few important aspects were still missing, such as hourly based system simulations and a thorough financial analysis. In this paper we report the results of detailed simulations using hourly weather data, renewable energy production and demand data during three years. Recent functional energy demands (year 2015) were extrapolated to the energy demands expected in 2050. From this the required renewable energy could be analyzed.
The simulation results give ample confidence that the system can work.
We also refined the system design such that all components cooperate well together to achieve an optimal final result. A detailed financial analysis shows that the EnergyNL2050 system is affordable: the annual energy costs are analyzed to be about €28 billion. The current annual energy costs are about €21 billion. But this cost difference is compensated by the avoided CO_2 tax (being €41 per ton CO_2) on the 185 Mton saved CO_2 emission.
The EnergyNL2050 system is a long-term outlook, focusing on 2050. This paper reports verification of our earlier results and describes the implementation of the system and in particular the steps that need to be taken in the near future. The results are presented in the last section of this paper. It addresses the main issue which is: how to match the variable supply of energy with the different demands of the future. We complete the paper with a series of policy issues that the government should work on.

The main facts of this energy plan

As already stated in the title the plan is completely CO_2 neutral, and this without the use of biomass , synthetic gas, fossil fuels and the use of geothermal heat. The energy needs for heating, transport and industry are satisfied mostly by electricity and hydrogen is used as chemical feedstock for industry and to supply backup power. Hydrogen is produced by a series of large scale electrolyzers. Backup power is provided by a distributed network of fuel cells and they also provide additional power in case of very cold weather. Batteries are used as short term storage to match the variability of wind and sun with electricity demands and the efficient operation of the electrolyzers. The plan can satisfy almost completely in the energy needs and needs only a very small amount of import. Often it is claimed that import may be cheaper, but our analysis shows that this is not the case. In the implementation care is taken that the Dutch landscape is preserved as much as possible by proposing only a very limited amount of wind power on land and only a very small amount of solar parks. One important feature also is that the electricity network does not need a significant capacity enlargement by using several interesting techniques such as smart charging, a distributed net of fuel cells, an efficient curtailment strategy and the location of the electrolyzers. The total cost of the system has been modelled and the plan is derived from a total cost optimization of the entire system, including the different segments of the electricity grid.

1. Introduction

In 2018 we published in the white paper "EnergyNL2050" the results of our study on a full carbon free Dutch energy system 2050. Vision and approach to the study are carefully described in the paper. A clear overview of the 2050 energy system was presented (Persoon et al. 2017).
EnergyNL2050 from KIVI is one of the systems analyzed by Berenschot in 2018 in the report on system options as input for the Dutch Climate Agreement (Den Ouden et al. 2018).
We were able to obtain a good mix of renewable energy sources: Wind power onshore and offshore, PV-electricity, some other renewables and some imported electricity, covering most of the energy demands. We were able to get a rough estimate of the minimal required backup electricity. However we did not have tools for studying the reliability of the energy supply chain, covering the demands on an hourly basis!
But Koen Huizer (KIVI-Electrical Engineering) who joined our study team, was able to develop the required tools. With his software tools the energyNL2050 system could be simulated, using the hourly data for PV and wind electricity. These new possibilities have led to this follow up study. In part 3 of this study the simulation results are carefully analyzed and are also extended with a financial analysis, aiming to obtain an optimal 2050 NL Energy System based on minimal annual energy costs.
The approach for our study on the carbon free energy system, as explained in the white paper, has not been changed: basic conditions, like a 100 % carbon free energy system, no carbon capture and storage (CCS), no nuclear energy and biomass as part of the mix of energy sources, and the analysis of the energy demands in 2050 are still the same. Also the full decarbonation of the energy demands with electricity and hydrogen as the main energy carriers are conditions that have not changed. The energy system is such that the Netherlands is largely self-sufficient for its energy.
The analysis shows, among other results, that a well-balanced backup system, based on H_2-fuel cells for re-electrification, will cover the electricity demands also in longer periods with low wind and solar conditions, the so called "Dunkelflaute".
The system simulation results however in higher figures for curtailment and backup output:
Curtailment is now 6 TWh annually compared with the 2 TWh as originally mentioned in the 2018 white paper and **Backup output** now requires 16 TWh annually, where as we expected 12 TWh in the 2018 white paper.

Cost calculations for the 2050 energy system are also included, see part 4. Based on those simulations and projected prizes several financial data are derived, giving an insight in the total cost of the system and enabling the energy system optimization for minimal system costs.

In our 2018 white paper document we described and analyzed the future situation as we see it in 2050. In this paper we also analyzed the implementation of this plan with two focus points: how the energy system should be realized in steps from this point on and secondly where the necessary components, such as electrolysis systems and fuel cells, should be located. We also developed ideas about the roadmap on how to implement the growing renewable energy capacity, which is described in part 5. In part 2 the system setup (what is the 2050 energy demand also compared with the current demands) is explained together with the changes in some energy system parts.

An important conclusion is that our complete substitution of the fossil energy carriers through electrification and hydrogenation results in a substantial low primary energy demand!

- **Low Temperature Heating** only with heat pumps and heat networks using the residual energy from the different system parts.
- **Transport** with only electrical propulsion systems, battery based and hydrogen-fuel cell based, including the shipping sector, inland as well as international
- **Refineries for transport fuels** are not necessary anymore
- **Basic steel making** using hydrogen as the deoxidizing medium
- **Wind- and solar electricity** are 85% of the mix of renewable energy sources.
- **Reliable energy delivery is ensured** due to a well-balanced hydrogen-fuel cell based backup system, supported with a decentralized battery based one day storage systems.
- **The Plastics industry** only uses biomass as the raw input material. Biomass is not used for energy production.

The resulting primary energy demand is 414 TWh in 2050 , much lower compared with other studies! See for instance (Den Ouden 2020,p. 38) figure 7, national control.

2. The high level energyNL2050 system, the demands and the mix of required renewable energy sources

2.1 The functional energy demands in 2050

The verification study explained in detail in part 3, delivers a lot of new, useful insights in our energy study EnergyNL2050, resulting in improved outputs. This investigation was also a good motivation to inspect the various blocks of the high level energy plan. It was clear that some assumptions could be improved, resulting in more realistic energy conversion and energy loss figures. See the improved high level energy system diagram in appendix A for more information.

The expected energy demand 2050
First we present the results of the functional energy demands 2050 when switching over from the fossil based energy demand nowadays to the use of electricity and hydrogen as the only energy carriers of the 2050 demands.
The description of our energyNL2050 system is based on the functional energy demand grouping as introduced by CE Delft in their 2014 study (Warringa and Rooijers 2015):

- Basic electrical demand
- Transport
- High temperature heat (temperatures>100 °C) and
- Low temperature heat (T<100 °C)

Using the 2015 functional energy demands we estimate the demands in 2050 assuming an annual growth of about 1% (more exactly we used 1,15%). We also assumed an annual energy saving of 1%, resulting in 2050 demands, slightly higher than the current demands.
This results in the 2050 demands compared with the current demands as described in the next table 2.1.

Functional Energy Demand	2015 Fossil based TWh	Electricity TWh	2050 Hydrogen TWh	Heat Nets TWh
Basic electricity demand	120	127		
Transport	160	28	47	
Hydrogen compression (700 bar)		5		
High Temperature Heat	160	26	60	
Low Temperature Heat	200	25		20
Total Demand TWh	**640**	**211**	**107**	**20**

Table 2.1: Functional energy demands 2050 compared with the 2015 demands

Using heat pumps for producing the low temperature heat and the full transfer to electrical propulsion systems in the transport sector (road an shipping as well), battery based and hydrogen fuel cell based, means a strong energy saving: the functional energy demand 2050 is about half of the energy demand nowadays due to this full transition to electricity and hydrogen as the only energy carriers.

2.2 Three important parts of the energyNL2050 system (for more information see appendix A)

The renewable energy sources must generate the above mentioned electricity and hydrogen demands. (Be aware that the heat net energy will be derived from the residual heat from other parts of the system like electrolysis systems, backup systems and industrial plants with high temperature processes, meaning that the heat net does not require own energy sources as part of the mix of energy sources.)
Two main energy system parts should be briefly discussed: the electrolysis system to produce all the required hydrogen followed by the hydrogen temporary storage and transport network, and the backup system, delivering the electricity when the electricity production of the renewable energy sources is lower than the electricity demands.
A third important system part is the One Day Storage system. This system is a battery based storage system, storing the excess electricity for some hours.

- **The Backup System delivering the electricity during low wind and solar conditions.**

An important system part is the backup system, essential to deliver the directly required electricity in periods (hours up to days or even weeks) with wind and solar conditions, too low to produce the required electricity demand. Considering the future carbon free energy system with a high part of the variable renewable energy sources (vRE) important properties for the backup system are
. fast switching from no load to full load when required
. suited to be used in a decentralized way,
. having a good efficiency and good life time and preferably cheap.
The conventional high temperature generator based power plants do not have those properties. But (again) PEM fuel cells, converting hydrogen in electricity, have those properties: fast responding, efficiencies up to 60%, low temperature working condition, long life. We expect that the fuel cells from the automotive sector are a well suited choice, being also relatively cheap!

- **The Proton Exchange Membrane (PEM) Electrolysis system**

The PEM electrolysis systems are a suitable choice due to their good properties such as fast response on strongly varying input power, low working temperature and long life characteristics. A PEM electrolysis system needs some energy for a number of auxiliary systems as compression up to 40-80 Bar, cooling system, water purification, etc. The energy used by these systems is estimated to be 5% of the hydrogen output (HHL). Accepting an 80% efficiency for the electrolyser system plus an extra 5 % energy for the auxiliary systems, the ***overall electrolysis system efficiency will be 76%.***

- **One Day Storage System (ODS system)**

The ODS system is an important battery based storage system, enabling the PV electricity generated during the daily light hours to be used during the night or delivered back to the electrical grid. A part of the households with PV installation on the roofs will have battery installation to be used for this function. Residential areas could be equipped with a residential area battery system balancing de local PV production with the demand. EV batteries could be used for such a function as well. ODS can also be used in combination with the wind parks playing a role as peak shaving. ODS will reduce the curtailment, which will be necessary when the produced electricity exceeds the total electricity demand. In the simulations several ODS values are introduced and the applied ODS with a capacity of 80 GWh is a relatively optimal choice, based on the energyNL2050 System with minimal costs. Total ODS electricity stored for a couple of hours per day results from the simulations to be 18 TWh on an annual base. With the 95% efficiency the additional losses are an acceptable 0,9 TWh.

2.3 The mix of the renewable energy sources.

The only energy sources we want to use are wind power (on- and offshore), solar (PV) power, some import and some possible new renewables, but still in research phase nowadays. As a result of the verification study, discussed in part 3 (fig 4.1), and based on the energy system diagram of appendix A, the following mix of the renewable energy sources follows:

Renewable Energy Sources Mix	Power GW	Energy/year TWh.el	Contribution %	full load hours
1. PV	77	71	17%	920
2. Wind offshore	60	269	65%	4500
3. Wind onshore	6	14	3%	2500
4. Other renawables	2,5	20	5%	8000
5. Import electricity	(variable)	40	10%	
6. Import hydrogen		-		
Total Primary Energy Demand		414	TWh	

Table 2.2: The mix of renewable energy sources for the energyNL2050 system (Other renewables means energy sources we may expect coming decades, but yet in research phase)

Other main results, based on the simulation results of part 3:

- Curtailment: 6 TWh/yr
- One Day Storage system (battery based, decentralized organized) capacity: 80 GWh
- Electrolysis system: 40 GW, full load hours: 3600 full load hours
- Fuel Cell Backup System: 16 TWh/yr, 33 GW, 485 full load hours

- **PV: 77 GW/71 TWh, full load hours =920 , PV efficiency=30%**

Up to now the PV full load hours are officially defined to be 875 hours. But the KNMI observes a trend that the annual sun irradiation has been increasing during the last decades. For that reason we expect in 2050 an annual full load hours of 920 hours. Regarding the PV efficiency, now being 20%, this will be improved the coming years up to 30%. The available roof surface on householdings and larger buildings is estimated to be 400 km2. The required 77 GW requires about 65% roof surface, meaning that together with available PV parks on appropriate ground stretches enough surface is available.

- **Offshore wind: 60 GW/269 TWh, full load hours=4500 hours**

The full load hours for offshore wind parks are about 4000 hours up to now. But the modern wind turbines are increasing in nominal power to 15 MW or even more and in full load hours up to 5500 hours in 2050. Together with the wind park efficiency of 85%, the effective full load hours are estimated to be 4500 hours in 2050. The Dutch economic exclusive zone (EEZ) in the Nord Sea is 55.000 km2. With an average turbine power density of 7 MW per km^2, the required sea surface is about 16% for the 60 GW wind power. Although the Nord Sea is a one of the busiest seas of the world, we expect that this 16% sea surface is available for the required wind parks.

2.4 Decarbonizing the international shipping and air transport to a full sustainable transport sector.

The international transport sector is not part of the official energy based CO_2 emission calculating system. But it should be decarbonized nevertheless for a full carbon free 2050 energy system. The Dutch petrol chemical industry produces 12.3 Mton (=145 TWh) fuel oil for the shipping transport and 3.7 Mton (=48 TWh) kerosene for the air transport (CBS 2015).
We assume that in 2050 the international transport sector will ask about the same amount of fuels. Switching over the shipping transport to hydrogen fuel cell based driving systems requires a factor 1.5 less energy than the combustion transport nowadays and decarbonizing the international shipping transport to full hydrogen fuel cell based shipping transport requires about 100 TWh hydrogen, equal to 2.5 Mton hydrogen.
For a sustainable international air transport sector using hydrogen is not yet a clear way to go and this sector therefore will have to use a kerosene produced with synthetic processes. Basic pre-processing is the production of so called syngas, a mix of hydrogen and carbon monoxide (CO). The hydrogen will be produced by electrolysis and the CO from CO_2 obtained for instance with direct air CO_2 capture or from CO_2 emission point sources in the chemical industry .We assume that the 48 TWh synthetic kerosene for international air transport will require about the same amount of hydrogen (48 TWh hydrogen).

The total amount of hydrogen for a 2050 sustainable international transport (air and shipping transport) requires 148 TWh hydrogen, equal to 3.8 Mton hydrogen. Producing this with electrolyzers the 3.8 Mton hydrogen requires 210 TWh sustainable produced electricity. 45 GW offshore wind parks should be necessary as a possibility. Our energyNL2050 system design already asks 60 GW offshore wind as part of the mix of renewable energy sources, meaning that for most of this extra 45 GW offshore wind parks no room is available in the Dutch exclusive economic zone (EEZ).
Most of this international transport hydrogen should be imported as an alternative.

