WHEN TRUST MATTERS

INDUSTRY ELECTRIFICATION IN A RENEWABLE POWER SYSTEM

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WHITEPAPER

SUMMARY

This paper is about the gradual electrification of industry and its relation to the growing penetration of variable renewable electricity generation. The interaction between these developments can significantly reduce the challenges associated with either of them.

Decarbonizing the energy system is very challenging. However, it is essential to limit global warming to acceptable levels. The main pathway to decarbonization – replacing fossil fuels with renewable energy – is not straightforward. For the energy system, it involves installing large amounts of variable renewable electricity generation. However, a large installed capacity of renewable electricity sources leads to increasingly longer periods where generation exceeds demand ('surplus' electricity), while on the other hand, periods where renewable electricity generation is insufficient to meet demand remain.

Because of the simultaneity of variable renewable generation, an increase of its installed capacity leads eventually to an increasing need to curtail during oversupply and thus to a reduced yield of added variable renewable capacity. This will threaten the business case for new variable renewables.

The increase in renewable electricity generation capacity and the potential mismatch with electricity demand leads to issues for the market as well as for the infrastructure:

1 MARKET ISSUES

An electricity price of zero for electricity when there is a surplus[1] and high electricity prices during shortage.

2 INFRASTRUCTURE ISSUES

Constraints in the electricity grid that limit the transportation and distribution capacity.

Storage and demand response – such as shifting electricity demand to match variable generation – are seen as solutions. Especially lithium-ion batteries are very well-equipped to accommodate load swings of up to one day. The effect of storage and demand shift on electricity prices is twofold: it creates demand at very low electricity prices, and it increases electricity supply at high prices, mainly caused by a (relative) shortage of variable renewable generation. This leads to a significant reduction in the need to curtail variable renewable electricity in terms of MWh, but unfortunately not as much in terms of the duration of curtailment. This means that, with an increasing amount of storage, the price-boosting effect of storage during charging will increasingly be offset by the price-reduction effect of discharging. Hence, a large capacity of storage and demand shift will have a limited impact on the overall business case for variable renewables.

Demand response that does not rely on shifting demand is another option that is especially suited to free up capacity in emergency situations. This may for instance involve shutdown of operations or industrial demand response capable of falling back on other energy carriers, such as biomass, natural gas, and eventually hydrogen. Such demand response is characterized by 'opportunity costs', i.e. the cost of curtailing production (generally expensive) or the cost of switching to the alternative energy carrier (generally relatively cheap). In this report, we call the latter 'opportunity demand'.

Gradual decarbonization of industry

For industry, the primary path towards decarbonization is electrification, preferably using renewable sources. In this report, we looked at using opportunity demand for industrial heating, i.e. heat supply that is capable of switching between gas boilers and electric boilers depending on the price difference between natural gas and electricity.

Taking Germany as an example, our case-study calculations show that a structurally positive commercial business case is emerging for a hybrid electric-gas system for large-scale industrial heating, provided that the industry is exposed to ETS carbon prices and that synergies with the grid allow for low grid tariffs similar to industry with large continuous electricity load. Hence, opportunity demand can be an economically attractive way to decarbonize industrial heating.

[1] In this report, surplus energy is defined as energy for which there is no use and thus has a value of zero. If it can be stored for later use, or used in alternative ways, it is no longer considered surplus energy.

Setting a price for renewable electricity

Opportunity demand increases demand during renewable surplus, but not during shortage. Because it is triggered by opportunity cost (the fuel price, e.g. for gas or biomass) and not directly related to the current or future electricity price, it can set a price for electricity. In an energy system with plenty of renewables and with sufficient opportunity demand and storage, the price-setting effect is amplified by storage, because storage will take the opportunity cost based on (predominately) natural gas as the low-price reference for charging, instead of an electricity price of zero set by surplus renewables.

From a societal point of view, renewable generation should preferably be stimulated indirectly. By stimulating the demand for variable renewable electricity rather than generation directly, a better fit is ensured between supply and demand, ultimately reducing curtailment of renewable generation. The main bottleneck for the electrification of industry through opportunity demand appears to be the increased need for transmission capacity in the electricity network. This is reflected in a significant increase of the grid fee covering transmission costs for the electric boiler (or electrolyser).

Infrastructure constraints

The German business case for opportunity heating highlights the need for an integrated view on the energy transition that should optimally utilize the synergies between the various aspects of the energy system. There are still significant synergies possible between variable renewable generation, flexible demand with a theoretically infinite sustain time, and the electricity network. We briefly discuss three of them: non-firm capacity, interruptible capacity, and capacity pooling. Compared to congestion management, the latter two options offer the additional advantage of opportunity demand, potentially giving industry a more secure and sustained coverage for the required investments.

In this paper, we define non-firm capacity as capacity for generation or demand that can be shed in advance to avoid congestion. We define interruptible capacity as capacity that can be instantaneously shed to free up capacity for higher-priority load. Because of this, it can make use of the reserve capacity in the transmission system needed to preserve the N-1 redundancy criterion. An alternative way of looking at it is that the load provides an 'N-1 service' to the network. With capacity pooling, several loads and generation units in a confined geographical area collectively contract capacity and are free to share it between themselves, as long as their total used capacity remains within the boundaries agreed upon with the grid operator. This allows the participants to exploit the synergies between their loads.

We show that significant synergies can be achieved through smart electrification of industry by applying opportunity demand to reduce the impact on the network and even help to reduce the impact of variable renewable electricity generation.

Conclusions

In summary:

1

Opportunity demand, especially for industrial heating, is becoming an economically attractive way for industry to gradually electrify using renewable electricity and can become an important mechanism to support the energy transition.

2

Opportunity demand supports the business case for renewables and for electricity storage. It provides a floor price for electricity based on the cost of the alternative (e.g. natural gas instead of electricity for industrial heating), thus avoiding zero prices.

3

Opportunity demand is well-suited to optimize the use of the electricity transportation and distribution grid. It can be applied as non-firm capacity, as interruptible capacity, or for capacity pooling. All three mechanisms promote optimal use of the grid.

CONTENTS

1. INTRODUCTION

1. INTRODUCTION

This paper is both about the increase in variable renewable electricity generation into the electricity system and the gradual electrification of industry. By looking at the potential interactions between these parts of the energy system, synergies emerge that can reduce the challenges either of them poses to the energy system.

Chapter 2 summarizes the impact of a high penetration of variable renewables in our electricity system. It is based on a series of previous DNV white papers. This series started with the paper 'Future proof renewables' [1] and was continued with 'Hydrogen in the electricity value chain' [2], 'The promise of seasonal storage' [3], and 'Sector coupling' [4]. In these papers, we explored how the increase in variable renewable electricity generation changes the electricity system, and whether hydrogen, seasonal storage, and sector coupling create new challenges and/or offer feasible solutions to some of the problems of increased renewables in the power system. In this chapter, we zoom in on the interaction between the different mechanisms that determine the electricity price governed by the balance between demand and supply of electricity, such as storage and opportunity demand. Then we discuss their impact on the power system and how this can help to solve one of the main problems identified in the paper 'Future proof renewables': the cannibalization of the value of renewables due to surplus generation in the electricity market.

In Chapter 3, we discuss the role of electrification of industry in the energy system, the positive impact on price-setting for renewable generation, and the added value of electrification beyond the use of storage. Electrification of industry will add a threshold price to the market based on a fuel switch between electricity and natural gas (typically for process heating). This is what we call opportunity demand; it can be met by different fuels, and the choice can be made based on the fuel price. This threshold price increases the value of surplus renewable electricity, thus setting a higher market price and promoting investment in variable renewable generation.

Chapter 4 illustrates this with a case study that demonstrates the added value of electrification of industry beyond the use of storage and how this impacts electricity prices and the feasibility of variable renewable generation.

Chapter 5 deals with a major hurdle to overcome to electrify industry: the current electricity grid operation and grid tariff design. Both European grid design and grid tariffs are generally based on a top-down approach. It assumes large central generation plants, a network of transmission and distribution lines and cables, and an N-1 safety philosophy for most of the grid, meaning that the failure of a main component (line, cable, or transformer) does not impact the electricity supply. In this chapter, we argue that traditional grid operation and tariff design needs to be adapted to accommodate electrification of industry.

Finally, in Chapter 6 we formulate the main conclusions of this paper.

2. REDUCED RETURN ON VARIABLE RENEWABLE GENERATION

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- Ensuring a profitable business case for variable renewable electricity generation in the long run is among the biggest challenges for integrating variable renewables into the power system. Variable renewable generation threatens to cannibalize its own business case as it drives down the capture price for electricity at higher penetrations.
- Storage provides an important but partial answer. For the electricity market to work for variable renewable generation, additional demand is required: opportunity demand. Opportunity demand is electric demand that is triggered if electricity prices fall below their opportunity costs, for example because it is possible to switch to natural gas.
- The main examples of opportunity demand are industrial heating, district heating, and electrolysis.

2.1 Challenges of high penetration of variable renewable electricity generation in the electricity system

The replacement of dispatchable fossil generation with weather-dependent variable renewable energy sources (VRES) raises several challenges. The electricity system is designed and operated 'top down' and demand following, not only technically but also regulatorily. For example, grid-tariff schemes and energy taxes assume that electricity flows from large-scale central generation to much smaller-scale demand. Power system operation is still based on relatively few large power plants providing energy to meet momentaneous demand, and thus is constantly adapting to changes in this demand.

The challenges caused by the reduced availability of large controllable generation can be roughly divided into two categories: (1) challenges that can be solved by replacing offered services with other technical solutions, which offer similar functionality and thus do not require substantial changes to the larger system; and (2) challenges that require a change to the electricity system itself and its users to be solved.

Some examples of the first kind of challenges are wind turbines and batteries providing existing system services that traditionally are provided by thermal power plants, and wind farms designed to be capable of performing a 'black start'; a functionality that is necessary to restore the power system from a complete blackout.

Examples of challenges that do require a systems approach include: grid capacity problems caused by changing power flows due to heat pumps; electric vehicles and local generation from solar and wind; generation capacity needed when renewables are not producing for a consecutive period that is too long for batteries to bridge; and – the main topic of this paper – finding ways of making economical use of the energy of variable renewables produced at times when there is insufficient demand, to avoid diminishing returns on variable renewable energy sources because of oversupply.

While some of these systemic challenges can be solved in a purely technical way, without involving other parts of the system, this will be excessively expensive. Intelligent system-level[2] solutions – creating synergies between multiple stakeholders – will be vastly more efficient.

[2] Though not necessarily centrally implemented or controlled.

2.2 Diminishing return due to oversupply of variable renewables

The paper 'Future proof renewables' [1] introduces the challenge of the diminishing return of variable renewables due to competition with itself at times of high electricity generation and low demand, also referred to as cannibalization. Long before sufficient capacity of VRES is installed to cover energy demand, there will be times when more renewable energy is being produced than is needed to meet momentary demand. This means that after this point, due to simultaneity of variable renewable generation, additional installed wind or solar capacity will add an increasingly large fraction of its produced energy during these periods of oversupply and thus will add less value to the system due to curtailment.

This challenge is illustrated by Figure 2-1, which shows the residual load duration curve (RLDC) of a hypothetical isolated power system (loosely modelled after the Netherlands in 2030) with 200% VRES capacity compared to the maximum demand and without flexibility, such as large-scale storage or demand response. Appendix 8.2 summarizes the modelling parameters.

An RLDC shows the electricity demand minus variable renewable generation for each hour of the year, sorted by size. If the RLDC is positive, it represents the size of dispatchable generation capacity needed. The grey area under the curve shows the total volume of dispatchable electricity needed.

The green area shows the total amount of variable electricity being produced. When the RLDC is negative, there is no demand for this electricity at this specific hour, and generation needs to be curtailed: surplus renewable electricity. The total system demand is equal to the RLDC plus the VRES generation. Appendix 8.1 gives a short introduction to the RLDC.

The RLDC in Figure 2-1 shows that even with 200% VRES, about two-thirds of the time there is not sufficient momentary VRES to meet the demand, and either the demand needs to be adjusted or an alternative electricity source is required. About one-third of the time, there is more variable renewable electricity produced than there is demand. If not stored, exported or or used otherwise, this electricity needs to be curtailed, resulting in an electricity market price of zero for all electricity generated at that time (assuming there are no subsidies or other benefits, such as from green certificates, the marginal cost of VRES can cause the electricity price to become negative). Figure 2-1 shows that this would happen one-third of the time, but for more than half of all generated VRES energy. The annual sales revenues for renewables will significantly decline because of competition between renewables unless an economically useful purpose for this surplus energy can be found.

In the next two sections, we will explore the two main solutions to this problem: energy storage and creation of additional demand specifically making use of low-cost variable renewable electricity. The benefits and limitations of energy storage will be discussed in the next section.

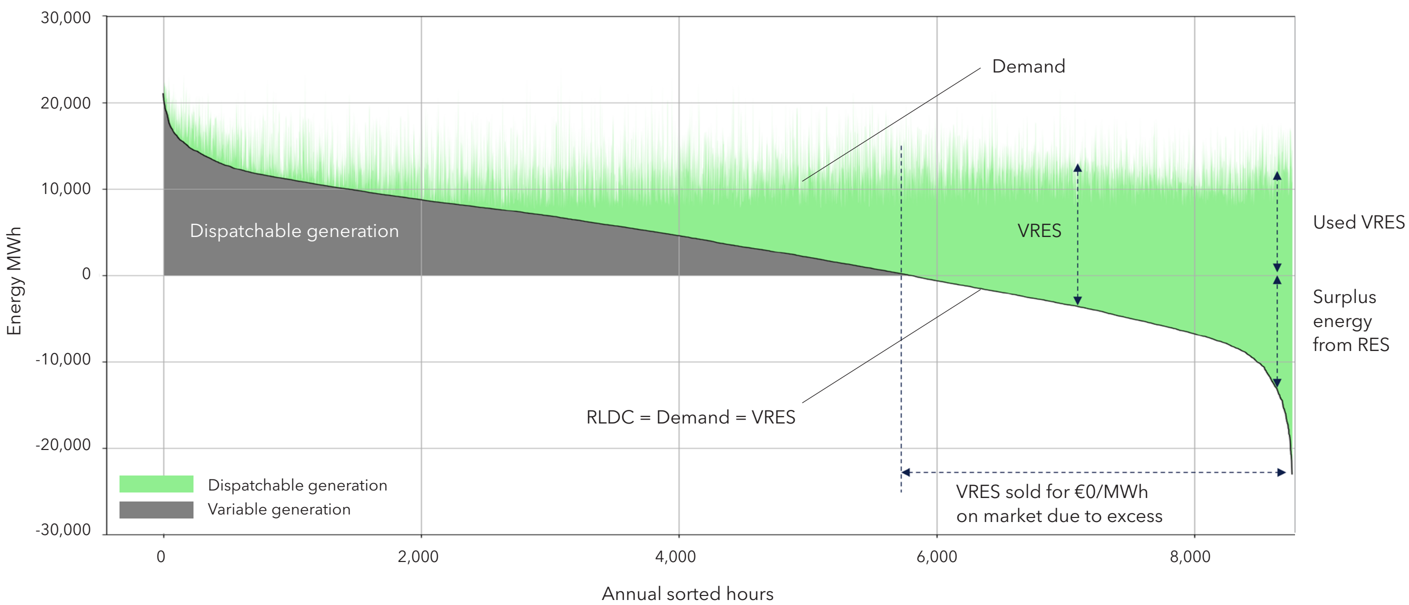

Figure 2-1 The residual load duration curve (RLDC) shows the remaining energy that needs to be sourced by non-variable sources

[2] Though not necessarily centrally implemented or controlled.

2.3 The role and limitations of storage

Storage is often seen as the answer to solve the variability in supply of wind and solar energy, and there is no doubt that storage will play a substantial role in integrating solar and wind energy in the power system. Both direct electricity storage in batteries and indirect electricity storage based on demand response that uses storage of heat, hydrogen, or an intermediate or end-product to create flexibility for the electricity system are viable.

As discussed in the previous white papers 'Hydrogen in the electricity value chain' [2] and 'The promise of seasonal storage' [3], electricity storage and demand response will play a major role in absorbing surplus VRES. However, they cannot completely solve VRES cannibalization. The positive influence of storage and demand response on the overall business case for variable renewables is limited by two effects:

(1) Storage and most demand response options have a limited storage capacity (in kWh). For example, the storage capacity that is used for day-and-night fluctuations typically can charge or discharge to or from full capacity in 8 to 12 hours, and can be reused every day, capturing the daily price spread. It cannot (fully) benefit from a peak or valley with a longer duration.
On the other hand, the storage capacity that is used to accommodate seasonal differences in electricity generation and demand will only be used once per year and typically will take several months to be fully charged or discharged. The cost of this storage capacity needs be recovered through a very limited number of cycles and thus either requires a very high structural price difference between seasons (the 'long' spread) or needs to have an extremely low cost per kWh of storage.
Low-cost (per kWh) technologies that might eventually qualify include: (local) low-temperature heat storage; large-scale pumped hydro; or large-scale sub-terrain hydrogen storage in depleted gas fields, aquifers, or salt caverns[3].

(2) The business case for storage and demand response depends on the price difference of electricity between charging and discharging (for demand response using and avoiding). Charging and discharging large amounts of storage will significantly affect market prices – for example, if stored electricity is sold in such quantities that the market price drops below the price for which it was purchased. Storage optimized for revenue will try to minimize this effect. It will try to absorb as much surplus electricity as possible without raising the electricity price. If storage is charged with renewable electricity, this implicitly means that electricity from VRES will have a lower price than electricity at other times. This apparent 'conflict of interests' between storage and VRES means that – on a macro scale – there is a limit on the effect of battery storage on the capture price for variable renewable electricity generation (see also Section 4.3).

Battery storage and demand response are some of the essential technologies for the energy transition and will play an important role in the electricity supply. The electricity market can support multiple storage technologies that specialize in different market niches, differentiated by capex per kWh and efficiency. The lower the number of cycles per year, the more important a low capex per kWh becomes compared to other factors, such as efficiency and price per kW. This means that most long-term storage technologies only become economically viable after a certain project scale can be reached.

[3] It should be noted that hydrogen can be converted back into electricity, but replacing electric demand, for example the demand of electrolysers or electric boilers, (see 2.4.2), is more efficient and should be utilized first.

2.4 Building a merit order of demand for low-cost renewable electricity

2.4.1 LOW-CAPEX SURPLUS APPLICATIONS

As mentioned in the previous section, the cost of (battery) storage scales with its storage capacity volume, while in general the business case scales with price-spread and throughput. Thus, the more cycles in a certain period, the better. Lithium-ion batteries are already widely used to provide short-term flexibility to the power grids, mainly through frequency containment reserve[4]. It is very likely that battery storage will become feasible for longer-duration fluctuations in electricity supply and demand, such as day-night fluctuations (365 cycles per year) and even fluctuations between week and weekends (52 cycles). However, to bridge longer cycles, such as seasonal variations, other technologies than batteries are required.

