RESEARCH OF SCENARIOS FOR COAL-FIRED POWER PLANTS IN THE NETHERLANDS

A Report for the Ministry of Economic Affairs (MinEZ)

01 July 2016

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EXECUTIVE SUMMARY

The Netherlands has committed itself to reaching a low-carbon energy system that is reliable, affordable and safe in 2050. Within this context, the Dutch Energy Agreement represents an irreversible step towards achieving this goal. As part of the Energy Agreement, two of seven remaining coal-fired power stations that are currently operational in The Netherlands will be closed mid-2017. On 26 November 2015, the second chamber of the Dutch Parliament has accepted a motion that asks the Minister of Economic Affairs to develop a plan to phase-out coal-fired electricity generation in The Netherlands.

In response to this request, the Ministry of Economic Affairs (MinEZ) has asked Frontier to model several climate policy scenarios in the power sector and to evaluate these scenarios based on a given set of indicators:

- **Scenario 1: Additional emission reduction at coal plants** – Operators implement additional CO_2 abatement measures at the coal-fired power plants from 2025 (co-firing of biomass, additional CCS, additional heat production).
- **Scenario 2: Regional collaboration** – Coordinated approach in The Netherlands and neighbouring countries to achieve additional CO_2 reductions in the power sector, modelled as a regional Carbon Floor Price of at least 30 € per tonne CO_2 emitted in the region.
- **Scenario 3: Early closure of coal-fired power plants** – Early closure of coal-fired power plants in the Netherlands from 2020 or later.

The results of the analysis can be summarised as follows:

- The **effectiveness** of additional national climate policy measures to achieve additional CO_2 reduction in the power sector is strongly **dependent on the level of displacement of power production from the Netherlands to other countries**. National policy measures will reduce emissions in The Netherlands, but at the same time, emissions in neighbouring countries will increase due to the high level of interconnections in the Central-Western European power market. For example, the closure of all coal-fired power plants in 2020 would lead to a substantial CO_2 emission reduction in the Netherlands (320 mn. tCO_2 from 2018 to 2049 in total). However, a large proportion of the domestic reduction would be offset by increased emissions abroad. Closure of the two coal plants built in the 1990's similarly leads to national emission reduction (approx. 4 mn. tCO_2 in 2020 and 63 mn. tCO_2 from 2018 – 2049) which is offset for a large part by increased emissions abroad. Closure of the two coal plants built in the 1990's in combination with additional abatement measures at the remaining plants leads to both higher national emission reduction (209 mn. tCO_2 from 2018 to 2049) as well as less carbon leakage.
- Additional **CO_2 emission reduction differs significantly between the analysed national/regional policy measures**. A climate policy approach coordinated with neighbouring countries yields the largest emission reduction (400 mn. tCO_2 from 2018-2049) in the Central-Western European power

market. Early closure of all coal-fired power plants leads to the highest CO_2 emission reduction in the Netherlands (320 mn. tCO_2 from 2018-2049), but this measure is at the same time associated with the highest level of carbon leakage to other countries (see above). Additional CO_2 abatement at all coal-fired power stations yields moderate CO_2 reduction compared to the other scenarios (180 mn. tCO_2 from 2018-2049), but has at the same time the least impact on the power generation in other countries and leads to only little carbon leakage.

- The **effectiveness** of additional national climate measures is furthermore **dependent on the interaction with the EU ETS**. Since the CO_2 emissions in the EU ETS are capped at a fixed amount, any national climate policy measure in the power sector only targeting national/regional CO_2 emissions will lead to higher emissions in other regions and sectors. Therefore, any additional national or regional climate policy measure in the power sector requires additional action in the EU ETS to ensure that the CO_2 abatement that has been achieved translates into real emission reduction in the EU emission trading system (e.g. by reducing the cap for CO_2 emission in the EU ETS or by “buying and burning” CO_2 certificates). These actions are associated with additional costs.
- At the same time, the analysed policy measures lead to **different impacts on the costs of the electricity supply and costs to final consumers**. While measures that have only limited effects on the operation of power plants (i.e. the implementation of additional abatement measures at the plants) also have a moderate impact on system costs (+ 1.4 - 2.1 bn. EUR NPV 2018-2049) and on costs to final consumers (+ 0.3 bn. EUR NPV 2018-2049), more structural changes to the system (i.e. early closure of all coal-fired power plants or a Carbon Floor Price in Central-Western Europe) significantly increase the costs of the electricity supply system (e.g. + 7.1 bn. EUR NPV 2018-2049 in the case of an early closure of all coal plants in 2020) and the consumer payments (e.g. + 3.5 bn. NPV 2018-2049 in the same case). Closure of the two coal plants built in the 1990’s has limited effects on both system costs (+ 1.1 bn. EUR NPV 2018 – 2049) as well as consumer payments (+ 0.7 bn. EUR NPV 2018 – 2049)
- The direct impact on power generation from **Renewable Energies** (RES-E) is strongly linked to the impact on biomass co-firing: Whereas biomass co-firing can be expected to increase if power plant operators implement additional CO_2 abatement measures at the coal plants, biomass co-firing is reduced if coal-fired power plants close before 2030. The indirect impact of the scenarios on RES-E power production (e.g. due to the impact on power prices) is limited.
- The impact of the policy measures on **other indicators** such as innovation and employment is expected to be moderate. In the scenarios, no real risks to the Security of Supply in The Netherlands were observed. Nevertheless, a closure of a major part of the power plants in the Netherlands *under short notice* (e.g. notification of less than 2-3 years before implementation) should be avoided in order to allow market participants to react to the new market situation e.g. by reactivating gas-fired power plants.

- Regarding heat supply, early closure of plants would require a replacement of current heat production. The impact on other emissions (NOx, SO_2, PM, Hg) inside the Netherlands and abroad depends highly on specifics of the affected power plants (including plants substituting power generation from the coal-fired power plants such as gas plants and power plants abroad) and other factors (such as fuel specifics) and should be investigated further.

SUMMARY

Background

The Netherlands has committed itself to reaching a low-carbon energy system that is reliable, affordable and safe in 2050. Within this context, the Dutch Energy Agreement represents an irreversible step towards achieving this goal. As part of the Energy Agreement, two of seven remaining coal-fired power stations that are currently operational in The Netherlands will be closed mid-2017. On 26 November 2015, the second chamber of the Dutch Parliament has accepted a motion that asks the minister of Economic Affairs to develop a plan to phase-out coal-fired electricity generation in The Netherlands. In response to this request, the Ministry of Economic Affairs (MinEZ) has asked Frontier to model several scenarios with our European power market simulation model and to evaluate these scenarios based on the given set of indicators.

Policy Scenarios

MinEZ has developed the outline for three main scenarios (and a number of sub-scenarios), each representing one policy measure addressing the future of coal-fired power generation in the Netherlands:

- **Scenario 1: Additional emission reduction at coal plants** – In this scenario the coal plants apply possible measures after 2025 to reduce the CO_2 emission per unit of delivered electricity to such a level that the emissions are at least equal to the average CO_2 emissions of a modern gas-fired power plant.
- **Scenario 2: Pentalateral collaboration** – This scenario represents a situation in which a common approach in the Pentalateral Forum[1] is taken to achieve additional CO_2 reduction. It is assumed that the countries of the Pentalateral Forum agree on CO_2 reduction targets that go beyond the targets agreed on a European level. These additional targets lead to additional incentives to lower the emission of carbon dioxide.
- **Scenario 3: Early closure of coal-fired power plants** – In the third scenario, coal-fired power plants in the Netherlands are required to shut-down at specific dates. These dates have been set prior to the expected technical lifetime of the coal-plants. For scenarios with closures after 2025, it is further assumed that additional abatements measures will be taken from 2025 that limit emissions of these coal plants to that of a modern gas plant (same as scenario 1). Specific sub-scenarios have also been included in which only the two coal-fired power plants built in the 1990's are closed in 2020.

The scenarios described above are evaluated using a European power market model and assessed against a Reference Case reflecting current policies.

[1] The Pentalateral Energy Forum represents a framework for regional cooperation toward the improvement of electricity markets integration and Security of Supply. It consists of Netherlands, Germany, France, Belgium, Luxembourg, Austria and Switzerland.

Indicator-based assessment

The Ministry of Economic Affairs defined a set of indicators to be used to evaluate the different policy measures. The indicators are based on the variables set out in the Letter of 18 December 2015 of the Minister of Economic Affairs to the Dutch Parliament:

- CO_2 emissions in the Netherlands;
- Carbon-leakage of CO_2 abroad (in the power sector);
- Security of Supply;
- Import dependency;
- Prices of energy for businesses and households; and
- The potential for the production of renewable energy.
- The growth of heat networks;
- Impact on innovation; and
- Impact on other emissions.

In the following, we summarise our main findings regarding the impact of the different policy scenarios on the above mentioned indicators.

Reduction of CO_2 emissions

The emission reduction in the Reference Case reflects the assumed development of CO_2 prices (up to over 50 EUR (real, 2015)/tCO_2 in 2050 and 80 EUR (real, 2015)/tCO_2 in 2050) as well as the growth of renewable energy sources. In the Reference Case, emissions of carbon dioxide in the power sector in Central-Western Europe decrease by ca. 67% from 2015 to 2040. CO_2 emissions in the power sector in The Netherlands decrease by 20% (-10 mn. tCO_2) from 2015 until 2030 and by 50% until 2040 (-27 mn.tCO_2).

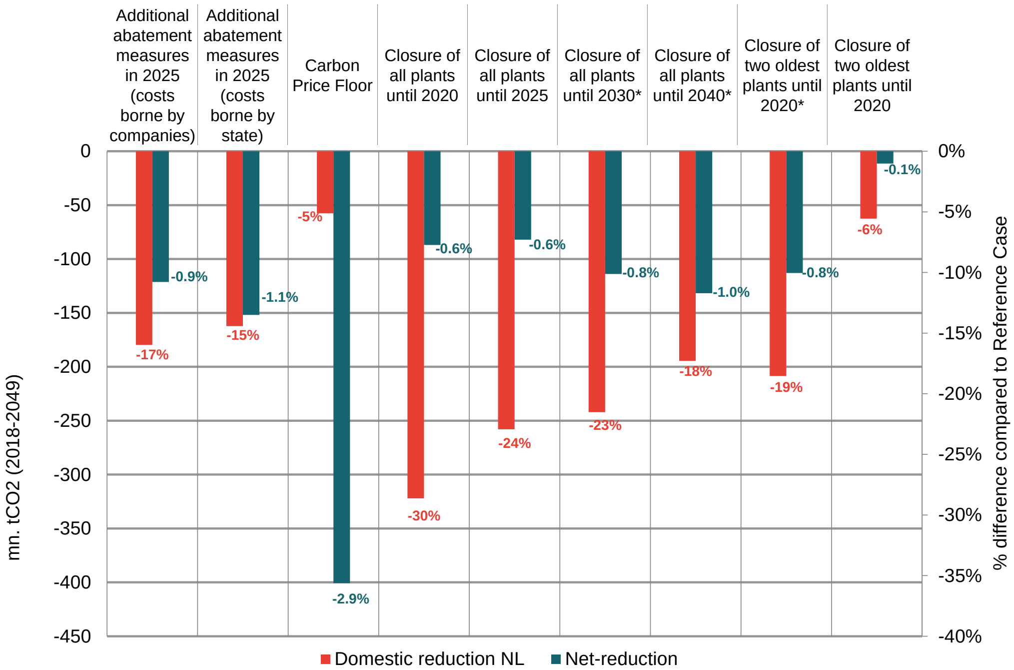
The policy scenarios all result in higher CO_2 reduction in the medium term, up to 55% reduction (- 28 mn. tCO_2) from 2015 until 2030, compared to the Reference Case. In the long-run (2040), the CO_2 emissions in the policy scenarios are similar to the Reference Case due to the already achieved emission reduction through closure of older coal plants until 2035 (due to reaching end of lifetime) and market based co-firing of biomass in 2040.

The different policy measures assessed in this study exhibit different degrees of emission reductions in The Netherlands and in Europe:

- Aggregated from 2018 to 2040, the closure of all coal plants results in the highest emission reduction in The Netherlands (closure until 2020 reduces domestic emission by 320 mn. tCO_2, 30%). The majority of this reduction, however, is substituted by emissions in neighbouring countries due to higher imports to The Netherlands. Due to this substitution, net-reduction on a European level amounts to just 87 mn. tCO2. If the two plants built in the 1990's are closed in 2020 (and the other plants remain in the market), CO2 reduction in the Netherlands amount to of 63 mn. tCO_2, but only 11 mn. tCO_2 in all modelled countries, meaning more than 80% of emissions are "exported" to other countries. In 2020, closure of these plants results in a reduction of 4 mn. tCO_2.

- If additional abatement measures, e.g. more co-firing of biomass, additional heat decoupling or CCS, are implemented at the coal plants (instead of plant closures), the aggregated emission reduction in the Netherlands is lower than in the case of plant closures (up -180 mn. tCO_2 from 2018-2049), but at the same time the leakage of emissions to other countries is significantly reduced. The need to import power from other countries is lower and CO_2 emissions in other countries are therefore affected to a lower degree. The net-reduction that is achieved in this scenario on a European level is around 160 mn. tCO_2.
- The highest emission reduction on a European level is achieved by the introduction of a Carbon Price Floor in 2018 in the countries of the Pentalateral Forum. The reason for this is that a larger share of the European electricity supply is impacted by the measure. The net-reduction that is achieved on a European level is 401 mn. tCO_2 in the period from 2018 to 2049. In The Netherlands, this measure leads to limited additional CO2-reduction, due to the relatively lower emission intensity of the power plant park in the Netherlands, which remains competitive even with significantly higher CO_2 prices.

Figure 1. Impact on CO_2 emissions (cumulated 2018-2049)



Source: *Frontier*

Note: ** additional abatement measures are implemented at the coal plants in 2025*

However, it is important to note that in all scenarios the additional national CO_2 abatement takes place in the context of the EU ETS. In our power market simulation, the effects of the policy measures on imports and exports of electricity from and to The Netherlands are captured. The import/export of CO_2 emissions due to the changes in the electricity trading pattern are therefore captured in the model, too. However, beyond this impact on electricity trade, the EU ETS itself is affected by the additional national policy measures: since the demand for CO_2 certificates decreases due to additional national CO_2 abatement measures in the power sector, the price of EU allowances ceteris paribus can be expected to decrease. This price effect induces additional CO_2 emissions in other countries or sectors. That means that regardless of national CO_2 abatement measures, the total amount of CO_2 emissions in the EU ETS remains constant as long as the total amount of CO_2 certificates remains constant.[2] This indirect effect is not captured in the model, but should be taken into account in the assessment of the scenarios.

The indirect effect of the measures on the EU ETS can be mitigated if the amount of additional national CO_2 emission reduction is in some way reflected in the overall supply of CO_2 allowances (e.g. through lower auctioning volumes or reducing the yearly cap on emissions in the EU ETS). Such a reduction of CO_2 certificates would lead to additional costs e.g. by holding back a certain amount of CO_2 certificates by the states or by buying back allowances from the CO_2 market.

System costs and distributional effects

The impact of the different policy measures on the affordability of electricity supply is reflected in two ways: the costs of the electricity system and the payments of final consumers:

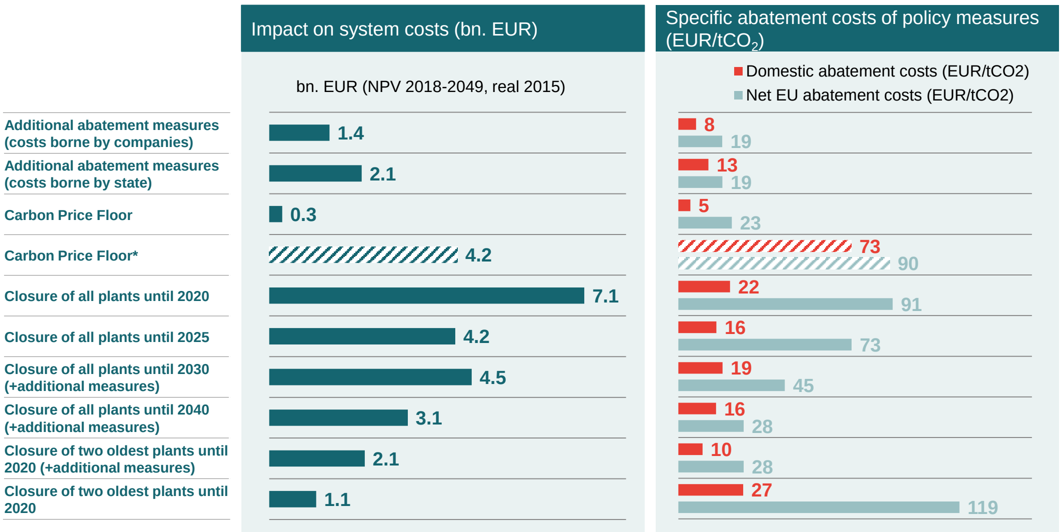
- From a system cost perspective, the introduction of a Carbon Price Floor is the most cost-efficient solution in The Netherlands if costs associated with higher CO_2 prices are not taken into account. In this scenario specific abatement costs are 5 EUR/tCO_2, while the total impact on system costs amounts to 300 mn. EUR (NPV 2018-2049)).[3] If the higher CO_2 prices are included, system costs increase by 4.2 bn. EUR (NPV, 2018-2049) compared to the Reference Case. In any case, the introduction of a Carbon Floor Price has a significant impact on power prices and consequently on the payments of final consumers due to the high increase of power prices. Consumer payments increase by up to 10% or 8.5 bn. EUR (NPV 2018-2049).
- The implementation of additional abatement measures at the plants increases system costs slightly (+1.4 - 2.1 bn. EUR), but has limited impact on consumer payments as the costs of the additional measures are either borne by the companies or by the state (0.1 - 0.2 bn. EUR, 0.2%). The specific abatement costs of these scenarios are the lowest of the scenarios with purely national measures.
- Closure of the coal plants leads to an increase of system costs of 7 bn. EUR (NPV 2018-2049) if plants close until 2020 and of consumer payments due to higher power prices (3.5 bn. EUR, NPV 2018-2049; +2.8%). Due to the low level of net CO_2 reduction that is achieved in all modelled countries with this scenario, specific abatement costs of this scenario from a European

[2] Not taking into account the effects of the Market Stability Reserve (MSR), that reduces the auctioning volumes by a certain amount if unallocated allowances exceed a threshold. If the allowances transferred to the MSR are brought back to the market at a later point in time, the impact on emission and prices is only temporary.

[3] The CO_2 price increase corresponds to higher state-income and is not a “cost” in the narrow sense.

perspective are higher: 91 EUR (real, 2015)/tCO_2. With later closure, the impact on costs and payments decreases and the specific abatement costs improve. Of all scenarios with fixed closure dates, the system costs are lowest when only the two plants built in the 1990's are closed. Specific abatement costs of this scenario are 27 EUR (real, 2015)/tCO_2 from the perspective of The Netherlands and 119 EUR(real,2015)/tCO_2 from a European perspective.