2.5 Required hydrogen buffer to secure the electricity delivery

Energy delivery has to be secured in the periods with low wind and solar conditions. Three subjects are considered: seasonal based surplus vRE, required periods from several days (so called Dunkelflaute) and the annual variations in de wind and solar.

- **Seasonal required storage including the buffer H_2 for the Dunkelflaute periods.**

The system simulations in part 3 show in fig. 3.1.1 (state of change Hydrogen Fuel cell backup system) that 40 TWh H_2 storage is needed. This also includes the 12 TWh H_2 buffer for the Dunkelflaute period of about 10 days in January 2017. But we require a buffer for a Dunkelflaute period of 4 weeks, meaning that during such a long 4 weeks period with almost no vRE, the hydrogen buffer should even be higher: 50 TWh of stored H_2.

- **Variations in the annual Wind and PV generated electricity.**

Studying the CBS statistics for solar power and wind power, the annual yield figures show considerable variations up to 5-10 % from the average values. For that reason a low vRE, up to 10% in a bad year has to be considered, requiring 30 TWh hydrogen available in the hydrogen storage. Another way to deal with such a bad year is to import the required 30 TWh Hydrogen.

3. EnergyNL2050 system verification

We have performed simulations of the above described system at a hourly resolution. The objective of the analysis is to validate the overall system behavior, to determine the sensitivity to some key parameters and to provide a basis for a financial analysis of the system as presented in the next section. Fig. 3.1 shows a simplified view of the simulation set up.

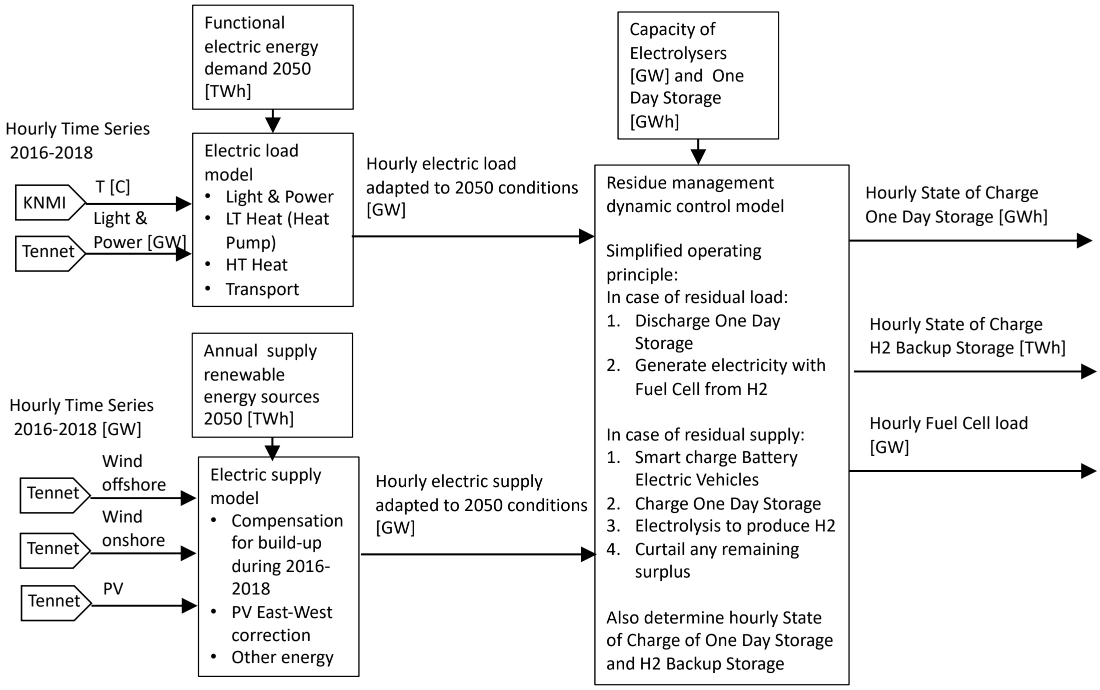


Fig. 3.1. Simulation set-up

The simulation consists of three main parts. Appendix C contains a more complete description of the simulation.

The first part, the Electric Load Model uses a number of Time Series (TS) , namely the actual hourly load on the electric energy transmission grid as published by TenneT over the years 2016-2018 (Tennet ENTSO-E OPSD 2019), the ambient temperature published by KNMI (KNMI 2019) over the same period as well as the functional electric energy demand for 2050 as described in the previous section to determine the total hourly electric load to be expected in the NL2050 system. It contains amongst others Heat Pump models as well as a provision for smart charging of Battery Electric Vehicles (BEV's). We assume that 50% of the BEV charging energy will be charged in a controlled ("smart") fashion.

The second part, the Electric Supply Model, is similar but focuses on the conversion of hourly Wind and PV generation data as well as the energy supplied by the renewable energy sources for 2050 as described in the previous section to determine the hourly electric supply to be expected in NL2050. It contains amongst others compensation for the build-up of the Wind and PV capacity over the years 2016-2018 as well as correction for the (preferred) East-West orientation of PV panels.

The third part of the simulation is the Residue Management Dynamic Control Model. This model is responsible for securing the continuity of the electricity supply. It manages the BEV smartcharge process, the charge and discharge of the One Day Storage (ODS), the production of H_2 by electrolysis and the Fuel Cell based electricity backup system. Next to the hourly electric load and supply data it takes the capacity of the Electrolysers and the ODS as input parameters and determines the minimum required capacity of the Fuel Cells and the H_2 Backup System (HBS).

Our simulations confirm large fluctuations in supply, from almost no production to over 100 GW in case of sunny days combined with strong winds. Similarly, the energy consumption shows a strong

seasonal variation caused by the heat load. As a result, the supply-load residue varies considerably as well. For example, January 2017 was a relatively cold month with periods of low sunshine and soft winds ("Dunkelflaute"). Such conditions form a suitable test for the robustness of the energy system. To mimic a period of extreme cold we actually lowered the temperature data for three days, January 23 to January 25, to a constant -10C.
Fig. 3.2 shows a number of relevant Time Series for this period clarifying the behavior of the One Day Storage and the H_2 Backup System under these conditions

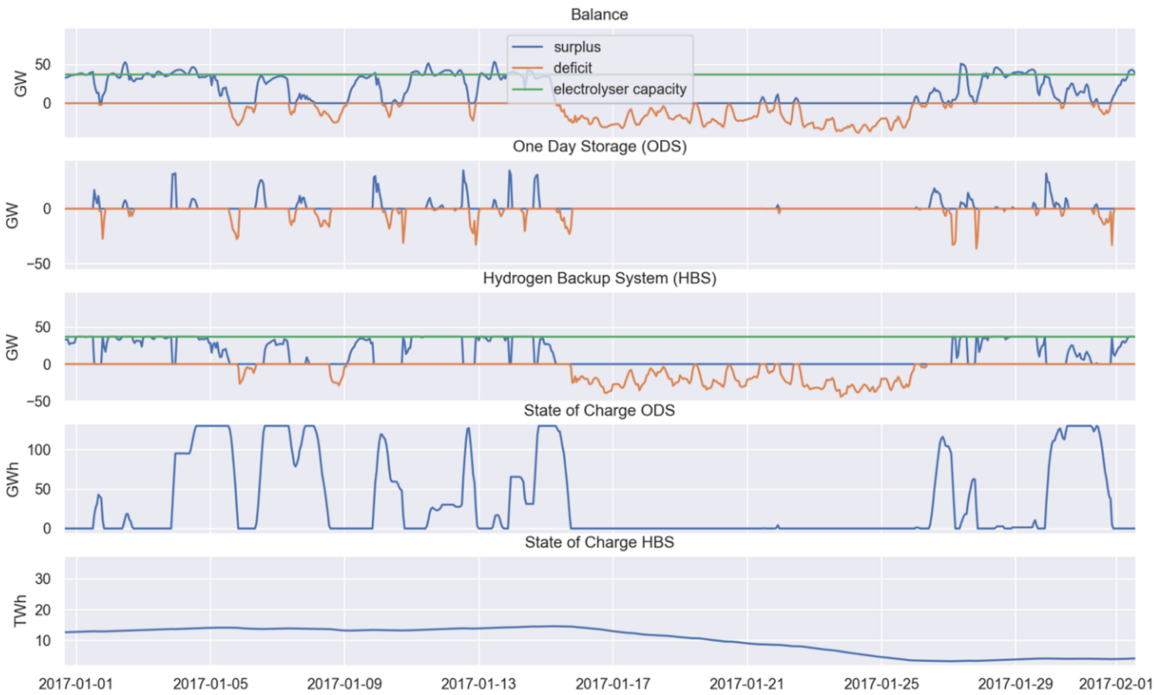


Fig. 3.2 NL2050 ODS and HBS behavior with extreme cold, low sunshine and soft wind conditions

The blue graphs indicate a surplus in the supply-load residue and charge of the ODS and HBS (generation of H_2 by the Electrolysers). Orange graphs indicate a deficit in the supply-load residue and discharge of the ODS and HBS (generation of electricity from H_2 by the Fuel Cells). The capacity of the Electrolysers is indicated with a green line. In the first half of the month on average a surplus exists, sometimes beyond the capacity of the Electrolysers. However there are also periods of deficit. Without ODS this would results in curtailment during some hours followed by generation of electricity by the Fuel Cells. It can be seen that the ODS significantly reduces both curtailment as well as Fuel Cell activity during this period. In the second half of the month the situation is quite different. There is a prolonged period of deficit. The ODS is quickly depleted and the Fuel Cells have to take over. As a result, the HBS is significantly depleted. The energy supply remains secure.

Power Duration Curves (PDC's) of the supply-load residue provide a general view of the behavior of the system as shown in Fig. 3.3.
We notice a variation from a surplus of 90GW on the left to a deficit of -40GW at the right. The circle denotes the cross-over point. The annual deficit (area where the balance is negative) is 21 TWh whereas the annual surplus (area where the balance is positive) is 193 TWh.

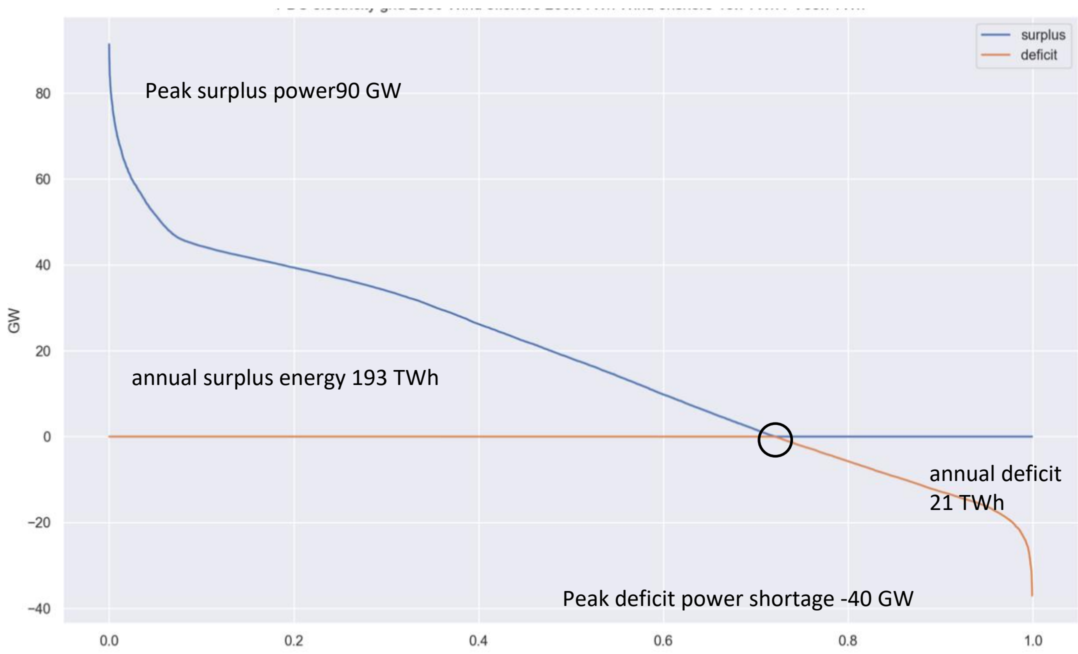


Fig. 3.3. PDC of simulated electricity supply & demand in 2050

The effectiveness of the ODS and the HBS components of the system can be seen from Fig. 3.4. Next to the PDC of Fig.3.3 we have shown the PDC from the supply-load residue after balancing by the ODS and after supplying the Electrolyzers. The left-hand circle in the graph shows as before the cross-over point between surplus and deficit. The right-hand circle shows the cross-over to the remaining hours where the fuel cells need to provide back-up energy. In between these circles all required hydrogen has to be supplied from storage. Also note a significant reduction in curtailed energy. Without ODS all surplus energy beyond 37GW would have been curtailed.