So, while battery storage will be an important part of the solution, other applications that are suitable to make use of the surplus electricity, 'surplus applications', are needed. Obviously, these applications need to generate added value; otherwise, the effect is equivalent to curtailment, which is 'free'[5]. Another criterion for such application is that it requires very low fixed cost, because of its relatively low utilization. These fixed costs consist of capex and fixed expenses and fees that are independent of operation. This is illustrated in Figure 2-2, which shows the levelized cost of an application that uses low-cost electricity.

If, for example, the surplus application is hydrogen production through electrolysis, Figure 2-2 would show the levelized cost of hydrogen ($LCOH_2$) to be the lowest when the electrolyser would operate between 4,000 and 5,000 hours per year (the numbers are hypothetical and for illustration only). Running fewer hours would mean that the fixed cost that is spread over the produced volume of hydrogen would cause an increase in the $LCOH_2$; running more hours would increase the $LCOH_2$ because of the use of higher-priced electricity.

As discussed in our paper on sector coupling [4] and further in this paper, assuming a large demand for surplus applications, these applications might become price-setting. This means that there will be sufficient demand to 'absorb' all oversupply, and electricity prices will rise to the opportunity costs of these applications. For example, an electrolyser is willing to pay for electricity as long as the marginal production[6] costs are lower than the value of the produced hydrogen. This value in turn can be determined by the cost of the production of hydrogen by alternative means, typically steam methane reforming (SMR) using carbon-taxed natural gas; or the cost of previously produced green hydrogen and its storage costs. Ideally this forms the average value, so the investment of hydrogen storage is covered, but momentarily this value will be determined by the chance that the storage will be depleted before it can be refilled.

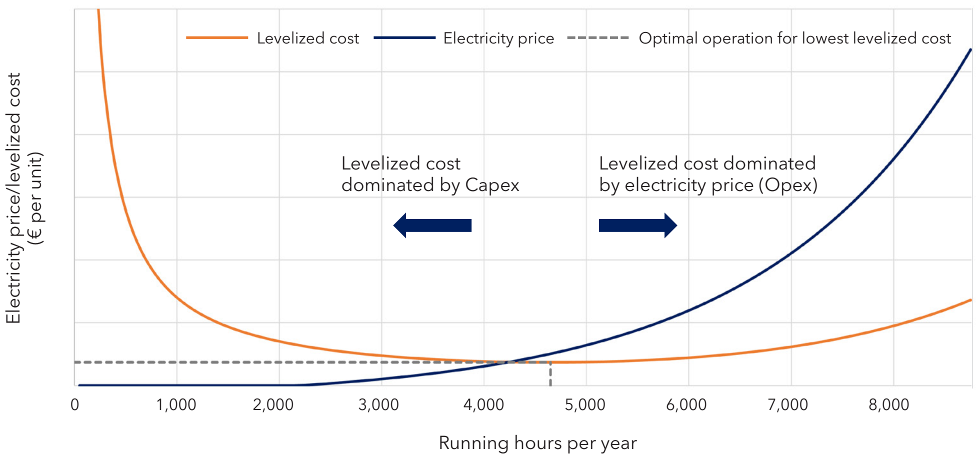

Figure 2-2 The variation of the levelized cost of a surplus application, such as electrolysis, varies with the number of operating hours per year and electricity prices

[4] Frequency containment reserve (FCR) is capacity used by the transmission system operator (TSO) to contain the grid frequency around 50 Hz by injecting or absorbing power form the grid.
[5] Though regulation can add 'opportunity cost', for example through green certificates or other mechanism, it can be financially optimal to continue to produce renewable electricity and then 'burn' it, to gain the green certificates, to retrieve a feed in tariff, or to meet the obligations of a PPA.
[6] Marginal costs are costs to produce an additional unit of product (e.g. hydrogen form electricity). Typically, these include fuel cost and variable operation and maintenance (O&M) cost. Capital cost and fixed O&M cost are not included.

The existence of a large capacity of electrolysers operating in opportunity mode – i.e. operating in conjunction with steam methane reforming (SMR) – would result in a significant period during which they would be price-setting. They would create a price plateau in the electricity price duration curve, where these electrolysers are running at marginal costs. The marginal costs are determined by the price of natural gas and the relative efficiency of electrolysis compared to SMR.

When electrolysers are price-setting, they generate just enough revenue to recover their marginal cost. Their overall revenue is determined by the relatively short period when they are not price-setting, and the electricity price is set to zero by a surplus of VRES. So, the profitability of surplus options, such as electrolysis for producing industrial hydrogen, is determined by short periods of surplus production when electricity prices are zero.

Hence, to build a merit order of applications that can absorb surplus renewable energy and make good use of this, we should start with applications that have a very low capex.

2.4.2 BUILDING A DEMAND MERIT ORDER THROUGH SECTOR COUPLING

In the previous section, as well as in our seasonal storage paper [3], we introduced the concept of a demand merit order. This is a merit order on the demand side consisting of low-capex applications that can absorb surplus electricity when available and that can be shut down when there is insufficient renewable electricity.

So, we search for a huge potential of surplus applications for electricity. Such applications need to have value, but this value will be limited. Therefore, it will respond to low electricity prices but will shut down when prices rise to the marginal cost of electricity from dispatchable generation[7]. Besides storage, this hints towards demand that is currently being supplied by other energy carriers, such as natural gas, and which can switch back and forth between electricity and the original carrier depending on the electricity prices. This principle is shown in Figure 2-3, using industrial heating as an example[8].

In our study on sector coupling [4], we defined 'opportunity demand' as electricity demand from surplus applications because it has the opportunity to use low-cost renewable electricity. In that paper, we identified district heating, industrial heating, and hydrogen production as candidates for opportunity demand that would satisfy the requirements discussed in the previous section.

To build a model for a demand merit order that includes opportunity demand, a similar logic can be followed as for the electricity generation merit order. For an application to be developed, the electricity prices must be expected to be sufficiently low long enough to ensure sufficient running hours and recover the investments, possible risks, and the cost of capital. Once developed, this demand will be dispatched if the marginal production value is equal to or higher than the cost of electricity plus any other variable costs.

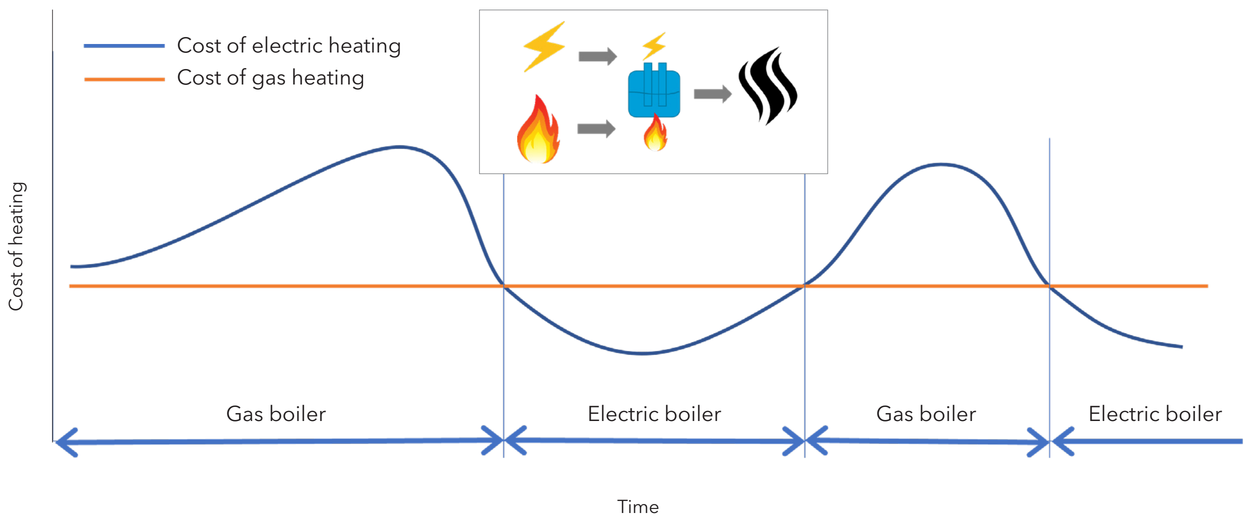

Figure 2-3 Opportunity demand: switching between gas and electricity to generate the required commodity (in this case heat, but it also applies to hydrogen for industrial use)

[7] In principle, the value of a surplus option should be larger than zero (the added value of curtailment), but lower than the cost of electricity form dispatchable sources.
[8] To increase efficiency and flexibility, a technical implementation would try to have one boiler vessel and share as many of the components as possible, so these do not need to be reheated when switching between energy carriers.

Curtailing electricity generation requires no capex at all and is the most effective solution if there will be only a few expected hours of surplus electricity per year. However, just like its marginal costs, its marginal value is zero. A hybrid boiler, or an electric boiler that is installed parallel to a gas-fired boiler, will require more running hours at low electricity prices to justify its investments. The marginal value of such a boiler is based on its opportunity costs, i.e. the gas price corrected for the efficiencies of electric heating and gas heating, respectively (see Figure 2-3). In other words, once the electric boiler is installed next to the gas boiler, the opportunity is created to switch between both energy carriers, depending on which one provides the cheapest heat, as is shown in Figure 2 3. For industrial hydrogen production using electrolysis and operating as opportunity demand supplementing methane reforming, a similar logic can be followed.

Storage and demand response, which in most cases uses buffering to be able to shift electricity demand in time, do not have a fixed opportunity price. Instead, their dispatch charge price depends on an expected future electricity price. How storage and demand response relate to opportunity demand and the demand merit order will be discussed in Chapter 3.

Figure 2-4 demonstrates what such a demand merit order can look like. It shows the right side of the RLDC with surplus renewable electricity. This electricity will be used to charge battery storage devices and demand response; then in electrolysis to produce green hydrogen; then for electric opportunity heating; finally, any remaining surplus renewable electricity is curtailed.

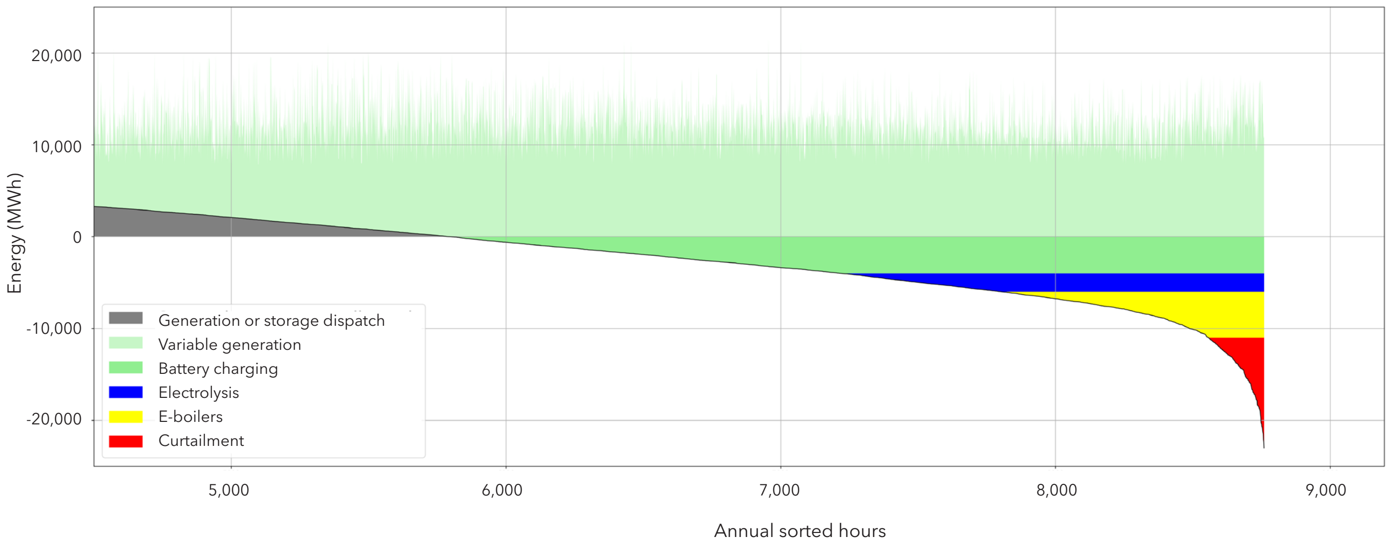

Figure 2-4 Conceptual representation of a demand merit order absorbing surplus renewable electricity, including electrolysis and electric opportunity heating [2], [3].

3. THE EFFECT OF OPPORTUNITY DEMAND ON THE ELECTRICITY PRICE

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- The interaction between storage/demand response and opportunity demand on the electricity market has the potential to protect the profitability of variable renewables by avoiding the cannibalization effect.
- In this interaction, storage (and demand response) provides the capacity to absorb a major part of the surplus volume, while opportunity demand sets the price.

3.1 Introduction

In Chapter 2, we addressed that generating surplus electricity threatens the profitability of variable renewable generation unless the surplus can be put to economical use. Storage and demand response can absorb most of this surplus but will eventually struggle during longer periods of surplus and shortages, because of limitations in storage capacity.

Opportunity demand depends on the ability to switch between electricity and another commodity and does not depend on storage capacity that might become depleted or full. However, its utilization depends on whether the price of electricity is lower than the price of natural gas, which is determined by the capacity of the renewables connected to the grid. Although this capacity is increasing, it is still relatively low. The relatively low number of hours per year that electricity prices are lower than the gas price means that the investment needed for opportunity demand must be low.

In this chapter, we will discuss how flexibility from opportunity demand differs from flexibility from storage and demand response, how these forms of flexible demand interact, and how this can help to set a market price for surplus electricity and thus increase the hosting capacity of the electricity market for generation of variable renewable electricity.

3.2 Flexibility from storage

In markets, prices are based on negotiations and thus, in principle, on the (perceived) 'next best' alternative for each of the involved negotiators. The value that electricity generates for its consumers is generally much higher than its generation costs. Thus, consumers will buy electricity almost regardless of the price, making electricity demand very inelastic. However, buyers do have a choice as to whom to buy from. Therefore, the electricity price on the wholesale market is almost purely determined by the supply price curve (called the merit order) and the total demand, which varies throughout the day [1].

Storage and demand response change this system. Their flexibility gives consumers a (limited) choice as to when to buy. Owners of storage systems, operating in the commercial market, purchase electricity to charge at a low price and sell or use this later when prices are high. For each charge/discharge cycle, the resulting margin or saving should be at least sufficient to make up for degradation, efficiency losses, and transaction costs such as taxes. The overall margin should be sufficient to cover the investments and other fixed costs. Provided the cycle margin is positive, storage owners will try to cycle as many times as possible. It does not matter whether this storage is regarded as 'short-term storage' or 'seasonal storage'. In principle, both compete for the same low-priced electricity to charge, and both sell high-priced electricity when discharging.

However, differences in degradation, efficiencies, and transaction costs will lead to differences in operation. The main principal difference between short-term storage and long-term storage is the available storage capacity. In principle, all economical storage is dispatched in the most profitable way. Increasing the storage capacity will, in principle, make the operation equally or less profitable. In practice, short-term storage, such as batteries, will have a higher efficiency and therefore will be able to profit from smaller price differences. However, this often comes at a higher cost of storage capacity (cost per installed kWh), thus requiring a higher energy throughput to become economically feasible, which is realized by a higher number of load cycles. This provides an economical limit on the storage capacity of batteries, which, as costs decrease and reused (second-life) batteries become more common, will likely be able to accommodate cycles ranging from daily (365 cycles per year) to weekly (about 52 cycles per year) [3].

In the wholesale market, the business case for storage depends on alternating low and high prices. In a system with an abundance of surplus electricity, there is sufficient opportunity for batteries to charge at a price of zero, because there is still VRES being curtailed. Charging more at these times would increase the charging price and thus reduce the profitability of all battery systems.

From a competition perspective, this means that the market share of an individual battery storage operator is irrelevant. A small-scale battery operator can increase the charging price of all charged energy of a large battery operator, because the price of all energy goes up due to his demand. For the operator of the large battery system, it is more beneficial to reduce charging and allow the small operator a 'piece of the pie' than to pay the increased market price for the high volume of electricity they are charging. The battery storage operator is a 'price maker', meaning that they can influence the market price by dispatching their own storage capacity.

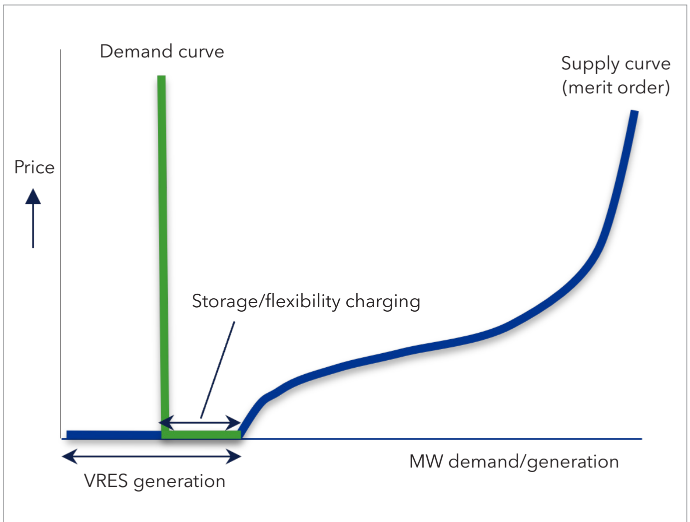

Figure 3-1 Demand and supply curve of electricity, during a time interval when there is surplus renewable electricity. Storage tries to charge with renewable electricity without increasing the price.

Figure 3-1 is a very schematic illustration of the position of storage and demand response, such as intelligent charging of electric vehicles in the demand curve, during a time interval when there is surplus renewable electricity. Obviously, at times when the electricity price is not zero but expected to increase shortly afterwards, the batteries will charge as well. However, during a time of surplus, storage can charge for free as long as there is a surplus of electricity generation, but prices will increase sharply once this surplus has been absorbed. Hence, charging will stop unless the price that is expected after this charging period will be high enough to justify it.

Storage and demand response – especially considering electric vehicle charging and vehicle to grid (V2G) – have a huge potential. While the flexibility of smart charging is determined by replenishing the energy that was used for driving, V2G can make use of the entire battery capacity. This increases the effective storage capacity by a factor of 5 to 10 compared to just charging the amount of electricity used for driving. However, a margin reserved for driving and to reduce battery degradation will limit this capacity[9]. A limited availability of charging locations will also reduce the available storage capacity for the systems. Storage and demand response, including V2G, will be used to smoothen out large but relatively short peaks and drops in electricity supply and demand and therefore in the electricity price[10].