Figure 2. Impact on system costs and specific abatement costs



Source: Frontier

*Note: * including cost increase driven by Carbon Price Floor*

Security of Supply and import dependency

The Dutch electricity system is characterised by a high degree of Security of Supply. The introduction of the policy measures assessed in this study does have an impact on the level of operational capacities in The Netherlands. However, due to high levels of import capacities available, the measures do not lead to a risk to Security of Supply:

- The closure of coal-fired power plants directly decreases generation capacity in The Netherlands. However, this decrease is compensated by earlier reactivation of mothballed power plants and higher imports due to vast power generation capacity around Europe in the short and medium term. However, it has to be noted that the reactivation of the mothballed plants depends on the view the owners take on the future energy market. Early closure of the two plants built in the 1990's has a limited negative effect on the reserve margin and import dependency.
- The additional abatement measures at the plants do not influence the availability of generation capacities to a large extent. Consequently, Security of Supply and import dependency are not affected.
- The introduction of a Carbon Price Floor in the short term increases the generation capacities in The Netherlands as the Dutch power plant park has a comparative advantage due to lower emission intensities of electricity supply when compared to neighbouring countries. More power is generated in The

Netherlands in the short- to medium-term and exported to neighbouring countries.

- Nevertheless, a closure of a major part of the power plants in the Netherlands *under short notice,* (e.g. less than 2-3 years before implementation of the measure) should be avoided in order to allow market participants to react to the new market situation e.g. by reactivating gas-fired power plants (the longer the plants are mothballed the longer is the time period required to reactivate). In addition, discretionary market interventions have in general negative effects on the investment climate and investor's certainty which means in the medium and long term a tendency towards higher costs for society to attract investments.

Impact on RES-E

The different policy measures can have an impact on the development of renewable energy sources in The Netherlands either directly through a changing framework for biomass co-firing (e.g. further subsidies for co-firing) or indirectly through a changing market environment (e.g. higher wholesale power prices leading to earlier market driven investment in RES-E):

- The additional emission reduction achieved in Scenario 1 is largely based on increased co-firing of biomass in the coal plants. This measure also increases the absolute amount of RES-E in the system.
- There is only a small impact of the Carbon Price Floor on the development of RES-E in The Netherlands.[4]
- The closure of all coal plants in Scenario 3a and 3b results in a decrease of the renewable energy sources of net-demand by up to 6%-points, as no co-firing of biomass takes place as the plants close in these scenarios. However, it is assumed that funds not used for co-firing of biomass are not spent on subsidies for RES-E somewhere else in the system. .

  The implementation of additional abatement measures at the plants in the Scenarios 3c-e leads to a medium-term increase of RES-E (prior to plant closure) due to higher co-firing of biomass as an element of the additional measures.

Other emissions

Emissions of other gases and pollutants (SO_2, NOx, PM, Hg) are affected by the different policy measures:

- Closure of coal plants leads to lower emissions of SO_2, PM and Hg in The Netherlands as the omitted generation is substituted by gas-fired power generation which emits less of these pollutants per unit of produced electricity.

[4] The additional amount of investment in RES-E in the model is limited; therefore, the Carbon Price Floor leads to limited additional market-driven investment in RES-E.

Emissions of NOx are reduced to a lower extent due to the increasing emission from gas plants and the relatively low emission intensity of the modern coal plants.

- The introduction of a Carbon Price Floor reduces utilisation of coal plant and increases generation from gas-fired power plants. Nevertheless, the emission of SO_2, NOx, Hg and PM decreases only slightly due to an absolute increase of domestic power generation in the short- to medium-term compared to the Reference Case.
- Additional abatement measures influence the emission of other pollutants due to less emission from biomass co-firing and lower utilisation if the costs of the measures are borne by the companies.

The emission of the above mentioned pollutants is highly dependent on fuel and plant specifics. Furthermore, increasing emission in other countries are not taken into account in the analysis. Therefore, the results should be understood as an indicative estimation of the impact on local emissions and further research should be pursued to assess the impact of these factors, in a national as well an international context.

Heat networks and supply

Some of the coal power plants currently provide heat to regional heat networks or steam to industrial installations. Depending on the development of coal-fired generation, e.g. if plants cease operation earlier than expected, alternative heat supply needs to be developed for the plants that are currently producing heat for district heating or industrial processes. This could be achieved by;

- Connecting the heat network to other heat networks with sufficient capacity to replace the heat from coal/biomass fired power plants;
- Investing in new facilities to provide heat to heat networks. In the short- to medium-term, these are likely to be modern gas boilers;
- Discontinue the provision of heat to industry and households by replacing it with local heat production.

All options will lead to additional costs as investments have to be made into the expansion of heat network and new facilities to provide heat. We estimate that the additional costs for heat supply from gas boilers would amount to 48.8 - 89.5 mn. € per year.

Furthermore, additional heat supply can constitute an abatement measure to reduce specific emissions of a power plant. In such a case, additional investments might have to be undertaken in order to fully utilise the additional heat provided by the power plant. This could include for example the cost of expanding the heat network. On the other hand, an increased heat supply from coal-fired power plants saves new investments into alternative heating technologies.

Impact on innovation

The policy measures can have the following impacts on innovation:

- **Implementation of additional abatement measures can increase innovation –** The implementation of additional abatement measures can lead to higher innovation with regard to the development of CCS and biomass supply chains (e.g. international implementation of Dutch sustainability criteria for biomass). In addition, the innovation potential related to the transportation and storage of carbon dioxide can be transferred to the implementation of CCS at gas plants.
- **Closure of coal plants could lower innovation activities –** If the newest coal plants are closed early, currently planned testing of CCS might not be realised.
- **Impact on innovation with respect to RES-E –** Some scenarios result in higher investment in wind-offshore and solar PV. In these scenarios, additional operation of RES-E could lead to higher learning effects for these technologies. These effects, however, are deemed to be rather small due to the already achieved cost reductions and the relatively small impact on investments.

Employment

The closure of the five coal plants under investigation can have direct and indirect effects on employment:

- **Direct employment effects**: Up to 1000 people[5] are directly employed at the five coal-fired plants. After closure of these plants, these employees would have to be transferred into other workplaces.
- **Multiplier effects**: The closure of the plants can have indirect effects on employment especially through multiplier effects example given negative effects on suppliers of the coal plants and spending power of employees in the affected regions.
- **Compensating effects**: On the other hand, the substitution of coal-fired power generation with power supply from other sources can offset at least to some extent the impacts on employment at the coal plants. These compensating effects cannot be expected to totally balance out the loss of employment at the coal plants (at least in the short term).

[5] Based on full-time-equivalents (FTE)

1 INTRODUCTION

1.1 Background of the Project

The Netherlands has committed itself to reaching a low-carbon energy system that is reliable, affordable and safe in 2050. Within this context, the Dutch Energy Agreement represents an irreversible step towards achieving this goal. As part of the Energy Agreement, two of seven remaining coal-fired power stations that are currently operational in The Netherlands will be closed mid-2017. On 26 November 2015, the second chamber of the Dutch Parliament has accepted a motion to phase-out coal-fired electricity generation in The Netherlands. In its proposal, the Parliament

- has taken the view that **no permissions to build new coal-fired power station** in The Netherlands will be granted; and
- has asked the government and the electricity sector to develop a plan to **phase-out existing coal-fired power generation**.

In his letter to the parliament from 18 December 2015 about this proposal, the Minister explains that scenarios for the potential phase-out of coal plants in the Netherlands should be developed and points out several variables that need to be examined in order to evaluate these scenarios:

- **CO_2 emissions in The Netherlands** - How do the different scenario affect the emission of carbon dioxide in The Netherlands, also taking into account the emissions from potential alternative heat-production?
- **Carbon leakage of CO_2 abroad** - Would a coal phase-out induce a transfer of domestic CO_2 emission to neighbouring countries; i.e. would emissions in other countries increase due to a phase out of coal plants in the Netherlands and if so, what is the net-reduction effect?
- **Security of Supply** - Coal-fired power generation accounts for approximately 17% of the electricity supply[6]. Would phasing-out all coal-fired plants affect the Security of Supply level in The Netherlands?
- **Import dependency** - How would different scenarios of phasing-out coal-fired generation affect the import/export balance of The Netherlands?
- **Prices of energy for businesses and households** - How does a coal phase-out impact wholesale and retail prices for power in The Netherlands?
- **Potential for the production of renewable energy** - How does a coal phase-out affect the production and integration of renewable energy sources in the electricity system?
- **Impact on heat networks** - How do the policy measures impact the up-keep of district heating and the maintenance of heat-networks?
- **Impact on innovation** - Will the policy measures lead to more or less innovations related to emission abatement?

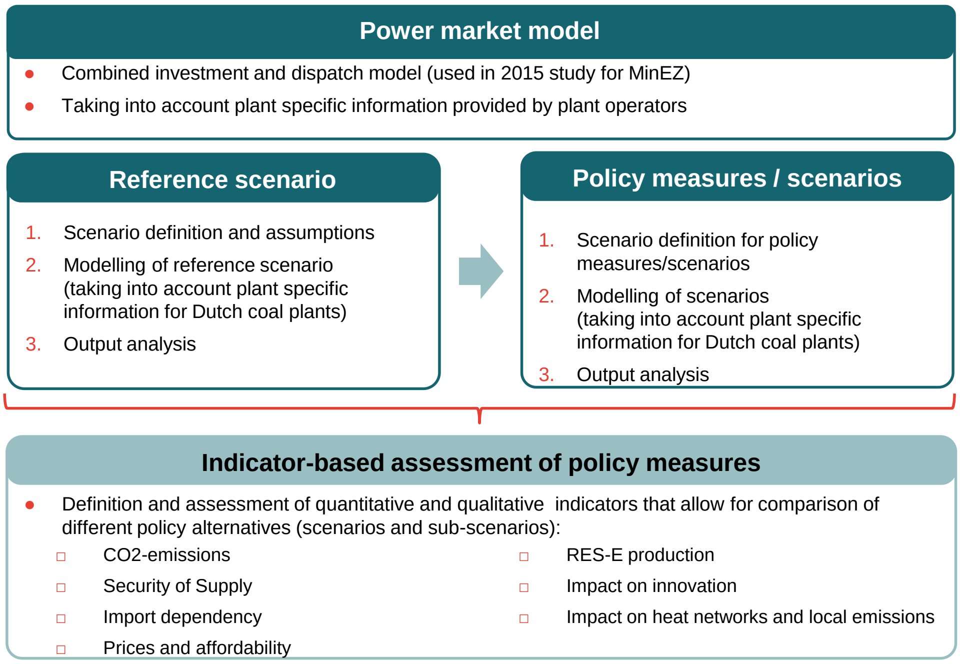
[6] Letter from the Minister of Economic Affairs to the Second Chamber of the Dutch Parliament (18.12.2015).

Based on these questions, MinEZ has asked Frontier to model several scenarios with our European power market simulation model and to evaluate these scenarios based on the given set of indicators.

1.2 Approach of our analysis

In the following, we describe our approach for the power market simulations and the indicator based assessment of different climate policy scenarios (**Figure 3**).

Figure 3. Approach of the study



Source: Frontier Economics

We apply the following steps in our analyses:

- **Power market modelling** – In this assignment, we use our power market model applied in the study “Scenarios for the Dutch electricity supply system” (2015) undertaken on behalf of MinEZ.[7] We adapted the power market model especially regarding a more detailed representation of the coal-fired power plants under investigation and the implementation of the policy scenarios. We explain the applied framework of power market modelling in **section** 0 further**.** This includes a description of the power market model used as well as information on the specifics of the Dutch coal plants.
- **Reference Case** – We define a Reference Case that serves as the counterfactual for the analysis of the different policy scenarios. The Reference Case represents an up-to-date view on recent and future market developments in The Netherlands and Central-Western Europe. It is largely based on our 2015-study[8], the National Energy Outlook (Nationale Energieverkenning) published by ECN and PBL as well as the targets set out

[7] Frontier Economics (2015): *Scenarios for the Dutch electricity supply system*.

[8] Frontier Economics (2015): *Scenarios for the Dutch electricity supply system*.

in the Energy Agreement. **ANNEX B** includes a description of the key results of the Reference Case.

- **Policy measures and scenarios** – MinEZ has developed the outline for three main scenarios (and a number of sub-scenarios), each representing one policy measure addressing the future of coal-fired power generation in The Netherlands:
  - **Scenario 1: Additional emission reduction at coal plants** – In this scenario the coal plants apply possible measures after 2025 to reduce the CO_2 emission per unit of delivered electricity to such a level that the emissions are at least equal to the average CO_2 emissions of a modern gas-fired power plant (350 gCO_2/kWh_{el}).
  - **Scenario 2: Pentalateral collaboration** – This scenario represents a situation in which a common approach in the Pentalateral Forum[9] is taken to achieve additional CO_2 reductions. It is assumed that the countries of the Pentalateral Forum agree on CO_2 reduction targets that go beyond the targets agreed on a European level. These additional targets lead to additional incentives to lower the emission of carbon dioxide.
  - **Scenario 3: Early closure of coal-fired power plants** – In the third scenario, coal-fired power plants in The Netherlands are required to shut-down at specific dates. These dates have been set prior to the expected technical lifetime of the coal plants. For scenarios with closures after 2025 it is further assumed that additional abatement measures will be taken from 2025 that limit emissions of these coal plants to that of a modern gas plant (same as Scenario 1). Specific sub-scenarios have also been included in which only the two coal-fired power plants built in the 1990's are closed in 2020.

  Section 3 provides a more detailed description of the different scenarios.

- **Indicator based assessment** – MinEZ defined a set of indicators to be used for the evaluation of the different policy scenarios. The indicators are based on the variables set out in the Letter of 18 December 2015 of the Minister of Economic Affairs to the Dutch Parliament:
  - CO_2 emissions in The Netherlands;
  - Carbon-leakage of CO_2 abroad (in the power sector);
  - Security of Supply;
  - Import dependency;
  - Prices of energy for businesses and households;
  - The potential for the production of renewable energy;
  - The growth of heat networks;
  - Impact on innovation; and

[9] The Pentalateral Energy Forum represents a framework for regional cooperation towards the improvement of electricity markets integration and Security of Supply. It consists of Netherlands, Germany, France, Belgium, Luxembourg, Austria and Switzerland.

- Impact on other emissions.

Section 4 provides a summary of the main results of the indicator based assessment as well as a description of the methodology used for the individual indicators.

1.3 Structure of the report

The report is structured as follows:

- Description of our approach towards modelling of the Dutch and European power market, including the aim and outlook of the Reference Case (**Section 2**);
- Definition of the policy measures and scenarios (**Section** 3);
- Indicator based assessment of the different policy measures and scenarios (**Section 4**)

Detailed information on the model, the modelling assumptions as well as on the results can be found in the Annexes.

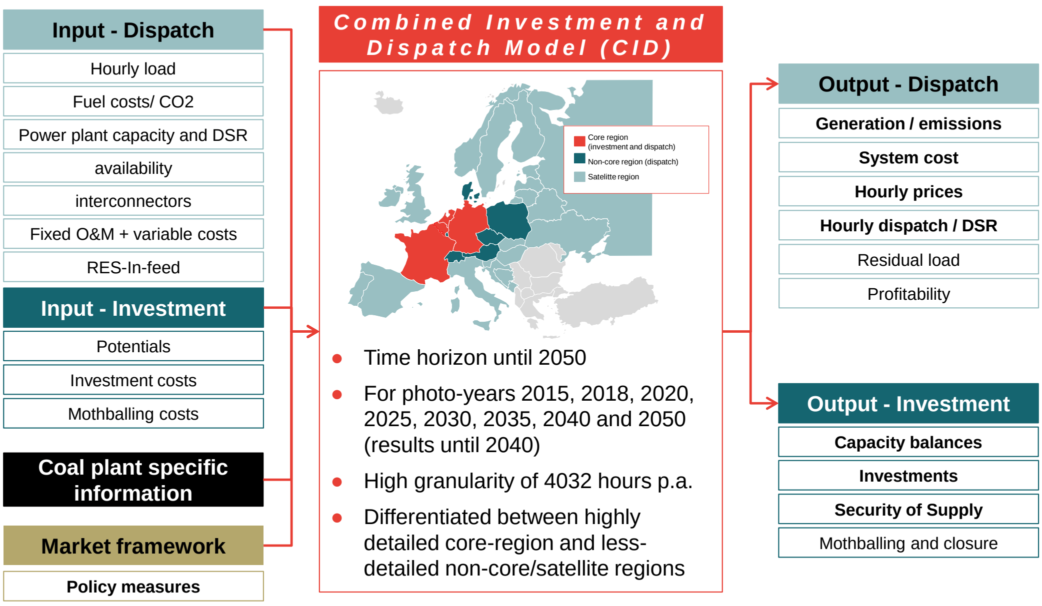
2 POWER MARKET MODELLING

The following section describes the structure and underlying logic of the power market model.

2.1 Model description

Figure 4 illustrates the structure of the power market model including the most important inputs and outputs.

Figure 4. Power market model



Source: Frontier

The main characteristics of the model can be summarised as follows:

- **Cost optimisation model** – The model is an integrated investment- and dispatch model for the European power sector. The model is set up as an optimisation problem minimising the system costs for serving power demand across the modelled regions. The model optimises the hourly dispatch of the power plants as well as the development of installed capacity based on representative hours and selected photo-years (investments, divestments, mothballing and reactivation).
- **Geographical scope –** Our model focusses on Central-Western Europe as core-region, including The Netherlands. Other neighbouring countries are included as non-core regions or satellite regions. This differentiation allows for modelling of the power plant park in the core-region on a very detailed (unit-based) basis. Power exchange with regions modelled with lower granularity and level of detail are at the same time included:
  - **Core-regions:** The Netherlands, Belgium, Germany, Austria and France. The power plant park is modelled on a very detailed (unit-based) level, the

dispatch of power plants and demand-side response (DSR), as well as investment or divestment, are model outcomes.

- **Other model regions:** Great Britain, Denmark, Poland, Czech Republic, Switzerland, Italy. The power plant park is modelled as aggregated blocks. Capacity is set exogenously, i.e. investment and divestment decisions are not optimised.
- **Satellite regions:** Other adjacent regions - for example South-Eastern Europe, the Noordpool region and Spain - are modelled as satellite regions. Power can be traded with those regions based on typical prices representing the marginal costs of generation in those countries/regions.

- **Temporal resolution –** The time frame for optimisation follows the technical lifetime of power plants. The time horizon for our analysis is from 2015 until 2049 with an hourly resolution of 4032 representative hours per photo-year, the model optimises until the time period 2050.[10]

A more technical and detailed description of the model can be found in **ANNEX D**.

2.2 Definition of the Reference Case

The Reference Case serves as a basis against which the different policy scenarios can be evaluated and compared. The Reference Case represents the current and intended policies in The Netherlands and North-Western Europe without additional national measures to reduce CO_2 emissions in The Netherlands and other modelled countries beyond what has already been politically decided. As a principle, we only take political decisions into account as definitely decided at the beginning of May 2016. This holds for The Netherlands as well as foreign countries.[11]

The reference scenario is characterised by the following key assumptions:

- The EU ETS remains the central instrument to trigger a market-based phase-out of coal-fired power generation; however, additional national climate policies are included in the analyses as far as these measures have already been definitely decided (e.g. the lignite reserve in Germany and the Carbon Price Floor in the UK);
- The Netherlands and other European countries pursue the goal of lowering carbon emissions from power generation through increasing shares of renewable energy sources (RES); and
- No additional CO_2 abatement measures beyond currently planned investments and developments are taken into account for coal-fired power plants in The Netherlands. Decided measures taken into account in the Reference Case include subsidised biomass co-firing in coal plants of up

[10] Analysed photo-years: 2018, 2020,2025, 2030, 2035, 2040

[11] As a consequence, we don’t take any additional political action into account which may be developed or decided in the future following the Paris Agreement (COP 21). This is consistent with the aim of the study to evaluate specific options for further political in comparison to a reference case not including these actions.

to 25 PJ place from 2020 until 2028 and the realisation of a CCS demonstration project in 2020.