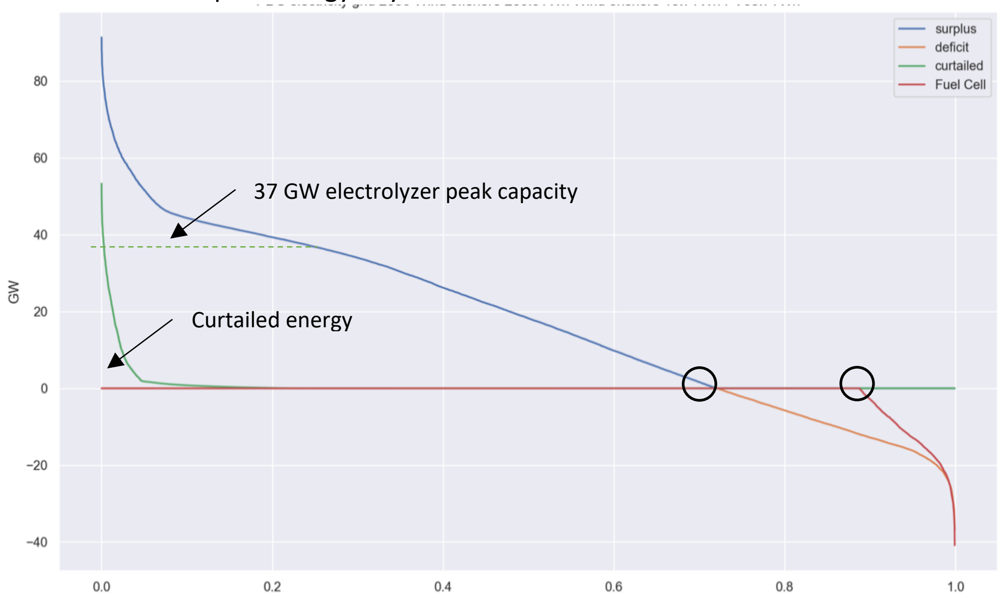
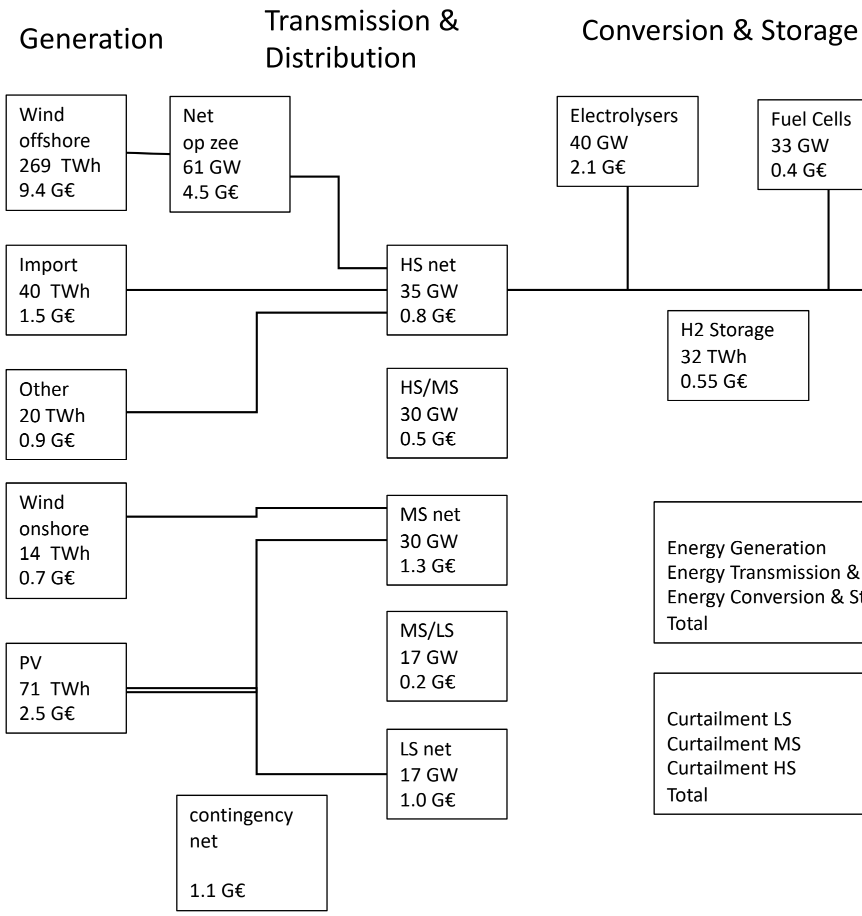


Fig. 3.4. PDC with improvements in curtailed energy and use of fuel cell backup

The conclusion from this simulation study is that with an adequate hydrogen-based Fuel cell Backup System, supported with a battery based One Day Storage system, the energy delivery is fully secured.

4. Financial/Economic analysis

The simulation described in the previous section is used for our cost analysis. We refer to Appendix D for additional details. A first result, namely the annual cost of the NL 2050 system is given in Fig. 4.1



	G€
Energy Generation	15.0
Energy Transmission & Distribution	9.4
Energy Conversion & Storage	3.8
Total	28.2

	TWh
Curtailment LS	0.0
Curtailment MS	0.0
Curtailment HS	6.3
Total	6.3

Fig. 4.1 Cost build-up of the NL2050 system

We distinguish between three main cost categories: Generation is the largest at €15 billion, followed by Transmission and Distribution at €9.4 billion and Conversion and Storage at €3.8 billion resulting in a total cost of €28.2 billion annually.
Note that our Fuel Cell annual cost in terms of €/kW is substantially lower compared to other studies (Rooijers and Jongsma 2020). We assume the use of low-cost automotive Fuel Cell technology. Appendix D and E provide more background.
Cost for transmission and distribution is mainly determined by the peak loads in the three network planes: HS, MS and LS. In the present analysis we significantly increased the network capacity to handle the additional load of heat pumps and electric transport. A superior approach is presented in Section 5 of this paper.

We calculated the total annual cost of the system for a range of ODS and Electrolyzer capacity values. Changing ODS and Electrolyzer capacity impacts curtailment and round-trip losses in the ODS and the HBS and we adjust the energy generation volumes accordingly. Fig. 4.2 gives an overview.

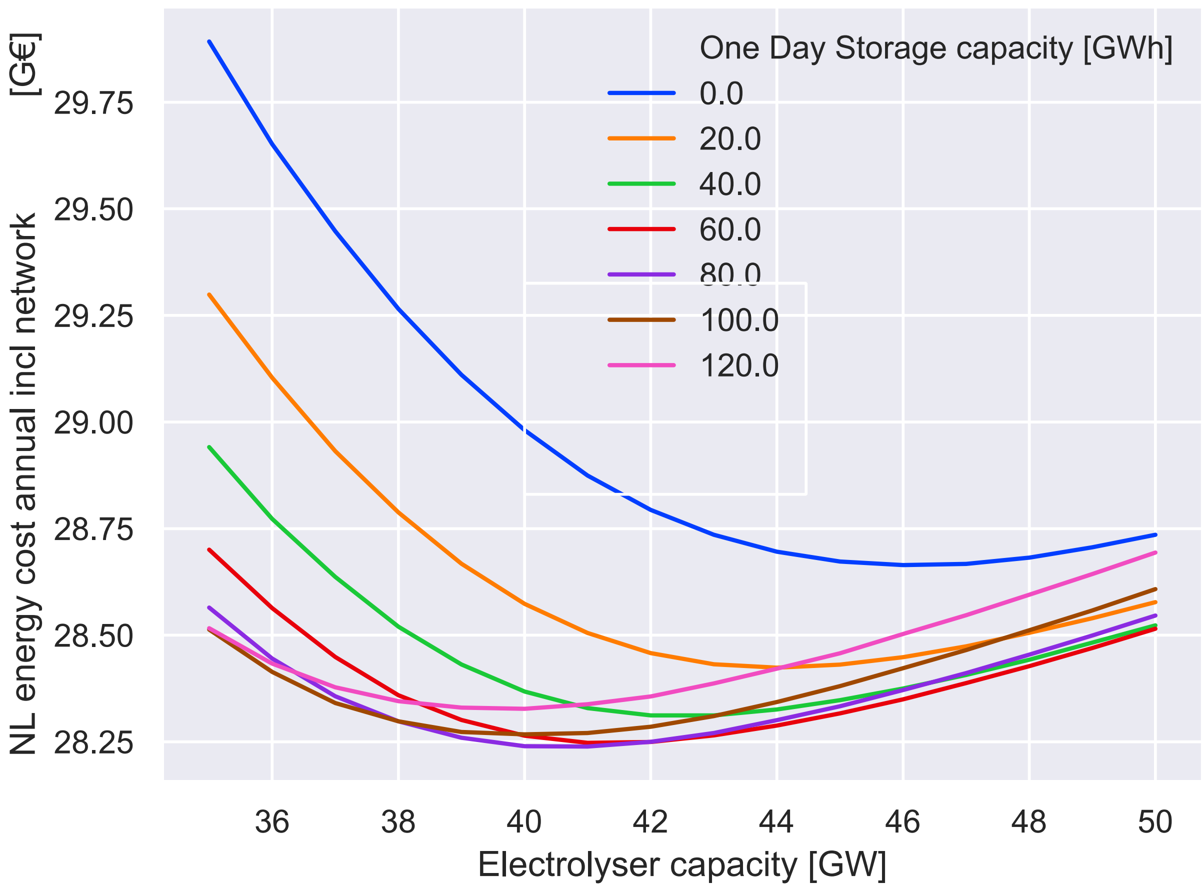


Fig. 4.2 System cost dependency on Electrolyser capacity with ODS capacity as a parameter

We observe that if the Electrolyser capacity is low, costs are increasing due to an increase in curtailed energy. The minimum cost we obtained was 28.2 € billion for an ODS of 80 GWh and an Electrolyzer capacity of 40 GW, the same as shown in Fig. 4.1. It should be noted that the cost curve in the neighborhood of these values is relatively flat which gives considerable freedom of implementation. E.g. for ODS 100 GW and Electrolyzer capacity 37 GW the cost difference is marginal, just 60 M€ on an annual basis. At the right-hand side, the cost increases almost linearly with increasing Electrolyser and ODS capacity as the fixed costs increase without a significant further reduction in curtailment.

It has been argued that importing nearly all energy from regions with abundant solar or wind energy could be advantageous versus local generation. We have analyzed a hydrogen-based import scenario to benchmark NL2050. See Fig. 4.3 for the build-up.

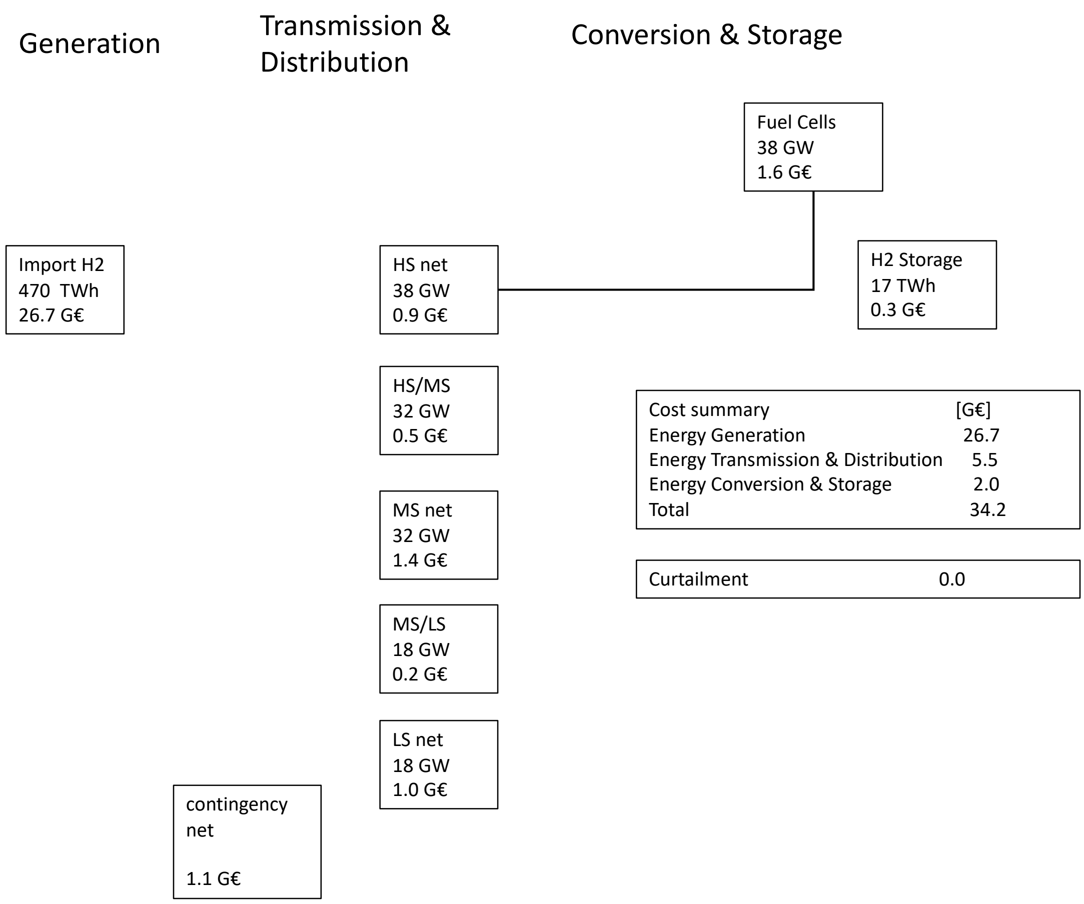


Fig. 4.3 Cost build-up of a fully H_2 import Energy system

The H_2 import price is a key parameter in this scenario. We assume a H_2 import price of €2.25 per kg (Hers et al. 2018). This results in an annual cost of €34.2 billion, so significantly higher than the NL2050 system. The cost difference is mainly due to the conversion losses in the Fuel Cells that cause a significant cost disadvantage compared to energy generated from wind or solar. Another disadvantage of a fully import based system is the obvious dependency on external parties. However, partial import of H_2 may be useful and our analysis shows that this could lead to a modest cost improvement.
Finally, we made a comparison with the cost of the current fossil fuel-based energy system. See Appendix D.
We notice a substantial increase of €7.5 billion, about 36%. This corresponds with a savings of 185 Mton CO_2, on average €41 per tonCO_2

5. Implementation aspects

In our energy plan we propose to install 60 GW at sea and 77 GW PV on land by 2050. In the first part of this report we have explained that our energy plan is both feasible and affordable. This has been verified by elaborate system simulations, assuming that the capacity of the network planes HS, MS and LS (see for more explanation fig. 5.1) would be significantly increased to take care of the additional load of heat pumps and electric transport.

In this part we will focus on the set-up of the total Dutch energy system with an emphasis on how to manage the large peak powers that will arise during the year taking into account that large currents can only be transported either using either very high voltages or short distances. We will first briefly discuss the planning from now on till 2050. Secondly the issue of managing peak powers will be discussed with associated aspects like where do we place the important One Day Storage systems (ODS) , the electrolysis systems and the backup fuel cell systems and how much the electricity grid has to be upgraded. We concentrate on the electrical infrastructure.

The phasing over time

We assume that the planned 60 GW at sea and 77 GW PV, with about 47 GW PV roof installed and 30 GW PV park installed, will be implemented in a linear fashion. This means 2 GW a year has to be installed for wind and 2.5 GW for PV from now on. Moreover we assume that the missing electric power will be realized by gas plants from now on. The required power and delivered energy of those gas plants will therefore decrease in a linear fashion from now until 2050 and also the corresponding CO_2 emission.

In the first phase the power generated by PV and wind will not exceed the power level that is required by the demand. That power is around 20 GW currently.

However by 2030 we will have a maximum wind power of already 22 GW and a PV power of 25 GW. That is much higher than the current maximum demand. So from 2030 onwards or even earlier one has to take measures to accommodate this extra power on the electric grid. A report has been published that claims that the current low-voltage part of the electricity network can be left unchanged for PV power levels up to 27 GW (Lemmens et al. 2014). This includes all cabling of the low-voltage network as well as the LV-MV transformers (see fig 5.1). But to make this possible the PV panels need to be distributed evenly over all the low voltage networks. For power levels between 16 GW and 27 GW a curtailment provision has to be implemented that will remove 2 to 3 % of the annual energy production of the PV panels, and reduces the peak power with 30%. This seems to be a good and acceptable approach. The curtailment method must however be carefully implemented such that every PV owner experiences the same percentage of energy loss.

The question is however whether the rest of the network can deal with the strongly varying supply of 16 GW of PV power. This has to be examined further in detail. It may be necessary to install local batteries to limit the peak power and consume electricity locally. Also one should preferably install the PV panels of solar parks in the east/west orientation, limiting the peak power and provide electricity during a longer period of the day.