3.3 Flexibility from opportunity demand

In general, electrification of demand will not only increase electricity demand at times of surplus, but also at times when there is not sufficient variable renewable electricity available. This can cause additional dispatchable – usually fossil-fuelled – generation to run, causing additional carbon emissions. While this is not negative per definition – as demonstrated by electric vehicles and heat pumps, whose increase in efficiency compared to local use of fossil fuels can result in an overall emission reduction – it would be more beneficial if the increased electric demand could predominately use surplus renewable electricity that would otherwise be curtailed.

In the previous chapter, we identified heating and hydrogen production as interesting candidates for opportunity demand in industry. Contrary to most electricity demand, this electricity demand is very sensitive to the electricity price, and it offers a huge potential source of flexibility to the electricity system, which can be sustained indefinitely because it does not rely on storage or buffering.

[9] The term 'vehicle to grid' (V2G) is used to indicate the capability of electric vehicles to discharge power into the grid when beneficial to the system, and thus effectively function as battery storage. For example, a vehicle with a 100-kWh battery using 10 kWh for daily driving would, on average, charge 10 kWh daily. Assuming a band of 20 kWh on the lower and upper size of the battery to prevent degradation and for emergency use, this car could charge 60 kWh and discharge 50 kWh on a daily basis.
[10] Note that this assumes that there is sufficient charging infrastructure. Smart charging, and especially V2G, assumes that cars are connected to the system and have the opportunity to charge/discharge at their convenience. A limited number of (public) chargers that are shared between cars means that these chargers are needed for charging, and less flexibility remains for smart solutions used for optimizing the electricity system.

This opportunity demand switches between natural gas and electricity as a fuel depending on which will result in the lowest cost of heat or hydrogen, as depicted in Figure 2-3 in the previous chapter. Assuming sufficient opportunity demand, the electricity demand curve becomes elastic near the gas price. Figure 3-2 shows this demand curve and the supply curve (the merit order). Additional renewable electricity with zero marginal cost will shift the supply curve to the right, but if there is unused opportunity demand, this capacity will be activated, and the electricity price will remain stable.

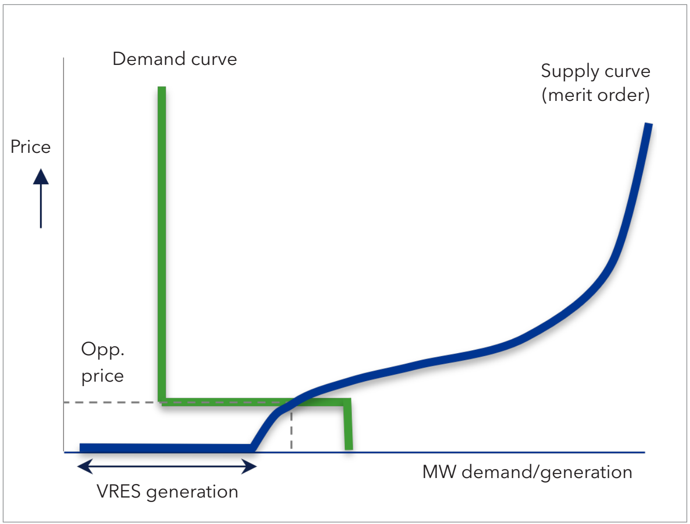

Figure 3-2 Electricity demand and supply curve with opportunity demand. When the electricity price drops below the opportunity price – the price of natural gas, compensated for efficiencies – opportunity demand (such as electric boilers) will take over from gas-fired demand (such as gas fired boilers).

Prices drop to zero only if the capacity of opportunity demand is fully activated and there is still surplus renewable electricity to be curtailed. Assuming no subsidies or other financial tools, only during these hours will surplus applications (electric boilers and electrolysers) create a revenue. An increased capacity of variable renewables will result in an increased number of hours per year that this will happen, triggering additional investments in opportunity demand.

3.4 The interaction between storage and opportunity demand

In the previous two sections, we discussed the effect of storage and opportunity demand on the electricity market.

The main differences between both forms of flexibility are:
- Opportunity demand has infinite 'stamina', whereas storage and demand response might become saturated or depleted.
- Opportunity demand has (in the short run) an independent reference price outside the electricity market: namely, the fuel cost of the alternative way to produce heat or hydrogen, whereas storage and demand response depend on price fluctuations within the electricity market.

Battery storage wants to make as many cycles as possible; therefore, it will 'consider' a limited time horizon, determined by the frequency of price fluctuations in the electricity market that fits its storage capacity. Opportunity demand does not react on relative fluctuations in the electricity price. It responds when the electricity price drops below a threshold determined by its opportunity price. Only when the capacity of opportunity demand is fully utilized will the electricity price drop to zero. For batteries, the chance to charge at zero cost (without the charging itself affecting the price) will be severely limited; so, most of the time, storage will experience that the opportunity price for opportunity demand is the optimal charging price. This is graphically shown in Figure 3-3.

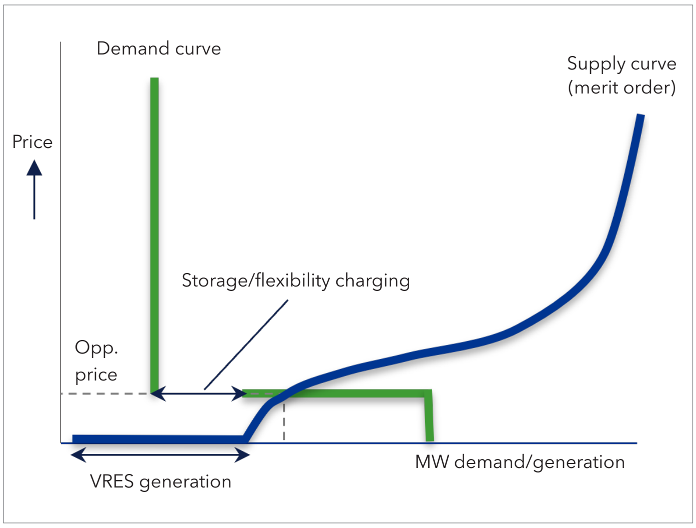

Figure 3-3 The interaction between storage and opportunity demand

The result of this interaction is that storage increases the price-setting effect of opportunity demand in the electricity market, resulting in periods when the electricity price will be relatively stable around the opportunity costs of electric boilers and electrolysers.

3.5 The resulting residual and price duration curves

Figure 3-4 shows the results of a calculation of the residual load duration curve for the same electricity system that was shown in Figure 2-1. A description of this system, including the amount of storage and opportunity demand, is given in Appendix 8.2. This system has 200% variable renewable generation installed compared to peak demand and roughly resembles the anticipated energy demand and generation in the Netherlands in 2030 (though without interconnections). The dotted lines (reference RLDC and reference electricity price) in Figure 3-4 refer to a system without flexibility from storage and opportunity demand, as was shown in Figure 2-1.

In the calculations leading to Figure 3-4, 30 GW/180 GWh of storage was used, optimized with respect to price. This storage potential represents all sorts of storage and demand response; but to give an indication, this could be provided by 3 million vehicle-to-grid-able electric vehicles (30% of the total Dutch fleet) offering the system an average (dis)charge capability of 10 kW and 60 kWh per car. Furthermore, 1 GW of electrolysis and 5 GW of industrial electric heating operating as opportunity demand are added, which switch between electricity and natural gas depending on the lowest cost of producing hydrogen and heat, respectively.

Figure 3-4 illustrates how storage increases the price-setting effect of opportunity demand in the electricity market. The interaction between relatively small amounts of opportunity demand compared to storage will still lead to periods when the electricity price is relatively stable around the opportunity costs of electric boilers and electrolysers.

In this chapter, we have demonstrated how opportunity demand can create a price for oversupply of renewable electricity by temporarily replacing natural gas for heating and hydrogen production. Storage and demand response use this price to charge. This increases the time this price-forming mechanism is in effect, resulting in price plateaus around the gas price (the 'opportunity cost' of opportunity demand).

Both storage and opportunity demand are essential in creating an electricity market capable of supporting a large capacity of variable renewable electricity generation that can stand on its own in the market. This will be further discussed in the next chapter, alongside the impact on the different stakeholders.

For industry, it can potentially offer a gradual and economical way to decarbonize, making use of the growing capacity of variable renewable electricity. For wind and solar farms, it may offer a large source of flexible demand, which – together with storage – is able and willing to pay a price for electricity that otherwise would need to be curtailed. For governments, opportunity demand would help create an electricity market that is able to support a high volume of variable renewable electricity. As renewable hydrogen produced through opportunity demand gradually replaces natural gas, such an electricity market could eventually lead to a fully decarbonized energy system.

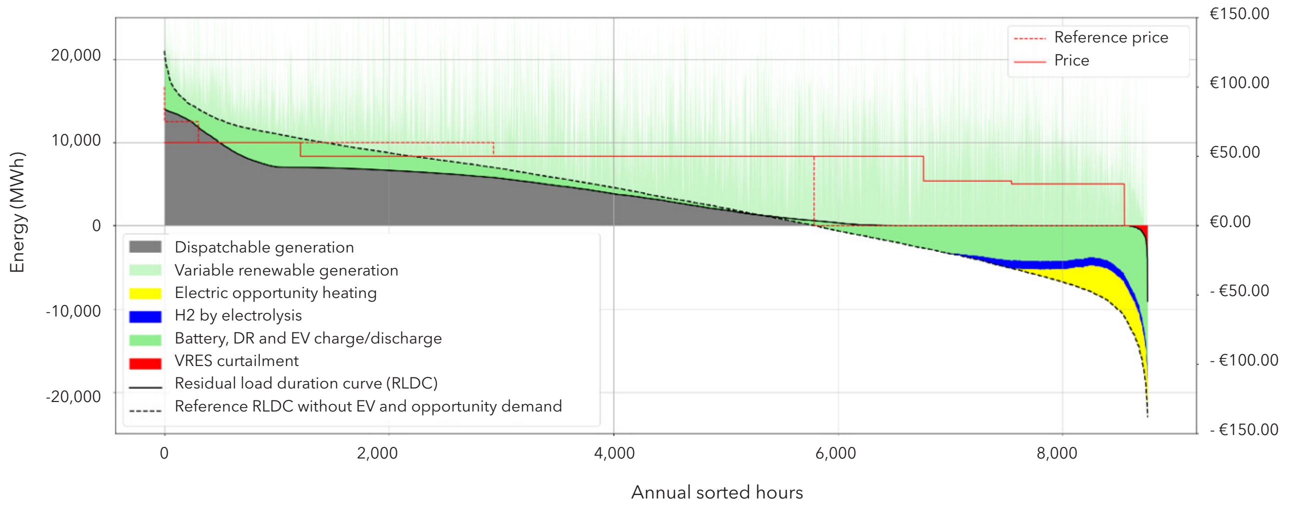

Figure 3-4 Load duration curve including opportunity demand and storage. In the graph, the effect of storage is represented as the difference between the RLDC with and without storage, instead of the actual storage itself.

4. EXPLORING THE FINANCIAL COSTS AND BENEFITS OF OPPORTUNITY DEMAND

4. EXPLORING THE FINANCIAL COSTS AND BENEFITS OF OPPORTUNITY DEMAND

- A business case for opportunity heating in Germany shows that, with the right synergy with the network, opportunity heating can already be made profitable.
- This business case is determined by the number of running hours of the electric boiler, which in turn is determined by the cost difference between heating with gas and heating by electricity. Grid tariffs and taxes play a major role.
- On a societal level, it shows that opportunity demand leads to a better fit between renewable power generation and demand, resulting in a larger hosting capacity of the market for variable renewable electricity.
- The importance of grid tariffs on the business case reflects the impact on demand for scarce network capacity. This indicates that, besides synergy between generation and demand, synergy with the network is essential.

4.1 Introduction

In this chapter, we discuss the economic possibilities and consequences of opportunity demand for different stakeholders: first, for industry that needs to decarbonize; second, for operators of variable renewable energy; and third, for governments and users that do not operate opportunity demand.

At the end of this chapter, we briefly discuss how increased electric load may influence grid investments. In the next chapter, strategies are discussed concerning how the impact on the grid can be reduced by finding synergies between generation, demand, and the grid.

Calculations are presented, which are meant to be illustrative and show the general consequences for the different stakeholders, including benefits and disadvantages of opportunity demand, such as electric heating and green hydrogen production.

4.2 The business case for electric heating for industry

Industry that is electrifying its heat demand will face high electricity prices at times when the price is set by dispatchable power generation, e.g. from natural gas. This electricity is not renewable, and it would be more efficient to use the gas directly for heating.

However, full electrification[11] has the benefit of only requiring a single infrastructure. For opportunity demand, the (existing) gas infrastructure needs to remain in place, while the capacity of the electricity infrastructure needs to be increased. Heat generation should be able to switch between gas and electricity within a few minutes, without much efficiency loss, implying that the 'heat side' of the system, such as hot-water and steam tanks and piping, should be integrated and shared as much as possible.

The cost of opportunity demand in industry is mainly determined by the required investments in additional industrial electric infrastructure and in the public grid infrastructure (covered by grid tariffs), the number of hours that electricity-based heat is cheaper than gas-based heat, and the price spread between electricity and natural gas used to generate this heat.

Because of the relatively high capacity of variable renewable electricity installed, we look at Germany to come up with an illustrative business case for an industry electrifying its heat demand through opportunity demand, based on historical German gas and electricity market prices. A key element of the calculation is the number of running hours of the electric boiler. The electric boiler runs if the variable cost of heat from electricity is equal to or less than the cost of heat from natural gas.

[11] For low-temperature heat (currently up to about 200°C) heat pumps may sometimes be an interesting option. Because of the much higher investments (and lower electricity costs due to the efficiency), such solutions (when applicable) will likely replace natural gas instead of complementing them, like electric boilers.

Figure 4-1 shows the wholesale day-ahead electricity price and the daily TTF gas price from January 2019 to November 2022.

The electric boiler will run when electric heating is cheaper than gas heating, all energy-related costs (per MWh) included. This means that the electric boiler will run if:

$$P_e \leq (P_g + G_g + T_g + d \times C) \times \frac{eff_e}{eff_g} \times \frac{hhv}{lhv} - (G_e + T_e)$$

with subscript e indicating electricity; subscript g indicating natural gas; P being the purchase price; G indicating grid tariffs; T indicating taxes; and *eff* indicating the efficiency of the boiler. It is assumed that the boilers are equally efficient.

Furthermore, C is the carbon price in €/tonne CO_2 equivalent; d is the conversion factor in MWh natural gas per tonne emitted CO_2 by burning that natural gas (d=0.203 MWh/tonne CO_2); and finally, hhv/lhv is the conversion factor of higher heating value of natural gas (the energy content which is traded on the market) to lower heating value of natural gas (the energy content that is actually used). This factor assumes that the condensation heat of the water vapour cannot be recovered in the gas boiler[12] (hhv/lhv=1.108).

Calculating the number of running hours for 2021 with the help of this formula and using German taxes and grid tariffs and data from Figure 4-1 results in 168 running hours and a financial loss of 208,000 euros for 2021 compared to 100% heating with natural gas, as is indicated in Figure 4-2.

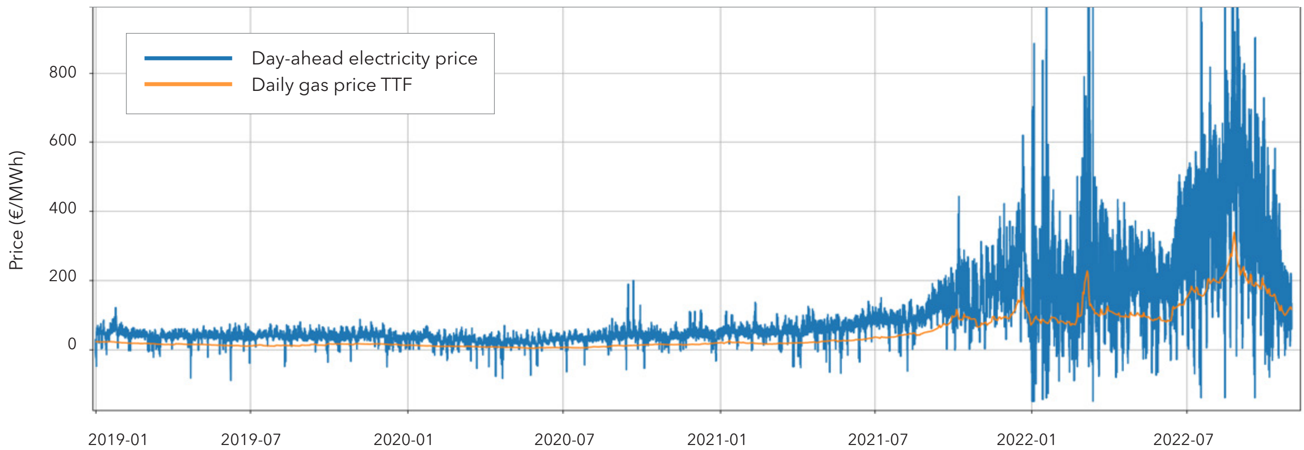

Figure 4-1 German day-ahead electricity price compared to the day-ahead gas price (TTF), data from [5] and [6]

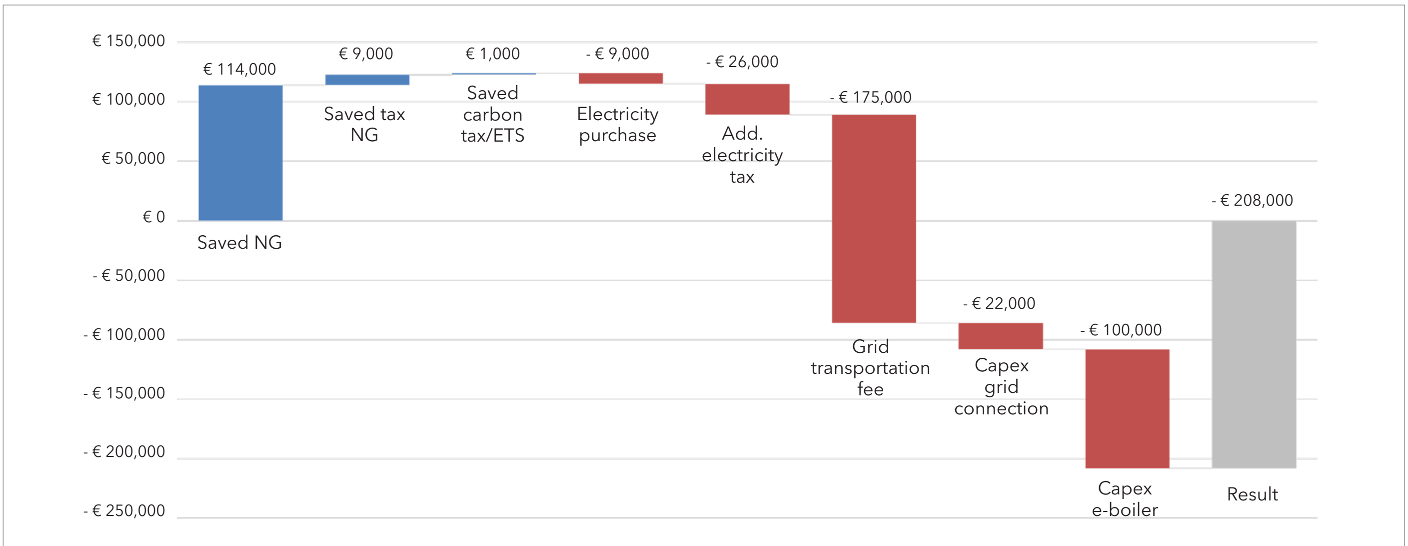

Figure 4-2 2021 business case for a 10 MW German electric boiler running in opportunity-demand mode next to a gas boiler

[12] That is, it is an industrial boiler producing steam, and not a condensing boiler for residential or office heating.