In previous work for MinEZ[12], we developed a comprehensive “base case” scenario taking into account the latest development in the Dutch and European electricity market:

- Key trends in The Netherlands have been derived from the National Energy Outlook (Nationale Energieverkenning) and the Energy Agreement.
- Key trends for neighbouring countries and longer-term visions are based on inter alia national plans or the European Commission’s climate and energy package.

The underlying assumptions of the Reference Case have been checked for consistency by ECN. The assumptions are described in **ANNEX A** in more detail.

Incorporation of the EU Emission Trading System (ETS)

The European Emission Trading System (EU ETS) constitutes the central instrument to combat climate change on the European level. It is designed as a cap-and-trade system within which an annual cap on total emission from sectors covered (especially power & heat / industrial sector) is implemented (volume-based control). For each ton of carbon dioxide emitted, the participants of the scheme have to submit one certificate (EU Emission Allowance – EUA). As the total number of allowances is fixed and decreases over time (-2.2%/a), the system provides an individual incentive to reduce emissions. Participants of the power sector need to purchase the required amount of allowances through auctions in their respective member states. Alternatively, allowances are also traded on secondary markets. Therefore, the primary incentive to lower emission is induced by the costs of emission, i.e. the price of the emission.

The EU ETS is incorporated in the model by a price-based approach (exogenous price) since only parts of the EU ETS are captured in the power market model and a volume based approach (CO_2 cap on emissions in the model) can easily lead to distorted results. This means we define the carbon price as a model input. Assumptions on the CO_2 emissions price development are based on the National Energy Outlook, the Frontier study (2015) on scenarios for the Dutch electricity supply system, and other relevant publicly available sources (e.g. World Energy Outlook) (see **ANNEX A**).

We derive our CO_2 price assumptions according to the following logic:

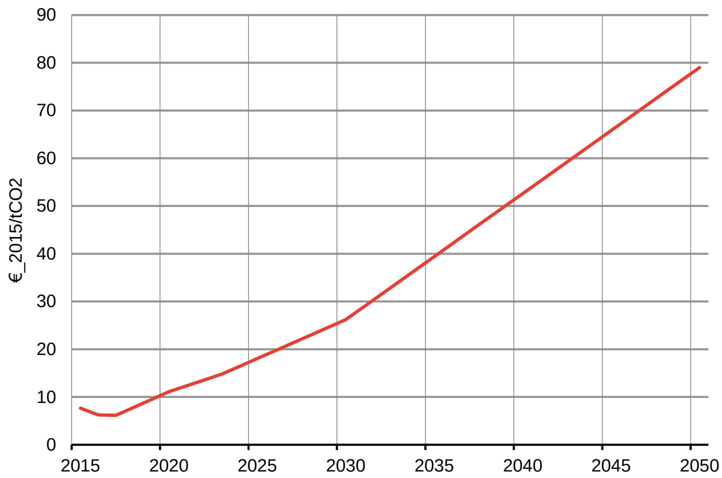
- **Short-term** (until 2017) development according to current market expectations – We use CO_2 price futures (trading day 28 April 2016) to derive our short-term price projection.
- **Medium-term** (2018-2035) price development based on the National Energy Outlook – We use the CO_2 price assumptions derived in the National Energy Outlook in 2016.[13]

[12] Frontier Economics (2015): *Scenarios for the Dutch electricity supply system.*

[13] ECN/PBL (2016, forthcoming), scenario “Voorgenomen beleid”.

- **Long-term price development** (after 2035) is modelled as linear extrapolation based on the price projection of the National Energy Outlook 2016 for the years 2030 and 2035.

Figure 5. Assumed CO_2 price development



Source: Frontier based on ECN/PBL (2016)

Note: Prices are noted in real values (2015)

2.3 Modelling of Dutch coal-fired power plants

Currently, seven coal-fired power plants are operating in The Netherlands. As part of the Energy Agreement, three older power plants have already been decommissioned and two plants will cease operation in the near future:

- Amercentrale 8 (AC 8, built in 1981): decommissioning 01 Jan 2016 (645 MWe);
- Borssele (built in 1987) : decommissioning 31 Dec 2015 (400 MWe);
- Gelderland (built in 1981) : decommissioning 31 Dec 2015 (Gelderland 592 MWe); and
- Maasvlakte MV1 / MV2 (Uniper) (built in 1987/1988): decommissioning until 01 July 2017 (total 1,040 MWe).

At the same time, a number of new power plants has or will come online:

- Eemshaven A / B in 2015 (total 1,540 MWe);
- Maasvlakte (Engie) in 2014 (735 MWe); and
- Maasvlakte 3 (MPP3) in 2016 (1,069 MWe) (see **Table 1**).

After 2017, 4.6 GW of coal-fired power plants will be operational in The Netherlands. The newest addition to the coal-fired power plant includes the Rotterdam capture and storage demonstration (ROAD) project, a demonstration plant for carbon capture and storage (CCS).

As part of this project, plant specific information has been provided by the plant operators. This information includes:

- Technical information on the dispatch and emissions of the plants;
- Economical information on variable and fixed cost of operation; [14] and
- Options and costs of additional measures to reduce CO_2 emissions at the plant side, i.e. further co-firing of biomass, additional CCS as well as additional heat production (see **section 3.1**)[15]

Table 1 includes a summary of the Dutch coal-fired power plants currently or recently operating in The Netherlands.

Table 1. Coal-fired power plants in The Netherlands

Plant name	Operating / Owner company	Online date	Net generating capacity	Recent / known decom-missioing
Amercentrale 8	RWE / ESSENT	1981	645	End of 2015
Amercentrale 9	RWE / ESSENT	1993	600	-
Borssele	EPZ	1987	400	End of 2015
Eemshaven A / B	RWE / ESSENT	2015	1.540	-
Gelderland	Engie	1981	592	End of 2015
Hemweg	Nuon NV (Vattenfall)	1994	650	-
Maasvlakte 1/2	Uniper	1987/ 1988	1.040	Mid 2017
Engie Maasvlakte	Engie	2014	735	-
MPP3	Uniper	2016	1.069	-

Source: Frontier based on information provided by plant operators

2.4 Key results of the Reference Case

In the following, we summarise the main results of the Reference Case. **ANNEX B** provides a more detailed description.

- **Coal plants stay operational until the end of their assumed technical lifetime** – Under current market conditions with an assumed increase of RES-E and increasing CO_2 prices, the five coal-fired power plants in The

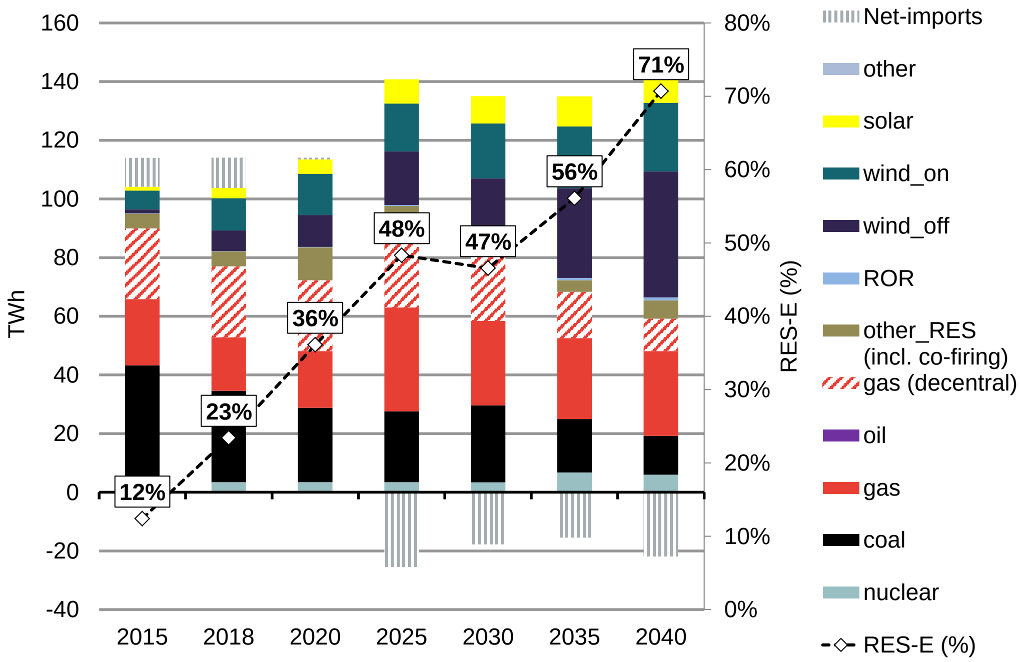
[14] The information itself is treated as confidential information is not included in this report.

[15] The information itself is treated as confidential information is not included in this report.

Netherlands stay operational until the end of their assumed technical lifetime (40 years). Due to the assumed increase of the CO_2 price, co-firing of biomass becomes economically viable in the long-run (2040).[16]

- **Significant increase of RES-E** – According to the current political targets and long-term vision of the European and Dutch power sector, renewable energy sources play an increasingly important role in the power system. This development is reflected in the assumptions of the Reference Case. The renewable share of net demand is assumed to increase from ca. 12% today to almost 50% in the 2025. After 2025, the combined effect of additional growth of the RES-E share and the cessation of co-firing due to the end of subsidies for biomass co-firing, leads to a slight reduction of the renewable share to 47%. With additional investments in RES-E, the share increases to 71% of net-demand in 2040.
- **Changing import position in the medium-term –** With increasing tightening of the power market in neighbouring countries and an increase of RES-E, The Netherlands move from being a net-importer of power in the short-term to a net-exporter of power after 2025.

Figure 6. Development of electricity supply in The Netherlands (Reference Case)



Source: Frontier

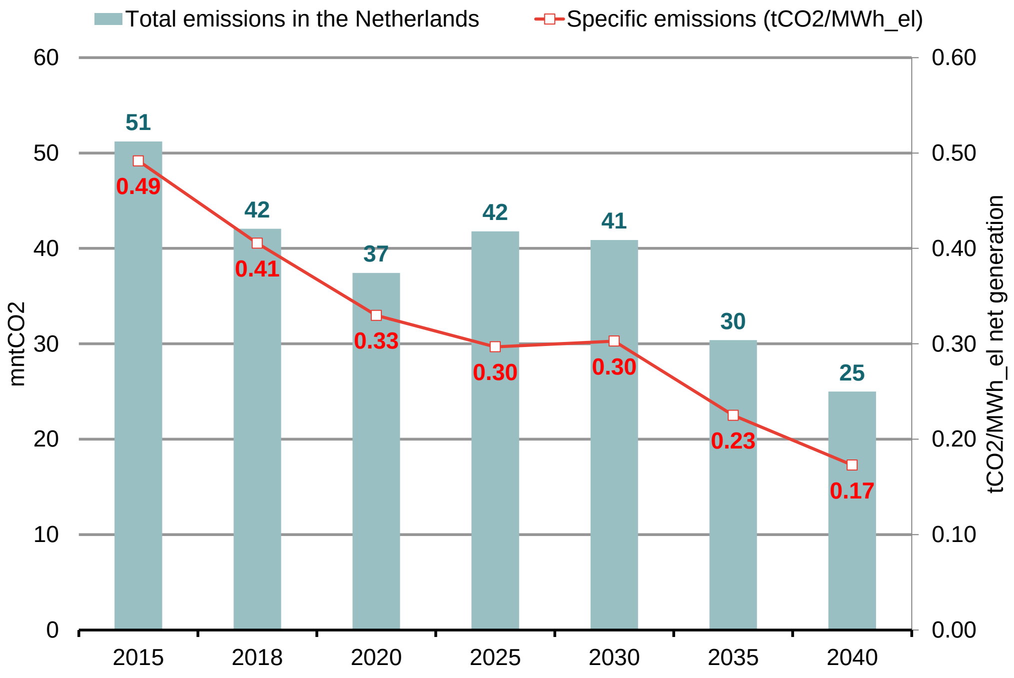
- **Decrease of power market-related CO_2 emissions** – The development of the Dutch electricity system is characterised by a strong increase of RES-E in the Reference Case. Accordingly, the power related carbon emissions in The Netherlands decrease significantly from 51 mn. tCO_2 in 2015 to 25 mn. tCO_2 in 2040. The development of CO_2 emissions can be summarised as follows:

[16] The total amount of biomass co-firing allowed in the Reference amounts to 25 PJ/a.

- Short-term decrease of carbon dioxide emissions by c. 27% to 37 mn. tCO2 in 2020 after closure of coal-fired power stations built in the 1980's in The Netherlands until 2018.
- Medium-term (model period 2025) increase to 42 mn. tCO_2 with higher exports of power to neighbouring countries.
- Long-term decrease by 51% from 2015 until 2040 to 25 mn. tCO_2.

The specific emissions per unit of electricity produced in the Dutch power system decreases (almost) steadily until 2040 (**Figure 7**).

Figure 7. Power sector CO_2 emission NL



Source: Frontier

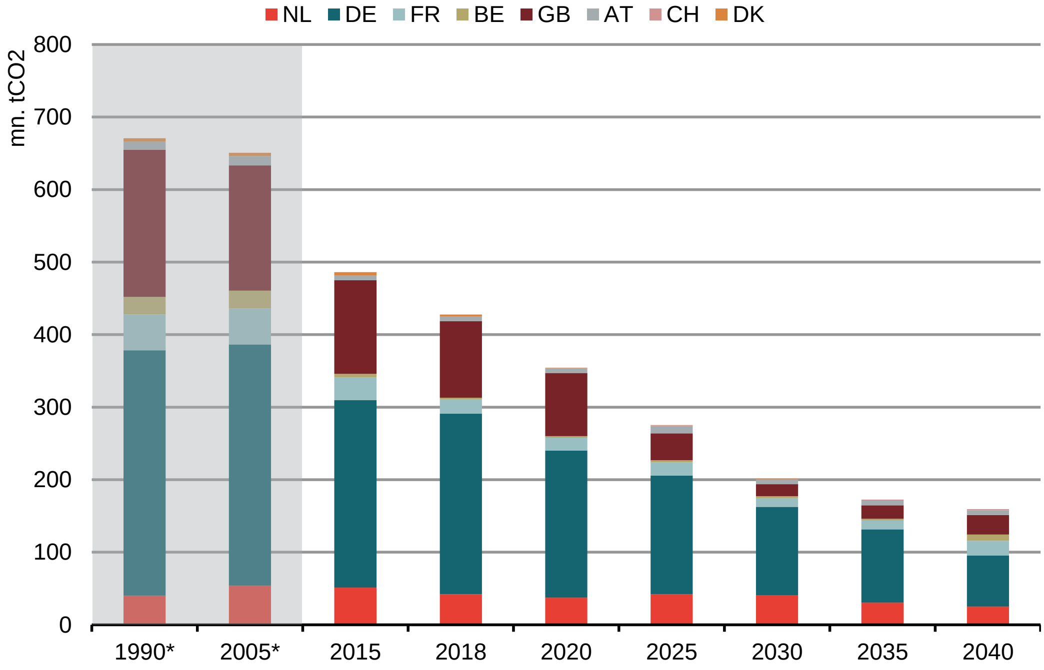
Note: Including emissions from CHP
Specific emissions calculated based on total net electricity generation

As in The Netherlands, power supply in Europe is moving towards carbon-neutrality in the long-term. In the following, we provide information on the development of carbon dioxide emissions in Central-Western Europe (including The Netherlands), in Great Britain and Denmark.[17] Power market related emissions of these countries decrease by ca. 67% from 2015 until 2040.[18] Based on this decrease, the Reference Case tends to be broadly in line with the ambition of the EU to come to a total CO_2-reduction in 2050 of 80 – 95%.

[17] Great-Britain and Denmark are not part of the "core-region", i.e. plant dispatch is modelled with a lower level of detail and capacity development is assumed exogenously.

[18] Historical emissions based on UNFCCC data (1.A.1.a - Public Electricity and Heat Production) are comparable only to a limited extent (due to different definitions of included installations).

Figure 8. CO_2 emissions in the Reference Case (CWE and neighbouring countries)



Source: Frontier

Note: * 1990/2005 based on UNFCCC data (1.A.1.a - Public Electricity and Heat Production)

As explained in **Section 2.2**, the Reference Case represents the current and intended policies in The Netherlands and North-Western Europe without additional national measures to reduce CO_2 emissions in The Netherlands and elsewhere beyond what has already been politically decided. That means, possible policy actions that might be taken in the future in relation to the Paris Agreement have not been taking into account since It is currently not possible to predict what such actions might be and what effects these would have on the power markets in the EU.

However, one possible outcome might be that future CO_2 prices would be (even) higher than assumed in this study. It is straightforward that a higher CO_2 price would lead to (even) higher CO_2 abatement in the EU as well as in the Netherlands (at least in the long term) than compared to the current Reference Case: Coal plants in the Netherlands can be expected to be dispatched less often in the long run, and shares of RES-E can be expected to increase further in The Netherlands and in the EU (including additional usage of biomass co-firing).

3 POLICY MEASURES AND SCENARIOS

MinEZ has developed the outline for three main scenarios (and a number of sub-scenarios), each representing one policy measure addressing the future of coal-fired power generation in The Netherlands:

- **Scenario 1: Additional abatement measures at the plants** – In this scenario the coal plants apply possible measures to reduce the CO_2 emission per unit of delivered electricity to such a level that the emissions are at least equal to the average CO_2 emissions of a modern gas-fired power plant (350 gCO_2/kWh_{el}).
- **Scenario 2: Pentalateral collaboration** – This scenario represents a situation in which a common approach in the Pentalateral Forum[19] is taken to achieve additional CO_2 reduction. It is assumed that the countries of the Pentalateral Forum agree on CO_2 reduction targets that go beyond the targets agreed on a European level. These additional targets lead to additional incentives to lower the emission of carbon dioxide.
- **Scenario 3: Closure of coal-fired power plants** – In the third scenario, coal-fired power plants in The Netherlands are required to shut-down at specific dates. These dates have been set prior to the expected technical lifetime of the coal plants. For scenarios with closures after 2025 it is further assumed that additional abatements measures will be taken from 2025 that limit emissions of these coal plants to that of a modern gas plant (same as Scenario 1). Specific sub-scenarios have also been included in which only the two coal-fired power plants built in the 1990's are closed in 2020.

In the following, we describe the assumptions of these scenarios in more detail.

3.1 Additional abatement measures at the plants

In the first scenario, it is assumed that operators implement additional measures at the coal plants to reduce the CO_2 emission per unit of delivered electricity to such a level that the emissions are at least equal to the average CO_2 emissions of a modern gas-fired power plant (350 gCO2/kWh_{el}). It is assumed that these measures are effective in the model period 2025, which means implementation of the measures has to happen before 31 December 2024.

Plant operators of the Dutch coal plants have been asked to provide information on possible additional abatement measures that could be implemented at their power plants to lower their emission to the threshold of 350 gram/kWh_{el}[20], which is comparable to a highly efficient gas-fired power plant.

In the following, we describe which measures have been included and how they are implemented in the context of the power market model.

[19] Netherlands, Germany, France, Belgium, Luxembourg, Austria and Switzerland.

[20] Based on 58% electrical efficiency and 203g CO_2/kWh.