The conclusion is that until 2030 probably no major upgrades should be made of the electricity network. However soon after that , this will for sure become necessary.

But it is important to say that many of those actions need time to prepare and plan, and some of them will first need small scale implementations to verify the approach before it is deployed at a large scale. Therefore it is recommended that such a plan is already developed now soon. Later on we will propose such a plan.

Where do we have to install things and how much?

5.1 Offshore wind and location of electrolyzing systems

It is clear that the required wind turbines at sea will be located far from the coast and the required PV preferably on the available roof space. The first consequence of this is that a lot of energy will arrive from sea at the Dutch seacoast. And the second consequence is that large cities, with a lot of installed PV panels, will generate large peak powers.

Concerning the wind power that will arrive at the coast we follow the following reasoning. This energy has a Power Duration Curve (PDC) that is currently approximately a triangle with around 4000 hours of full load at the most. But around 2050 we suppose that the many offshore wind parks covering 60 GW, will be widely spread across the Dutch part of the North Sea: from the Doggers Bank to the Wadden, along the Holland Coast region to the sea area above Zeeland, a sea area of 55.000 km^2. All the wind turbines will have a nominal 15 MW (or more) output power and up to 5500 full load hours! That means that during more than half the year power will be generated larger than 30 GW. It doesn't seem wise to distribute this excess power across the Netherlands (we assume that we need about an average of 30 GW of power on the demand side in 2050). In our plan we will need a lot of electrolyzer power (about 40 GW, see part 3 for more information). The area of the North Sea is shared between a number of European countries and they combine forces for optimal usage of the offshore wind power in the North Sea Wind Power Hub consortium (NSWPH 2020). It is clear that the proper choice of interconnection, the location of electrolyzers and the storage of hydrogen are also crucial in their implementation ideas.

How to get the produced electricity from the wind parks on the Doggersbank to mainland? In our energy system design we suppose that the offshore wind park electricity is transported to land via cables. The system simulations and financial analysis are based on this assumption. As the offshore cable costs are a substantial part of the total systems costs, the electrolysis systems should be located as close to the wind parks as possible, so along the coast line on locations where the cables arrive at the mainland. An advantage is that the rest heat of the electrolysers is then available for the heat nets. The alternative is producing the hydrogen close to the wind parks on the Doggersbank, using one or more energy islands for installation of the electrolysers. The produced hydrogen can be transported via new and existing gas pipes to the mainland. Both those options are currently considered and studied (NSWPH 2020). Another design consideration may be the location of some electrolysis systems around large cities, but are not analyzed yet in our current study.

5.2 PV panels

We propose that 77 GW of PV power will be installed on homes, utility and business buildings and on large PV parks. It will be necessary to install close to or inside big cities, but also together with PV parks, a sufficient amount of ODS but also electrolyzers. It is strongly preferred to have PV panels of large buildings and PV parks installed in the east/west direction, resulting in a better distribution of power during the day and it also means a better load for the electrical grid. Installing PV panels on a roof with direction to the east(or the west) reduces the efficiency of the panels with about 80%. This is very acceptable because it makes the power management much easier and less expensive. This should be promoted when subsidies are given to install PV panels, or even made mandatory or it can be promoted using a suitable electricity tariff (see section 5.6).

One should avoid that most of the installed PV panels are facing the south. It is interesting to note that a house with panels placed east/west on both roof halves can produce at least 1.5 times the energy compared to a house with PV panels only on one roof halve directed to the south.

About the chosen ratio of wind versus PV the following. It has been chosen to approximately match the supply of electricity during the summer and winter months with the expected electricity consumption during those to parts of the year.

Doing so will minimize the amount of hydrogen that has to be made and stored in the season buffer. But there could be other arguments to determine the ratio of wind versus PV. What also must be taken into account is that the landscape in the Netherlands should not be disturbed too much by the installation of large amounts of PV or wind turbines. That is why we have kept the amount of wind turbines on land to a minimum. Also we want to limit the amount of solar parks as much as possible and assume that the available area on roof tops will be sufficient to supply the main amount of needed solar energy. In this way we arrived at 77 GW of PV power.
The network overview below gives an overview of where several components need to be placed.

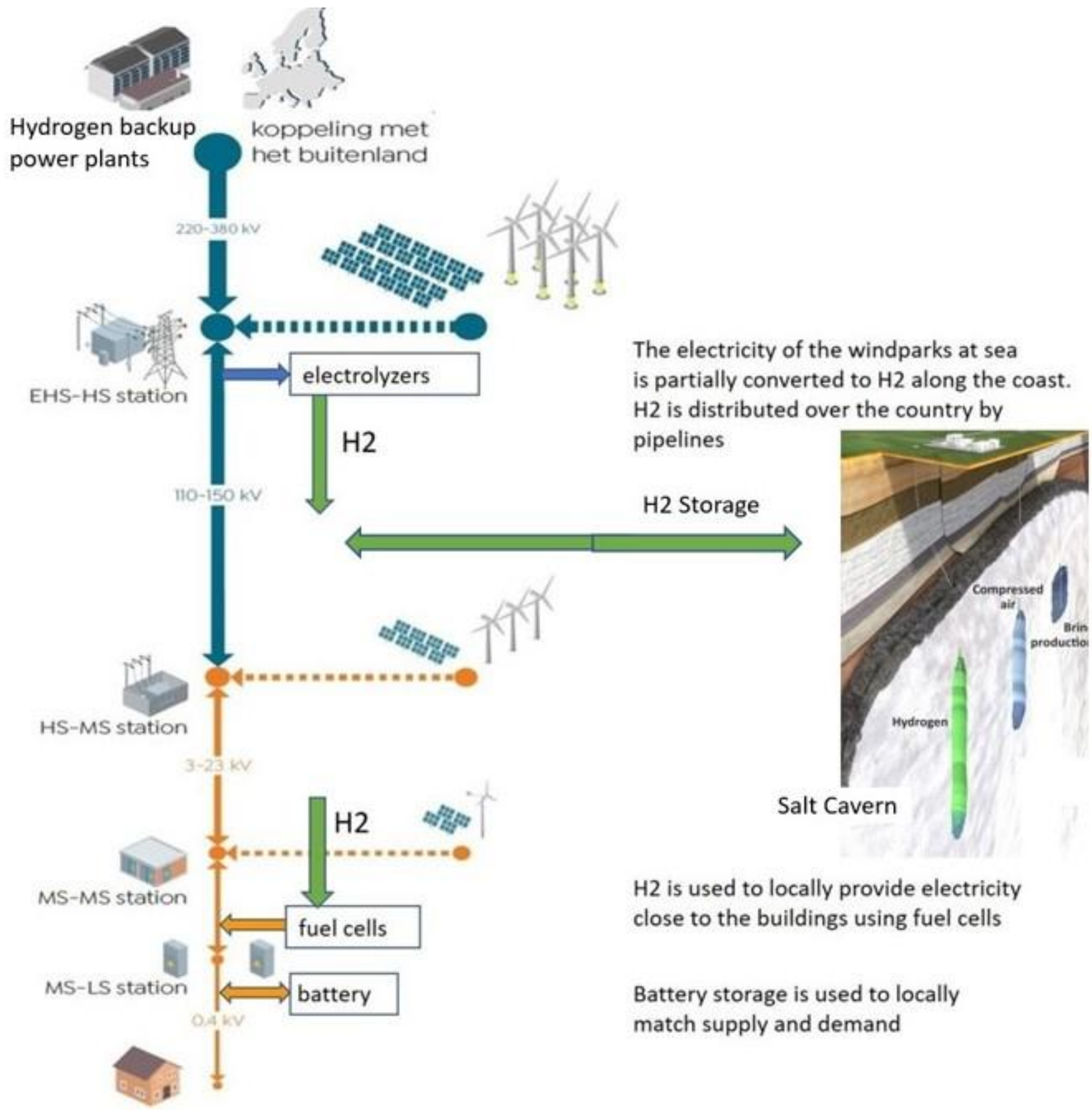


Figure 5.1 Electricity network with connected components in 2050 (Netbeheer Nederland 2019)

Currently the electrical power is distributed to the homes via a low voltage (LV) network that is supplied by a transformer that converts medium high voltage (MV) to the needed low voltage (LV). Typically 400 homes in a residential city area are served by one (MV to LV) transformer now and the transformer has currently a rating of 400 KVA to 600 KVA. If we assume an average of 5KW of PV panels for each home in 2050 , that will require 11 panels based on the 2050 values for PV efficiency and full load hours.

If we assume that the 400 homes have an average of 5 KW PV installed panels , the peak power of the combined PV panels on a sunny day may be much higher than the capacity of the transformer (Lemmens et al. 2014). Therefore it is desirable to install a sufficient amount of battery storage in the low voltage section. Moreover part of the peak power may be also consumed in the homes for example to make high temperature water (70 degrees) that can be stored in a warm water tank or by charging an electric vehicle. This proposal may in principle solve the issue of peak power of PV panels. The MV-LV transformer will need a sufficient high rating but the required rating will be mainly determined by the needed power to heat the homes on cold winter days. This will be explained in section 5.4.

5.3 Electricity backup power plants

They will be needed for some time during the year to supply the needed electricity. This will be done in the beginning by gas turbines. It would be advantageous that those gas turbines could later also operate on hydrogen. Investigations are already done to design such gas turbines. In the long term however we prefer fuel cells to deliver the needed electricity, mainly because they can be better designed for smaller power ratings and be installed in a very decentralized manner.

5.4 Heat demand for the homes

We propose to have two main sources : heat nets and heat pumps.

Some people propose to heat homes with hydrogen. Although this could be done , the efficiency of this solution is lower compared to the use of heat pumps. The only important problem with heat pumps is the large amount of power that is needed when we have <u>very cold outside</u> temperatures. We propose the following solution to be able to handle this.

There is a lot of interest currently in installing heat networks. Important sources for heat delivery are geothermic heat, green gas (hydrogen) and rest heat from the electrolysis systems, backup systems and industry. As the installations of heat nets may be cheaper than a required electrical grid strengthening, heat nets are an attractive solution for the low temperature heat demand. It will lower the high electrical demands for the heat pumps during cold winter days. We have questions using geothermal heat however since it may be available only on restricted locations in our country. Also heat produced with green hydrogen may have a disadvantage due to a lower efficiency compared to heat from heat pumps.

So we assume the heat for the future heat nets will be delivered mainly from rest heat. Based on this analysis, the heat demand for houses and buildings of our proposal is based on heat pumps and decentralized heat nets.

The amount of available rest heat will however decrease in the future. But an important new source of heat will be the electrolyzers which will have a capacity of 40 GW and will produce about 46 TWh of heat, which should be used wherever possible. By putting most of the electrolyzers along the coastline , major cities along the coast can have heat nets that may be supplied by this heat. Moreover seasonal heat storage in large water tanks may be implemented to use the heat, generated during the summer months, for the winter period. This is a plan that should be worked out in more detail. Nevertheless we suggest that a lot of attention must be given to a solution where homes are only supplied with electricity to provide the necessary heat. We will explore this solution now in more detail.

In 2050 an hydrogen network will become available throughout the Netherlands that will be connected to all the villages and cities. This network should be a network, parallel to the current gas network. It is needed to carry pure hydrogen that can be used by fuel cells, as a feedstock for the chemical industry and to provide an energy backup. Hydrogen may of course also be injected in the current gas network if needed. We propose that this hydrogen network is extended to places close enough to a larger group of homes. At those places fuel cells need to be installed that can deliver the required power. The hydrogen gas network can fuel in that way the fuel cells system. Hydrogen trucks are expected to have a fuel cell power source of at least 250 kW in the future. Similar high power fuel cells can be used to serve a large number of homes. This electricity can be delivered to the 10 KV network or the 220 V network, whichever is more appropriate. The capacity of the low voltage electricity network will have to be upgraded to accommodate the winter peak demands. A serious overloading of the transformer will occur during the winter on a cold winter day with temperatures lower than zero degrees Celsius, caused by the heat pumps of the homes. The energy demand is estimated to be in that case 2 to 2,5 kW for an “all electrical” home. So the 400 “all electrical” homes cause a peak demand for the transformer of 800 – 1000 kW!

The required power rating of the needed MV-LV transformer is therefore estimated to be around 1000 kVA for 400 homes.

A fuel cell unit of 600 KW, connected to the MV network and situated near the neighborhood MV-to-LV transformer, may be sufficient to provide the homes with the needed extra electricity for the heat pumps in the homes. An alternative solution may be to install only 300 KW of fuel cells and supply the other needed 300 KW directly from the electricity grid, which then should be able to supply the additional power. Also, if there is enough space available close to the MV-LV transformer the fuel cells may feed directly to the LS network which will allow to use the available transformer.

There is another way to limit the peak power needed for the heat pumps. During cold winter days there is still a considerable difference between the maximum temperature (during the day) and the minimum temperature (during the night). It must be possible to install a small heat storage tank that is supplied by heat during the day and that can supply the heat to the heat pump when the outside temperature is very low. This will result in a higher COP value with which the heat pump can operate. A water storage tank of about 300 liters may be already sufficient for this purpose.

Regarding the heat nets, it is assumed that the heat nets in the future will be low temperature heat nets delivering about 40 degrees to the homes. The heat required to feed those heat networks needs to be carefully studied because much less waste heat will become available in the future. One of the solutions could be to make use of the surface water which is plenty available in the west and north of the Netherlands and use this as input to the heat pumps. Another source may be the heat generated by the electrolyzers and fuel cells.

Another interesting option is to consider a micro heat network that serves all the houses in a row of houses (terraced houses). At the end of the row of houses a common powerful heat pump can be installed that provides the necessary heat to all the houses in that row. This heat pump can be supplied with extra electricity from attached fuel cells, and the heat generated by those fuel cells can then also used.

5.5 Charging electric vehicles

It is foreseen that in the future the charging of electric vehicles can lead to high power peaks on the electricity grid, especially when many high-power charging stations are used. Already now 350 kW charging stations are being deployed. In the future the desire for fast charging will even increase to be able to fully charge large capacity batteries in less than 30 minutes. But also power peaks may arise when people arrive at home in the evening and start charging their cars. Some smart control will have to be used to avoid large power peaks. But it may be even necessary to install extra battery capacity between the grid and the charging stations to lower the power peaks. It is also advisable to introduce higher kWh prices for cars that charge with high power, which is currently already the case.