The savings on the gas bill are not nearly sufficient to recover the amortization of the electric boiler investments and especially the increase of the grid transportation tariff that is needed to cover investments in the electricity transportation grid. Both are very high compared to the benefits, because of the very low boiler utilization of 2% (168 hours in 2021). The results for the first 10 months in 2022 would result in 496 running hours and a result of -32,000 euros for a 10 MW boiler, suggesting that a boiler also hedges against strongly fluctuating gas prices. This can be explained by the fact that periods with low electricity prices are mainly determined by variable renewables.

While it looks like opportunity demand with an electric boiler will be far too costly, there is considerable leverage coming from carbon taxes/ETS prices and the grid transportation tariff. Changes in these costs not only affect the cost directly but can also have a significant impact on the number of running hours of the electric boiler. We shall look at two parameters:

- an increased carbon price from €2.53/tonne CO_2 (German carbon tax in 2021) to €60/tonne CO_2 (comparable to ETS prices in 2021, adding about €12/MWh to the gas price), and
- applying a 90% reduction on grid transport costs that can be claimed by large industrial users through the 'Individuelles Netzentgelt' (art §19 (2) of the StromNEV), if their demand profile is favourable for the grid[13].

Table 8-3 shows the business case for the electric boiler for different years with these different carbon and grid transmission costs. More details can be found in Appendix 8.3.

Figure 4-2 and Table 4-1 show that the main factor determining the business case is the grid transportation fee, which is meant to cover the general investments in and maintenance of the transmission grid, so the capacity remains sufficiently large to withstand the peak in electricity demand and supply, even if this only occurs a few hours per year. To justify a reduction of this fee, sufficient synergy with the grid is needed. Options for creating synergy between opportunity demand and the grid, to reduce the grid costs that are supposed to be covered by the transportation fee, will be discussed in Chapter 5.

	Base case		Carbon cost of €60/ton +90% reduction of grid tariff	
	RUNNING HOURS	RESULT	RUNNING HOURS	RESULT
2019	46	-€232.000	471	-€51.000
2020	49	-€235.000	699	-€43.000
2021	168	-€208.000	737	€58.000
2022 (up to Oct)	496	-€32.000	1059	€368.000

Table 4-1 Running hours and profit of a 10-MW German electric boiler running in opportunity-demand mode next to a gas boiler for different years and cost scenarios

4.2.1 OPPORTUNITY DEMAND IN A MATURE MARKET

In the previous section, we discussed the benefits and costs of opportunity heating, using historical electricity and gas prices. If opportunity demand scales in size, it will absorb surplus renewables. At times when this surplus is fully absorbed, it will result in an electricity price equal to the marginal (opportunity) cost of opportunity demand, which is equal or close to the carbon-taxed price of natural gas. This means that, at such times, opportunity demand will run at operational break-even costs.

At times when the capacity of opportunity demand is not sufficient to absorb all surplus renewables, electricity market prices fall to zero and renewable generation needs to be curtailed. Only at these times will opportunity demand create a return on investment. In principle, this would mean that the amount of investment in capacity for opportunity demand would be limited by the expected duration of the periods when electricity prices are zero and the savings on fuel costs are sufficient to recover the investments and cost of capital. In other words, investment in opportunity demand will be postponed until justified by the number of hours with low electricity prices caused by newly built variable renewables, thus creating an equilibrium between investment in renewables on the one hand, and opportunity heating and electrolysis on the other.

4.3 Implications for variable renewable electricity generation

The business case for variable renewables becomes more challenging as the penetration of variable renewables increases, as discussed in detail in [1]. In this section, we will explore the effect of opportunity demand on the business case for variable renewables compared to a system without opportunity demand.

To explore the influence of opportunity demand on the profitability of variable renewable electricity generation, we analyse three different cases: one without any flexibility, one with a sizable amount of flexibility in the form of storage, and one with both storage and opportunity demand (which is the same system as discussed in Section 3.5). We modelled these cases in a relatively straightforward electricity system with a conceptual generation merit order and without interconnections or grid capacity constraints. The quantitative results are illustrative, but they do show the relative effects of storage and opportunity demand in the electricity market.

- **CASE 0**
  An isolated system is considered with a peak demand of 24 GW of traditional price-inelastic demand; 26 GW of solar PV; 12 GW of offshore wind; and 10 GW of onshore wind (see Table 4-2)[14].

- **CASE 1**
  This is the same case with an addition of 30 GW/180 GWh of storage, optimized with respect to electricity prices. This total amount of flexibility can be compared to 3 million electric vehicles (1/3 of all available passenger cars), each on average offering 60 kWh of storage to the grid through a 10-kW connection, while reserving the remaining 40 kWh of their 100-kWh battery capacity for driving (and to prevent excessive battery degradation).

- **CASE 2**
  It builds on Case 1 with an additional 5 GW of opportunity demand (4 GW of electric boilers and 1 GW of electrolysis). Both forms of opportunity demand are triggered when using electricity is cheaper than using natural gas for production. The difference in dispatch price is caused by differences in efficiency.

Table 4-2 gives an overview of the different cases.
In Figure 8-2 in Appendix 8.2, the duration curves for the non-flexible traditional demand and the variable renewable sources can be found, as well as the used generation merit order of dispatchable generation.

CASE 0	Installed/peak capacity in % of peak demand	Energy per year, in % of non-flexible demand
Non-flexible traditional demand	100% (24 GW)	100% (108 TWh)
Solar	108% (26 GW)	21% (23 TWh)
Onshore wind	42% (10 GW)	20% (22 TWh)
Offshore wind	50% (12 GW)	33% (36 TWh)
Total VRES	200% (48 GW)	75% (81 TWh)
CASE 1, equal to case 0, but with added flexibility modelled as storage		
Flexibility (storage)	125% (30 GW, with 180 GWh total capacity)	15% (16 TWh annual throughput)
CASE 2, equal to case 1, but with added opportunity demand		
Opportunity demand (scenario 2)	21% (5 GW) (1 GW electrolysis and 4 GW heat)	3.0% (3.2 TWh)

Table 4-2 Case descriptions:
CASE 0 - an isolated system
CASE 1 - the same system including flexibility in the form of storage
CASE 2 - the same system as case 1, including additional opportunity demand

[14] It should be noted that this system is comparable to the Netherlands in 2030, but without any interaction with neighbouring countries. Interaction between neighbouring countries would reduce the simultaneity of variable renewable generation and of demand and would thus bring the cases closer to each other.

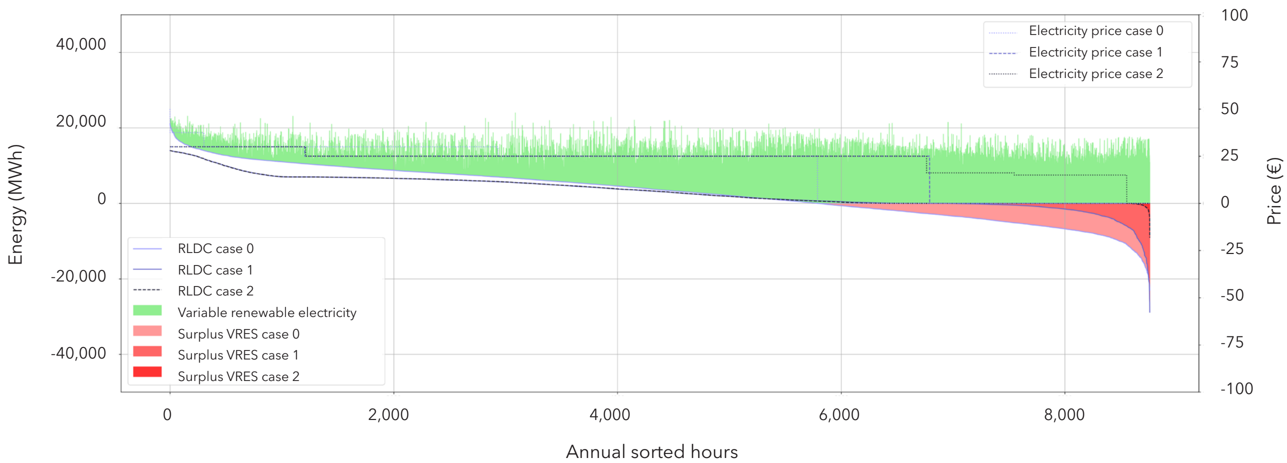

Figure 4-3 The impact of flexibility and opportunity demand on surplus renewables and the electricity price for the three described cases.

Figure 4-3 shows the surplus renewable and electricity prices for all three cases. From the results of the calculations, the revenue of variable resources can be calculated, as well as the generation-weighted average (GWA), the average price of a MWh of variable renewable electricity in the market, sometimes called capture price. These are shown in Table 4-3.

While very susceptible to the used assumptions, such as the generation merit order and amount of variable renewable generation, Table 4-3 does show that the profitability of variable renewable energy generation depends to a large extent on factors such as the natural gas price (and price of other fossil fuels). Table 4-4 zooms in on Case 2 with a gas price of €30/MWh. It shows that, in this case, onshore wind would the only renewable power source built in 2022 that could be fully supported by the simulated market in 2030. Both solar and offshore wind would still require government support.

Table 4-3 shows that a higher gas price results in significantly higher electricity prices. Even without any flexibility (Case 0), VRES would be profitable, except for solar PV (the GWA Solar PV is €48,5/MWh, see Appendix 8.4.4). A high gas price results in a higher return on variable renewables, to offset the effects of cannibalization. Thus, it allows for a higher penetration of VRES that can be supported by the market. Eventually, however, the reduced income due to cannibalization will limit the amount of economically feasible VRES. Table 4-3 shows that (30 GW of) flexibility increases the profitability and thus the hosting capacity of the market for VRES because less VRES needs to be curtailed. Adding another 5 GW of opportunity demand doubles this effect. Appendix 8.4.4 shows this effect per renewable source and shows that especially solar – with its high simultaneity and low-capacity factor – benefits from flexibility.

CASE	GWA VRES (€/MWh) Carbon-taxed gas price €30/MWh	GWA VRES (€/MWh) Carbon-taxed gas price €80/MWh
Case 0 - No flexibility	€20.4	€54.4
Case 1 - Case 0 with added 30 GW, 180 GWh of storage	€31.3	€83.5
Case 2 - Case 1 with added 5 GW opportunity demand	€41.6	€111.2

Table 4-3 Annual revenues and generation-weighted average (GWA) for variable renewable generation for the three different cases and different gas prices[15].

VRES levelized cost vs. GWA (Case 2, carbon-taxed gas price €30/MWh)	GWA for specific VRES	LCOE (€/MWh)	Needed government support LCOE-GWA (€/MWh)
Solar PV	€43.8	€52.4	€8.6
Onshore wind	€39.9	€39.3	- €0.6
Offshore wind	€40.3	€47.0	€6.7
VRES mix (weighted average LCOE)	€41.6	€46.4	

*Table 4-4 Levelized cost of VRES for 2022 build large plants (source: PBL, see Table 8-5 in Appendix 8.4).
In case 2 with a gas price of €30/MWh, only onshore wind without government support.*

[15] It should be noted that these numbers are the results of calculations based on simplified assumptions and are meant to show the dynamics of interaction of different parts of the power system, such as variable renewable power generation, storage, and sector coupling. Their value lies in the comparison to each other and do not stand on their own. Appendices 8.4.3 and 8.4.4 and Table 8-5 show more detailed results of the calculations, among others the separate GWAs for PV, onshore wind, and offshore wind.

CASE	Average (base load) electricity price per MWh at gas price of €30/MWh	Average (base load) electricity price per MWh at gas price of €80/MWh
Case 0 - No flexibility	€36.9	€98.3
Case 1 - Case 0 with added 30 GW, 180 GWh of storage (16 TWh throughput)	€40.1	€107.2
Case 2 - Case 1 with added 5 GW opportunity demand	€46.3	€123.7

Table 4-5 Impact of flexibility and opportunity demand on the average electricity price at different gas prices.

4.4 Implications for the government and non-flexible consumers

The previous section shows that variable renewable electricity generation will benefit greatly from opportunity demand. However, to make a more complete assessment of the impact of opportunity demand, the government and electricity consumers that do not apply to opportunity demand need to be considered as well.

4.4.1 IMPACT ON NON-FLEXIBLE ELECTRICITY DEMAND

As mentioned, opportunity demand sets the electricity price during times when dispatchable generation is idle and renewable generation is not sufficient to saturate the flexible and opportunity demand. Compared to a system with the same amount of installed renewable capacity, the electricity bill to non-flexible electricity users is therefore higher, though on average this will be compensated by additional taxes needed to support the same capacity of renewables (see Table 4-4).

Table 4-5 shows the average electricity price for non-flexible demand for the three cases, using the two different annual gas prices (€30/MWh and €80/MWh).

Obviously, these figures are very dependent on the assumptions regarding capacity mix and therefore the merit order of generation, as well as the amount of variable renewable generation. Like all calculations in this paper, these numbers are meant as illustrations to provide insight into the mechanisms of the electricity market and the effect of opportunity demand in this. It is nevertheless clear that the electricity bill for non-flexible demand increases because of opportunity demand. However, this implies that the same amount of VRES is being built, which requires that the revenue be sufficient to cover the costs and thus that the market income be supplemented by government support.

Table 4-4 in the previous section shows that, if the structural gas price is €30/MWh and a maximum of flexibility is available, including opportunity demand, VRES still requires support from subsidies (except for onshore wind, which is just above break-even). This subsidy is paid through taxes and levies, and the total amount needed should be sufficient to cover the gap between LCOE and market revenues. In other words, depending on the way these taxes and levies are distributed across energy customers and citizens, the impact of taxes may offset any electricity price differences between the cases.

With a (stable annual) gas price of €80/MWh, however, market revenues cover more than the LCOE of all VRES, and subsidies are not required. In this case, VRES is very profitable and more VRES can (and should) be built.

4.4.2 IMPACT ON GOVERNMENT SUPPORT

To limit climate change, most governments have agreed on goals to reduce greenhouse gas emissions. To reach these goals, they have several tools at their disposal, such as:

- taxing greenhouse gas emissions through direct taxes and/or by limiting the allowances that can be emitted
- direct subsidies for renewable electricity generation
- subsidies for renewable electricity use, such as storage/ demand response and opportunity demand; and
- taxing energy use.

Increasing the cost for carbon emissions significantly increases the cost of energy, which is an incentive for energy savings and leads to a higher percentage of variable renewable generation that the market can support, as argued in the previous section. It will increase the overall energy prices, and therefore will have a negative impact on the economy. More importantly, the effectiveness of increasing the price for carbon emissions declines as the capacity of renewables increases to a large amount.

Subsidies are a way to stimulate the capacity increase of variable renewables. But they need to be covered by taxes and levies. Such subsidies can be offered directly to increase the installed capacity of variable renewables, or to supplement market revenues up to the LCOE. Subsidizing renewables pushes the capacity of renewables, and, through increasing the periods with low electricity prices, indirectly pushes the amount of storage and opportunity demand. However, this is lagging and all its costs in Figure 4-2, including the grid costs, need to be covered by replacing natural gas with cheap electricity. Consequently, it will require long periods of low electricity prices and thus entail the disadvantage of relatively extensive curtailment of renewables. So, subsidizing VRES directly stimulates the production of VRES, but is less efficient in stimulating the use of this renewable electricity when there is surplus, because other costs, such as grid transportation costs, are a hurdle.

Subsidies directed to stimulate flexible demand, such as storage and opportunity demand, will instead increase the pull from the electricity market for renewable generation, especially when local grid conditions are considered (see Chapter 5). As Table 4-4 shows, support for opportunity demand cannot replace direct support for variable renewables or carbon tax, but it is a very effective and economical way to reduce carbon emissions for heating and hydrogen production while at the same time increasing the capacity of variable renewable electricity that the electricity market can support – and it does not need to be supported directly by the government. However, this only applies to demand that is responsive to differences between the gas and electricity prices, so any support should be aimed at establishing capacity for opportunity demand and be careful not to disrupt its operation.

Finally, taxing energy use, so-called energy tax, is mostly aimed to stimulate energy efficiency – besides being a source of income for the government. This is often a fixed amount per kWh, commonly dependent on the annual amount of energy taken but independent of the time or energy price. While energy tax is an effective and relatively simple measure, their effectiveness deteriorates in a high-VRES electricity system, where timing becomes important. Until now, energy taxes do not differentiate in time. This leads to the situation where government-supported renewable electricity is not used and needs to be curtailed because it is taxed, except for large energy-intensive industry that tends to pay relatively little energy tax[16]. An energy tax based on the percentage of the (retail) price – similar to VAT – would solve this issue to a large extent, provided energy retailers have a dynamic pricing product for electricity. Several retailers have already had such kinds of contracts for several years, for example where the customer pays an electricity price based on the hourly day-ahead price plus a service fee. A price-dependent energy tax would amplify variation in price and stimulate the use of low-priced (renewable) energy. For energy users who favour (long-term) energy price stability while still being able to benefit from short-term price fluctuations due to the variability of renewable generation, it would be relatively straightforward to create contracts that simulate the purchasing strategy hedging both long-term forward markets and the day-ahead market.

To conclude, the government has several tools at its disposal to influence the direction in which the electricity market develops. As the amount of renewable energy increases, the relative effect of these tools' changes. Direct stimulation of renewables is straightforward, but it loses its effectiveness if renewables need to be curtailed because of a lack of demand. Stimulating demand becomes more effective, but only if it absorbs renewable electricity that otherwise would need to be curtailed. Lastly, care should be taken to avoid government measures that potentially counteract each other.

[16] See Figure 4-2 and Appendix 8.3.

4.5 The business case for the grid operator

Figure 4-2 shows that the cost of expanding the transmission infrastructure – paid through the added grid transportation fee – is a major hurdle to the integration of electricity demand and generation through opportunity demand. While tariff schemes are highly situational and vary across countries, the investments in upgrading the grid to accommodate electric heating and electrolysis are significant. Transportation tariffs represent the actual (average) cost necessary to maintain and expand the network capacity.