3.1.1 Emission abatement measures

Measures that could be implemented by the plant operators include:

- **Co-firing of biomass** - Co-firing up to 25 PJ/a across all Dutch coal plants is included in the Reference Case, subsidised co-firing takes place from 2020 until 2028. In addition to this amount, plant operators could use higher shares of co-firing compared to the Reference Case. Biomass co-firing is regarded as CO_2-neutral and reduces the specific emissions of the plant accordingly. Based on the information received from the operators, all coal plants would implement biomass co-firing as a measure to reduce the specific carbon emissions to the level of a modern gas plant.
- **Increase utilisation of residual heat output** - Two of the power plants in focus already dispose of combined-heat and power production (CHP) in the Reference Case. In this scenario, additional utilisation of heat decoupling could be implemented in order to lower specific emissions of the power plant. For each additional MWh_th heat output, a heat credit for CO_2 emission reduction is granted that equals the avoided amount of carbon dioxide emissions in the heat sector. Based on the information received from the operators, one power plant would increase its heat output to lower the specific emissions per unit of electricity produced. Other plant operators indicated that additional heat decoupling is theoretically possible, but not included in this context.
- **Implementation of Carbon Capture and Storage (CCS)**: The ROAD-facility at the Maasvlakte represents the only CCS installation included in the Reference Case. In addition to this, plant operators could implement CCS to lower their emission. One plant operator indicated that additional CCS would be used in order to lower specific emissions of the power plant in this scenario. Furthermore, one additional plant operator indicated that the implementation of CCS at its plant is in general possible, but not necessary to achieve the target emission-intensity in this context.

3.1.2 Modelling framework

The abatement measures described above only include measures that are not economically viable by themselves in 2025. Scenario 1 consists of two sub-scenarios which are differentiated by different treatment of the costs associated with the implementation of the additional emission reduction:

- **Scenario 1a**: **Emission reduction measures at the plants (no compensation) –** Plant operators have to bear the costs associated with the additional emission reduction themselves. This includes investment costs to achieve the required emission reduction, increased variable and fixed operating and investment costs as well as efficiency losses. In this scenario, abatement measures and associated costs are included as off 2025. Based on the parameters included, the model optimises whether the plants stay operational until the end of their lifetime or cease operation earlier.
- **Scenario 1b**: **Emission reduction measures at the plants (compensation)** This sub-scenario includes the same abatement measures as sub-scenario

1a. The cost associated with the optimised emission reduction, however, are not included in the firm's cost base. Therefore, this scenario can be interpreted as a framework in which plant operators are compensated for additional costs arising from the implementation of additional abatement measures at their plants.

3.2 Pentalateral collaboration

In the second scenario, it is assumed that the countries of the Pentalateral Forum[21] reach an agreement to implement common measures to achieve additional CO_2 reductions from 2018 onwards. It is assumed that the agreed CO_2 reduction targets go beyond the targets agreed on European level.

3.2.1 Definition of the collaborative approach

There are several possible ways to implement a regional system to incentivise additional CO_2 abatement beyond the EU ETS, e.g.

- **Regional CO_2 emission limit –** The governments of the Pentalateral Forum could agree on a carbon dioxide limit below the corresponding limit derived from the EU ETS. This volume-based approach ensures that the envisaged amount of CO_2 is abated. The cost associated with the CO_2 reduction is derived by the market. While this is theoretically possible, a CO_2 emission trading scheme on top of the EU ETS and restricted to a specific European region seems rather unlikely.
- **Emission performance standards** – An alternative policy option is to cap the specific or annual CO_2 emission of power plants. This can be done by defining how much CO_2 may be emitted for the production of one unit of electricity (relative emission performance standard). Plants that do not meet the standards either need to invest in efficiency improvements or face decommissioning. Alternatively, the total amount of carbon dioxide emitted by coal plants annually could be capped (absolute standard). Without additional CO_2 abatement measures at the Dutch coal plants, this option would result in a de-facto reduction of the running-hours of the plants.
- **Carbon price adjustment –** Alternatively, governments of the Pentalateral Forum could agree on a carbon price adjustment, i.e. an additional price incentive on top of the CO_2 price observed in the EU ETS.

In this study, the collaborative approach pursued by the countries of the Pentalateral Forum is modelled as a carbon price adjustment: it is assumed that the governments of the Pentalateral Forum agree on an additional price incentive on top of the CO_2 price provided by the EU ETS carbon price. This price adjustment could be implemented in the following ways:

  - There could be a Carbon Price Floor on the price achieved in the EU ETS;
  - A carbon tax could be imposed that applies alongside the price signals of the EU ETS;

[21] The Netherlands, Germany, France, Belgium, Luxembourg, Austria and Switzerland

- Additional price incentives could arise from an uplift of the carbon price either by a constant or varying amount (EUR/tCO_2).

A similar approach has been introduced in Great Britain with the Carbon Price Floor that aims to support low carbon technologies. The Carbon Price Floor has been introduced in April 2013 as an administered levy on fossil fuels used to generate electricity. Currently, the Carbon Price Floor amounts to GBP 18/t CO_2, which is added to the price of one EU Allowance in the EU ETS. The Carbon Price Floor was set up to reach a price of GBP 30/t CO_2 in 2020.[22] Recently, the French government announced that it also intends to introduce a Carbon Price Floor by 2017. According to media reports, the floor price could amount to 30 EUR/ t CO_2.[23]

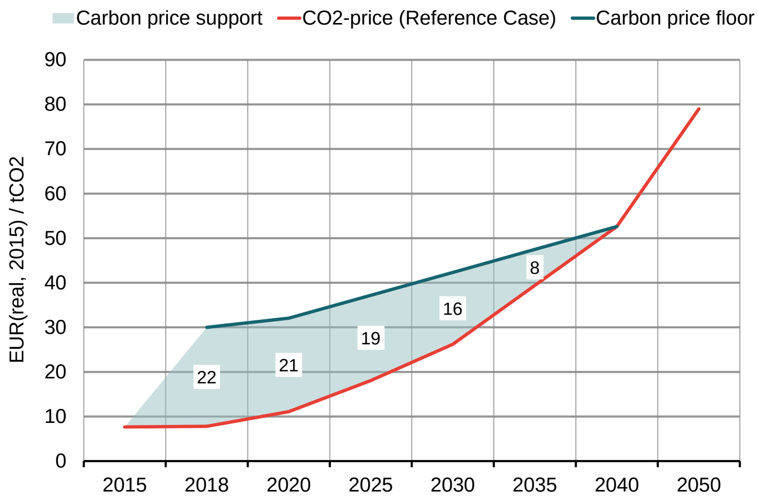
3.2.2 Modelling framework

Based on the reasoning above, the collaborative approach is modelled as a Carbon Price Floor. The level of the floor price has been chosen in accordance to the price levels discussed in France and to the Carbon Price Floor in Great Britain:

- The Carbon Price Floor starts at 30 EUR(real, 2015)/tCO_2 in 2018;
- Gradually increases to 42 EUR(real, 2015)/tCO_2 in 2030; and
- Reaches the Reference Case carbon price of 53 EUR(real, 2015)/tCO_2 in 2040 (**Figure 9**).

From 2040 the Carbon Floor Price no longer applies since the carbon price itself exceeds 50 EUR(real, 2015)/tCO_2.

Figure 9. Carbon Price Floor (Scenario 2)



Source: Frontier

Note: CPF applies to fossil fuelled generation in NL, DE, FR, BE, AT,CH

[22] HM Revenue & Customs (2014): Carbon Price Floor*: Reform and other technical amendments.* Department of Energy and Climate Change (DECC) (2011): *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity.*

[23] Reuters (17 May 2016): *France will set* Carbon Price Floor *at about 30 euros/T* ; http://af.reuters.com/article/commoditiesNews/idAFL5N18E1R3?sp=true

The Carbon Price Floor affects the variable costs of all fossil fuelled generation in the countries of the Pentalateral Forum.

It is important to note that under the EU ETS, the total amount of emissions per year is subject to the cap defined according to the Linear Reduction Factor. Therefore, total emissions in the EU ETS stay constant and are not affected by national or regional CO_2 abatement such as the CPF if no additional measures are implemented. The introduction of a carbon price floor reduces demand for emission allowances in some parts of the EU ETS, which leads to a price reduction in the overall system. This, in return, increases emissions in other regions or sectors that are not subject to the price floor. We do not take the CO_2 price reducing effect of national/regional CO_2 abatement measures into account. The repercussion on the demand for and the price of emission allowances is therefore not included in the analysis. This holds for all of the Policy Scenarios analysed in this study.

3.3 Early closure of coal-fired power plants

The third policy scenario is based on the pre-term closure of coal plants in The Netherlands. The six sub-scenarios are differentiated by the dates at which the coal plants have to cease operation. Further, this scenario differentiates between scenarios in which no emission reduction measures in addition to the implemented measures of the Reference Case are included (3a/3b/3f) and scenarios in which the abatement measures of Scenario 1 are also taken into account (3c/3d/3e) (**Table 2**):

- Scenario 3a: Closure until 2020 (31-12-2019);
- Scenario 3b: Closure until 2025 (31-12-2024);
- Scenario 3c: Closure until 2030 (31-12-2029) + additional abatement measures;
- Scenario 3d: Closure until 2040 (31-12-2039) + additional abatement measures;
- Scenario 3e: Closure of 1990’s plants until 2020 (31-12-2019) + additional abatement measures;
- Scenario 3f: Closure of 1990’s plants until 2020 (31-12-2019).

Table 2. Assumed closure dates (Scenario 3)

Plant name	Scenario 3a	Scenario 3b	Scenario 3c	Scenario 3d	Scenario 3e	Scenario 3f
Amer-centrale 9	2019	2024	2029	2039	2019	2019
Eemshaven A / B	2019	2024	2029	2039	2019	2019
Hemweg	2019	2024	2029	2039	-	-
Engie Maasvlakte	2019	2024	2029	2039	-	-
MPP3	2019	2024	2029	2039	-	-
Additional abatement measures at the plants after 2025	no	no	yes	yes	yes	no

Source: Frontier

4 INDICATOR BASED ASSESSMENT

In this chapter, we summarise the results of the indicator-based assessment of the different policy measures and scenarios. Details can be found in **ANNEX C**

The section is structured as follows:

- Summary of the main findings (**Section 4.1**);
- Impact on carbon dioxide emissions in The Netherlands and Europe (**Section 4.2)**
- Impact on the affordability of the power system (**Section 4.3**);
- Impact on power prices (**Section 4.4**) and consumer payments (**Section 4.5**);
- Impact on Security of Supply and import dependency (**Section 4.6**);
- Impact on the development of RES-E (**Section 4.7**); and
- Impact on other indicators (**Section 4.8**).

4.1 Summary

Table 3 summarises the indicator based assessment. The definition of the different indicators in the table is specified as follows (more detailed description can be found in the following chapters):

- **Impact on CO_2 emissions** - Accumulated difference of CO_2 emissions compared to the Reference Case (2018-2049) in The Netherlands (domestic emission reduction); total CO_2 emission reduction in all modelled countries, including The Netherlands (net emission reduction).
- **Impact on wholesale prices for electricity in The Netherlands** - Difference of the yearly average wholesale power price compared to the Reference Case.
- **System costs and specific abatement costs -** Impact on the system costs of the electricity supply in The Netherlands and in all modelled countries, expressed as net present value from 2018-2049, compared to the Reference Case. Specific abatement cost have been calculated by dividing additional system costs by additional CO_2 emission reduction - from a Dutch perspective (Domestic abatement costs) and a European perspective (Net-EU abatement costs).
- **Impact on consumer payments** - Difference to the Reference Case of consumer payments for electricity supply and RES-E support, expressed as net present value from 2018-2049.
- **Impact on Security of Supply and import dependency** - Impact on the average reserve margin (based on peak load and de-rated generation capacities) from 2018-2049 and impact on average level of net-imports from 2018-2049, compared to the Reference Case.

- **Impact on RES-E** - Impact on the average share of renewable energy sources of net-demand (%-points), compared to the Reference Case.

Table 3. Indicator based assessment - Summary

Scenario	Scen. 1a	Scen. 1b	Scen. 2	Scen. 3a	Scen. 3b	Scen. 3c	Scen. 3d	Scen. 3e	Scen. 3f
Impact on emissions									
Domestic emission reduction (mn.tCO_2, sum 2018-2049)	-180 (-17 %)	-162 (-15 %)	-58 (-5 %)	-322 (-30 %)	-258 (-24 %)	-242 (-23 %)	-194 (-18 %)	-209 (-19 %)	-63 (-6 %)
Net emission reduction all countries (2018-2049)	-121 (-0.9 %)	-152 (-1.1 %)	-401 (-2.9 %)	-87 (-0.6 %)	-82 (-0.6 %)	-114 (-0.8 %)	-132 (-1.0 %)	-113 (-0.8 %)	-11 (-0.1 %)
Impact on wholesale prices for electricity in the Netherlands									
Price increase in 2020 EUR/MWh	-	-	10.5	4.1	-	-	-	0.9	0.9
Price increase in 2030 EUR/MWh	0.8	0.0	3.6	3.7	3.7	3.7	0.8	1.1	0.7
System Costs and specific abatement costs									
Impact on system costs in the Netherlands (bn. EUR)	1.4 (1.7 %)	2.1 (2.6 %)	0.3 * (0.4 %)	7.1 (8.8 %)	4.2 (5.2 %)	4.5 (5.6 %)	3.1 (3.9 %)	2.1 (2.7 %)	1.1 (1.3 %)
Impact on system costs in EU (bn. EUR)	2.3 (0.3 %)	2.8 (0.4 %)	9.4 * (1.2 %)	7.9 (1.0 %)	6.0 (0.8 %)	5.1 (0.7 %)	3.6 (0.5 %)	3.1 (0.4 %)	1.4 (0.2 %)
Domestic abatement costs (EUR/tCO_2)	7.5	12.8	5.1*	21.9	16.2	18.7	16.0	10.3	27.5
Net-EU abatement costs (EUR/tCO_2)	18.6	18.7	22.7*	90.9	73.5	45.1	27.7	27.7	119.2

Scenario	Scen. 1a	Scen. 1b	Scen. 2	Scen. 3a	Scen. 3b	Scen. 3c	Scen. 3d	Scen. 3e	Scen. 3f
Impact on consumer payments									
Impact on household payments (bn. EUR/%)	0.1 (0.3 %)	0.0 (0.0 %)	2.1 (9.6 %)	0.9 (4.2 %)	0.5 (2.4 %)	0.4 (1.6 %)	0.2 (0.9 %)	0.2 (0.9 %)	0.2 (0.7 %)
Impact on other consumer payments (bn. EUR/%)	0.2 (0.2 %)	0.0 (0.0 %)	6.4 (8.0 %)	2.6 (3.3 %)	1.5 (1.9 %)	1.0 (1.3 %)	0.6 (0.8 %)	0.6 (0.7 %)	0.5 (0.6 %)
Security of Supply and import dependency									
Impact on average Reserve Margin (GW)	0.0	0.1	1.0	-1.2	-1.0	-0.5	-0.1	-0.2	-0.3
Impact on average net-imports (TWh)	2.6	1.2	1.2	14.3	11.5	8.4	3.7	4.6	2.8
Impact on Renewable Energy Production									
Impact on average RES-E %-points	3.6%	4.8%	0.7%	-2.1%	-1.8%	-0.2%	2.0%	2.7%	-0.5%

Source: Frontier

Note: Values shown in table above represent differences compared to the Reference Case
* Not including the increase of variable costs related to the carbon price floor

The results are described and explained in more detail in the following chapters.

4.2 Impact on carbon dioxide emissions

The policy scenarios defined in **section 3** aim to reduce the carbon dioxide emissions from Dutch coal plants through different policy measures. In this chapter, we describe the impact of the different measures on the CO_2 balance in The Netherlands and the other countries modelled.

4.2.1 Methodology

The carbon dioxide emissions from power production are calculated as all power related emissions, based on net-electricity production and plant or technology specific CO_2 emission intensities. Emissions from CHP-production are taken into account on the basis of plant-specific emission intensity. If the policy measures include an improvement of the plant specific emission intensity based on an increase of heat utilisation, a credit for this increase in the form of lower emission intensity is granted.[24]

[24] Based on the emission intensity of an alternative heat source.

CO_2 emissions are reported as differences to the Reference Case and defined as:

- **Domestic emission reduction** in the Netherlands, that takes into account lower emissions from Dutch coal plants and an increase of emissions from other Dutch power plants; and
- **Net emission reduction** taking into account changes of emissions in all modelled European countries, including the Netherlands.

In addition, we analyse to what extent the development path of emissions from 2015 until 2040 is affected by the implementation of the policy measures.

EMISSION REDUCTION IN THE EU ETS

National measures can have an impact on emissions in the EU ETS in two ways:

- **First-order effect:** Generation in The Netherlands decreases due to e.g. phase-out of coal-fired generation. The omitted amount of generation is partially substituted by higher generation in interconnected countries. Subsequently, emissions of CO_2 in these countries increase. This first-order effect is included in the electricity market model.
- **Second-order effect**: Annual emission levels in the EU ETS are fixed according to the EU-wide annual CO_2 emission cap and should therefore not be affected by national additional CO_2 abatement measures in the power sector as long as the cap is not reduced or CO_2 emission certificates are taken out of the market. In this case, total CO_2 emissions in the EU ETS stay the same irrespective of additional CO_2 abatement measures in the power sector in a specific country or region.[25] More explicitly, a reduction of emissions in one country ceteris paribus leads to less overall demand for allowances and therefore induces downward pressure on the price of EU allowances. This has an adverse effect of higher emissions in other countries or sectors. The total emissions in the system in such a situation stay the same.

  This second order effect of national climate policy could be avoided by the implementation of additional measures such as e.g.

  - An overall reduction of the CO_2 emission budget/cap in the EU ETS (e.g. yearly EU ETS cap) corresponding to the amount of emission reduction achieved in The Netherlands / in the countries of the Pentalateral Forum;
  - A cancellation of CO_2 certificates from the market (e.g. “buy and burn”), corresponding to the amount of emission reduction achieved in The Netherlands / in the countries of the Pentalateral Forum.

  This adverse second-order effect is not captured in the model as the price of EU allowances is kept constant despite the implementation of the national climate policy scenarios.

4.2.2 Results

The policy measures have the following impact on carbon dioxide emissions in The Netherlands:

[25] Not taking into account a possible reduction of the yearly auctioning volumes in the EU ETS through the Market Stability Reserve.

Domestic emission reduction differ significantly between scenarios

- **Scenario 1: Additional abatement measures at the plants from 2025** – Implementing additional abatement measures at the Dutch coal plants reduces the CO_2 emission intensity to the level of a modern gas-fired plant as off 2025.
  - In **Scenario 1a**, the costs of the emission reduction are borne by the plant operators. This leads to an earlier decommissioning of one of the coal plants built in the 1990s: For this plant, operation with an increased (unsubsidised) share of biomass co-firing becomes no longer economical viable after 2028 and the plant closes before 2030 instead of until 2035. In total, the implementation of additional abatement measures in Scenario 1a reduces the CO_2 emissions in The Netherlands by ca. 180 mn. tCO_2 (aggregated emission reduction from 2018-2049).[26] The highest yearly emission reduction is achieved in 2030 with 14 mn. tCO_2 less emissions than in the Reference Case.
  - In **Scenario 1b**, the abatement costs are not fully incorporated into the firm's cost base (increased fuel and fixed costs are assumed to be compensated by the state)[27]. This leads to lower variable costs of generation in the medium term and therefore higher utilisation of coal plants compared to Scenario 1a.[28] Further, earlier decommissioning of coal plants does not take place. Therefore, emission reduction in The Netherlands in Scenario 1b are (moderately) lower than in Scenario 1a (-162 mn. tCO_2, aggregated from 2018-2049).
- **Scenario 2: Introduction of a Carbon Price Floor in CWE** – Introducing a Carbon Price Floor in Central-Western Europe in 2018 leads to an emission reduction in The Netherlands of 58 mn. tCO_2 from 2018-2049 (aggregated). Due to the comparatively low emission intensity of the Dutch power sector (e.g. as compared to Germany), Dutch power plants achieve a cost advantage due to higher CO_2 prices. This increases utilisation of Dutch plants while generation of plants with higher carbon intensity abroad (e.g. German lignite) decreases. Therefore, the majority of the achieved emission reduction in the modelled region takes place in other countries in Central-Western Europe, especially Germany.
- **Scenario 3: Early closure of coal plants** – The effect of closing all coal-fired power plants on total CO_2 emission reduction depends significantly on the assumptions regarding the date of closure:
  - **Scenario 3a/b**: Closure of coal plants until 2020 reduces emissions in The Netherlands by 322 mn. tCO_2 from 2018 until 2049 (-30 %). If all plants are closed until 2025, 258 mn.tCO_2 (-24%) is emitted less in The Netherlands. Due to the earlier closure of coal-plants, less gas-fired plant capacity is mothballed in 2018. Consequently, domestic power supply and

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[26] Emission reduction from 2018 until 2049 have been calculated based on the representative modelled years.