5.6 Government directives

To achieve the desired goals the government will have to intervene to set directives.
It is common opinion that some kind of CO_2 tax will be necessary to stimulate the conversion to green energy. This will help, but then there should also be affordable alternatives available. Currently the main problem is that there is not a sufficient amount of (cheap) green electricity available to replace the electricity generated by the current power plants.
Another problem is the CO_2 emission by airplanes. It is already possible to make synthetic jet fuel from CO_2 and electricity. But the cost is still too high. Similar to the directive that 10 percent of the gasoline should be bio based, one should set a directive that will demand that a certain percentage of the jet fuel will be green. That percentage should be increased every year until the entire jet fuel supply is green.
From the above analysis is it clear that a large amount of electrolyzers need to be installed. They will become needed in the near future. The government must develop soon a plan on how to realize sufficient affordable electrolyzer power in time.
A similar directive could be set to the supply of hydrogen. One could demand that a certain percentage is green hydrogen and increase this percentage over the years.
Another issue is the kWh price that owners of wind parks on the North Sea will receive in the future. This is not addressed now but need to be addressed soon. It is expected that the price will decrease at moments when there is too much electricity produced (not counting the electricity used by the electrolyzers). A lower price will be attractive for the owners of the electrolyzer plants along the coast line, but not acceptable for the owners of the wind parks. This issue needs to be addressed as well. From our financial analysis we can conclude that a financial viable system is possible when the average price one gets for delivering electricity to the net is around €7 per kWh or more and that the price for electricity delivered to the electrolyzers is around €3 per kWh or less. Those figures must be kept in mind when developing the new tariff rules.
One more important issue is to have a good successor of the current “saldering” system. One can assume that in the future the network manager can access the electrical power that is consumed and also delivered by each home on a continuous basis. The new system should use that information. The new system should of course promote that house owners install as much PV panels as possible on their homes but also that homes with east/west roofs have a fair return on their investment. But a second issue is that the new system should also promote that an sufficient amount of the PV electricity is directly used by the homes in the neighborhood or being buffered by the local battery. In this way it will be avoided that too much electricity power is passed through the local MS-LS transformer further on into the network. Therefore a plan for installing batteries in or close to homes must be developed soon. We propose to mainly use for this second life batteries from the existing electric vehicles which should become in large quantities in the (near) future.

6. Conclusions

The main conclusion is that the energyNL2050 system we described and analyzed is both achievable and cost effective. It is based on a realistic estimation of the future energy demands and detailed hourly simulations of the energy system. Emphasis should be placed again on the fact that the system is 100 percent CO_2 free except for aviation fuels. But those will be synthesized in a CO_2 neutral manner.

Due to the full substitution of the fossil energy carriers with electricity and hydrogen in all sectors - from transport, industry to household - results in a low final energy demand, about half of the current final energy demand. The mix of renewable energy sources , in total 420 TWh , includes 85 % of variable renewable electricity from wind and solar. A very large part of the required 420 TWh energy can be produced in the Netherlands by PV and Wind, onshore and offshore as well.

The simulations show, that energy delivery is fully assured if a well-balanced backup system is part of the energy system. Large scale Hydrogen storage with Fuel cell systems have preferable properties as backup systems.

A first important observation is that the speed of introducing PV installations and wind turbines at sea is currently far too low in order to meet the 2050 goals. There is an urgent need to have more green electricity soon not only to be able to reduce the current amount of power stations but also to increase the supply of green hydrogen. Especially the slow speed of installing wind at sea is worry some.

The proposed system requires many essential components of which the electrolyzers need a faster development as well as cost reduction. Currently the largest installed electrolyzers plants have a capacity of 20 MW. At this moment such plan is not in place. Promising plans in the northern part of the Netherlands (Groningen Seaports, Eemshaven) and the Port of Rotterdam (Maasvlakte 2) still must materialize (Shell 2020) and (Port of Rotterdam 2020). Strong support from EU and Netherlands government is needed e.g. vision on hydrogen (Wiebes 2020).

The preferred technology is PEM because it is most suited to operate with fast changing power input and also because it has a small footprint. But PEM requires very rare earth catalysts such as iridium and there could be an insufficient supply of this in the future.

The fuel cell systems need faster development and cost reduction as well. Key technology under development for automotive applications seems well suited in terms of specification and cost.

The financial analysis shows that the annual costs are relatively flat, when varying the capacity of the electrolysis system and one day storage system (ODS) , and results in €28 billion per year with a 40 GW electrolysis system and a 80 GWh ODS. Compared with the current total energy demand costs of about €21 billion, the 2050 energy costs are €8 billing higher. A CO_2 tax of only €44 per ton CO_2 emitted will compensate this difference.

Our system simulations are largely based so far on a copper plate model. We are in the process of replacing the copper plate model with a model based on the common HS, MS and LS-planes. First results are encouraging and indicate that with proper distribution of the Fuel cell systems there is no need to substantially increase the MS and LS capacity.

So our general conclusion remains that we are convinced that our energy plan is both achievable and cost effective.

7. Acknowledgment

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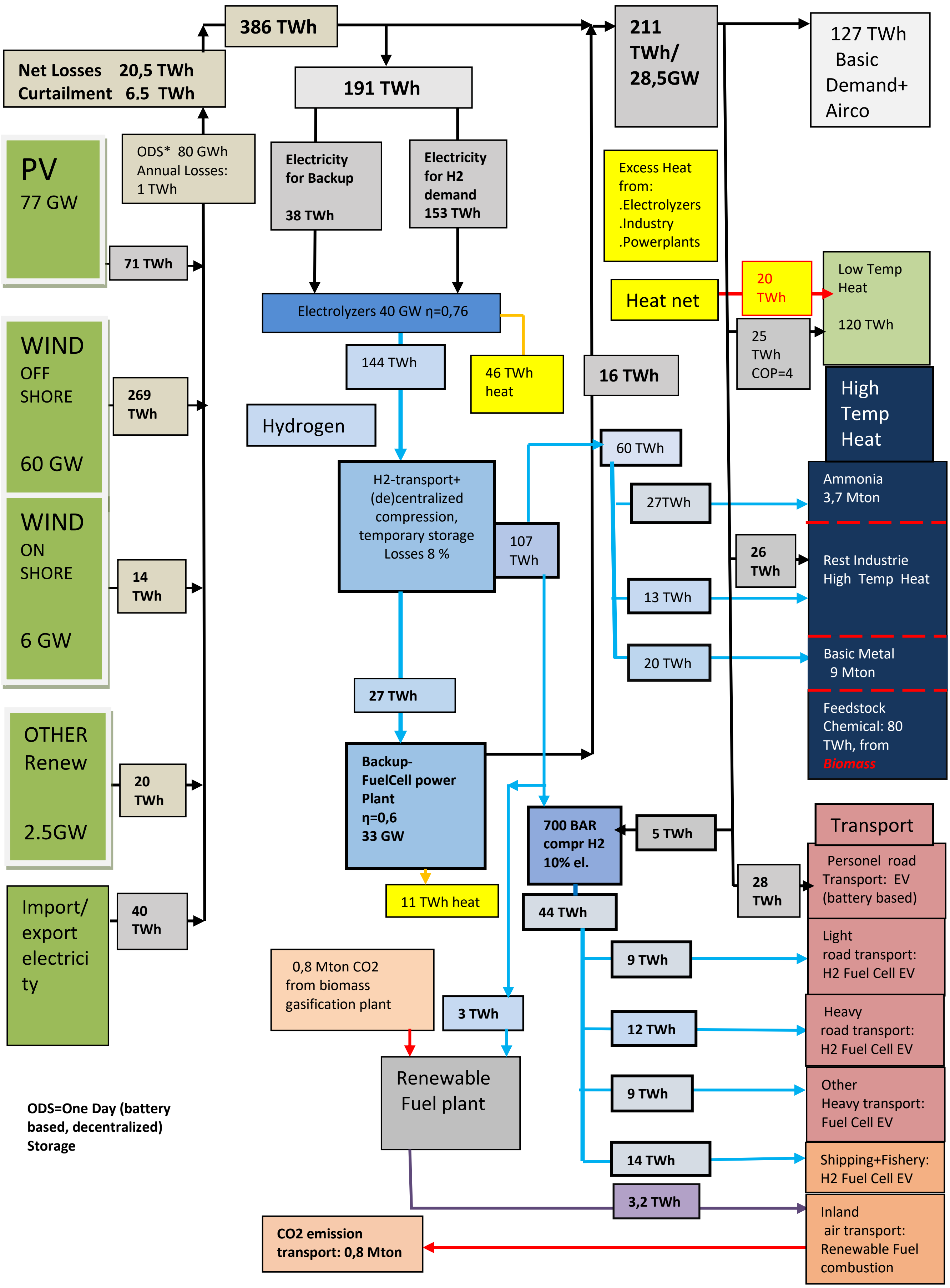

Appendix A: Improved High level Energy System: energyNL2050
Annual primary energy: 414 TWh; CO2-emission: 0 (0,8) Mton
PV=20% of vRE version 16/10/2020

Appendix B: Energy demand of the energyNL2050 system.

2015 Functional Energy Demands.
Total functional energy demands are 640 TWh, based on the CE-Delft study (Warringa and Rooijers 2015):

- **Basic electricity demand: 120 TWh**

Basic electricity demands covers the electricity need of all apparatus in all sectors from households to industry etc.

- **Transport: 160 TWh**

80 TWh for passenger cars and 80 TWh for all other road transport plus inland shipping. The energy required is almost entirely fossil based and the *tank-to-wheel efficiency* (TTW efficiency) of the various transport types differs between the types of course, but we assume for simplicity an average TTW efficiency of 25%.

- **High Temperature Heat (temperatures >100 ^oC): 160 TWh**

Basic steel production 30 TWh, refinery energy 22 TWh, cement industry 5 TWh, ammonia industry 28 TWh, other industries: 75 TWh. The plastics industry requires 160 TWh fossil fuels, but does not make officially part of the energy demand calculation.

- **Low Temperature Heat (T, <100 ^oC): 200 TWh**

This is the heat demand for the build environment, Utility sector, Industry and Agriculture. 80% of the low temperature heat is for space heating, 20% for hot water and cleaning services. Some heat is also used as process heat in the industrial sector.

2050 Functional Energy Demands.
For the functional energy demands in the period between 2015 and 2050 we expect an average annual saving of 1 % and an economical growth of about the same 1 % annually (more exactly 1,15%). This means for the functional demands:

- **Basic electricity demand: 127 TWh**

This demand figure includes also the energy for air-conditioning. We originally supposed this demand is about a constant demand throughout the year. But the hourly variations derived from historical data sets are now used in the energy system simulations in part 3, resulting in improved, realistic system simulations. Main characteristic is that the night electrical demands are about 20% lower than the daylight demands.

- **Transport: 75 TWh. Electricity 28 TWh and Hydrogen 47 TWh.**

Transport is fully switched over to electrical power propulsion systems, battery based for the passenger EV (BEV) and hydrogen-fuel cell based for all other road transport (FCEV). Shipping (inland and international) is also switched over to hydrogen – fuel cell based electrical power drive. Air transport will mainly use synthetic kerosene.
The electrical drive systems have a much higher efficiency compared to the combustion systems nowadays:
BEV: the EV efficiency has been defined more accurately The tank-to-wheel (TTW) efficiency is 75%, meaning that BEV is 3x more efficient than combustion drive systems. So the Passenger EV sector requires 28 TWh electricity.
FCEV: the TTW-efficiency is lower due to the on board fuel cell with 60 % efficiency: 45%. But compared with combustion systems the efficiency is 1,8 more efficient and because of this the heavier transport part requires 44 THW H_2.
The fuel cell vehicles require strongly compressed hydrogen up to 700 bar enabling a good distance range. 700 Bar hydrogen pump stations have been added in the system design for that reason. A typical group of hydrogen compressors are ionic compressors. Hydrogen pump stations therefore have an additional electrical demand of 10% of the compressed hydrogen energy content, resulting in an additional 5 TWh electricity demand.

- **High temperature heat demand: 76 TWh. Electricity is 26 TWh and hydrogen is 60 TWh.**

High Temperature demand from the in industrial sector shall also be fully based on electricity and hydrogen as energy carriers, resulting in significant energy savings.
. No refinery energy will be required, as transport is based on electrification.
. The basic steel production will use hydrogen as the deoxidizing medium, resulting in CO2 free steel making and also some energy saving.
. HT Heat energy demand with temperatures between 100-250 degrees Celsius will be produced with industrial heat pumps with a coefficient of performance (COP) of 2 or higher.
. Ammonia and the associated fertilizer industry will be based on green hydrogen.
Together with some smaller energy savings the HT Heat demand will be 76 TWh**.**
Remark: The plastics industry output will have an energy value of 160 TWh. In 2050 we expect that 50% will be produced from recycled plastic material and for the other new plastics biomass will be the basic input material.

- **Low temperature heat demands: 120 TWh, 20 TWh via heat grid with heat from residual heat of energy system parts (electrolysis systems, fuel cell backup systems, high temperature industries) and 100 TWh via heat pumps, requiring 25 TWh of electricity**

The low temperature heat demand shows large energy savings due to significant homes and buildings insolation in the coming decades, resulting in a total LT heat demand of 120 TWh.
We start with the 2012 LT Heat demand of 200 TWh, based on the 2014 CE Delft study (Warringa and Rooijers 2015). The study for the *Dutch Climate Agreement 2030, part Heat Demand build environment* (Nijpels and Samson 2018)*,* second column of table 2.1, shows a significant energy saving, which can be extrapolated to 2050, third column in table 2.1).
LT Heat demands for Industry and Agriculture are assumed to stay fairly constant (economic growth and energy savings are expected to be equal up to 2050). Based on this analysis the results for LT Heat demand are shown In table2.1:

Low Temperatur Heat Demand	**2015 TWh**	**2030 TWh**	**2050 TWh**
Households	94	68	57
Utilities	64	25	21
Industry	17	17	17
Agriculture	25	25	25
Total TWh	**200**	**135**	**120**

Table 2.1: LT Heat Demand 2015-2050, partly based on the results of the Dutch Climate Agreement 2030.

The heat demand will mostly be delivered by heat pumps with an average COP= 4. Also a heat grid will deliver 20 TWh heat, derived from residual heat of different energy system parts. As a consequence the LT heat demand will be reduced to 120 TWh heat: 25 TWh electricity for the heat pumps and 20 TWh via heat grids.
The heat pumps have an average COP=4, but in part 3, a COP depending on the daily temperature has been introduced, meaning a lower COP at lower winter temperatures. This results in a more realistic energy demand during the winter period.
The 20 TWh heat network is supplied by the excess heat of the electrolysis systems, backup systems and from the industry.

Overall result of the 2050 functional energy demand:

Energy Demand per Function	2015 Fossil based TWh	2050 Electricity TWh	Hydrogen TWh	Heat Nets TWh
Basic electricity demand	120	127		
Transport	160	28	47	
Hydrogen compression (700 bar)		5		
High Temperature Heat	160	26	60	
Low Temperature Heat	200	25		20
Total Demand TWh	**640**	**211**	**107**	**20**

Table 2.2: Functional energy demands 2050 compared with the 2015 demands

Appendix C: EnergyNL2050 system verification

This appendix describes the simulation of the NL2050 system. Focus is on the essential elements of the simulation and the key results. A full description of the simulation is outside the scope of this paper and may be published in future.