Electrification will play a major role in decarbonizing industry and will lead to a significant increase in the required network capacity. This capacity increase will in principle be covered by the income from transport tariffs and hence be paid by industry itself, or by the government through subsidies.

Without government support, the grid transportation costs might be too high for opportunity demand, which is used only for a relatively short duration per year. With government support, grid operators, many of whom already struggle to keep up with the demand for grid capacity for renewable generation, will face even harder pressure.

However, opportunity demand is by nature very flexible and has no duration limit caused by full or depleted buffers, like storage (see Section 2.3). While this flexibility will be predominately used to benefit from low electricity prices caused by oversupply of variable renewables, there are opportunities to create synergies with the network, which have the potential for significant reduction of the required capacity and costs, especially when combined with the integration of local variable renewable electricity sources. These synergies are explored in the next chapter.

5. CREATING SYNERGY WITH THE ELECTRIC INFRASTRUCTURE

5. CREATING SYNERGY WITH THE ELECTRIC INFRASTRUCTURE

- Because of the flexible 'staying power' and relatively transparent cost structure of opportunity demand, it is better suited to provide capacity-related synergies to the network than flexibility.
- Examples of capacity-related synergies are:
  - Flexibility through non-firm capacity contracts
  - Interruptible capacity contracts (or 'N-1 as a service')
  - Capacity pooling (or a virtual microgrid)

In the previous chapter and in Appendix 8.3, we sketched a business case for a 10-MW electric boiler in Germany. In that business case, the grid transportation fee represented a major part of the cost. Such a grid transportation fee covers the costs of expanding and maintaining the collective capacity of the electricity grid, so that it remains sufficient to satisfy the capacity required by all connections. Because historically the electricity network and generation were integrated, it is still the case that in most countries the cost of transmission capacity is paid by electricity users, whereas electricity generators are exempted from paying this fee.

Still, in many countries, such as Germany and the Netherlands, large continuous stable demand receives a huge reduction on the required fee (up to 90%). Because of the large utilization, the relative impact of this demand on the required grid capacity is low compared to the impact of more fluctuating demand, and thus imposes less cost to the grid per kWh[17].

An electric boiler or electrolyser, on the other hand, can be operated very flexibly, even more so than a battery system, which is limited by its storage capacity (in kWh). To justify a similar reduction of the transport fee, this flexibility should result in real savings and/or avoided investments in the electricity grid. This implies that the grid operator should be able to impose restrictions on the freedom to operate opportunity demand to ensure this synergy.

So, what options are there to create synergy between opportunity demand and the operation and capacity expansion of the electricity grid? And what restrictions and conditions regarding the operation of opportunity demand would that imply?

We will explore three possible options:

- Flexibility through non-firm capacity
- Interruptible capacity or N-1 as a service; and
- Capacity pooling

We disregard flexibility through day-ahead auctions to solve potential congestions (congestion management auctions), because for the involved industry this will result in highly uncertain variable revenues, depending on whether there is congestion. The dependency on congestion and the risk that these revenues will not be able to structurally cover the investments and fixed transportation tariffs make this a very expensive option for financing opportunity demand.

Flexibility through a non-firm capacity contract basically comes down to a similar arrangement as flexibility through congestion management auctions. It allows the grid operator to curtail load based on day-ahead predictions for congestion. Unlike with congestion management auctions, the industry must comply with the request from the grid operator. However, depending on the contract, it is a long-term arrangement with a structural financial reduction of the transport tariff[18] that can be used to partly cover the required investments.

Interruptible capacity means that the demand (or generation) does not benefit from the required N-1 capacity in the transmission grid. In the case of an incident that reduces the capacity in the grid, this demand/generation will need to be curtailed, so that the remaining grid capacity can be used to meet other demand/generation. Unlike non-firm capacity, interruptible capacity is triggered by grid faults which are not

[17] Section 4.2 and Appendix 8.3 gives the calculations of the transmission tariff for the business case of an electric boiler in Germany. An overview of special transmission tariffs in other European countries can be found in Appendix 8 of [16].
[18] Although there might also be a compensation per curtailment, the fixed part of the arrangement is important to cover the fixed cost for investments.

announced a day ahead. This capacity is basically part of grid security and should respond fast enough to prevent the activation of other security mechanisms that would cause loss of load. However, the possible overvoltage and current is but a fraction of that of a short circuit. Still, strict technical requirements should apply. An alternative way of looking at this option is to regard it as an ancillary service offered by industry to the grid operator: 'N-1 as a service'.

Capacity pooling is another way to create synergy with the grid and reduce the required overall transmission capacity, for example by synchronizing the electric heating with local renewable generation – with a high negative correlation with electricity prices – making sure that the electricity that is consumed does not need to be transported over the transmission grid and thus does not take up additional transmission capacity. Assuming this can be guaranteed to the grid operator, the grid operator can avoid additional investments in the transmission grid.

All three options will be explored in more detail in the following sections.

5.1 Non-firm capacity and interruptible capacity

5.1.1 NON-FIRM CAPACITY

Non-firm capacity is capacity that is not guaranteed to the user and can be curtailed by the grid operator in case of congestion. Non-firm capacity can be regarded as flexibility that has been contracted (and paid) in advance and that can be curtailed under certain predefined circumstances. This curtailment is typically announced in advance, for example on day-ahead basis, when it becomes clear that the grid runs a risk of becoming congested. For opportunity demand, this is a more favourable form of grid integration than congestion management through flexibility auctions, because it guarantees an income or cost reduction. The drawback is that the grid operator has bought the right to curtail, and thus the participating industry cannot 'opt out' if it is called upon at a moment that is unfavourable to this industry. However, this will not jeopardize operations, because the flexibility is always available in the possibility switch to (or from) natural gas. This means that the risk is relatively confined to the opportunity cost of the switch between natural gas and electricity and is relatively easy to determine.

5.1.2 INTERRUPTIBLE CAPACITY

In most countries, the electricity transmission grid is designed to be N-1 secure – a clear and relatively simple way to ensure the resilience of the electricity system. It means that if one random component fails, electricity supply will not be interrupted[19]. The capacity that is provided even when a grid fault occurs is called 'firm' capacity. Sometimes, this requirement applies under maintenance, meaning that, without any ongoing maintenance, the grid operates N-2 secure.

Opportunity heating and opportunity electrolysis inherently have their own back-up, and their final demand is inherently N-1 secure. Requiring N-1 secure transmission capacity for this load seems costly and unnecessary, assuming the time to switch between energy carrier is limited, for example by sharing boiler vessels and heat infrastructure as much as possible.

When drawing electricity from the grid, this load can be cut very fast when a single fault occurs in the electricity grid, to free up capacity needed for load with a higher priority (firm capacity). This allows opportunity demand to make use of the N-1 transmission capacity reserved in the case of a fault, freeing it up when it is needed for 'firm capacity' and thus avoiding or postponing investments to build additional capacity.

[19] While this is a simple and clear metric, it does not define the risk of a failure. More components mean a higher risk of failure. For example, a connection consisting of five lines with one spare (5+1) will have a different (often higher, though not always) chance of failure than a connection of just one line with one spare (1+1), e.g. depending on the actual load during a failure, duration of maintenance and repairs, etc.

5.1.3 DIFFERENCE BETWEEN NON-FIRM CAPACITY AND INTERRUPTIBLE CAPACITY

Figure 5-1 shows the principle assuming a grid with 100% reserve capacity (Figure 5-1a). The capacity is indicated with dark blue; the reserve capacity is indicated with light blue. If the load in the area is higher than the N-1 secure capacity, part of the load needs to be reduced to maintain the N-1 criterion (Figure 5-1b). The grid operator procures upward flexibility to increase local generation and/or reduce local demand, to make sure that the load on the grid is reduced to be within the N-1 secure capacity. This flexibility procurement can be through congestion management auctions or through non-firm capacity contracts.

Somewhat counterintuitively, non-firm capacity needs to be curtailed to make sure the load is within the N-1 secure capacity of the grid, whereas interruptible load does not, because the reserve capacity is still available. In this situation, it would also mean that demand requiring firm capacity cannot be connected, but opportunity demand connected through interruptible capacity still can. Of course, in case of a fault, this interruptible demand needs to be cut fast enough to prevent damage to the grid and to free up capacity for load connected through firm capacity contracts.

Figure 5-1c shows a situation in which the grid is congested on the generation side, and the surplus generation in the area cannot be transported out. In this case, both interruptible demand and demand connected with non-firm capacity function as normal demand, absorbing local generation and making sure that the grid operator needs to purchase less downward flexibility than would otherwise be the case, by curtailing local generation or increasing demand.

5.1.4 CHALLENGES AND BENEFITS FOR NON-FIRM AND INTERRUPTIBLE CAPACITY CONTRACTS

While conceptually straightforward from a technological point of view, contractual and legal implementation of non-firm capacity contracts, and especially interruptible capacity, can be challenging. This is because they transfer the consequences of grid design and operation practices, normally within the domain of the grid operator and shielded from the end-user by ensuring the grid has sufficient redundancy, to the end user. While this is in principle true for all solutions that exploit synergy between the electricity network and power generation and demand, it adds an additional challenge when this solution is part of the infrastructure ensuring the reliability of the grid.

Technically, this can be solved. Unlike when using firm capacity, however, the frequency and duration of curtailment of load and generation that is connected through non-firm and/or interruptible capacity are highly dependent on local circumstances. For non-firm capacity, these are the load and generation of other grid users; for interruptible capacity, this is determined by the risk and frequency of single grid faults, and by whether the reserve (N-1) capacity is actually needed at the time of the fault. This means that the consequences of having a non-firm capacity contract or interruptible contract might not be fully known in advance and can differ hugely between end users: one might experience an interruption every month, while another does not experience any difference from a contract for firm capacity, except for the tariff.

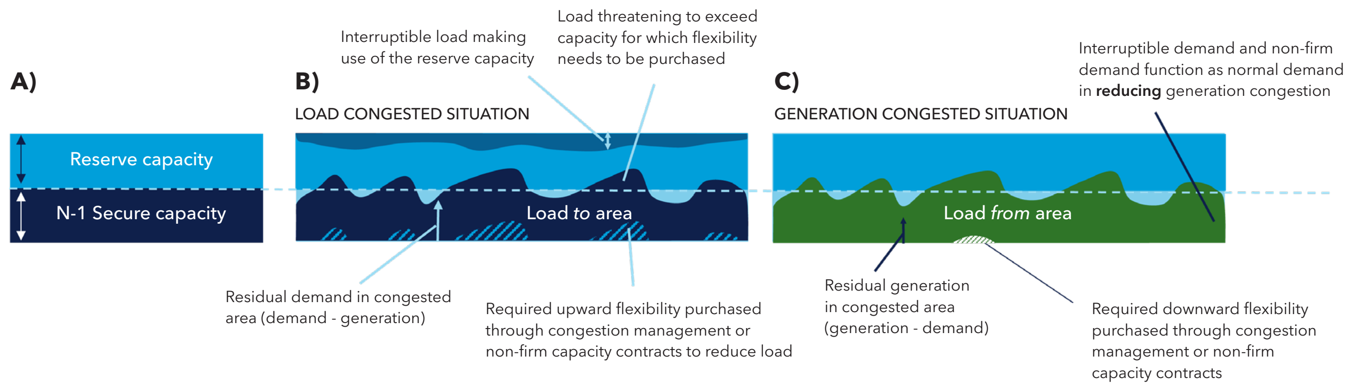

Figure 5-1 Schematic principle of opportunity demand making use of the reserve capacity in transmission grids.

There are two ways to solve this issue, which can be combined. One is to set performance criteria for non-firm contracts offered to end users, such as the maximum number and duration of curtailments because of grid management. However, this implies some prior knowledge of the number of curtailments or interruptions, which will not always be available[20]. Besides, in the case of interruptible capacity, the N-1 criterion is meant to guarantee a certain high level of availability of the grid. Guaranteeing such new predetermined (and less ambitious) criteria for interruptible capacity contracts, such as a maximum duration and maximum frequency of interruptions, will often require technical measures that eventually come down to making sure the most critical (and likely most expensive) components will be N-1 outfitted. Thus, setting performance criteria for interruptible contracts will, at best, partly solve this issue.

Another way to solve this issue is to offer a compensation for the impact of the possible curtailments on the end user with the interruptible or non-firm capacity contract, assuming this impact is quantifiable and limited. An end user with an interruptible capacity contract will have a reduced fixed transport tariff to cover the additional investments they need to make, but the frequency and duration of curtailment of their demand (or generation) are part of grid operations and should pose a minimal risk to the finances and operation of this end user for a non-firm capacity or interruptible capacity contract to be attractive[21].

For renewable generation, this compensation will be based on lost sales revenue, i.e. on the forecasted but not realized generation and the power prices. For opportunity demand with a non-firm or interruptible capacity contract, this can be based on the actual heat (or hydrogen) production through the more expensive route times the price difference.
For example, in a hybrid heating system with an interruptible capacity contract running on electricity, the electricity demand will need to be curtailed to free up capacity for other demand. It will switch to natural gas, and the operator of the heating system will be compensated by the grid operator for the additional cost to produce heat via the gas route for as long as is necessary.

5.2 Capacity pooling

Capacity pooling is another way that the impact of opportunity demand on the grid can be reduced compared to traditional demand. Basically, this means that two or more connections share transmission capacity. Together, they are responsible for ensuring that their collective use of grid capacity does not exceed an agreed amount[22]. Sometimes, this mechanism is referred to as a microgrid, but capacity pooling does not require that all connections behind a bottleneck in the transmission grid participate, which would be the case in a physical microgrid.

The application of capacity pooling is, in principle, not limited to congested areas and may be applied to end users in all situations to preserve transmission capacity. This can make capacity pooling generally applicable and independent of specific situations in the grid. It also allows end users to take the initiative to establish capacity pooling among themselves and reduce the need for transmission capacity.

While capacity pooling can be applied to all demand and generation, the flexibility of opportunity demand – especially its ability to sustain a higher or lower demand for an indefinite period – allows it to offer guaranteed capacity at a relatively low cost. This capacity can be used to limit the requested transmission capacity of the grid. Grid operators do not like to depend on third parties when grid safety is concerned, so additional measures – operated by the grid operator – will be required, but only as an additional fail-safe.

The benefits to the grid become significantly higher when variable local generation participates in capacity pooling and local variable generation with a low-capacity factor is guaranteed to be absorbed locally, eliminating the need for reinforcement of the transmission grid.

[20] In an area that turns out to have a lot of curtailments, the grid operator could enter into non-firm capacity contracts with multiple users and disconnect them 'in turn'. In this way, the grid operator can have some control over the number of curtailments of users with a non-firm capacity contract.
[21] Although the alternative of not having a grid connection for this load might be even less attractive.
[22] This is different from applying a simultaneity factor in the design of distribution grids, where the grid operator is responsible for having sufficient capacity.

5.2.1 AN EXAMPLE OF CAPACITY POOLING

To show the potential of capacity pooling, we take an example inspired by the Dutch province of Zeeland. In this province, 5.5 GW of offshore wind capacity will be landed in 2030, as shown in Figure 5-2.

Figure 5-3 gives a schematic overview of the situation. The existing grid capacity connecting the province to the rest of the country is about 2.0 GW (while still able to operate under the N-1 criterion). By 2030, this capacity should have increased to 3.5 GW. At the same time, the present industry has the ambition to develop major hydrogen infrastructure in the area. Currently, 1850 MWe of electrolyser capacity is announced and 50 MWe of electric boilers.

Other parameters used for the calculations are the opportunity cost of the electric boilers (the maximum electricity price acceptable to the boilers): €31/MWh and the opportunity cost of electrolysis: €30.6/MWh, both determined by the price of natural gas.

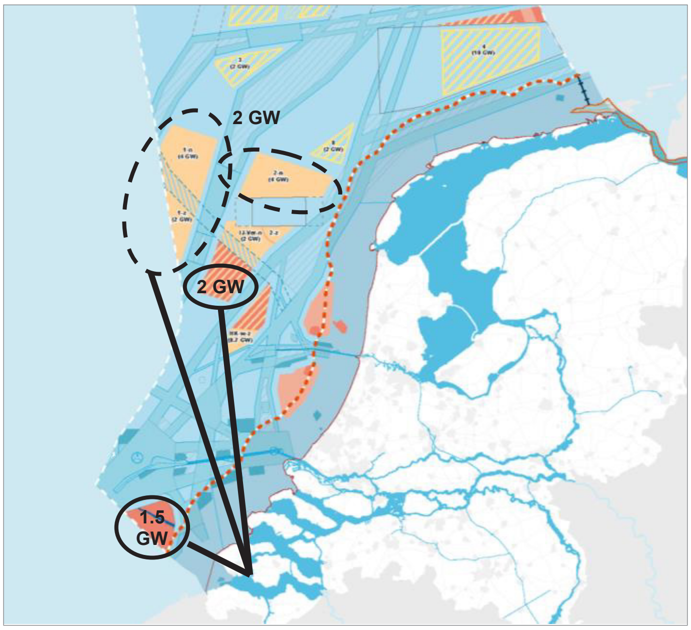

Figure 5-2 Realized and planned offshore wind to be landed in southwest Netherlands (the province of Zeeland). The ambition of the Netherlands is to have 21 GW of offshore wind by 2030.

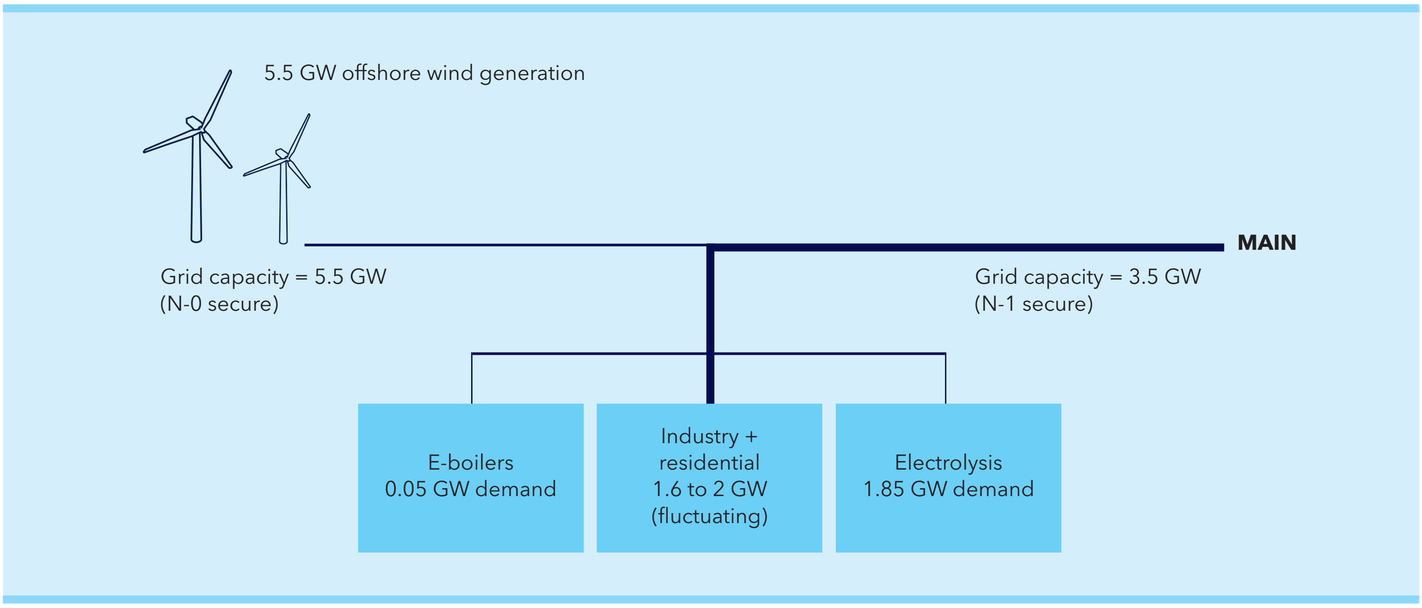

Figure 5-3 Schematic overview of the province in 2030.