[27] Calculated costs of the additional measures (excl. efficiency losses) amount to 2.6 bn EUR (NPV 2018-2049); see section 4.3.1.

[28] Emission reduction measures are implemented to achieve a reduction of the specific emission factor to at least 350 gCO_2/kWh_el .

emissions in The Netherlands increase slightly in 2018/2020 before plants close in 2020/2025 (**Table 4**).

- **Scenario 3c/d**: Assuming a later closure date while implementing additional abatement measures at the coal plants lowers the achieved emission reduction in The Netherlands to 242 mn. tCO_2 (-23%) if plants close before 2030 or to 194 mn. tCO_2 (-18%,) if closure is pursued until 2040.
- **Scenario 3e/f:** If the two oldest plants close before 2020 and additional abatement measures are implemented at the remaining plants (Scenario 3e), total emissions in The Netherlands decrease by 209 mn. tCO_2 (-20 %) from 2018-2049. If, however, no additional abatement measures are implemented, the emission reduction only amounts to 63 mn. tCO_2 (-6%). Closure of the two oldest plants results in around 4 Mton CO_2 reduction in 2020 in The Netherlands.

Table 4 summarises the domestic reduction of emissions in The Netherlands compared to the Reference Case.

Table 4. Domestic emission reduction (NL)

mn.t CO_2	Sum 2018-2049	2018	2020	2025	2030	2035	2040
Scenario 1a	-180 (-17 %)	0 (0 %)	0 (0 %)	-10 (-24 %)	-14 (-33 %)	-6 (-22 %)	-3 (-12 %)
Scenario 1b	-162 (-15 %)	0 (0 %)	0 (0 %)	-9 (-21 %)	-12 (-29 %)	-6 (-21 %)	-3 (-12 %)
Scenario 2	-58 (-5 %)	3 (7 %)	0 (0 %)	-4 (-10 %)	-5 (-13 %)	-3 (-10 %)	0 (0 %)
Scenario 3a	-322 (-30 %)	1 (1 %)	-12 (-33 %)	-16 (-37 %)	-17 (-42 %)	-11 (-36 %)	-4 (-18 %)
Scenario 3b	-258 (-24 %)	1 (1 %)	1 (2 %)	-16 (-37 %)	-17 (-42 %)	-11 (-36 %)	-4 (-18 %)
Scenario 3c	-242 (-23 %)	0 (0 %)	0 (0 %)	-10 (-24 %)	-18 (-44 %)	-11 (-37 %)	-5 (-19 %)
Scenario 3d	-194 (-18 %)	0 (0 %)	0 (0 %)	-10 (-24 %)	-14 (-33 %)	-6 (-22 %)	-4 (-18 %)
Scenario 3e	-209 (-19 %)	0 (0 %)	-4 (-11 %)	-12 (-28 %)	-14 (-34 %)	-6 (-22 %)	-3 (-12 %)
Scenario 3f	-63 (-6 %)	0 (0 %)	-4 (-10 %)	-4 (-9 %)	-5 (-12 %)	0 (0 %)	0 (0 %)

Source: Frontier

Note: Reduction of emission compared to the Reference Case
Scenarios 1a and b assume implementation of additional abatement measures in 2025. Earlier implementation, e.g. in 2020, would yield earlier emission reductions.

Increase in emissions abroad partially offsets domestic emission reduction

National measures that affect the operation of power plants in one country can have an impact on the operation of plants in interconnected countries. The Netherlands can be described as a relatively small power system with a high level of interconnections. Therefore, interactions with other countries have to be taken into account when assessing the CO_2 reduction effects of national measures in The Netherlands.[29] Again, it has to be noted that the second order effect in the EU ETS due to national climate policy measures in The Netherlands is not taken into account in this analysis.

- **Scenario 1: Domestic emission reduction is partially offset by increased emissions abroad** – The implementation of the additional abatement measures in The Netherlands affects power generation in other countries only if the abatement costs are included in the firm's cost base (*Scenario 1a*). Due to lower utilisation and earlier decommissioning of coal-fired plants in The Netherlands, power generation and CO_2 emissions in neighbouring countries increase. The net emission reduction in all modelled countries amounts to 121 mn. tCO_2 from 2018 to 2049 (aggregated over the period), i.e. ca. 60 mn. tCO_2 emissions are "exported" to neighbouring countries.

  If additional abatement costs are compensated by the state, the operation of the coal plants is only affected to a limited extent. Therefore, emissions in neighbouring countries do not change significantly. The net-reduction of CO_2 emissions from 2018 until 2049 in all modelled countries amounts to 151 mn.t CO_2 as compared to 162 mn. tCO_2 of domestic reduction (aggregated). This means 11 mn.tCO_2 are "exported" to other countries over the period from 2018 until 2049.

- **Scenario 2: Carbon Price Floor leads to significant additional CO_2 emission reduction in other European countries –** The Carbon Price Floor leads to a significant increase of the CO_2 price, not only in The Netherlands, but also in all other countries of the Pentalateral Forum. The biggest impact in the short-term, however, is on Germany due to the high share of carbon-intensive lignite and coal-fired power generation. The CPF leads to a ca. 50% decrease of coal- and lignite-fired generation in Germany in 2018 compared to the Reference Case. In comparison, due to the comparatively low emission intensity of the Dutch power plant park, generation in The Netherlands increases in 2018 to substitute omitted generation in neighbouring countries. In total, from 2018 until 2048, the Carbon Price Floor reduces CO_2 emissions by 401 mn. tCO_2 (-37%) with the majority of emission reductions taking place in the early years from 2018-2025.

- **Scenario 3: Closure of Dutch coal plants significantly increases emissions abroad –** Closing the Dutch coal plants reduces net emissions in The Netherlands by up to 31% (Scenario 3a): Lower emissions from closing coal plants are partly offset by more emissions from other power plants in the Netherlands: Around 30% of omitted power generation from Dutch coal plants

[29] It has to be noted that the optimisation of interconnector flows in the model is subject to simplifying assumptions. In reality, interconnector flows are also influenced for example by transit or loop flows that could limit the extent to which other countries are affected by national measures.

is substituted by domestic electricity supply, especially gas-fired power generation.[30] The larger share is substituted by higher net-imports of power and, consequently, CO_2 emissions in neighbouring countries increase. :

- **Scenario 3a/b**: The domestic emission reduction of 322 mn t.CO_2 in *Scenario 3a* (closure until 2020) corresponds to net-reduction in the modelled countries of only 87 mn. tCO_2 in the period 2018 until 2049 (aggregated). 70% of the emission reduction achieved in The Netherlands is offset by higher emissions in other EU-countries. For example, German power generation from hard coal increases by 5 TWh, lignite-fired generation increases by 1 TWh and gas-fired generation increases by 1 TWh in 2020.[31]

  In *Scenario 3b*, with closure until 2025, 65% of domestic emission reduction is compensated by higher emissions abroad (net-reduction amounts to 82 mn. tCO_2).

- **Scenario 3c/d:** If power plants have to cease operation at a later point in time (e.g. until 2030 in *Scenario 3c*) and if additional abatement measures are implemented at the coal plants as of 2025, net-reduction increases compared to an early closure of coal plants (-114 mn.tCO_2 in *Scenario 3c*). The difference between the scenarios with early closure and with later closure arises due to the smaller amount of omitted generation of closed coal plants. With closure in 2040, less generation needs to be substituted abroad. Consequently, the net emission reduction is slightly higher with 132 mn. tCO_2 (-12%).

- **Scenario 3e/f:** If the two oldest coal-fired plants were to close before 2020, net emission reduction would amount to 113 mn.t CO_2 aggregated from 2018 to 2049 (-11%) in the case that additional abatement measures are implemented at the remaining plants. If no additional abatement takes place at the newer plants, net-reduction amounts to only 11 mn. tCO_2 (-1%) due to the fact that more than 80% of the foregone emissions from the oldest plants is offset by higher emissions in neighbouring countries. The substitution effects described above are partially driven by the fact that the average emission intensity in The Netherlands is lower compared to e.g. Germany, today. Therefore, if power generation from The Netherlands is moved to e.g. Germany, overall emissions in the region can increase at least in the short term.[32]

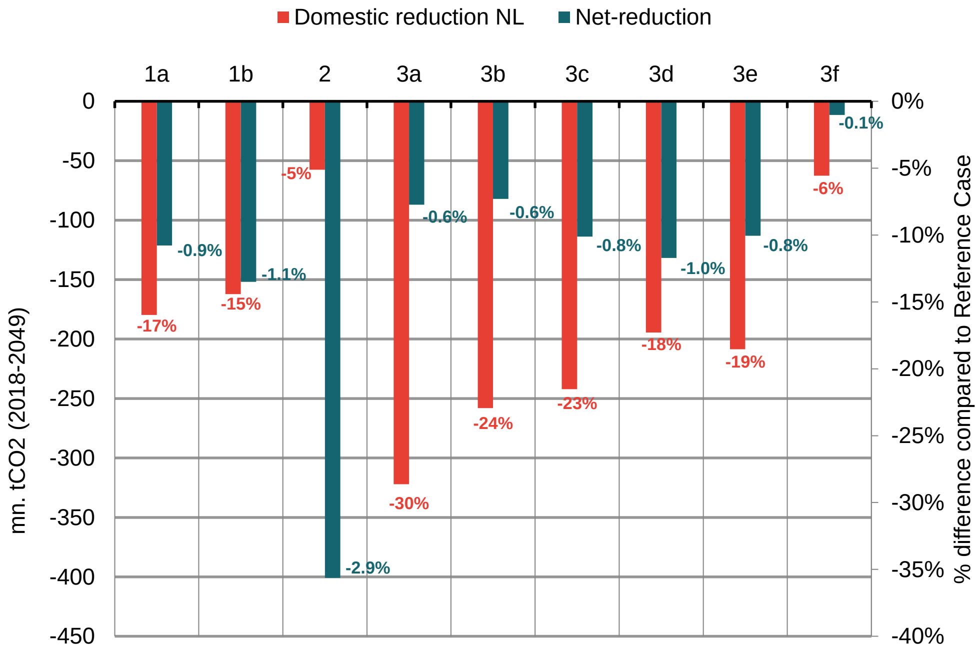
Table 5 summarise the net-reduction of CO_2 emissions in all modelled countries compared to the Reference Case.

[30] %-share of domestic substitution varies from 43% in 2020 to 13% in 2035 and 60% in 2040 (see Annexe C.4)

[31] See Annexe C.4.

[32] In the short-term, one MWh of electricity generation in Germany instead of in The Netherlands leads to increase in emission of 0.03 tCO_2 (Reference Case 2018-2025).

Figure 10. Domestic and net-reduction of CO_2 emissions



Source: Frontier

Note: Domestic emission reduction in The Netherlands and net-reduction in all modelled countries

Table 5. Net emission reduction (model region)

mn.t CO_2	Sum 2018-2049	2018	2020	2025	2030	2035	2040
Scenario 1a	-121 (-0.9 %)	0.0 (0%)	-0.1 (0%)	-5.2 (-1%)	-8.4 (-2%)	-5.5 (-1%)	-2.5 (-1%)
Scenario 1b	-152 (-1.1 %)	0.0 (0%)	-0.1 (0%)	-8.0 (-2%)	-11.2 (-3%)	-6.1 (-2%)	-2.5 (-1%)
Scenario 2	-401 (-2.9 %)	-58.0 (-9%)	-33.3 (-6%)	-17.5 (-3%)	-3.7 (-1%)	-2.3 (-1%)	-0.1 (0%)
Scenario 3a	-87 (-0.6 %)	0.8 (0%)	-0.2 (0%)	-2.3 (0%)	-6.0 (-1%)	-3.0 (-1%)	-3.1 (-1%)
Scenario 3b	-82 (-0.6 %)	0.8 (0%)	0.8 (0%)	-2.3 (0%)	-6.0 (-1%)	-3.0 (-1%)	-3.1 (-1%)
Scenario 3c	-114 (-0.8 %)	0.0 (0%)	-0.1 (0%)	-5.2 (-1%)	-6.7 (-2%)	-3.6 (-1%)	-3.5 (-1%)
Scenario 3d	-132 (-1.0 %)	0.0 (0%)	-0.1 (0%)	-5.2 (-1%)	-8.4 (-2%)	-5.5 (-1%)	-3.5 (-1%)
Scenario 3e	-113 (-0.8 %)	0.0 (0%)	0.1 (0%)	-4.2 (-1%)	-8.0 (-2%)	-5.5 (-1%)	-2.5 (-1%)
Scenario 3f	-11 (-0.1 %)	0.0 (0%)	0.1 (0%)	-0.3 (0%)	-2.1 (0%)	0.0 (0%)	0.0 (0%)

Source: Frontier
Note: Reduction of emission compared to the Reference Case

Reduction of annual CO_2 emission in The Netherlands (2040)

The impact on the long-term CO_2 emission reduction path depends on the long-term structural change induced by the policy measure.

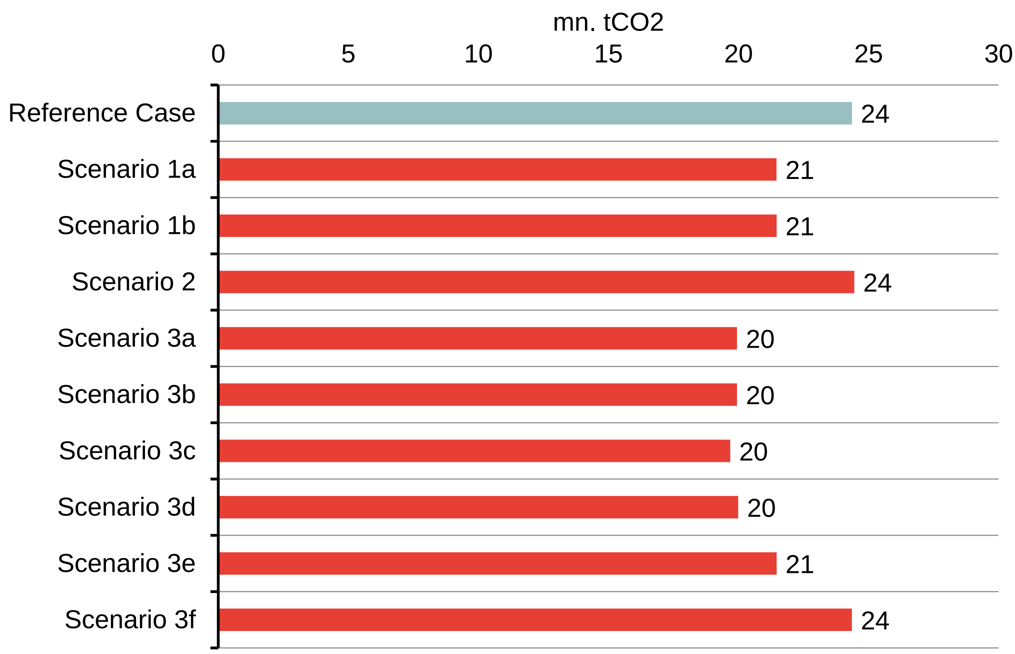
Table 6 shows the absolute impact of power-related CO_2 emissions in The Netherlands in 2040 and the relative change compared to 2040 emission in the Reference Case:

- **Scenario 1: Additional abatement measures induce 12% reduction of CO_2 emissions in 2040 –** If additional abatement measures are implemented at the Dutch coal-fired plants after 2025, domestic power-related CO_2 emissions in 2040 are 12% lower than in the Reference Case.
- **Scenario 2: No long-term impact of Carbon Price Floor on domestic emissions –** As described above, the Carbon Price Floor leads to an increase of CO_2 emissions in the Netherlands in 2018 and only a limited effect on CO_2-reduction in the medium-term. In the long-run, from 2040 onwards, the Carbon Price Floor is assumed to phase out since carbon prices are assumed to increase significantly anyway. Therefore, there is no additional CO_2 abatement compared to the Reference Case in The Netherlands in 2040.

- **Scenario 3: Early closure of coal plants reduces long-term emissions by up to 20% –** By closing the remaining coal-fired power plants before 2030, long-term emissions in 2040 drop additionally by ca. 5 mn. tCO_2, which is equal to ca. 20% of power related emissions in the Reference Case in 2040. If the two oldest plants are closed in 2020, there is only a long-term effect if additional abatement measures are implemented at the remaining plants (Scenario 3e). This is due to the fact that these plants reach the end of their assumed technical lifetime until 2035.

Figure 11 and **Table 6** illustrate the impact of the policy scenarios on the level of CO_2 emissions in 2040.

Figure 11. CO_2 emissions (NL) in 2040



Source: Frontier

Table 6. Differences of annual CO_2 emissions in 2040 (NL)

mn.t CO_2	Scen. 1a	Scen. 1b	Scen. 2	Scen. 3a	Scen. 3b	Scen. 3c	Scen. 3d	Scen. 3e	Scen. 3f
Difference in CO_2 emissions in 2040	-2.9	-2.9	0.1	-4.4	-4.4	-4.7	-4.4	-2.9	0
%-reduction compared to Reference Case	-12%	-12%	0%	-18%	-18%	-19%	-18%	-12%	0%

Source: Frontier

Note: Reduction of annual emission compared to the Reference Case

4.3 System costs and specific abatement costs

In this section, we analyse the impact of the different policy measures / scenarios on the affordability of the electricity system. For each of the policy scenarios, we calculate two indicators that inform about the cost impact:

- Impact on the system costs of electricity supply in The Netherlands; and
- Specific abatement costs.

4.3.1 Impact on system costs of electricity supply

The calculation of the impact on system costs of The Netherlands is based on the methodology described in Frontier (2015).[33]

Definition of system costs

The system costs include the following cost elements:

- **Variable costs of generation** include all costs directly incurred by the production of electricity in the short term, i.e. fuel costs, costs of CO_2 certificates and other variable costs of power generation; both for generation capacities and demand side response;
- **Fixed costs of operation** of power plants include the costs for investment[34], mothballing, reactivation and fixed operation and maintenance costs of power generation capacities and demand side response.
- In addition, the system cost includes **cost of the assumed RES-E capacity additions**, i.e. investment costs and fixed operation and maintenance costs of intermittent energy sources, i.e. wind-onshore/offshore and solar PV.
- **Credits/debits of power exchange with neighbouring countries** have to be taken into account since otherwise costs of power supply are not assigned to the countries in which the power is consumed. Credits/debits of power exchange with neighbouring countries include
  - the costs of electricity imports to the Netherland valued at the wholesale power price in the country exporting to the Netherlands;
  - as well as the value of exports valued at the wholesale power price in The Netherlands;
- **Grid costs** that are associated with the increased deployment of RES-E in the Dutch electricity system are also taken into account.