C.1 Simulation setup & used data sources

Fig. C.1.1 shows the scope of the simulation. It covers the electric elements as well as the electrolysis, hydrogen storage and fuel cell components.

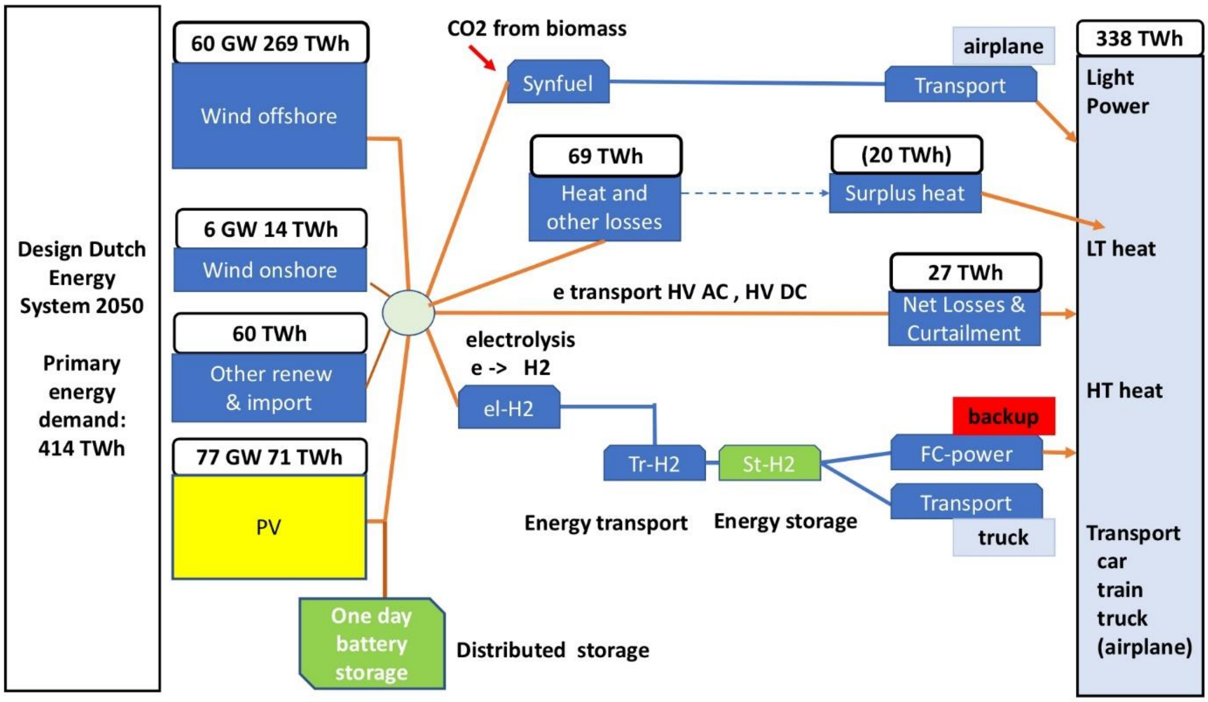

Fig. C.1.1 Simulation set-up

As stated in Section 3, the simulation relies on actual hourly renewable electric energy production data as well as the load on the electric energy transmission grid as published by TenneT over the years 2016-2018 (Tennet ENTSO-E OPSD 2019).
Obviously, the load pattern in 2050 will be quite different, however the TenneT data of today are a good basis for the Light & Power component in 2050 as shown in Fig. C.1.1.
To determine the LT heat component of Fig.C.1.1, it uses the ambient temperature data from KNMI over the same period. The resulting Time Series (TS) are shown in Fig. C.1.2 in overview and in Fig. C.1.3 for the month of January 2017. This was a relatively cold month with prolonged periods with low wind and little sun ("Dunkelflaute"). The modelling of the HT heat and the Transport components of Fig. C.1.1 are described in the next Section.

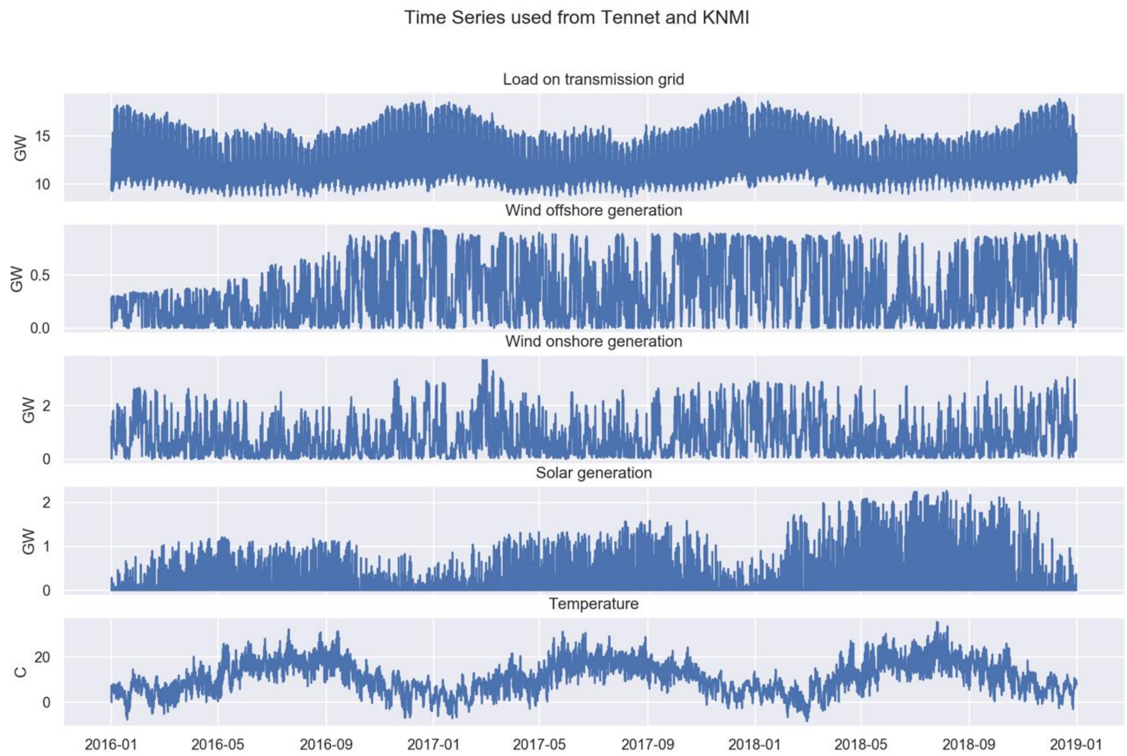

Fig. C.1.2 Overview of source data

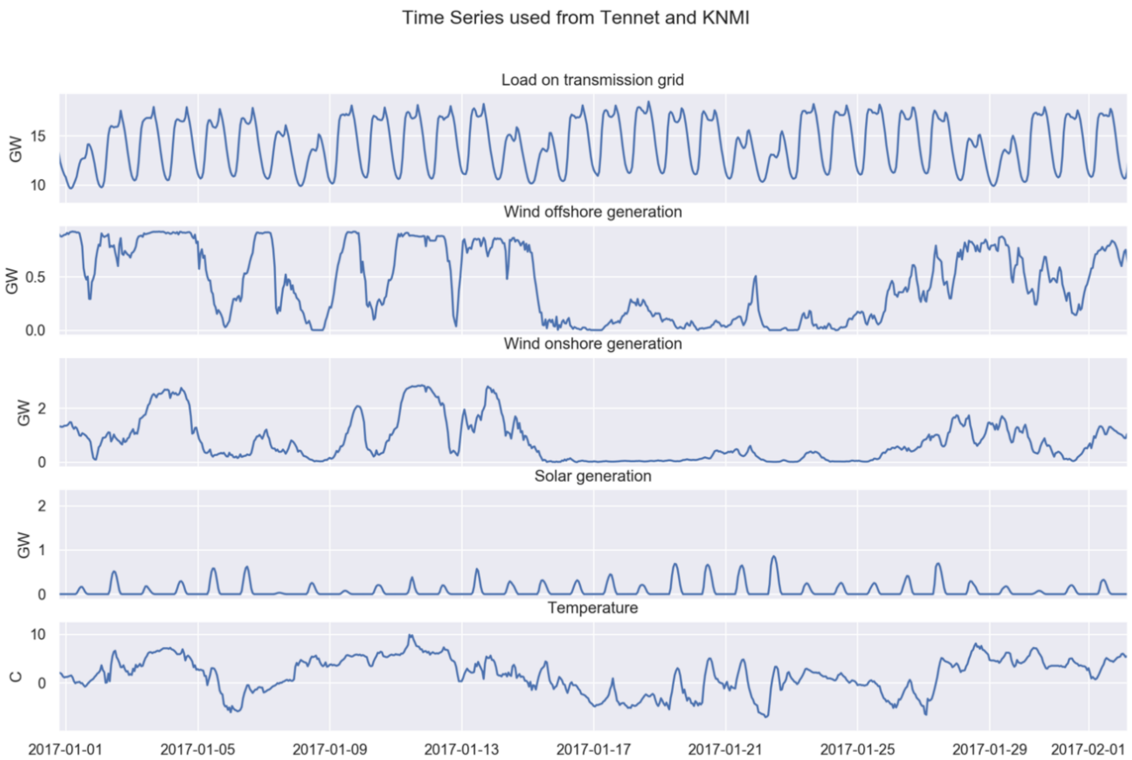

Fig. C.1.3 “Dunkelflaute” in January 2017

C.2 Source data processing

This section outlines how we process the source data in several ways to mimic the expected behavior of the proposed 2050 energy system.

In 2016 the large Gemini wind park located 85 kms off the coast of the Netherlands became operational. Also, during the full period from 2016 till 2018 much additional PV capacity became available. We have compensated the hourly production data of both the wind and PV system for the buildup over the period.
The offshore wind turbines in use in 2050 will show an increase in the number of full load hours per year compared to the current ones. We have included this aspect by clipping the power levels at 80% of the maximum. This compares to 4350 full load hours in 2050.
Finally, we have taken into account the preferred East-West orientation (be it in a relatively crude way) by splitting the PV generation TS in two halves followed by time shifting the two parts plus and minus two hours.
We then scaled the data to represent the envisioned production volumes for 2050, resulting in an hourly Time Series (TS) representing the total energy production as delivered to the electrical grid.

For the energy consumption in 2050 we started with the existing load on the transmission grid.
To account for the increase in electric energy consumption for heating we used actual ambient temperature data from KNMI. We modeled the required capacity for heating on a daily basis as well as the efficiency of the heat pumps (COP) on an hourly basis.
The time period 2016-2018 did not include periods of extreme cold. To validate the concept also in these situations we modified the temperature data of the three 24-hour periods from January 23 till January 25 to a constant -10C
The required energy to charge the battery based electric vehicles (BEV) is included assuming semi-smart charging: a fraction of the BEVs is not charged when there is a power deficit.
We also took into account the existing load on the transmission grid.
Adding all the above energy consumption elements this resulted in an hourly Time Series representing the total electric energy demand. This obviously excludes the electric energy required for electrolysis.
By subtracting the energy demand TS from the energy production TS (and also taking into account the electricity from import plus other sources) we obtain the supply-load residue TS, from now on called the Grid Balance Time Series (GBTS) that for each hour indicates the unbalance in the system, either an energy surplus or an energy deficit, that would happen if no further measures would be taken. As described above, in our proposed system energy supply and demand are matched by proper use of the One Day Storage and Hydrogen Backup Systems (HBS). As the round-trip energy loss of the HBS is significantly higher than the round-trip loss of the ODS batteries it is a key objective to limit the use of the hydrogen backup system as much as possible.
It is assumed that in 2050 the various power transmission networks will not be limiting (copper plate assumption). In the financial analysis in Section 4 / Appendix D will revisit this assumption.

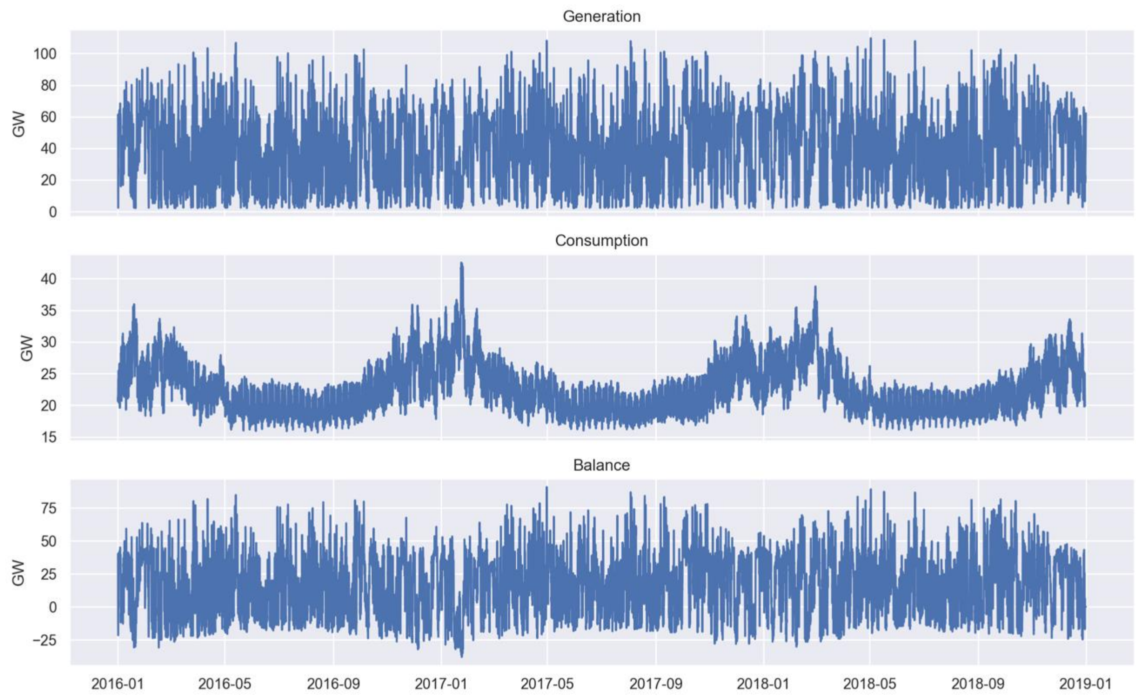

Fig. C.2.1 Expected Energy Balance for NL2050 system

Fig. C.2.1, Fig. C.2.2 and Fig. C.2.3 show the three TS mentioned above for the full three-year period, January 2017 and a period in June 2018 with large variations in wind conditions.