Based on the numbers above, we calculated the residual load duration of the province, which is shown in Figure 5-4 below. The first graph shows the situation with the 5.5 GW of offshore wind being connected in the province of Zeeland, but with no change to demand (so no opportunity demand). It shows that an increase from 2 to 3.5 GW would dramatically reduce the amount of energy production that would need to be curtailed. About one-fifth of the time, however, there would still be a limited amount of energy that could not be produced.

The graph to the right shows the situation where the opportunity demand (1.85 GW of electrolysis and 50 MW of electric heating) is operated by switching between natural gas and electricity. The light blue line indicates the residual demand that needs to be imported when opportunity demand is operated purely based on the price difference between natural gas and electricity, without grid restrictions.

Compared to the left graph, it shows that opportunity demand without capacity pooling will reduce the need to curtail wind production, but curtailment of offshore wind cannot be completely avoided, even when the grid capacity is increased to 3.5 GW[23]. The left side of the graph shows that opportunity demand will run even when there is hardly any offshore wind and local demand increases beyond the capacity of the transmission grid. This is predominately caused by solar generation outside the province driving down electricity prices below the opportunity costs.

The dark blue curve is the residual load in the province if the offshore wind electricity generation and the opportunity demand participate in capacity pooling to keep demand within the 2 GW limit of the transmission grid, with only the opportunity demand adapting to the grid situation. It shows how capacity pooling can avoid congestion in the transmission grid. Instead of using solar energy from outside the province, it uses natural gas (left side of the graph); and instead of curtailing offshore wind, it can be absorbed by opportunity demand, despite electricity prices higher than the opportunity costs.

A capacity pooling contract could keep demand and generation in the province within the capacity boundaries of the transmission grid connecting the province, even without the planned grid reinforcement to 3.5 GW. The cost of electric heating and electrolysis is higher because it runs when wholesale electricity prices are higher than those of gas, to absorb the oversupply of offshore wind in the province. Without capacity pooling, this local oversupply of wind energy would have been curtailed and would not profit from the relatively higher electricity prices. Selling the electricity at the opportunity costs of opportunity demand – for boilers this is the gas price – would compensate opportunity demand and generate a profit from what would otherwise be surplus wind energy.

Capacity pooling in its extreme thus becomes a variant to nodal pricing, where the participants – but only the participants themselves – are limited by their shared capacity contracted with the grid operator. Requesting the grid operator to increase the shared capacity will increase the grid costs but will lead to transaction prices between the participants that are closer to the wholesale price.

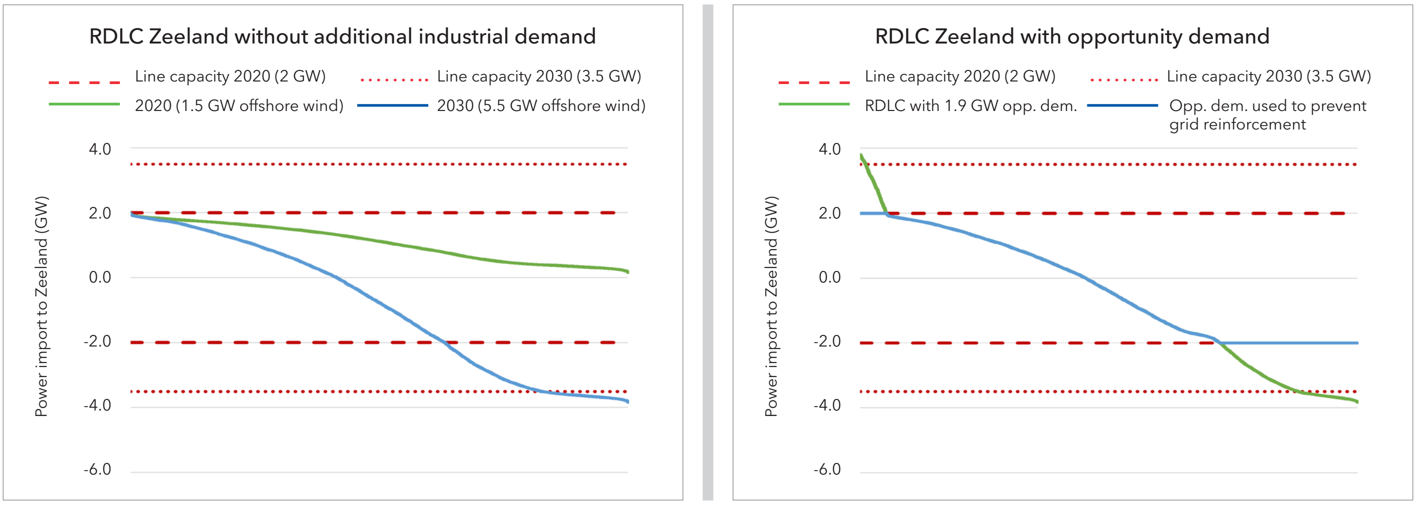

Figure 5-4 Overview of load duration curves for the province of Zeeland in 2030 without electrification of industry (left), and with electrification of industry with and without electrification of industry including capacity pooling (for 2.0 GW) (right).

[23] Comparing the left and the right graph. for a grid with 2 GW transmission capacity the available opportunity demand reduces the numbers (right) of curtailment from 3200 to 2400 hours; for a grid with 3,5 GW transmission capacity this will be from 1500 to 1000 hours.

5.2.2 CHALLENGES AND BENEFITS OF CAPACITY POOLING

Capacity pooling can have major benefits, such as avoiding curtailment of renewable generation due to grid capacity constraints and enabling better utilization of existing transmission capacity. It can bring down required investment in the transmission grid by utilizing the reliable, or 'firm', flexibility of hybrid boilers and (industrial) electrolysers to offset the impact of other demand and generation with which it is pooled.

Looking at the business case for opportunity demand in Section 4.2, capacity pooling can be a way to reduce grid investments and increase the utilization of the transmission grid, which benefits the grid operator. If it can be translated into a reduction of the transport tariffs, it will benefit industry as well. A major advantage over congestion management – where a grid operator buys flexibility through an auction to prevent overloading of the grid – is that the reward for participants is more secure and aligned with their cost structure. Instead of selling flexibility to the grid operator, participants share their flexibility capacity to cover the required investments.

Capacity pooling with multiple parties can eventually lead to a system in which grid capacity is valued into the electricity system, and where capacity pooling 'communities' exchange available transmission capacity among themselves depending on their needs. If needed, the community can request additional capacity from the grid operator, possibly triggering a reinforcement of the transmission capacity.

Nevertheless, there are major challenges. For renewable generation in general, opportunity demand helps to prevent oversupply and the erosion of VRES return on investment. However, this benefits all variable renewables, and not just renewable plants engaged in capacity pooling contracts. In most countries, grid operators have little to offer to specific generation plants, because they do not need to pay for transmission capacity [7]. This means that the incentive for wind and solar parks to participate in capacity pooling contracts should come from industry that needs the renewable energy to decarbonize. New-to-build wind and solar plants in generation-congested areas might have a greater incentive to engage in capacity pooling contracts with nearby industry, as for them it might be the only way to ensure a timely realization of a grid connection.

Another challenge is the dependency between partners that engage in capacity pooling. If a capacity pooling contract is dissolved for some reason, for example because one of the participants leaves, the other participants have to apply for a capacity increase. Depending on whether this capacity is available or requires a grid expansion, this may take quite some time.

A third challenge is that existing customers who coincidentally have load profiles with peaks at different times may apply for a contract in which they couple their capacity and apply for a lower transportation tariff without changing their behaviour. This could reduce the revenues the grid operator needs to maintain the grid or lead to higher grid tariffs for other customers. On the other hand, the customers engaging in a coupled capacity contract do need to technically ensure that their collectively used capacity will remain within the boundaries of the contracted capacity. So, additional grid capacity will become physically available for other customers without requiring additional grid investment. Even in currently non-congested areas, this capacity is becoming valuable[24].

Capacity pooling contracts can be closed to third parties, or they could be (obligatorily) open to parties that want to participate. In the latter case, grid operators themselves could take the initiative to offer a pooled capacity contract for a congested area that end users could join freely. The relation with congestion management can be further explored. One example could be to offer parties with opportunity demand a reduction in transport tariff in exchange for their participation in congestion management auctions with an obligatory bid price related to the gas price.

For the energy transition to be successful, synergies between electric infrastructure and electricity demand and generation are essential. Capacity pooling is an example of what such synergies may look like, but it will require further research before it can be successfully implemented.

[24] With the possible exception of low-voltage residential networks, which historically were designed with a simultaneity factor as low as 20%. On the other hand, the investments necessary in households to physically ensure that the load on a distribution station will never exceed 20% of the capacity of all households will be prohibitive. Solar, and demand potentially reacting on dynamic electricity prices like heat pumps and electric vehicle charging, might nevertheless require such investments eventually. When they do, capacity pooling can be an alternative to congestion management (which will require similar technology and investments).

6. SUMMARY AND CONCLUSIONS

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- The energy transition is a major challenge, which transcends the energy system.
- To keep this transition affordable, synergies between energy supply and electricity generation, energy use, and energy transport should be exploited.
- Opportunity demand, producing heat or hydrogen by alternating between renewable electricity and natural gas, is an example of such synergy, provided the network is considered.
- Allowing the strengths of the different systems to compensate for the weaknesses of others requires a shift from topic-wise regulation to designing the right regulatory interface between systems.
- For industry, the synergy between this new industrial opportunity demand and the electricity grid should be sustained and not depend on whether there is congestion or not.
- Concepts like connecting opportunity demand N-0 secure and pooling the capacity of this demand with local variable renewable generation provide possibilities to create sustained synergy with the grid.

6.1 Summary

The energy transition is not limited to the electricity system, and energy is not the only sector that will need to go through a transition. Still, the energy transition is an essential element in ensuring a sustainable future, and the electricity system plays a pivotal role in the energy transition.

A major challenge is to match electricity demand to variable renewable electricity generation. Storage and demand response – for example using heat storage – can to a large extent solve the mismatch between electricity generation and demand between hours, days, and even between weekdays and weekends. However, the longer the duration of the mismatch, the more energy needs to be stored or shifted and the more expensive the storage and demand response options will be. A battery used for day/night storage cycles 365 times a year. A storage system that covers seasonal differences between electricity demand and generation will only cycle one time per year. This means that all costs, including amortization of the capex, need to be recovered in this single cycle.

While it seems obvious to store surplus renewable electricity in summer to use it during winter, when there is structurally more demand and less generation, this energy does not need to be coupled directly. Since the electricity system is not an isolated system, surplus renewables can be used to replace other fuels, particularly natural gas, while renewable shortages can be offset by the natural gas saved during the surplus. If this gas is later replaced with hydrogen, it will result in a carbon-free energy system that utilizes the efficiency of renewable electricity when it is available, while avoiding inefficient conversion of (hydrogen) gas to electricity when it is not[25].

To keep the energy transition affordable, it is important to consider the larger energy system and look for synergies. In other words, it is essential to look at sector coupling. In this paper, we examined the business case for opportunity demand using continuous industrial heating, switching between electricity and natural gas depending on availability, which is represented by market prices. While sensitive to disruptions[26], such as Covid and very high natural gas prices, our calculations on the business case for electric boilers are starting to become profitable, especially in specific cases where the grid transportation tariffs can be avoided[27].

[25] Using the heat from combined heat and power generation using hydrogen would be even more beneficial, because this system will operate when there is a shortage of renewable electricity generation. The same applies for electrolysis, when both heat for direct use, as hydrogen for future use, needs to be produced.
[26] It is likely these kinds of disruptions will appear more frequent. On the one side because of greater instability through climate change and a less stable global political environment, on the other side because the world economy is much more entangled and efficient, meaning relatively small disturbances can have a major impact.
[27] For example, if the boiler can make use of existing contracted capacity or makes use of renewable generation on the same site.

On a societal level, opportunity demand has positive effects. Creating a demand for large amounts of variable renewable electricity that otherwise would have little economic value, the electricity market will be able to 'host' a much larger share of variable renewable electricity generation capacity. Thus, replacing natural gas used for heating and industrial hydrogen production with renewable electricity, when it is available, benefits renewable electricity producers and/or governments that are otherwise required to structurally provide subsidies for renewable electricity generation to reach the targets[28]. Financing renewable electricity through the market instead of subsidies ensures a more effective fit between electricity generation and demand and reduces the need for curtailment of renewable electricity, albeit at a cost over which government exercises less direct control[29].

'Ordinary' electricity users will face higher electricity prices. Instead of relatively long periods where electricity prices are zero, electricity prices in these periods will converge to the gas price, pushed by the demand from industrial heating and hydrogen production. However, on a societal level, these electricity prices provide revenue that will be invested in new-to-build renewable capacity (until a new equilibrium is reached), which otherwise would need to be financed through tax-funded government subsidies.

The main barrier for opportunity demand is infrastructure costs. Under current regulations, opportunity demand requires a significant increase in investment in the electricity transmission network. This capacity would have a low utilization and thus be very inefficient from a network perspective. However, this capacity would be very flexible, because the electricity demand could be curtailed at any time by switching to gas. The cost would be equal to the spread between the price of natural gas and the price of electricity. This flexibility, combined with its relatively transparent cost, offers great opportunities to create synergy with the network and thus reduce the required transmission capacity and network investments. This would in turn reduce the transmission tariffs for the user. Examples of such opportunities are non-firm capacity, interruptible capacity, and capacity pooling.

6.2 Finding the right synergies

There are many well-sketched visions and models that show what a sustainable energy system might look like. Most include a lot of wind, solar and hydro power, electrification of energy use through heat pumps, and electric mobility and storage[30]. These visions and model calculations show that a zero-emission future is possible, although it will take a lot of effort and political and social willpower to reach it.

Maximizing synergies between all aspects of the energy system is therefore essential. This includes electricity generation, demand, storage, and infrastructure; hydrogen, initially as feedstock and eventually as energy carrier; and using the remaining fossil fuels as efficiently and effectively as possible while reducing our dependence thereon.

To keep things understandable, systems are often viewed in isolation. This is especially true of new regulations, which can have a huge impact and where mistakes in implementation can have large and sector-wide implications that are hard to correct. The drawback of such an approach is that regulation can become a barrier to synergies between systems.

An example of this is the requirement for green hydrogen, produced form renewable power, as stated in the EU Renewable Energy Directive II (RED II). To prevent green hydrogen production from absorbing existing renewable electricity, which would lead to an increase in fossil electricity generation, a requirement is issued that green hydrogen must be produced from 'additional' renewable electricity. Unfortunately, such a requirement raises barriers for creating synergies. For example, how certain is it that renewable electricity generation would have been curtailed if it were not used by the electrolyser? Does the electricity from a dedicated wind farm need to be used for the electrolyser, or can it be sold on the market if the electricity is more needed than hydrogen? If, at the same time, natural gas is being burned to generate electricity, then the electricity from wind is better used to replace electricity from this gas plant than for green hydrogen. However, it would mean that the farm would no longer be 'additional'. While this requirement was removed from the directive in September 2022 because it was deemed too restrictive and would chase hydrogen developers away, individual member states can still choose to implement it [7].

[28] Another solution to organize this money flow form consumption (tax) to generation is to 'rearrange the market model'. However, this can only materialize if enforced through governmental regulation or by reducing the competitiveness in the market, for example by monopolizing (renewable) power generation.
[29] A market is in essence a naturally occurring decentralized mechanism optimizing demand and supply, which works if all stakeholders have (and continue to have) realistic and relevant choices. How to include external costs, such as environmental cost and societal costs (e.g. poverty-induced choice limitation, infrastructure, and other shared assets) remain political choices and need to be enforced somehow.
[30] Good examples are the IEA [13] , IPPC and DNV's own "The pathway to zero emissions" report from 2021 [12].

While issues like these can be solved through clarification or additional regulation, new issues that prevent synergy between systems will likely emerge that will require even further regulation. Instead of trying to prevent undesired consequences caused by 'green hydrogen' – such as additional carbon emissions in the power system – by creating a specific value chain for green hydrogen, it would be more beneficial to put more focus on developing consistent interfaces between systems. This could for instance be achieved through (real-time) green certificates in the electricity system that could be used for the electricity generating green hydrogen. At the same time, new investments in power generation need to favour renewable generation, and this requires a solution to the effects of oversupply. Green hydrogen (together with opportunity heating) is a great solution, if the interface between the different energy and production systems allows synergies to emerge.

The same applies to the interfaces with the infrastructure. There are considerable synergies possible between electricity generation and demand and the infrastructure, as indicated in this paper. However, this requires the ability for all involved parties to negotiate the right balance for their specific situation, which in return requires a thorough understanding of the consequences and risks. Without the opportunity to create more specific synergy between the infrastructure, generation, and demand, grids need to be unnecessarily reinforced, and grid development will remain a hurdle to fast development of renewable generation and the electrification of demand.

Creating consistent interfaces between different sectors and energy systems is a daunting and complicated task. Often, if may seem faster and much more practical to isolate a development, such as green hydrogen production, grid capacity problems, electric mobility, decarbonization of industry, etc. However, too siloed short-term regulation will eventually become a hurdle to the further integration of energy systems. For an affordable energy transition, it is essential to strike the right balance between thoroughly consistent regulation across sectors and speedy, 'for the time being good enough' regulation to guide developments.