System costs are reported as net-present value over the time horizon analysed (2018-2049)[35] and represent an estimate for the efficiency of different policy measures as compared to the Reference Case. Potential compensation of plant

[33] Frontier (2015): *Scenarios for the Dutch electricity supply system.*

[34] It has to be noted that not all cost of the electricity system are included in our estimation: For instance, capital expenditure / investment costs of existing power plants are not included, as they are regarded as "sunk costs" in the model. Furthermore, investment costs for replacement investment in de-central CHP-generation are not included.

[35] Assumed social discount rate of 5%.

operators for foregone profits in the case of early closure of the coal plants (Scenario 3) are not part of the system costs since it is irrelevant for the system costs to which stakeholder costs are allocated or if profits are redistributed. Furthermore, it is irrelevant for the definition of the system costs, if the the costs incurred by the additional abatement measures implemented at the plants (Scenario 1, 3 c-e) are compensated by the state or not – only additional capacity and fuel costs are taken into account independent of allocation of costs to stakeholders.

Potential costs for alternative heat sources are not included in the system costs as calculated below.

System costs in the Netherlands

The policy measures analysed have the following impact on the costs of the Dutch electricity supply:

- **Scenario 1**: **Additional abatement measures at the plants increase system costs by 1.4 – 2.1 bn. EUR (real, 2015)** – If additional abatement measures are implemented at the Dutch coal plants, system costs in The Netherlands (NPV, 2018-2049) increase by 1.4 to 2.1 bn. EUR compared to the Reference Case. This increase is driven by two effects:
  - Higher variable and fixed costs of power plants due to the abatement measures that have been implemented ; and
  - The impact of higher costs on the operation of the power plants (if costs are borne by the companies): Average utilisation decreases by ca. 20% in 2025 compared to the Reference Case and one of the coal plants built in the 1990s ceases operation earlier than in the Reference Case (*Scenario 1a*).

  In the case of *Scenario 1a*, power generation from the Dutch coal plants decreases slightly since the abatement costs are borne by the plant operators. Therefore, total variable cost of power generation in The Netherlands decreases moderately (less domestic generation) while costs for imports from other countries and fixed costs for earlier reactivation of power plants increase.

  In Scenario 1b absolute generation from biomass increases slightly compared to *Scenario 1a* since power companies face no additional costs from higher co-firing of biomass. However, economically additional costs from co-firing have to be taken into account even if these costs are assumed to be compensated by the state. Total system costs in The Netherlands increase in this case by 2.1 bn. EUR (real 2015, NPV 2018-2049).[36]

- **Scenario 2: System costs of Carbon Price Floor depend on accounting for increase in CO_2 price** – The introduction of a Carbon Price Floor directly influences the variable costs of power generation through higher (variable) costs for CO_2 allowances. In addition, there is an indirect effect of changing

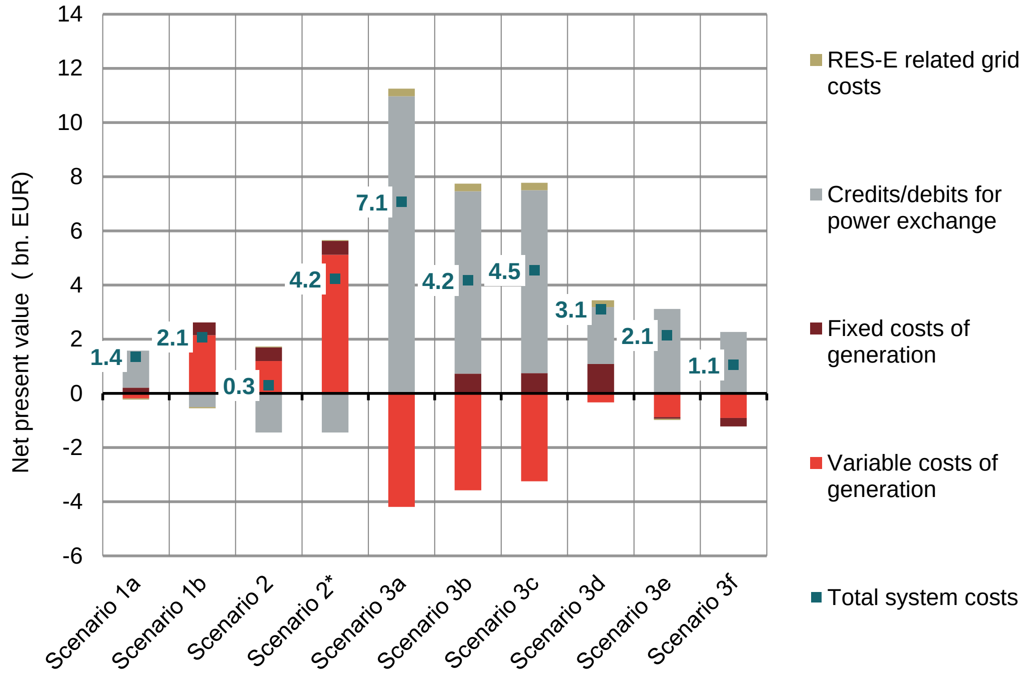
[36] If companies would be compensated for the full additional fuel and investment costs the compensation would amount to 2.1 bn. EUR (NPV 2018-2049) in total. However, companies also benefit from (slightly) higher wholesale power prices which might be taken into account when calculating the compensation.

the supply structure in The Netherlands, because the Carbon Price Floor leads to additional domestic power generation in The Netherlands and earlier reactivation of mothballed gas plants. Both factors increase system costs. The increase of costs is partially offset by higher credits for power exchange, reflecting an increase of power exports to neighbouring countries. Overall system costs increase by 4.2 bn. EUR (real, 2015).

The increase of variable costs, however, can be interpreted as a financial transfer from households and other consumers to the state (and to a lesser extent to producers) and does not reflect a “real” increase in costs in a narrow sense. If the system cost is corrected for additional state income generated by the Carbon Price Floor (taking into account CO_2 emissions incurred by higher exports to neighbouring countries), additional system costs of the Carbon Price Floor in the Netherlands amounts to 0.3 bn. EUR from 2018-2049 (NPV). The additional state income amounts to ca. 3.9 bn. EUR.

- **Scenario 3: Largest impact on system cost if plants close before 2020** – Closing the Dutch coal plants before 2020 or 2025 influences the supply structure of the Dutch power system. Domestic generation decreases in total and more electricity needs to be imported from neighbouring countries in hours when the price is high. Therefore, debits for higher imports more than offset the decrease in variable generation costs. Saved fixed costs by closing the coal plants are almost completely offset by higher fixed costs incurred from earlier reactivation and investment in gas-plants. Further, additional RES-E investment in the long-run increase the cost incurred by the grid-integration of these additional investments.
  - If all plants close until 2020, system costs increase by 7 bn. EUR (real, 2015, NPV 2018-2049) or 8.8% compared to the Reference Case.
  - If closure of all plants is postponed to 2030 and additional abatement measures are implemented after 2025, costs increase by 4.5 bn. EUR (5.6%) compared to the Reference Case.
  - Closure of the two oldest plants increases system costs by 1.1 bn. EUR (1.3%) (Scenario 3f). If additional abatement measures are implemented at the plants, costs increase by 2.1 bn. EUR (2.7%) (Scenario 3e).

Figure 12. Impact on system costs (NL)



Source: *Frontier*

Note: *Difference of system costs to the Reference Case (NPV, 2018-2049)*
** Additional "CO_2 costs" (state income) of ca. 3.9 bn. EUR .*
Subsidies for co-firing that are saved due to early closure are assumed not to be spent elsewhere

Table 7. Impact on system costs in The Netherlands

bn. EUR (NPV 2018-2049)	Total system costs	Variable costs of generation	Fixed costs of generation	RES-E related grid costs	Credits/debits for power exchange
Scenario 1a	1.4 (1.7 %)	-0.2	0.2	0.0	1.4
Scenario 1b	2.1 (2.6 %)	2.15	0.47	-0.04	-0.50
Scenario 2	0.3 (0.4 %)	1.2	0.5	0.0	-1.4
Scenario 2*	4.2 (5.2 %)	5.1	0.5	0.0	-1.4
Scenario 3a	7.1 (8.8 %)	-4.2	0.0	0.3	10.9
Scenario 3b	4.2 (5.2 %)	-3.6	0.7	0.3	6.7
Scenario 3c	4.5 (5.6 %)	-3.2	0.7	0.3	6.8
Scenario 3d	3.1 (3.9 %)	-0.3	1.1	0.3	2.1
Scenario 3e	2.1 (2.7 %)	-0.9	-0.1	0.0	3.1
Scenario 3f	1.1 (1.3 %)	-0.9	-0.3	0.0	2.3

Source: *Frontier*

Note: ** Additional "CO_2 costs" (state income) of ca. 3.9 bn. EUR are included*

Policy measures in The Netherlands also affect system costs in neighbouring countries

Political interventions and policy measures in one country have an impact on neighbouring and interconnected power markets. Therefore, additional climate policy measures in The Netherlands affect the costs of the electricity supply in all modelled countries.[37] In addition, the Carbon Price Floor in *Scenario 2* does not only affect the costs for CO_2 allowances in The Netherlands but also in all other countries of the Pentalateral Forum.

The effects on system costs in the modelled region can be summarised as follows (**Table 8)**.

- **Scenario 1: Small increase of system costs in neighbouring countries** – The structure and the operation of interconnected power markets is only affected if the costs of additional abatement measures are included in the firm's decisions to dispatch the power plant (see **Section 4.2.2**). In that case (*Scenario 1a*), system costs in all modelled countries, incl. The Netherlands, increase by 2.3 bn. EUR (real 2015, NPV 2018-2049) or 0.3%. If costs are not borne by the companies (*Scenario 1b*), total system costs increase slightly by 2.8 bn. EUR (real 2015, NPV 2018-2049).
- **Scenario 2**: **Carbon Price Floor increases variable costs significantly –** The introduction of a Carbon Price Floor significantly affects the variable costs of power generation of a majority of the power plants in the Central-Western Europe. Consequently, the total increase in system costs in all modelled countries is high at about 36 bn. EUR (real 2015) (NPV 2018-2049). As described above, the increase in variable costs can be interpreted as a financial transfer to the state and does not reflect a "real" increase in costs in a narrow sense. If the system cost is corrected for additional state income generated by the CPF, additional system costs of the CPF amounts to 9 bn. EUR from 2018-2049 (NPV). The additional state income amounts to ca. 27 bn. EUR.
- **Scenario 3: Coal phase-out increases overall European system costs** – In addition to the costs incurred in The Netherlands, phasing-out coal-fired generation before 2020 leads to higher power generation in neighbouring countries and therefore higher costs in these countries as well (*Scenario 3a*: + 1%). If closure is postponed to later years and combined with additional CO_2 abatement measures at the coal-fired power plants in the Netherlands (Scenarios 3c, 3d), the impact on overall system costs in the EU is lower.

  If no additional abatement measures are implemented, the closure of the two oldest plants leads to an overall increase of system costs in the modelled countries (incl. The Netherlands) of 1.4 bn. EUR. With additional measures, the overall increase of system costs is 3.1 bn. EUR (NPV 2018-2049).

[37] EU system costs include fixed and variable costs of operation, CAPEX for new investment and costs of power exchange with other modelled regions. Grid costs are not part of the definition. NL, DE, BE, FR, AT, CH, DK, CZ, PL, IT

Table 8. Impact of policy measures on EU system costs*

	Scen. 1a	Scen. 1b	Scen. 2	Scen. 3a	Scen. 3b	Scen. 3c	Scen. 3d	Scen. 3e	Scen. 3f
Difference in system costs (NPV 2018-2049)	2.3	2.8	9.4	7.9	6.0	5.1	3.6	3.1	1.4
%-difference compared to Reference Case	0.3%	0.4%	1.2%	1.0%	0.8%	0.7%	0.5%	0.4%	0.2%

Source: Frontier

*Note: * EU system costs include fixed and variable costs of generation (incl. Capex for investment) as well as costs of power exchange with satellite regions.*

4.3.2 Specific abatement costs

Specific CO_2 abatement costs can be calculated by relating the difference in system costs to the achieved additional CO_2 emission reduction. In effect, the specific abatement costs thereby provide a measure for the average costs incurred for the abatement of one ton ofCO_2, and thereby provide insight into the cost-effectiveness of a specific policy scenario. In the following, we differentiate between:

- **Domestic abatement costs** – Additional system costs in The Netherlands (NPV) are divided by the domestic additional CO_2 reduction (aggregated from 2018 to 2049). The increase of emissions from other Dutch plants is included in this calculation.
- **Net EU abatement costs in the region** – Additional system costs in modelled regions (NPV) are divided by the additional CO_2 reduction in all modelled countries (aggregated from 2018 to 2049).

The specific CO_2 abatement costs calculated cannot be compared to actual CO_2 prices in the EU ETS. In our calculation discounted system cost are divided by accumulated emissions (from 2018-2049). Furthermore, the calculated specific abatement costs are average costs per abated tonne of $CO_{2,}$ while prices in the EU ETS can be interpreted as marginal abatement costs.

The policy measures result in specific abatement costs as shown in **Figure 13:**

- **Scenario 1: Additional abatement measures at the plants amount to 8 – 19 EUR/tCO2 –** In *Scenario 1a*, the domestic abatement costs amount to 8 EUR/tCO2. If costs and the impact on emissions in neighbouring countries are taken into account the net EU abatement costs increase to 18.6 EUR/$tCO_{2,}$ especially due to the "export" of emissions abroad. If the costs of emission abatement measures are not included in the firm's cost base (Scenario 1b), the domestic abatement costs are 13 EUR/tCO_2, while net EU abatement costs increase moderately to 18.7 EUR/tCO_2, as less emissions are "exported" abroad.
- **Scenario 2: Specific abatement costs of the Carbon Price Floor depend strongly on system cost definition –** The introduction of the Carbon Price

Floor reduces emissions in The Netherlands at a cost of 73 EUR/tCO_2 if the increase of the CO_2 price is interpreted as a cost. The net EU abatement costs amount to 90 EUR/tCO_2 in this case.

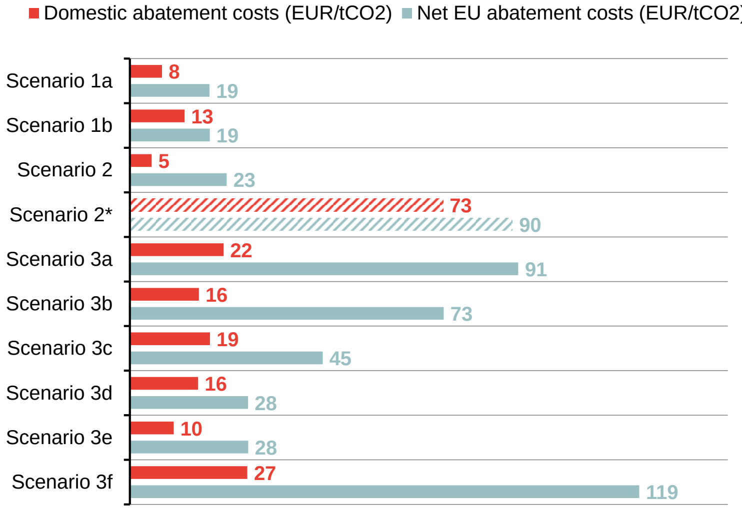
However, if the transfers to the state are not taken into account as a cost, specific abatement costs decrease to 5 EUR/tCO_2 in The Netherlands and to 23 EUR/tCO_2 from a European perspective. In this case, the large difference between the specific abatement costs in the Netherlands and costs on European level results from the relatively low emission intensity of Dutch electricity supply compared to e.g. Germany. Therefore, the increase of CO_2 prices influences the costs of electricity supply in The Netherlands to a lesser extent.

- **Scenario 3: Closure of coal plants with higher net abatement costs –** Closing the Dutch coal plants in 2020 reduces domestic emissions at the costs of ca. 22 EUR/tCO_2. From a European perspective, the specific abatement costs increase significantly to 90 EUR/tCO_2 due to the lower net-reduction achieved as compared to the domestic emission reduction in The Netherlands. If closure is postponed to 2025, the costs decrease to 16 EUR/tCO_2 from a Dutch perspective and to 73 EUR/tCO_2 from a European perspective.

  Closure of the plants until 2030 and the implementation of additional abatement measures incur costs of 19 EUR/tCO_2 in The Netherlands and 45 EUR/tCO_2 in all modelled countries. With closure of the plants until 2040, the specific abatement costs in The Netherlands and the EU decrease to 16 and 28 EUR/tCO_2 respectively.

  Closing the two oldest plants until 2020 and implementing additional abatement measures at the newer plants incurs costs of 10 EUR per tCO_2 abated in The Netherlands. If higher emissions in neighbouring countries due to substitution from the closure of the two coal plants are taken into account, net EU abatement costs increase to 28 EUR/tCO_2. If no additional abatement measures are implemented at the remaining plants, costs in The Netherlands increase to 27 EUR/tCO_2 and to 119 EUR/tCO_2 from a European perspective. The reason for the relatively high specific net EU abatement costs in Scenario 3f , is that around 80% of emission reduction in The Netherlands is offset by higher emissions elsewhere in the modelled region.

Figure 13. Specific emission abatement costs EUR(real, 2015)/tCO_2



Source: *Frontier*

Note: *Specific abatement costs have been calculated based on NPV of system costs differences and the accumulated sum of emission reduction (2018-2049).*
** Including cost increase related to the Carbon Price Floor (additional state income generated by CPF)*

4.4 Impact on power prices

In this sub-section, we analyse the changes in power prices in the different policy scenarios compared to the Reference Case. In the following, we describe the impact of the policy measures on:

- Wholesale prices for electricity in The Netherlands; and
- Electricity prices in Central-Western Europe.

Impact on wholesale price of electricity in The Netherlands

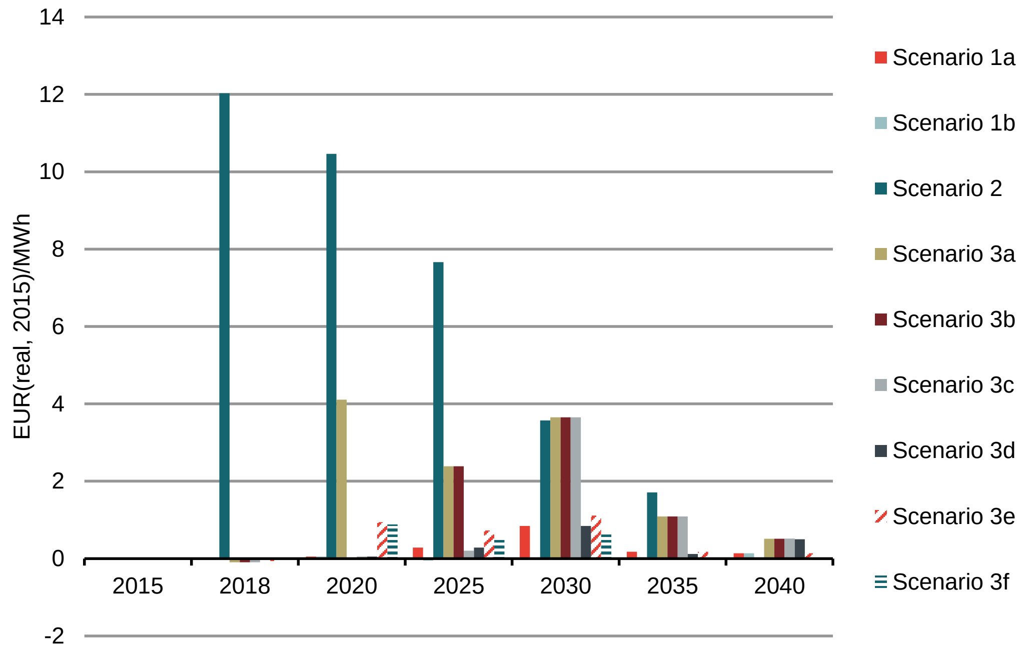
The impact of the modelled policy measures on the power prices in The Netherlands can be summarised as follows:

- **Scenario 1: Limited influence of abatement measures on power prices –** Implementing additional abatement measures at the Dutch coal plants affect the power prices in The Netherlands only to a limited extent. The maximum increase amounts to 0.8 EUR (real, 2015)/MWh in 2030 (*Scenario 1a*). If the costs of the emission reduction are not taken into account in the plants operation (*Scenario 1 b*), there is almost no impact on power prices.
- **Scenario 2: Carbon Price Floor with significant impact on short-term power price development –** The introduction of a Carbon Price Floor in the countries of the Pentalateral Forum influences the short-run marginal costs of almost all conventional power plants in Central-Western Europe since CO_2 certificates are variable costs from a power generator perspective. Consequently, the impact on power prices is relatively high and amounts to 12 EUR(real, 2015)/MWh in 2018 and decreases with the phasing-out of the price support in 2040.