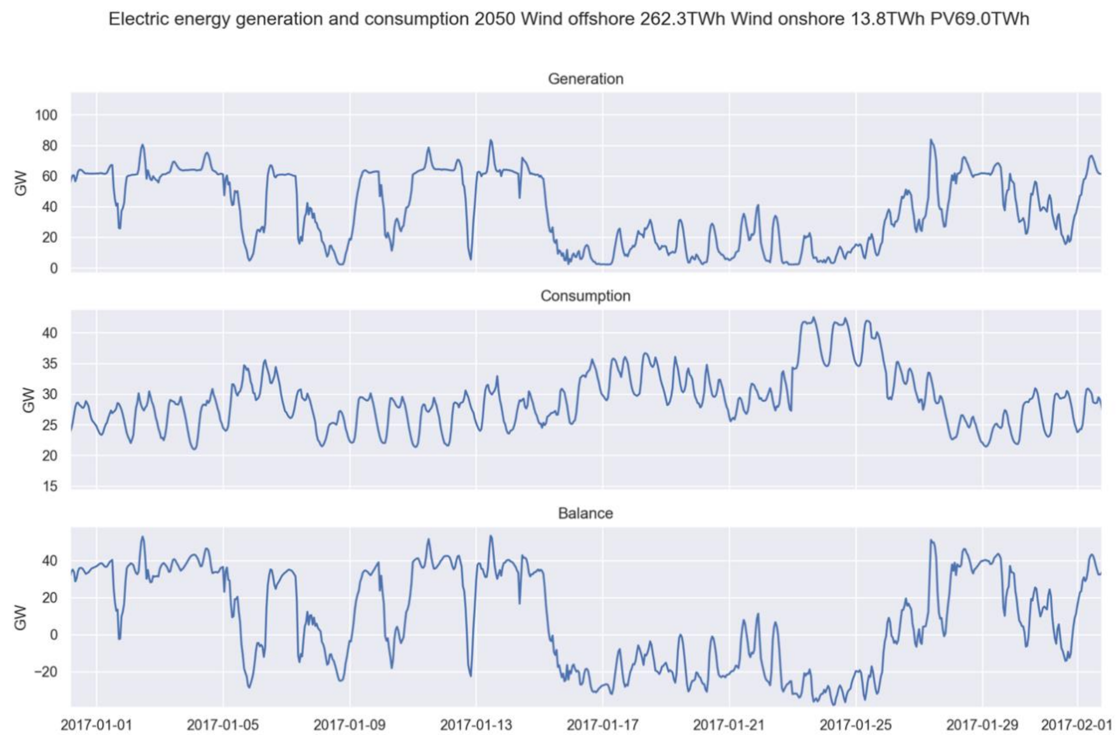

Fig. C.2.2 Expected Energy Balance for January 2017 conditions

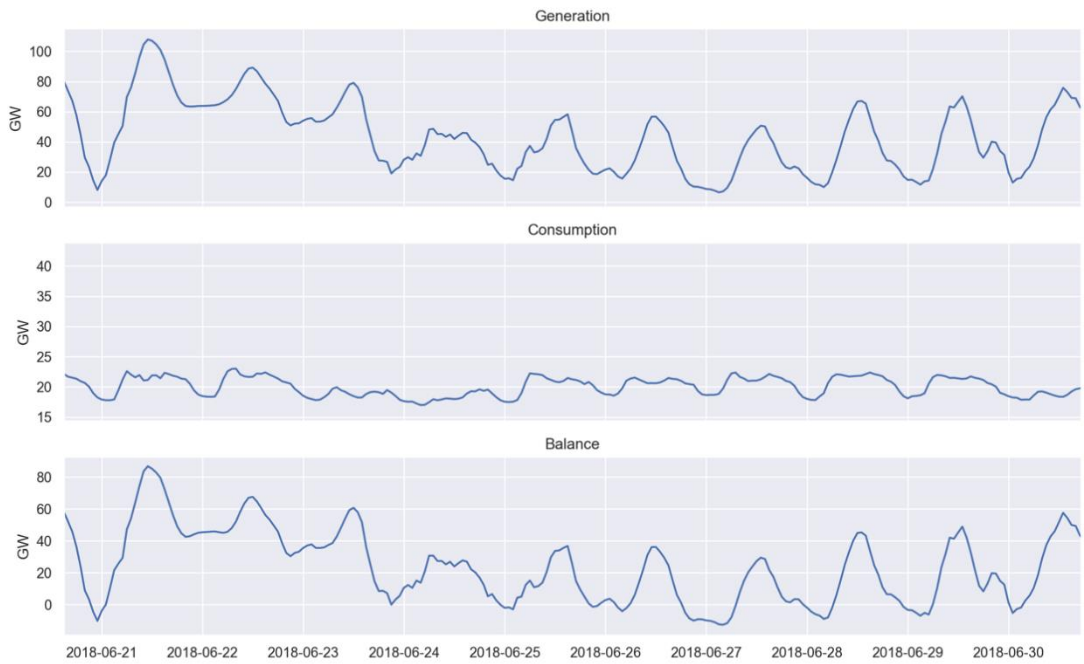

Fig. C.2.3 Expected Energy Balance for June 2018 conditions

The energy generation shows large fluctuations, from almost no production to over 100 GW in case of sunny days combined with strong winds. The energy consumption shows a strong seasonal variation caused by the heat load.
As a result of these effects, the Grid Balance Time Series varies considerably as well. This can be clearly seen from its PDC. Sorting the GBTS readily delivers the PDC as shown in Fig. C.2.4. We notice a variation from a surplus of 90W on the left to a deficit of -40GW at the right. The circle denotes the cross-over point. The annual deficit (area where the balance is negative) is 21 TWh whereas the annual surplus (area where the balance is positive) is 193 TWh.

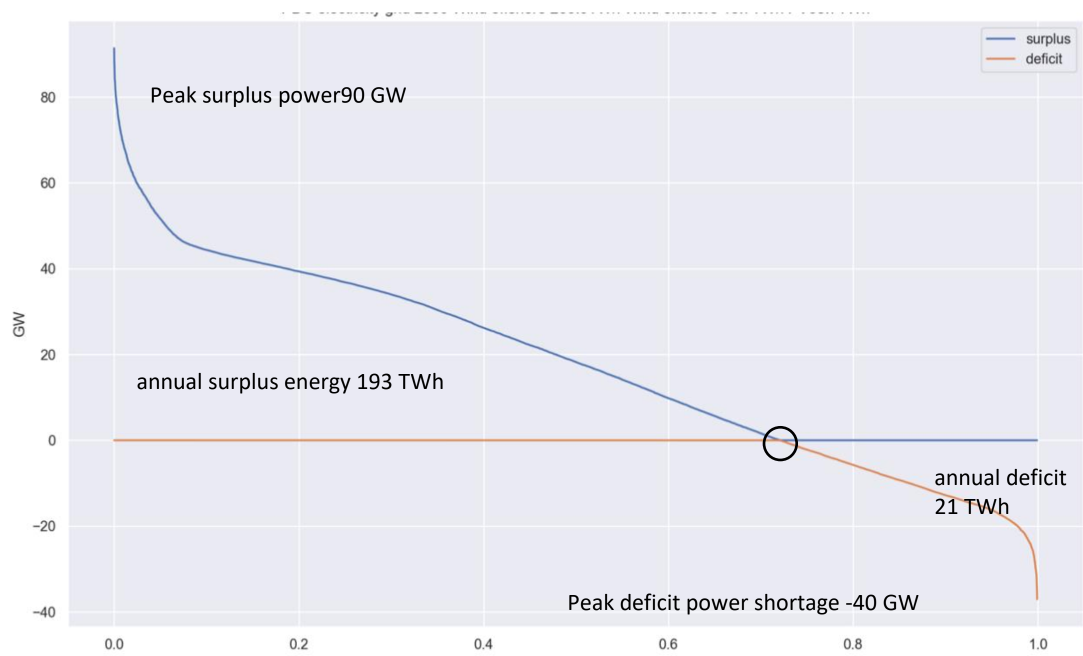

Fig. C.2.4 PDC of simulated electricity supply & demand in 2050

In the next section we describe the role of the ODS, the electrolyzers and the fuel cells to match energy consumption and generation.

C.3 Balancing the system

Short deficit periods of a few hours e.g. at night during the summer periods can be covered using the One Day Storage (ODS). For longer periods the Hydrogen Backup System (HBS) has to be used. As the round-trip energy loss of the HBS is significantly higher than the round-trip loss of the ODS batteries it is advantageous to limit the use of the hydrogen backup system as much as possible. This has been taken into account in designing the control algorithm of the ODS used in our simulation.
As described above and substantiated by the financial analysis described in the following Section it is not optimal to provide all the electrolysis capacity to completely cover the peak surplus. So, some curtailment is unavoidable. Limiting curtailment is also taken into account in the control algorithm of the ODS.

Based on current and expected energy production and consumption, and the State of Charge of the ODS (SoCODS) the control algorithm determines for every hour in the Grid Balance TS the amount that will be charged to or discharged from the ODS, resulting in the ODS Time Series (ODSTS).
Subtracting the ODSTS from the GBTS results in the amount of electric energy that can be supplied to the electrolyzers or that has to be delivered by the fuel cells, resulting in the Hydrogen Backup System Time Series (HBSTS).
From the ODSTS together with the losses in the charge-discharge round trip the SoCODS is calculated.
The SoC of the HBS is calculated in a similar fashion, taking into account the efficiency of the Electrolysers, Fuel Cells and H_2 storage, as given in Section 2.2. It is assumed that the amount of hydrogen supply required (except for the Fuel Cell backup system) is constant over time.
The electrical energy required for the 700 bar H_2 compression for transport is taken into account by an additional 5% loss of the Electrolyser efficiency.
By varying the capacity of One Day Storage and Electrolysis capacity we can firstly safeguard the proper functioning of the system (i.e. no shortage) and secondly optimize the system with respect to cost. The required capacity of the Fuel Cells can be readily determined by the minimum value of the HBSTS. We have identified an Electrolyzer capacity of 37GW and an ODS capacity of 130 GWh as suitable. As will be shown in the next Section the cost sensitivity with respect to these parameters is relatively low, as long as a certain minimum electrolyser capacity is provided, which gives considerable freedom of implementation.

Fig. C.3.1, Fig. C.3.2 and Fig. C.3.3 shows a collection of the above-mentioned Time Series for the full three-year period, January 2017 and a period in June 2018 for these parameters.
The blue graphs indicate the surplus in the balance, the electric energy supplied to the ODS and the electric energy supplied to the electrolyzers of the HBS. Graphs representing the deficit in the Balance, the electric energy supplied by the ODS and the electric energy supplied by the Fuel Cells of the HBS are all drawn as negative values in orange. The maximum Electrolyzer capacity in indicated with a green line, to identify possible or actual curtailment

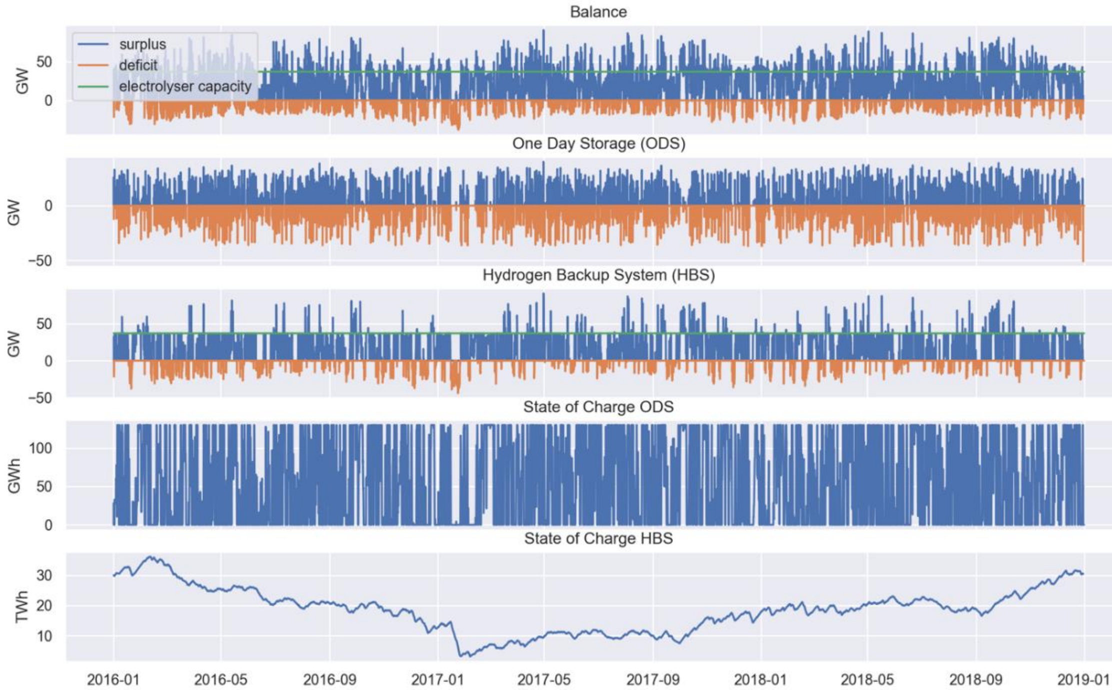

Fig. C.3.1 Time Series of the One Day Storage and Hydrogen Backup System for NL2050

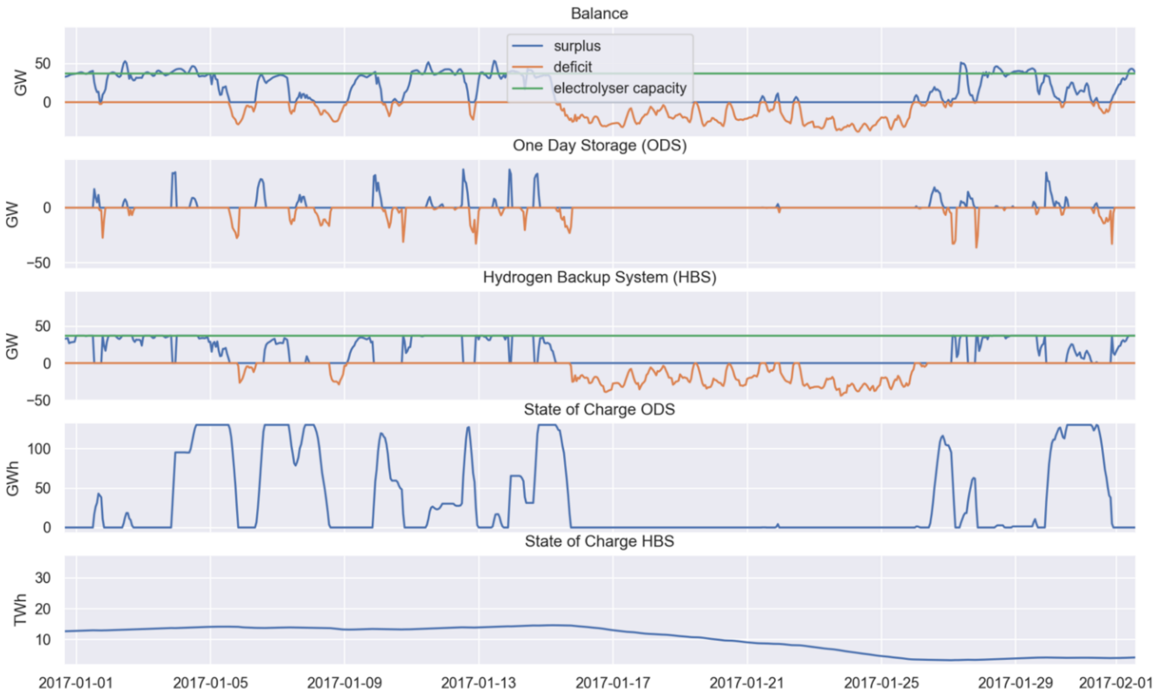

Fig. C.3.2 ODS and HBS TS for January 2017 conditions

We notice that even in winter the surplus in energy generation can be beyond the electrolyzer capacity, as indicated by the green lines in the graph. During the first two weeks, the ODS is useful to prevent curtailment and also to cover short periods of deficits. This is followed by a relatively longer period with a sustained energy deficit and the HBS has to take over.