Regarding the electrification of industry, the electricity network can become a major obstacle to the electrification of industry. Synergy between the electricity grid and new industrial demand, such as opportunity demand, should be explored. This synergy should be sustained and structural and should not depend on whether there is congestion in the grid. For industry undergoing electrification, such a business case should be structural, sustainable, and relatively easy to assess – although it depends on local, specific circumstances like the presence of local renewable generation. While still requiring significant development, concepts like capacity pooling between customers in a specific geographic area and N-0 secure connections for interruptible opportunity demand can offer such structural synergies.

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7. REFERENCES

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8. APPENDICES

8. APPENDICES

8.1 Load duration curve concept

Figure 8-1 shows how an RLDC is constructed. Graph A shows demand and variable renewable generation during a period, in this case one week. In graph b, the variable generation is subtracted from the demand, resulting in the residual load. It shows when there is insufficient variable renewable electricity to satisfy demand, and thus other generation is required, and it shows when there is a surplus of variable renewable energy generation. Graph c shows the residual load duration curve. It is the same data, sorted by the residual load.

The RLDC gives a clear view of the relation between generation capacity and the time (duration) that this capacity is required (or, in the case of oversupply, provided).

8.2 Input parameters for the calculations for the Netherlands 2030 including storage and sector integration

The numbers as in Table 8-1 were used for the calculations and simulations, roughly representing the electricity system in the Netherlands in 2030.

For the calculations, several time series are used. The normalized duration curves of these time series are shown in Figure 8-2. It should be noted that – for e.g. geographic reasons – solar, onshore wind, and offshore wind never reach their full capacity. The merit order of dispatchable generation is shown in Figure 8-3. The simplified merit order is built up by gas-powered generation with efficiencies of 60%, 50%, 40%, 30%, and 20%.

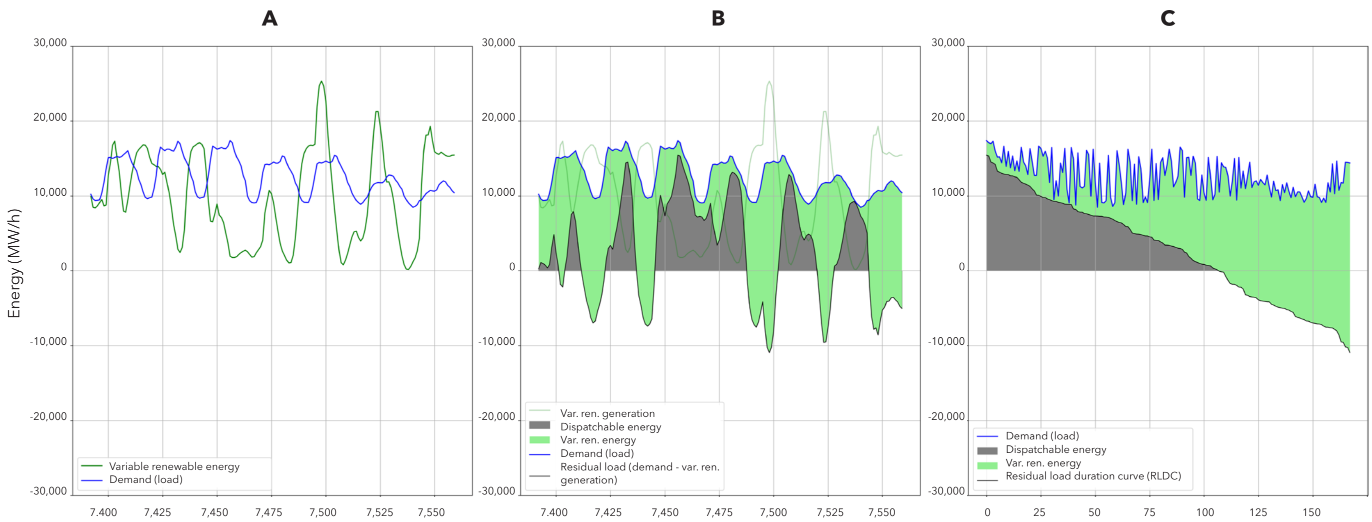


Figure 8-1 Concept of the residual load demand curve (RLDC)

	(Peak) capacity in % of peak demand		Energy per year, in % of demand	
Fixed demand	100%	(24 GW)	100%	(108 TWh)
Solar	108%	(26 GW)	22%	(23 TWh)
Onshore wind	42%	(10 GW)	20%	(22 TWh)
Offshore wind	50%	(12 GW)	34%	(36 TWh)
Total VRES	200%	(48 GW)	76%	(81 TWh)
Flexibility (storage) (incl. V2G of EVs)	125%	(30 GW/180 GWh)	15%	(16 TWh throughput)
Opportunity demand	21%	(5 GW: 4GW heat and 1% electrolysis	3.0%	(3.2 TWh)

Table 8-1 Input parameters for the calculations (case with both storage and opportunity demand).

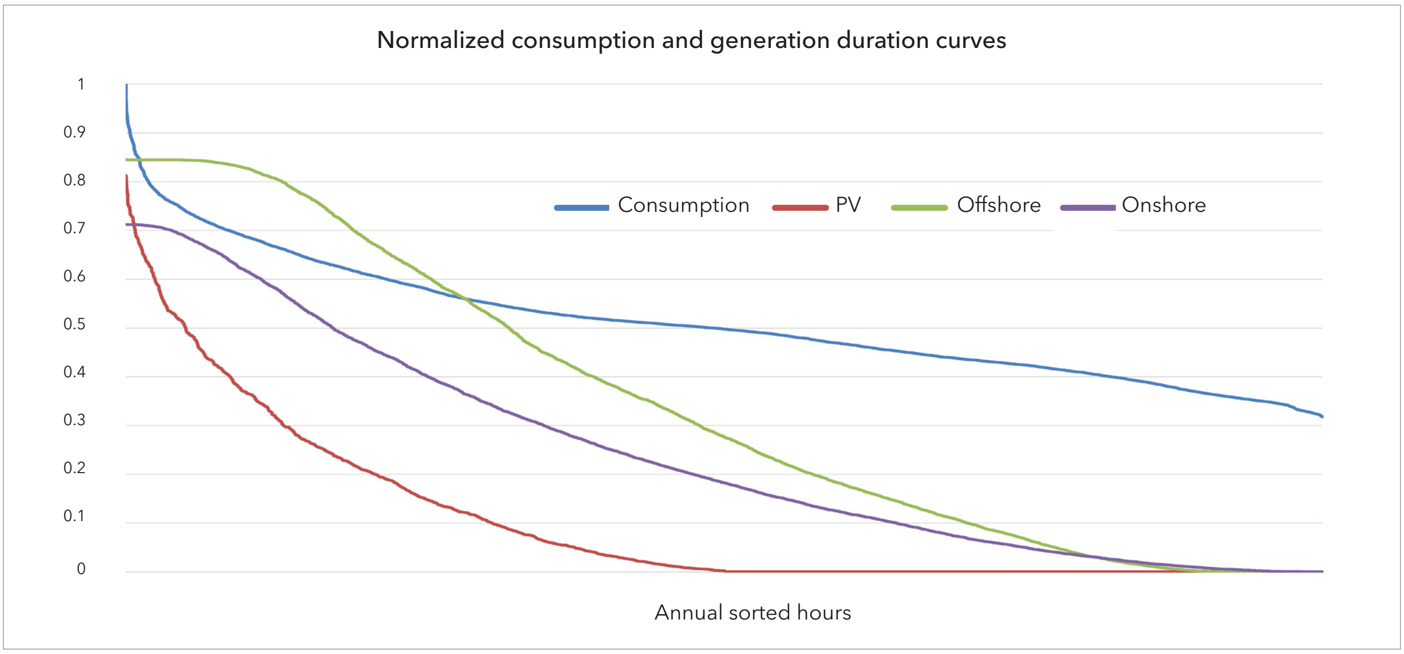


Figure 8-2 Normalized duration curves of variable renewable generation and demand.

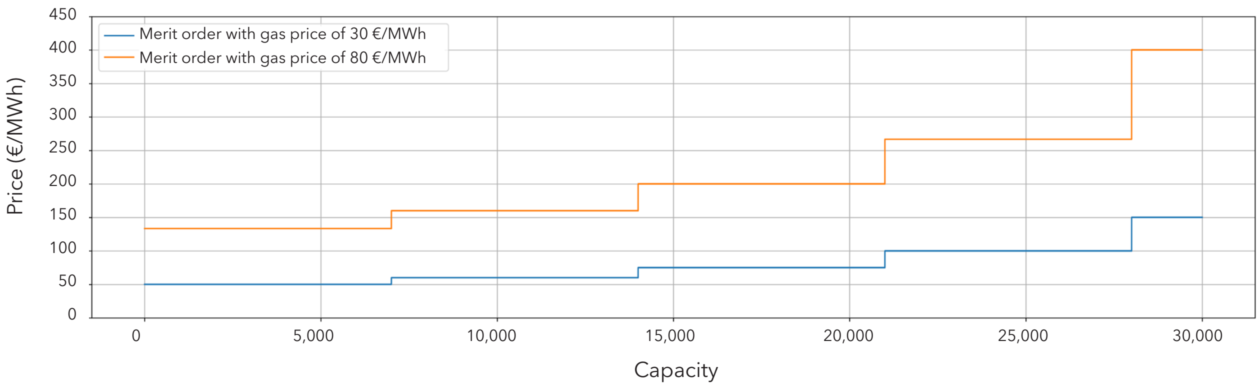


Figure 8-3 Simplified merit order used in the calculations. All generation is derived from natural gas (the most efficient generation is a CCGT with 60% efficiency, the next generation with 50% efficiency etc.).

8.3 Business case German electric boiler in opportunity demand

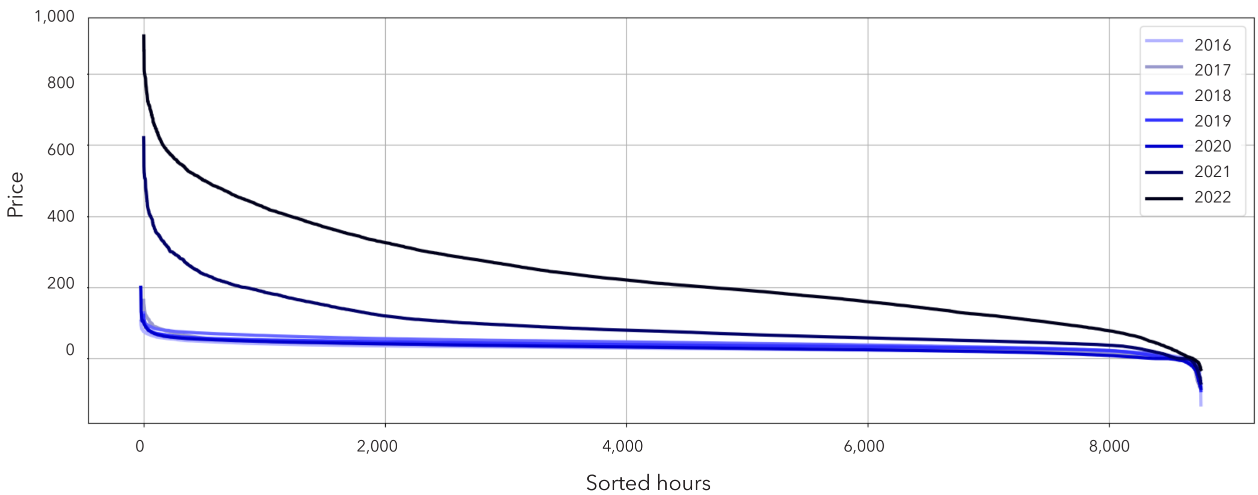


Figure 8-4 German price duration curves for electricity day-ahead market for 2016 to 2022.

	BASE CASE	CASE 2: Carbon tax	CASE 3: Reduced grid tariff
Capex electric boiler (€/MW)	€ 115,000	€ 115,000	€ 115,000
Capex grid connection fee (€/MW)	€ 25,000	€ 25,000	€ 25,000
WACC	6%	6%	6%
Depreciation period E-infra (yr)	20	20	20
Capacity boiler and added grid connection	10 MW	10 MW	10 MW
Tax on electricity (€/MW)	€ 15.37	€ 15.37	€ 15.37
Tax on gas (€/MW)	€ 5.10	€ 5.10	€ 5.10
Carbon tax/credit (€/tonne)	€ 2.53	€ 60.00	€ 60.00
Electricity grid transportation fee	€ 12.23/kW + 0.03140/kWh	€ 12.23/kW + 0.03140/kWh	€ 1.223/kW + 0.003140/kWh
Gas transportation fee	Capacity-based	Capacity-based	Capacity-based

Table 8-2 Main input parameters for calculating the various business cases, with differences highlighted.

Capacity boiler: 10 MW						
2019	CASE 1		CASE 2		CASE 3	
Saved NG	€	7,000	€	10,000	€	73,000
Saved tax NG	€	2,000	€	3,000	€	24,000
Saved carbon tax/ETS	€	-	€	8,000	€	57,000
Electricity purchase	€	25,000	€	29,000	€	16,000
Add. electricity tax	€	- 7,000	€	- 10,000	€	- 72,000
Grid transportation fee	€	- 137,000	€	- 143,000	€	- 27,000
Capex grid connection	€	- 22,000	€	- 22,000	€	- 22,000
Capex e-boiler	€	- 100,000	€	- 100,000	€	- 100,000
RESULT	**€**	**- 232,000**	**€**	**- 225,000**	**€**	**- 51,000**
Running hours		46		67		471
Gas replace with electricity (MW)		460		670		4,710
Amount of electrification in %		0,53%		0,76%		5,38%

Capacity boiler: 10 MW						
2020	CASE 1		CASE 2		CASE 3	
Saved NG	€	4,000	€	7,000	€	67,000
Saved tax NG	€	2,000	€	4,000	€	36,000
Saved carbon tax/ETS	€	-	€	10,000	€	85,000
Electricity purchase	€	27,000	€	34,000	€	32,000
Add. electricity tax	€	- 8,000	€	- 12,000	€	- 107,000
Grid transportation fee	€	- 138,000	€	- 147,000	€	- 34,000
Capex grid connection	€	- 22,000	€	- 22,000	€	- 22,000
Capex e-boiler	€	- 100,000	€	- 100,000	€	- 100,000
RESULT	**€**	**- 235,000**	**€**	**- 226,000**	**€**	**- 43,000**
Running hours		49		78		699
Gas replace with electricity (MW)		490		780		6,990
Amount of electrification in %		0,56%		0,89%		7,98%

Capacity boiler: 10 MW						
2021	CASE 1		CASE 2		CASE 3	
Saved NG	€	114,000	€	175,000	€	446,000
Saved tax NG	€	9,000	€	13,000	€	38,000
Saved carbon tax/ETS	€	1,000	€	30,000	€	90,000
Electricity purchase	€	- 9,000	€	- 41,000	€	- 246,000
Add. electricity tax	€	- 26,000	€	- 38,000	€	- 113,000
Grid transportation fee	€	- 175,000	€	- 200,000	€	- 35,000
Capex grid connection	€	- 22,000	€	- 22,000	€	- 22,000
Capex e-boiler	€	- 100,000	€	- 100,000	€	- 100,000
RESULT	**€**	**- 208,000**	**€**	**- 183,000**	**€**	**58,000**
Running hours		168		250		737
Gas replace with electricity (MW)		1,680		2.500		7,370
Amount of electrification in %		1,92%		2,85%		8,41%

Capacity boiler: 10 MW						
2022 until October	CASE 1		CASE 2		CASE 3	
Saved NG	€	674,000	€	808,000	€	1,331,000
Saved tax NG	€	25,000	€	31,000	€	54,000
Saved carbon tax/ETS	€	3,000	€	74,000	€	129,000
Electricity purchase	€	- 259,000	€	- 354,000	€	- 816,000
Add. electricity tax	€	- 76,000	€	- 94,000	€	- 163,000
Grid transportation fee	€	- 277,000	€	- 312,000	€	- 45,000
Capex grid connection	€	- 22,000	€	- 22,000	€	- 22,000
Capex e-boiler	€	- 100,000	€	- 100,000	€	- 100,000
RESULT	**€**	**- 32,000**	**€**	**31,000**	**€**	**368,000**
Running hours		496		609		1,059
Gas replace with electricity (MW)		4,960		6,090		10,590
Amount of electrification in %		5,66%		6,95%		12,09%

Table 8-3 Business case of an electric boiler in Germany for the years 2019 to 2022 for the three cases. 2022 only incorporates the months January to October.

Case 1 is the base case.
Case 2 is an increase of carbon tax from €2.50/tonne to €60/tonne.
Case 3 is Case 2 plus a 90% reduction of the grid tariff (similar to that for large continuous industrial users).

8.4 The effect of opportunity demand on the business case for variable renewables

8.4.1 SOCIETAL BENEFITS OF OPPORTUNITY DEMAND

The cost-benefit analysis is made for a system with an installed VRES capacity of 200% compared to dispatchable generation.

Figure 8-5 shows the ratio of variable renewable electricity generation (only wind and solar) vs. the amount of dispatchable generation (fossil, but also for example hydro).

The results of simulations are shown in the next sections. They show the residual load duration curves for each of the scenarios, as well as the price duration curves.

	(Peak) capacity in % of peak demand	Energy per year, in % of demand
(Fixed) demand	100% (24 GW)	100% (108 TWh)
Solar	108% (26 GW)	22% (23 TWh)
Onshore wind	42% (10 GW)	20% (22 TWh)
Offshore wind	50% (12 GW)	34% (36 TWh)
Total VRES	200% (48 GW)	76% (81 TWh)
Flexibility (storage) (cases 0 and 1)	125% (30 GW)	15% (16TWh throughput)
Opportunity demand (case 2)	21% (5 GW)	3% (3.2 TWh)

Table 8-4: Case descriptions: Case 0 - an isolated system Case 1 - the same system including flexibility in the form of storage Case 2 - the same system as Case 1, with additional opportunity demand.