- **Scenario 3: Early closure of coal plants increases wholesale power prices by up to 4 EUR(real, 2015)/MWh –** The decommissioning of all Dutch coal plants before 2020 leads to an increase of power prices by 4 EUR(real, 2015)/MWh in 2020. If plants close at a later stage and if additional abatement measures are implemented at the plants, prices increase at a later date and to a lesser extent. If the two oldest power plants are closed until 2020, the short-term price effect amounts to 0.9 EUR(real, 2015)/MWh in 2020.

Figure 14 and **Table 9** summarise the impact of the different policy scenarios on Dutch electricity prices.

Figure 14. Impact on power prices (NL)



Source: Frontier

Note: Difference of the power price to the Reference Case

Table 9. Wholesale prices of electricity in The Netherlands

EUR(real, 2015)/MWh	2018	2020	2025	2030	2035	2040
Reference Case	35.3	39.3	54.6	61.3	70.0	66.7
Scenario 1a	35.3	39.4	54.9	62.1	70.2	66.9
Scenario 1b	35.3	39.4	54.6	61.2	70.1	66.9
Scenario 2	47.4	49.8	62.3	64.8	71.8	66.7
Scenario 3a	35.2	43.4	57.0	64.9	71.1	67.3
Scenario 3b	35.2	39.3	57.0	64.9	71.1	67.3
Scenario 3c	35.2	39.4	54.8	64.9	71.1	67.3
Scenario 3d	35.3	39.4	54.9	62.1	70.2	67.2
Scenario 3e	35.3	40.2	55.3	62.4	70.2	66.9
Scenario 3f	35.3	40.2	55.1	61.9	70.0	66.7

Source: Frontier

Impact on wholesale price of electricity in neighbouring countries (example: Germany)

The policy scenarios examined in this study influence the dispatch of power plants not only in The Netherlands, but also in other countries either directly (through the Carbon Price Floor) or indirectly through interconnections and power exchange with The Netherlands. Therefore, power prices in neighbouring countries are also affected by the introduction of national climate policy measures in The Netherlands or coordinated measures in the Pentalateral forum. As an example, **Table 10** shows the impact of the different policy measures on power prices in Germany.

- **Scenario 1: Small increase of power prices in Germany** – Power prices in Germany increase moderately due to the implementation of abatement measures at Dutch coal plants. The maximum increase of wholesale prices amounts to 0.7 EUR(real, 2015)/MWh as compared to 0.8 EUR(real, 2015)/MWh in The Netherlands in 2030. Prices in Germany increase due to lower utilisation of Dutch coal plants and consequently lower net-imports from The Netherlands.
- **Scenario 2: Germany affected to a greater extent by Carbon Price Floor** – Due to the higher emission intensity of the German power plants, the price increase following the introduction of the Carbon Price Floor if higher than in The Netherlands (14.9 EUR(real, 2015/MWh in 2018; which is 2.9 EUR higher than in The Netherlands). The Carbon Price Floor also leads to an earlier converging of wholesale power price levels in Germany and The Netherlands (average price difference in 2018 decreases from 3 to 0.1 EUR/MWh).

- **Scenario 3: Dutch coal phase-out increases German power prices by up to 3 EUR/MWh –** The closure of coal-fired power plants has the most significant impact on German power prices in the period from 2030 when the supply demand balance is becoming tighter. The German power prices increase by 3.2 EUR(real, 2015)/MWh in 2030 following the closure of the Dutch coal plants (in 2020, 2025 or 2030, *Scenarios 3a – 3c*).
  - If the coal-fired plants are closed in 2020 (*Scenario 3a*), there is only a very limited impact on German power prices as compared to the 4 Euro increase of Dutch power prices in 2020 as additional plants in the Netherlands are reactivated and less generation needs to substituted abroad. Consequently, the price difference between Germany and The Netherlands in 2020 grows from 0.6 EUR(real, 2015)/MWh in the Reference Case to 3.8 EUR (real, 2015)/ MWh in Scenario 3a.
  - If the two oldest power plants close until 2020 (without implementation of additional measures at the remaining plants), prices in Germany increase by up to 0.5 EUR(real, 2015)/MWh. The impact is relatively low due to the limited amount of power generation shut down in the European context.

Table 10. Impact on wholesale power prices in Germany

EUR(real, 2015)/MWh	2018	2020	2025	2030	2035	2040
Scenario 1a	0.0	0.0	0.3	0.7	0.2	0.1
Scenario 1b	0.0	0.0	0.0	0.0	0.1	0.1
Scenario 2	14.9	11.0	7.8	3.5	1.7	0.0
Scenario 3a	0.0	0.8	2.2	3.2	1.0	0.4
Scenario 3b	0.0	0.0	2.2	3.2	1.0	0.4
Scenario 3c	0.0	0.0	0.2	3.2	1.0	0.4
Scenario 3d	0.0	0.0	0.3	0.7	0.1	0.4
Scenario 3e	0.0	0.4	0.7	0.9	0.2	0.1
Scenario 3f	0.0	0.4	0.5	0.5	0.0	0.0

Source: Frontier

Note: Increase of the yearly average (base price) in Germany compared to the Reference Case

4.5 Impact on consumers

The increase of power prices in The Netherlands described in **Section 4.4** increases costs for final consumers. In the following section, we describe the impact of the policy scenarios on consumer payments for households and business customers.

4.5.1 Methodology

The analysis focusses on the consumer payments arising from the consumption of electricity and additional costs incurred by the expansion of renewable electricity. We include the following cost elements in the calculations:

- **Costs for electricity –** The costs of electricity supply that have to be paid by consumers are calculated based on the hourly electricity consumption and hourly power prices. We assume that changes in the wholesale power prices are passed on without distortions or mark-ups through retail-services onto final consumers.
- **Costs of renewable electricity** – The costs of renewable electricity (wind-onshore, wind-offshore and solar PV) are included as the difference between total costs of renewables and the market revenues, i.e. the additional financial support needed to obtain the targeted capacity levels. We assume that all additional RES-E costs are passed onto final consumers, i.e. caps on RES-E subsidies (cap by RES-E budgets) are not taken into account in the analysis. Furthermore, RES-E related grid costs are included as additional cost element.[38]

In our analysis, we differentiate between households and other (business/public service or industrial) consumers. The calculation of costs for both customer groups is based on the following assumptions:

  - Changes in the wholesale electricity prices are passed-on to customers without distortions from retailers, i.e. retailers set tariffs on a cost basis;
  - The policy scenarios do not affect other taxes / levies apart from VAT for households and the potential impact of wholesale price movements on RES-E support;
  - The analysis does not include costs arising from enforcement or replacement investment in the power transmission and distribution grids that are not directly related to the connection of RES-E; and
  - Costs for renewable support are passed on to both consumer groups, based on their share of total consumption.

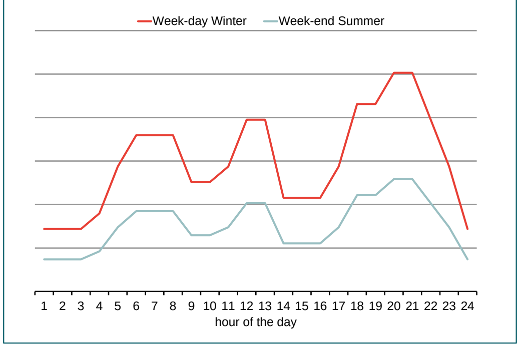
- The consumer payments for electricity are derived from two different consumption profiles for hourly consumption:
  - **Household consumption** varies over the course of the day according to a typical consumption profile. Consumption on weekends is lower than on weekdays as well as higher in the winter/autumn than in the summer; and
  - **Consumption from the public sector, businesses and industrial customers** varies to a lower extent than consumption from households. While it is apparent that this is quite a diverse group, we have tested a flat consumption pattern for other consumers (which is more appropriate e.g. for industrial consumers), and results do not vary significantly in that case.

[38] Methodology based on Frontier (2015).

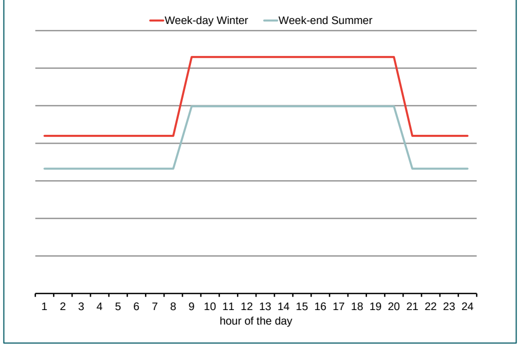
Total net-power demand is divided into these two consumer groups based on the historical split between household electricity consumption[39] (20%) and “business and industrial consumers” (80%).

Figure 15. Assumed consumption profiles

Households



Businesses and industrial customers



Source: Frontier

[39] CBS Stateline “Energy consumption households; energy commodities”, 84.43 PJ in 2013.

SYSTEM COSTS VS. CONSUMER PAYMENTS

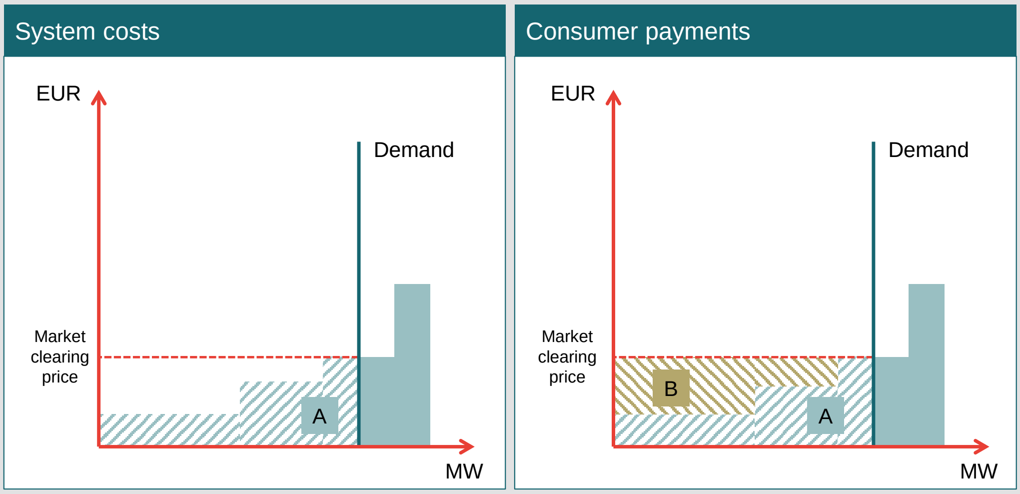
Two indicators, *System Costs* and *Consumer Payments,* are used in this analysis to provide insight into the impact of the different policy measures on the affordability of the electricity system.

The indicators provide different information:

- **System costs** inform about the *efficiency of a power system*, i.e. what are the costs to society to serve demand in a given region, in this case in The Netherlands. The distribution of benefits, rents and costs between stakeholders (consumers, producers, the state) is not relevant for the total sum of system costs.
- **Consumer payments** inform about the costs of electricity supply for the consumer (the consumer bill) and thereby show *distributional effects* of policy measures. That means that due to higher system, an increase in consumer payments can incur costs, as well as higher rents for producers, higher state income (taxes, levies) or a mix of these factors.

Figure 16 illustrates the difference between both concepts based on a simplified example of one hour of electricity supply (merit order). In the figure below, the system costs to cover demand are given by the costs of all operating power plants (blue dashed area "A"). These costs are inter alia included in the definition of *System Costs*. The *costs to final consumers* in that case, however, are given by the area "A" and the area "B" due to the principle of "uniform pricing". Therefore, the consumer payments also include rents for power suppliers in addition to their generation costs.

Figure 16. System costs vs. consumer payments



Source: Frontier

4.5.2 Results

In the following, we describe the impact of the different policy measures on the payments of consumers for electricity supply in the Netherlands. As described in **Section 4.4**, the policy measures affect the wholesale power prices in the Netherlands to a varying extent. As a consequence, the costs to consumers are affected differently in the individual scenarios:

- **Scenario 1: Comparably low impact of additional abatement measures on consumers** – The implementation of additional abatement measures increases costs for households by 0.1 bn. EUR (+ 0.3%) (NPV 2018-2049) and for other customers by 0.2 bn. EUR (+0.2%), assuming that no compensation for the implementation of additional measures is granted to the plant operators. The financing of state payments to the coal plant operators is not taken into account in the calculation since it is unclear where the financing would come from.

- **Scenario 2**: **Carbon Price Floor increases consumer payments by 8-10%** - The Carbon Price Floor has the largest impact on power prices and consequently also on the costs for electricity paid by final consumers. Assuming that additional state income from the increase in CO_2 prices[40] is not re-distributed to final consumers, costs for households increase by 2 bn. EUR (10%) and for other consumers by 6.4 bn EUR (8%).

  The power price related increase in consumer payments is in both cases partially offset by lower support requirements for RES-E since the difference between the levelised costs of RES-E on one hand and wholesale power prices on the other hand is lower than in the Reference Case.

- **Scenario 3: Early closure of coal plants increases consumer payments by 3-4%** - Closing all 5 coal plants until 2020 increases prices by up to 4 €/MWh and consequently the costs for households in The Netherlands increase by ca. 0.9 bn EUR (4%). Costs for other consumers increase by 2.6 bn EUR (3%). Closure in 2025 lowers the cost increases for households and other consumers to 0.5 bn. EUR (2.4%) and 1.5 bn. EUR (1.9%), respectively (*Scenario 3b*).

  If, in addition to the decommissioning of plants until 2030, supplementary abatement measures are implemented at the plants in 2025, costs for households increase by 0.3 bn. EUR (1.6%) and for other consumers by 1 bn. EUR (1.3%) compared to the Reference Case (*Scenario 3c*).

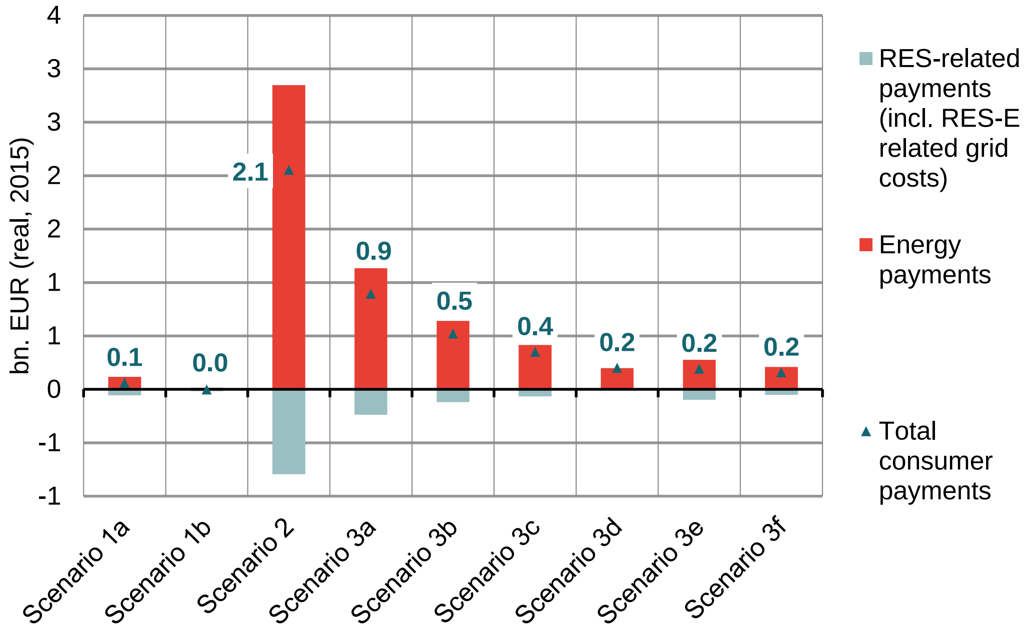
  Closing the two oldest coal-fired plants until 2020 (no additional abatement measures) increases costs to households by 0.16 bn. EUR (0.7%) and for other consumers by 0.45 bn. EUR (0.6%) (*Scenario 3f*). If additional abatement measures at the remaining plants are implemented, costs increase by 0.2 bn. EUR (0.9%) for households and by 0.6 bn. EUR (0.7%) for other consumers (*Scenario 3e*).

Figure 17 and **Figure 18** show the impact of the different policy scenarios on the electricity costs of “households” and “business and industrial consumers”. [41]

[40] According to our calculations, the additional state income could amount to ca. 4 bn. EUR.

[41] Higher prices for CO_2 prices also affect the surplus of power generators (defined as operating profit): Rents of producers with low carbon intensity increase (e.g. RES-E, nuclear) by ca. 110 bn. EUR (NPV 2018-2049, all modelled countries) as these producers profit from higher average power prices without having to pay additional costs for CO_2. Surplus of conventional fossil-fuelled generation in all modelled countries increases by 9 bn. EUR (NPV 2018-2049) while surplus of fossil fuelled generation in the PLEF region (affected by Carbon Price Floor) decreases by 5 bn. EUR (NPV 2018-2049). Therefore, there is a redistribution of rents from fossil fuelled power generation in the PLEF region to low-carbon power supply and to producers outside of the PLEF (not affected by higher costs).

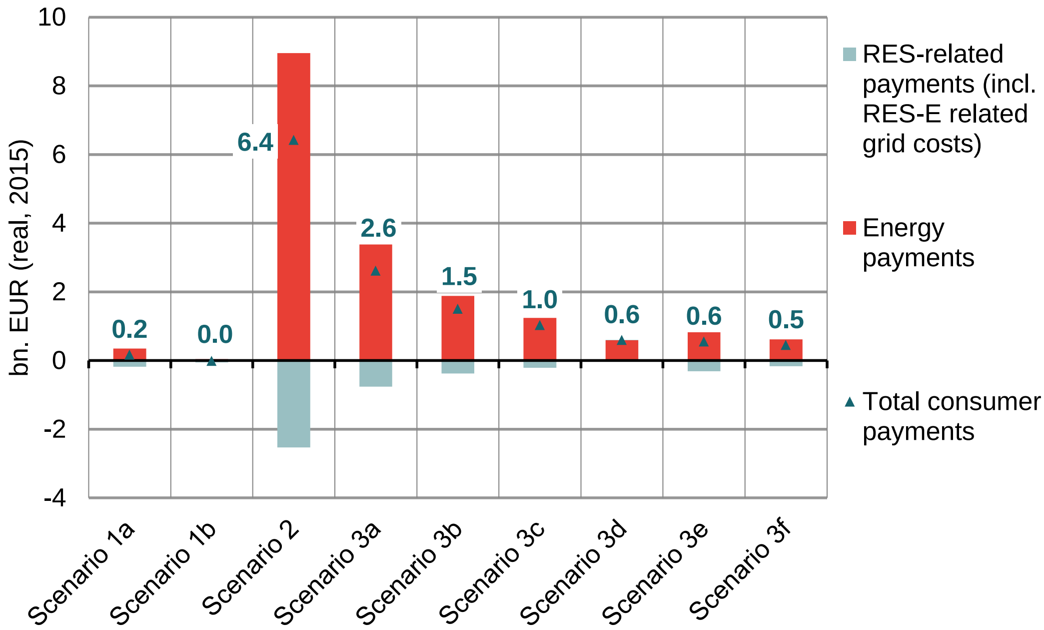
Figure 17. Impact on electricity payments of final consumers (households)



Source: *Frontier*

Note: *Difference to the Reference Case (NPV, 2018-2049)*

Figure 18. Impact on electricity payments of final consumers ("business and industrial consumers")



Source: *Frontier*

Note: *Difference to the Reference Case (NPV, 2018-2049)*

Table 11 and **Table 12** show the impact on yearly costs in the photo years in absolute cost figures and percentage increase compared to the Reference Case.