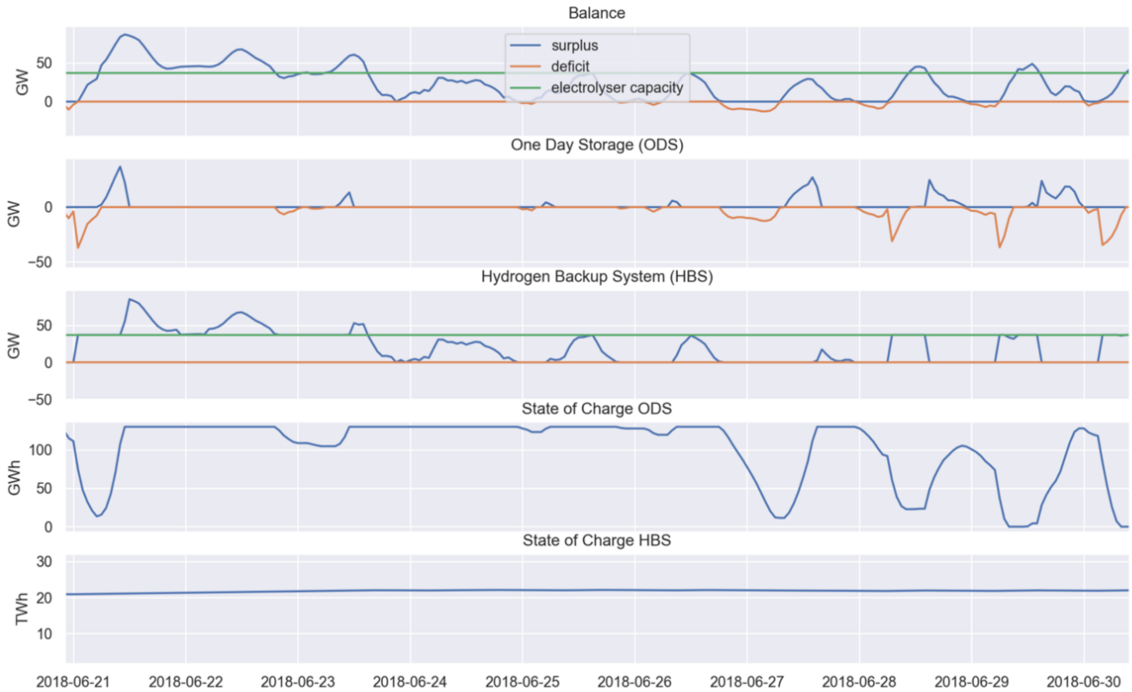

Fig. C.3.3 ODS and HBS TS for June 2018 conditions

In June 2018 we see periods of a large surplus as well as some deficit periods. The ODS is capable of supplying the energy deficits and to absorb some of the surplus to avoid curtailment. From June 21 till June 23 still some curtailment remains.

The effectiveness of the system can be seen from Fig. 3.3.4. Next to the PDC of Fig.3.2.4 we have shown the PDC from the energy balance after balancing by the ODS and after supplying the electrolyzers. The left-hand circle in the graph shows as before the cross-over point between surplus and deficit. The right-hand circle shows the cross-over to the remaining hours where the fuel cells need to provide back-up energy. In between these circles all required hydrogen has to be supplied from storage. Also note a significant reduction in curtailed energy. Without ODS all surplus energy beyond 37GW would have been curtailed.

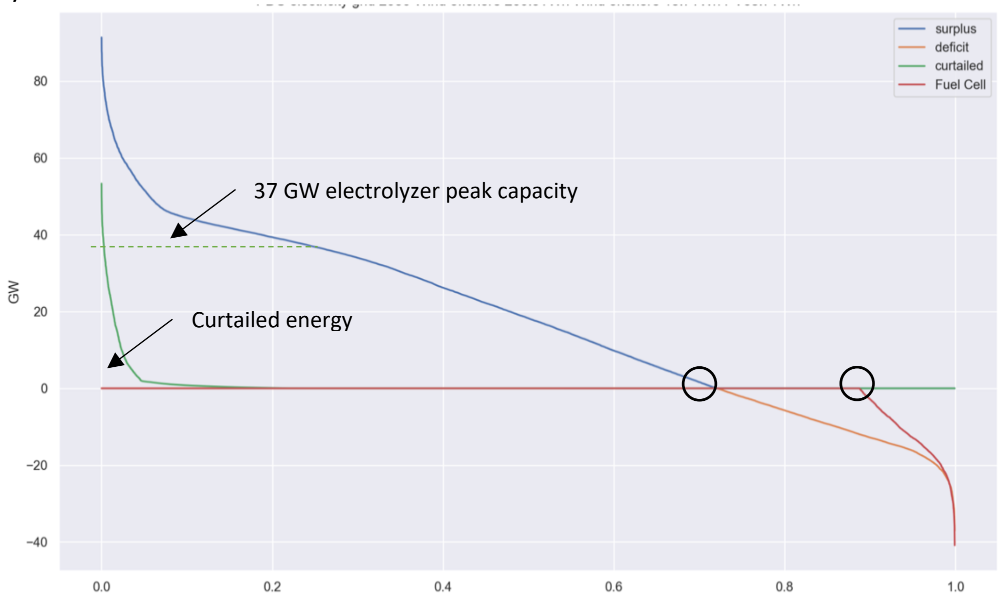

Fig. C.3.4 PDC with improvements in curtailed energy and use of fuel cell backup

Appendix D: Financial/Economic analysis background

For our cost analysis we have based ourselves on several recent studies that forecast the CAPEX of ODS batteries, electrolysis equipment and fuel cells CE Delft (Hers et al. 2018), Strategic Analysis Inc. (James et al. 2017), ENEA Consulting (De Bucy 2016). Similarly, the Levelized Costs of Energy (LCoE) of renewable electricity in the Netherlands from both PV as well as offshore wind has been forecasted for 2030 (Hers et al. 2018) at 36€ per MWh for PV and 35 € per MWh for offshore wind (excluding transmission at sea).

Finally, an important factor is the Weighted Average Cost of Capital (WACC). We have assumed a real interest rate of 4.5%, in line with the WACC mandated for "Maatschappelijke Kosten Baten Analyse' for infrastructure investments in the Netherlands (Dijsselbloem 2015).

We noted that a large research effort in fuel cells development for automotive applications has resulted in major cost reductions (James et al. 2017). In fact the CAPEX of a Fuel Cell for automotive is almost an order of magnitude lower than the CAPEX for a Electrolyzer. In our application the Fuel Cells have a relative low number of Full Load hours (less than 1000 annually). This fits very well with the envisioned application area of automotive Fuel Cells.

See Appendix E for an overview of the main cost parameters used.

Transmission and distribution forms a major part of the system cost. This is mainly determined by the peak loads in the three network planes: HS, MS and LS (see figure 5.1 for more information). We have taken care of the additional load of heat pumps and electric transport by significantly increasing the capacity of the network planes. In the present paper we have not taken this into account in the cost analysis.

Instead we estimate the peak loads in the three network planes as follows:

a. We take into account the assumptions of Section U in (Rooijers and Jongsma 2010): we assume that 39% of the energy for Power and Lighting is distributed via the LS-plane and a further 39% via the MS-plane. We also noted the variation of full load hours for the different planes and we compensated for this by varying the fractions of the constant and variable part of the Power and Lighting allocated to the different network planes.
b. We assume that the energy for electric transport is distributed via the LS plane as well as 50% of the electric energy for LT. The remainder of the energy for LT is distributed via the MS plane.
c. Given the above increase we have analyzed that the network planes have sufficient capacity to handle the upstream load of the PV panels if we allow for a small amount of curtailment.

Section 5 shows a superior approach based on proper distribution of the Fuel Cells and ODS over the three network planes. A yet unpublished analysis indicates that this almost eliminates the need for upgrading the network.

We made a simplified comparison with current cost levels. See Table D.1

NL2050 Energy use / source	*Annual Consumption NL2050 [TWh]*	*Curren t Energy Source*	*Annual Consumption Current [TWh]*	*Current cost [€/MWh]*	*Annual current cost [G€]*
Light & Power / Electric	127	Same	127	39	5.0
LT Heat / Electric	25	Nat gas	164	19	3.1
HT heat / Electric	26	Nat gas	26	19	0.5
HT heat / Hydrogen	66	Nat gas	66	19	2.0
Transport / Hydrogen	41	Diesel	82	42	3.3
Transport / Electric	34	Petrol	104	39	4.2
Network					2.7
Total	319		610		20.7

Table D.1 Cost comparison NL2050 versus today's energy system

We notice a substantial increase of 7.5 € billion, about 36%. This corresponds with a savings of 185 Mton CO2, on average 41 €/tonCO2.

Appendix E: Cost Parameters

This appendix describes the cost parameters as well as the sources and methods used to derive these parameters.

Table E.1 list for all cost parameters detailed information about the sources used. Except otherwise noted we assume a WACC of 4.5%, in line with the standard for infrastructure investments in the Netherlands (Dijsselbloem 2015).
For several parameters additional analysis was necessary, as outlined below. Where applicable we assumed the USD to Euro exchange rate to be 0.9 €/$.
For the One Day Storage system, we based ourselves on a recent forecast for Battery Electric Vehicle Battery Packs (BP). Based on information from {2018 Fraunhofer] we assume the BP cost to represent 60% of the total cost of the ODS and also a system lifetime of 25 years with one replacement of the battery pack. We assumed an OPEX of 1% of the CAPEX.
For the electrolyzers we used a similar approach including a system lifetime of 25 years. Electrolyzer stack is assumed to be 70% of the system cost and OPEX 2% of CAPEX.
For the Fuel Cells we found out that for automotive application extensive programs are running that forecast attractive costs also benefiting from the large volumes expected. As we predict a low number of full load hours, the application profile fits relatively well with the automotive fuel cell specifications. We do expect significant additional cost to secure sufficient system lifetime and allow for replacing the stack and to allow for this we take a multiplier of a factor two into account. We also assume additional project cost of 50%. Still the result of our analysis shows an attractive annual cost of €6.5 per kW excluding the cost of the stack. As the number of full load hours may vary, additionally we take into account a provision for stack replacement of €8.3 per MWh based on the expected lifetime and cost of the stack.
For the costs of the electric transmission and distribution network we follow the methodology and cost numbers as outlined in CE Delft (Afman and Rooijers 2017) including the lifetime of 50 years. When we calculated back the costs indicated for the four configurations outlined in this document, we found that apparently a contingency amount is added to cover planning uncertainties and the like of approximately €1.1 billion annually. We also took this amount into account.

Parameter	Value	Unit	Forecast year	Source	Remarks
Offshore wind electricity	35	€/MWh	2030	(Hers et al. 2018, 53)	Levelized
Onshore wind electricity	50	€/MWh	2030	(De Jager and. Noothout, 12)	Levelized
Photovoltaic electricity	36	€/MWh	2030	(Hers et al. 2018, 53)	Levelized
Other electricity	45	€/MWh	2050		Assumption as otherwise not viable
Hydrogen	2.24	€/kg	2030	(Hers et al. 2018, 31)	Import, integral cost
Battery EV	62	$/kWh	2030	(BloombergNEF 2019, 12)	
Battery	9.4	€/kWh.yr	2030	(BloombergNEF 2019) + own analysis	Annual cost, see text
Electrolyzer CAPEX	538	€/kW	2040	(Hers et al. 2018, 54)	Investment
Electrolyzer	53	€/kW.yr	2040	(Hers et al. 2018, 54 + own analysis	Annual cost, see text
Fuel Cell System CAPEX	27.09	$/kW	2025	(James et al. 2017, 35	Automotive
Fuel Cell Stack CAPEX	15.34	$/kW	2025	(James et al. 2017, 35)	Automotive
Fuel Cell System	6.5	€/kW.yr	2025	(James et al. 2017, 35) + own analysis	Annual Cost, see text
Fuel Cell Stack	8.3	€/MWh	2025	(James et al. 2017, 35) + own analysis	Stack replacement, see text
Hydrogen storage	17.5	€/MWh.yr	2017	(Afman and Rooijers 2017, 104)	Annual cost, see text
WACC E-net (LS/MS/HS)	4.5%		2018	(Afman and Rooijers 2017, 101)	Interest including risk premium
Lifetime E-net	50	Yr	2018	(Afman and Rooijers 2017, 101)	
OPEX E-net	1.27%		2018	(Afman and Rooijers 2017, 103)	Annual cost for operational expenses as fraction of CAPEX
Annuity factor E-net	19.76	Yr	2018	(Afman and Rooijers 2017, 103)	CAPEX / Annual Cost to recover CAPEX, including Interest
Cost HS-net	364	€/kW	2018	(Afman and Rooijers 2017, 103)	CAPEX
Cost HS/MS station	250	€/kW	2018	(Afman and Rooijers 2017, 103)	CAPEX
Cost MS-net	690	€/kW	2018	(Afman and Rooijers 2017, 103)	CAPEX
Cost MS/LS station	200	€/kW	2018	(Afman and Rooijers 2017, 103)	CAPEX
Cost LS-net	916	€/kW	2018	(Afman and Rooijers 2017, 103)	CAPEX
Cost Wind op zee connections	1159	€/kW	?	(Afman and Rooijers 2017, 103)	CAPEX

Table E.1 Sources of the cost parameters