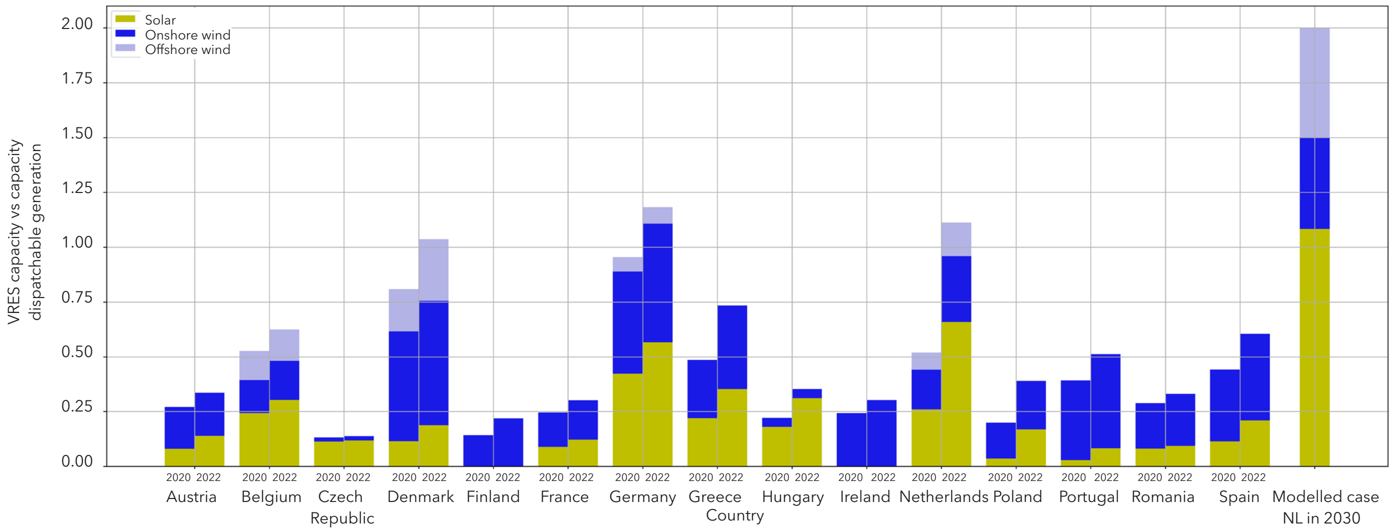


Figure 8-5 The paper describes a system with an installed VRES capacity vs. peak demand ratio of 2 (see the bar on the right side). This graph shows this ratio for several EU countries in 2020 and 2022, using installed dispatchable capacity as a proxy for peak demand (data retrieved from the ENTSO-E transparency platform).

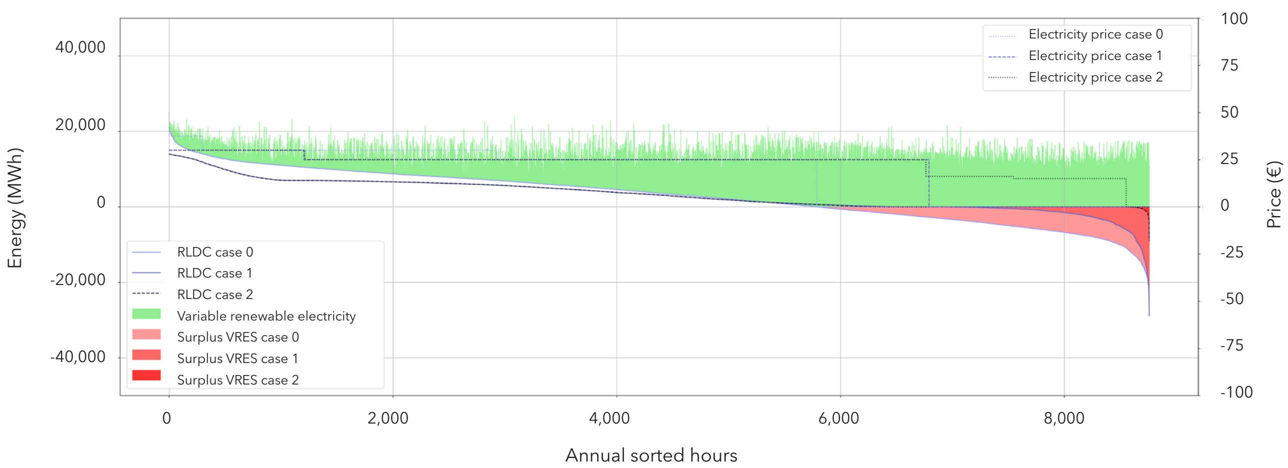
8.4.2 DATA USED IN THE CALCULATIONS OF THE 3 CASES USED IN THE COST-BENEFIT ANALYSIS IN CHAPTER 4

For comparison, the last row of Table 8-5 shows the LCOE per technology of 2022-built installations in the Netherlands. (Used for determining Dutch subsidy schemes. Source: https://www.pbl.nl/publicaties/eindadvies-basisbedragen-sde-2022; source: https://www.pbl.nl/en/publications/costs-of-offshore-wind-energy-2018)

CASE	Average electricity price (€/MWh)	Weighted average cost for non-flex demand (€/MWh)	GWA dispatchable (€/MWh)	GWA VRES (€/MWh)	GWA PV (€/MWh)	GWA onshore wind (€/MWh)	GWA offshore wind (€/MWh)	Storage revenues (€/MWh installed)
Case 0 no flex	€ 36.9	€ 37.9	€ 92.2	€ 20.4	€ 18.2	€ 21.0	€ 21.5	
Case 1 storage	€ 40.1	€ 40.8	€ 62.5	€ 31.3	€ 37.5	€ 28.4	€ 29.0	€ 679.7
Case 2 flex + opp. dem.	€ 46.0	€ 46.5	€ 53.9	€ 41.6	€ 44.5	€ 40.1	€ 40.6	€ 177.4
LCOE 2022 built installations					*€ 52.4*	*€ 39.3*	*€ 47.0*	

Table 8-5 Electricity price and generation weighted averages (GWA) for demand and generation types for the three different cases[31] at a gas price of €30/MWh.

8.4.3 RLDC AND PRICES WITH A GAS PRICE OF €30/MWH

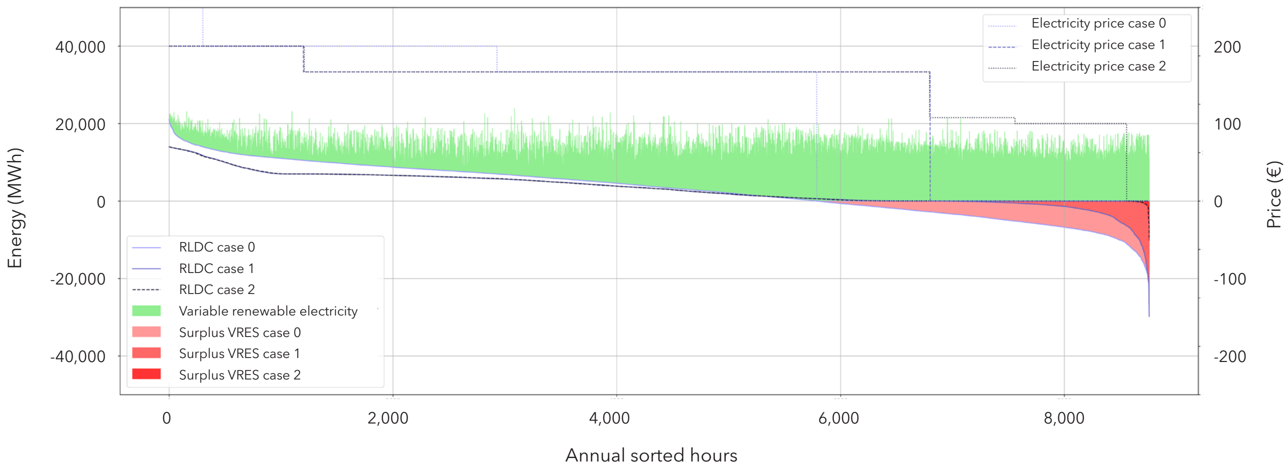


	Average price	WA consumption	GWA dispatchable	VRES revenue	GWA VRES	GWA PV	GWA onshore	GWA offshore	Storage revenue €/MWh installed
Case 0	36.9	37.9	92.2	1,660,822,356.5	20.4	18.2	21.0	21.5	
Case 1	40.1	40.8	62.5	2,547,649,505.2	31.3	37.5	28.4	29.0	679.7
Case 2	46.0	46.5	53.9	3,385,621,658.3	41.6	44.5	40.1	40.6	177.4

Figure 8-6 RLDC and prices for the three cases with a carbon taxed gas price of € 30/MWh.

[31] It should be noted that these numbers are the results of calculations based on simplified assumptions. They are meant to show the dynamics and interaction of different parts of the power system, such as variable renewable power generation, storage, and sector coupling. Their value lies in the comparison to each other and do not stand on their own.

8.4.4 RLDC AND PRICES WITH GAS PRICE OF €80/MWH



	Average price	WA consumption	GWA dispatchable	VRES revenue	GWA VRES	GWA PV	GWA onshore	GWA offshore	Storage revenue €/MWh installed
Case 0	98.4	101.0	245.8	4,428,712,647.4	54.4	48.5	55.9	57.3	
Case 1	107.2	108.8	166.2	6,800,812,923.9	83.5	100.0	75.9	77.4	1,840.6
Case 2	123.7	124.9	143.5	9,054,629,146.9	111.2	119.1	107.3	108.5	456.2

Figure 8-7 RLDC and prices for the three cases with a carbon taxed gas price of € 80/MWh.

8.5 Full decarbonization and the role of hydrogen

This paper is about how sector integration can increase the hosting capacity on the electricity market for variable renewable electricity sources. Opportunity demand only replaces natural gas for industrial heating and hydrogen production when there is plenty of renewable electricity available. There remains a dependency on natural gas when there is insufficient renewable power available, even when considering that a lot of battery storage and demand response will be present in the electricity system.

This raises the question of whether this gradual approach to decarbonization will be able to achieve full decarbonization rather than turning into a 'dead end' halfway along the journey. To fully decarbonize, either the remaining natural gas use needs to be decarbonized, or all energy used needs to come from electrified, carbon-free sources.

The most likely means of decarbonizing the remaining natural gas is through the use of hydrogen from (seasonal) storage produced from surplus renewable electricity and/or 'surplus' nuclear electricity[32]. This hydrogen can be fed into the natural gas grid, slowly replacing natural gas with hydrogen. However, this either requires that hydrogen be mixed with natural gas at a central location to ensure a stable and constant hydrogen percentage, or that switching to hydrogen be done for one geographical area at a time. If hydrogen is mixed with natural gas, the hydrogen percentage can be increased in steps, giving hydrogen production capacity as well as equipment that uses the gas mix to adjust[33]. Eventually, hydrogen production and storage will grow large enough for hydrogen to completely replace natural gas. Alternatively, switching to hydrogen can be organized geographically, one area at a time as more hydrogen production becomes available.

[32] Battery storage and demand response will likely take care of daily and even weekly variations in demand and supply.
Dispatchable generation needs to take care of more structural shortages and thus needs to be supplied from seasonal storage facilities.
[23] This requires equipment to be 'hydrogen ready', and to be periodically tuned if the concentration of hydrogen in the gas mix is increased in steps every few years. It will not be a trivial task, however, and may prove to be too expensive.

The other pathway towards achieving complete decarbonization of energy demand is through full electrification. This electricity is supplied from renewable electricity when available, and from carbon-free dispatchable generation when not. Full electrification makes optimal use of relatively capex-intensive, energy-efficient options, such as heat pumps. However, to fully decarbonize energy supply through full electrification, the electricity supplied when variable renewables are not producing needs to be carbon-free as well.

There are a few options for dispatchable decarbonized electricity production, such as hydro, nuclear, biomass, electricity from seasonal storage, and storing hydrogen produced from nuclear or surplus renewables. Hydro is very situational, and biomass has a relatively large footprint. Nuclear requires sufficient operating hours to recover the required high capital investments and is less suited to run for just a couple of hours per year, unless hydrogen production (or opportunity demand) provides a 'sink' for the electricity that is not directly needed. This means that large-scale full electrification requires a form of seasonal storage, very likely using hydrogen [3].

Large-scale storage using hydrogen will facilitate both decarbonizing natural gas use and large-scale full electrification. Opportunity demand using hydrogen requires a gas and electric infrastructure, while full electrification requires hydrogen to be converted back into electricity.

Assuming a conversion efficiency of 65% to 70%, full electrification will be almost 50% more expensive than using hydrogen directly for heating. However, situations with temperatures that allow heat pumps with a coefficient of performance (COP) of 2 or more can compensate for this. For large users with higher temperature needs, the benefits of having two infrastructures will outweigh the costs, especially if synergy with the infrastructure can be found.

Industrial hydrogen, produced on site, might follow a similar development path: starting from steam methane reforming from natural gas; then adding opportunity demand, switching between renewable electricity and natural gas, assuming the capex and fixed costs of the electrolyser are sufficiently low.

Finally, when natural gas is fully replaced by hydrogen, and assuming the quality of this 'centrally produced and stored' hydrogen is sufficient, this hydrogen can be used directly, making the SMR obsolete (but maybe not the hydrogen purification train behind it).

Whether this centrally produced hydrogen is also going to replace the local electrolyser is doubtful. The centrally produced and stored hydrogen is likely to be more expensive than locally produced hydrogen, but much cheaper than locally produced hydrogen that was locally stored.

It is even possible that, at industrial locations with both gas and electric infrastructure, excess electrolyser capacity will be used to produce hydrogen to be stored in the gas grid (line packing) or be transported back to the large-scale central hydrogen storage.

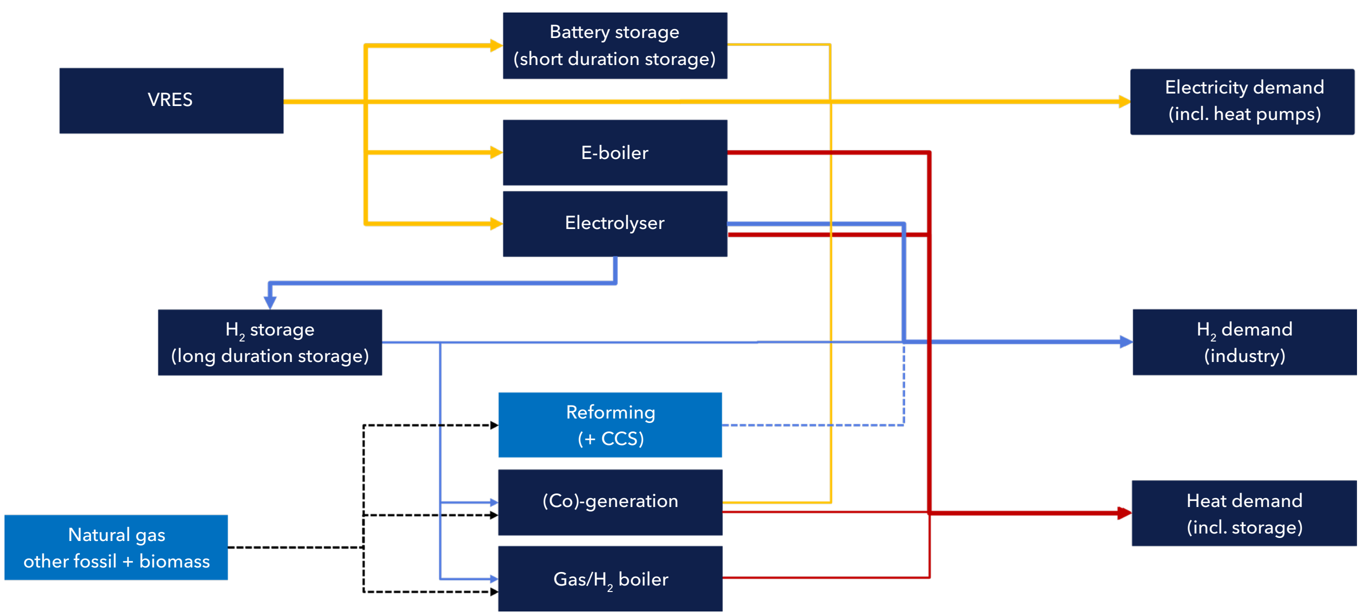


Figure 8-8 Schematic operation of the energy system during abundant availability of VRES.

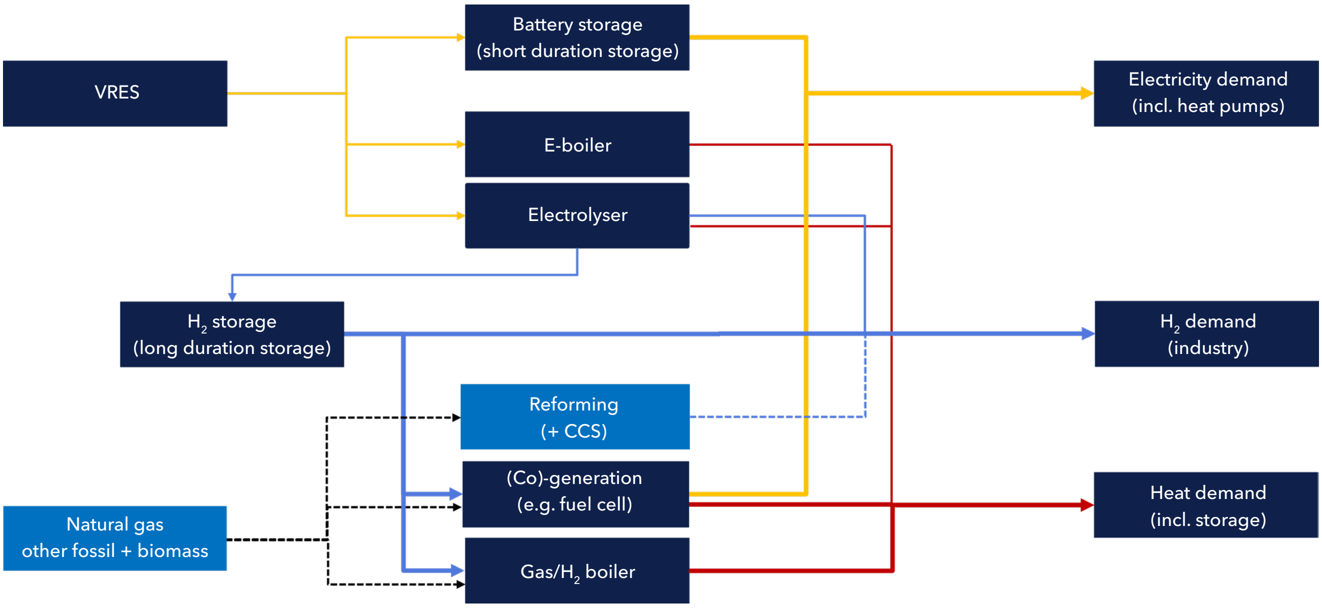


Figure 8-9 Schematic operation of the energy system during shortage of VRES.
Dependence on fossil fuel can be gradually reduced by scaling the hydrogen chain and by using biomass.

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DNV is an independent assurance and risk management provider, operating in more than 100 countries, with the purpose of safeguarding life, property, and the environment. Whether assessing a new ship design, qualifying technology for a floating wind farm, analysing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to manage technological and regulatory complexity with confidence. As a trusted voice for many of the world's most successful organizations, we use our broad experience and deep expertise to advance safety and sustainable performance, set industry standards, and inspire and invent solutions.

In the energy industry

We provide assurance to the entire energy value chain through our advisory, monitoring, verification, and certification services. As the world's leading resource of independent energy experts and technical advisors, we help industries and governments to navigate the many complex, interrelated transitions taking place globally and regionally, in the energy industry. We are committed to realizing the goals of the Paris Agreement, and support our customers to transition faster to a deeply decarbonized energy system.

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