Table 11. Impact on yearly costs to consumers (households)

mn. EUR (%)	2018	2020	2025	2030	2035	2040
Scenario 1a	0 (0 %)	1 (0 %)	3 (0 %)	17 (1 %)	2 (0 %)	1 (0 %)
Scenario 1b	0 (0 %)	1 (0 %)	0 (0 %)	0 (0 %)	1 (0 %)	1 (0 %)
Scenario 2	230 (19 %)	188 (14 %)	127 (8 %)	41 (2 %)	20 (1 %)	0 (0 %)
Scenario 3a	-4 (0 %)	78 (6 %)	47 (3 %)	82 (5 %)	12 (1 %)	7 (0 %)
Scenario 3b	-4 (0 %)	0 (0 %)	47 (3 %)	82 (5 %)	12 (1 %)	7 (0 %)
Scenario 3c	-4 (0 %)	1 (0 %)	-1 (0 %)	82 (5 %)	12 (1 %)	7 (0 %)
Scenario 3d	0 (0 %)	2 (0 %)	13 (1 %)	19 (1 %)	2 (0 %)	7 (0 %)
Scenario 3e	-2 (0 %)	19 (1 %)	10 (1 %)	24 (1 %)	2 (0 %)	1 (0 %)
Scenario 3f	-1 (0 %)	18 (1 %)	8 (0 %)	16 (1 %)	0 (0 %)	0 (0 %)

Source: Frontier

Note: Difference to the Reference Case

Table 12. Impact on yearly costs to consumers (other consumers)

mn. EUR (%)	2018	2020	2025	2030	2035	2040
Scenario 1a	0 (0 %)	4 (0 %)	12 (0 %)	54 (1 %)	7 (0 %)	4 (0 %)
Scenario 1b	0 (0 %)	4 (0 %)	-1 (0 %)	-1 (0 %)	2 (0 %)	4 (0 %)
Scenario 2	871 (19 %)	707 (14 %)	472 (8 %)	168 (2 %)	77 (1 %)	0 (0 %)
Scenario 3a	-11 (0 %)	283 (6 %)	162 (3 %)	277 (4 %)	48 (1 %)	24 (0 %)
Scenario 3b	-11 (0 %)	0 (0 %)	162 (3 %)	277 (4 %)	48 (1 %)	24 (0 %)
Scenario 3c	-11 (0 %)	4 (0 %)	3 (0 %)	277 (4 %)	48 (1 %)	24 (0 %)
Scenario 3d	0 (0 %)	9 (0 %)	51 (1 %)	63 (1 %)	7 (0 %)	21 (0 %)
Scenario 3e	-6 (0 %)	70 (1 %)	39 (1 %)	76 (1 %)	7 (0 %)	4 (0 %)
Scenario 3f	-5 (0 %)	66 (1 %)	27 (0 %)	49 (1 %)	0 (0 %)	0 (0 %)

Source: Frontier

Note: Difference to the Reference Case

4.6 Security of Supply and import dependency

In the following, we analyse the impact of the policy measures on Security of Supply in The Netherlands by analysing reserve margins of power generation and the import dependency of The Netherlands.

It has to be noted that we do not expect major challenges to Security of Supply of The Netherlands in the Reference Case. There is sufficient power generation capacity available in the Netherlands (including mothballed power plants) as well as in surrounding countries. In the medium term, mothballed power plants can be re-activated if required. However, reactivation of mothballed power plants will depend on the view owners of these plants have on the future of the energy market. Further, the power system is getting more flexible due to increased demand side response. A more detailed analysis and assessment of Security of Supply in the electricity system in The Netherlands can be found in Frontier (2015).[42]

4.6.1 Methodology

We analyse the impact of the policy measure on Security of Supply using the indicators of power generation adequacy, and import dependency:

- **Reserve Margins (RM)** inform about the level of de-rated[43] generation capacity compared to peak load. It has to be noted that this indicator only provides a national perspective and does not directly take into account contributions from interconnected countries.[44]
- **Import dependency –** The import dependency from foreign countries is assessed by the development of net-imports from other countries to The Netherlands.

4.6.2 Results

The policy measures have the following impact on Dutch Reserve Margins and import dependency.

Impact on Reserve Margins in The Netherlands

The policy measures have the following impact on the Reserve Margins in The Netherlands:

- **Scenario 1: Only very moderate impact on Reserve Margin by additional abatement measure at the power plants** – Implementing additional abatement measures at the Dutch coal-fired power plants after 2025 does not affect the adequacy of domestic generation sources to a large extent. In Scenario 1a, the RM decreases by 0.6 GW in 2030 due to the earlier

[42] Frontier (2015): *Scenarios for the Dutch electricity supply system.*

[43] Used de-rating factors can be found in ANNEX A.

[44] An alternative approach to evaluating Security of Supply is represented by the "Loss-of-Load-Expectation" (LOLE), a stochastic indicator that is for example used in the "Generation Adequacy Assessment" of the TSOs in the PLEF: Pentalateral Energy Forum Support Group 2 (2015): *Generation Adequacy Assessment.*

decommissioning of one coal plant. In the case of Scenario 1b, in which additional abatement costs are not allocated to the plant operators, there is no negative impact on the RM.

- **Scenario 2: Carbon Price Floor increases Reserve Margins in The Netherlands** – As compared to the scenarios in which coal plants in The Netherlands are decommissioned, the Carbon Price Floor leads to an increase of operational capacity in The Netherlands in the short-term: gas-plants that are mothballed in the Reference Case stay operational in this scenario due to cost-advantages compared to carbon-intensive power plants in other countries of the Pentalateral Forum. The RM increases by 4.8 GW in 2018 and by 3 GW in 2020. In the long-run, with the phasing out of the Carbon Price Floor in 2040, the RM converges to the levels achieved in the Reference Case.

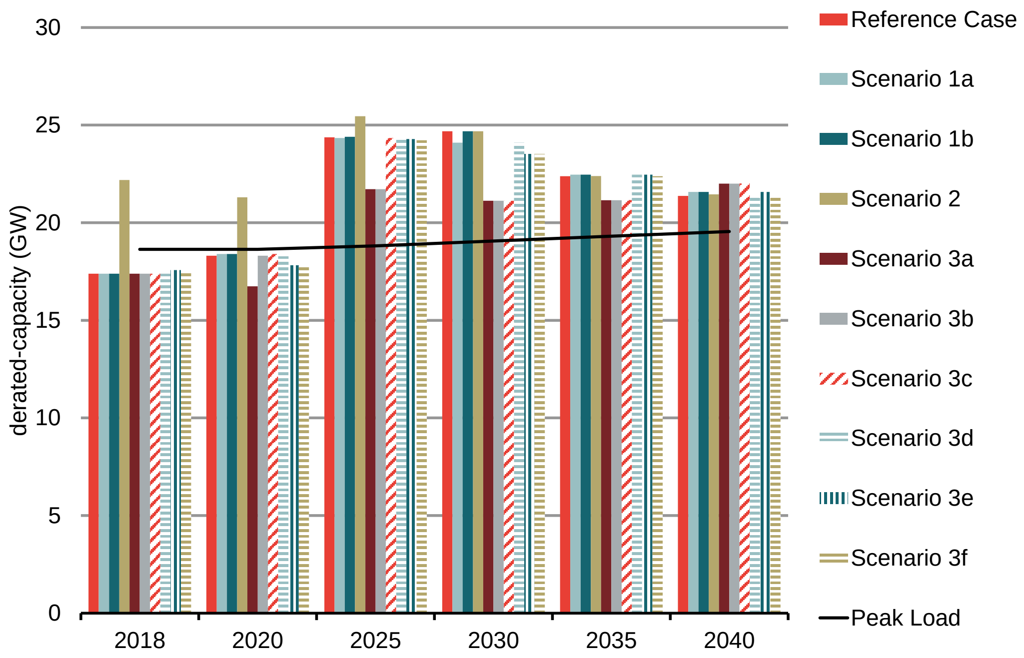
  Scenario 3: Earlier decommissioning of coal plants temporarily decreases the RM in The Netherlands – Closing the Dutch coal plant reduces the RM temporarily by 3.6 GW in 2030 (*Scenario 3 a/b/c*). However, since the RM is strongly positive in 2030, we expect no threats to Security of Supply. Early closure until 2020 (*Scenario 3a*) reduces the RM in the short-term (2020) by 1.2 GW. The RM inside the Netherlands is tightened in this period. However, since there is vast power generation capacity available in the European power market in the short and medium term, we don't expect a threat for Security of Supply in the Netherlands despite the tighter RM. Furthermore, reactivation of mothballed power plants occurs earlier than in the Reference Case. However, a short term closure of a high share of power plants *under short notice* should be avoided from a Security of Supply perspective in order to provide sufficient time for the market participants to react.

  Overall, the closure of all or only two (*Scenario 3e/f*) coal-fired power plants in The Netherlands is partially compensated by earlier reactivation of mothballed gas-fired plants or increase investment in the long-run. Taking into account the available import capacities, the RM remains positive in all sub-scenarios of Scenario 3.

Figure 19 compares the level of operational capacities (de-rated[45]) in The Netherlands in the policy scenarios and the Reference Case.

[45] De-rating factors are included in Annexe A.3.

Figure 19. Comparison of operational capacities (NL, de-rated*)



Source: Frontier

*Note: * de-rating factors in Annex A.3*

Impact on electricity imports and exports

In the Reference Case, The Netherlands will remain a net-importer of power in the short-term. In the medium- to long-term, however, this picture changes to a net-exporting position (see **ANNEX B**). The impact of the different policy scenarios on the import dependency is determined by the changing supply structure of the Dutch power system: if domestic power generation increases, dependency on imports decreases compared to the Reference Case and vice versa:

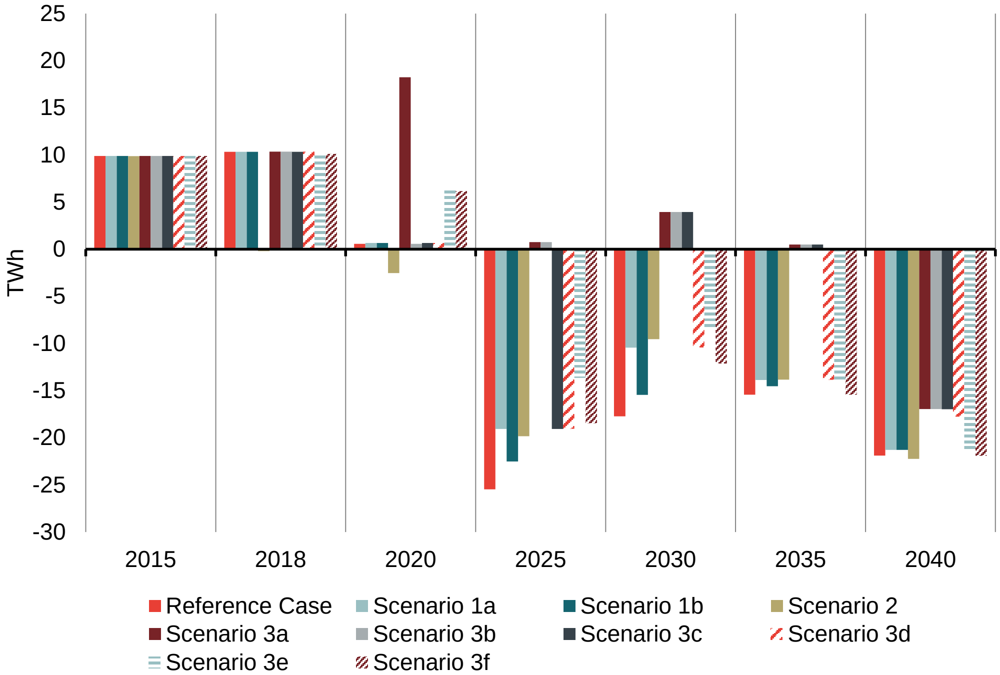
Scenario 1: Additional emission reduction at the Dutch coal plants has limited impact on import dependency – Implementing additional abatement measures at the Dutch coal plants only has a limited impact on the overall supply structure of the Dutch power system. If no compensation for additional costs is granted (*Scenario 1a*), utilisation of Dutch coal plants decreases slightly and one of the older units is decommissioned earlier than in the Reference Case. Net-imports increase by 7 TWh in 2030. On average, net-imports increase by 2.6 TWh/a. If the majority of costs are not borne by the operators (*Scenario 1b*), there is only a very small increase of net-imports by 2.2 TWh at most in 2025, on average by 1 TWh/a.

- **Scenario 2**: **Carbon Price Floor increases exports to neighbouring countries** –The implementation of a Carbon Price Floor in 2018 in the countries of the Pentalateral Forum increases Dutch power generation and exports to neighbouring countries in the short- and medium-term. Consequently, the dependency on imports decreases compared to the Reference Case.

- **Scenario 3: Early closure of coal plants increases import dependency in the short term –** The Reference Case is characterised by a medium-term net-exporting position of The Netherlands. This trend is postponed if the coal plants cease operation earlier than in the Reference Case and The Netherlands remain net-importer of power until 2040 (*Scenario 3 a/b*). On average, net-imports increase by 14 TWh/a (*Scenario 3a*). In the case of a later closure of the plants and if additional abatement measures are implemented at the Dutch plants, the average dependency on imports decreases.

Figure 20 shows the level of net-imports in the Reference Case and the different policy scenarios.

Figure 20. Net-imports (NL)



Source: Frontier

Note: Positive values represent net-imports to The Netherlands, negative values net-exports

Table 13 indicates the change of the net-position (net-imports/exports) in The Netherlands compared to the Reference Case.

Table 13. Net-imports (NL) – difference to the Reference Case

GW	2018	2020	2025	2030	2035	2040
Scenario 1a	0.0	0.1	6.4	7.3	1.6	0.6
Scenario 1b	0.0	0.1	3.0	2.3	0.9	0.6
Scenario 2	-10.5	-3.1	5.6	8.2	1.6	-0.3
Scenario 3a	0.0	17.7	26.2	21.7	15.9	4.9
Scenario 3b	0.0	0.0	26.2	21.7	15.9	5.0
Scenario 3c	0.0	0.1	6.4	21.7	15.9	4.9
Scenario 3d	0.0	0.1	6.4	7.3	1.6	4.1
Scenario 3e	-0.3	5.8	11.8	9.4	1.6	0.6
Scenario 3f	-0.2	5.6	7.0	5.6	0.0	0.0

Source: Frontier
Note: Positive values indicate higher imports / lower exports and vice versa.

4.7 Impact on the development of RES-E

The different policy measures can have an impact on the development of renewable energy sources in The Netherlands either directly through a changing framework for biomass co-firing (e.g. further subsidies for co-firing) or indirectly through a changing market environment (e.g. higher wholesale power prices leading to earlier market driven investment in RES-E).

Impact on the share of renewable energy sources in The Netherlands

The share of RES-E (expressed in % of net electricity demand) informs about the share of net-demand that is served by renewable energy sources:

- **Scenario 1: Additional abatement measures increase RES-E** – The additional emission reduction achieved in *Scenario 1* is largely based on increased co-firing of biomass in the coal plants. This measure also increases the absolute amount of RES-E in the system.[46] The share of RES-E increases by up to 7-11%-points in 2030 (+ 8-12 TWh). In the long-run, the amount of additional co-firing decreases due to market based co-firing already taking place in the Reference Case (+ 2%-points; + 3 TWh in 2040).
- **Scenario 2**: **No major impact on RES-E in The Netherlands –** There is only a small impact of the Carbon Price Floor on the development of RES-E in The Netherlands. Although profitability increases, the amount of additional investment in RES-E is limited (+ 0.5 TWh in 2035).[47]

[46] The 25 PJ/a limit on co-firing of biomass of the Reference Case does not apply to Scenario 1 and Scenario 3 (c,d,e).

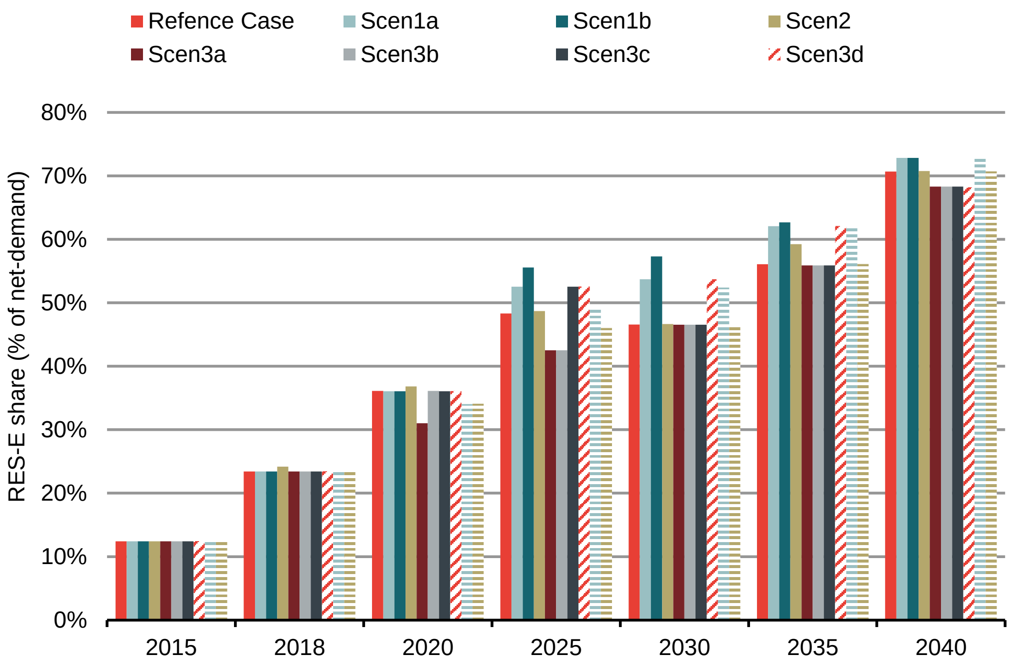
[47] Absolute investment potentials are limited and potentials already utilised in the Reference Case.

- **Scenario 3: Closure of coal plants reduces RES-E % due to less co-firing** – The closure of all coal plants in *Scenario 3a* and *3b* results in a decrease of the renewable energy sources of net-demand by up to 6%-points, as no co-firing of biomass takes place in the closed plants in these scenarios. For *Scenarios 3a* (plant closures in 2020) and *3b* (plant closures in 2025) this holds also for the already decided subsidised co-firing of biomass in the coal power plants of up to 25 PJ per year until 2028. Furthermore, if the two oldest coal-fired plants are closed until 2020 (without implementing additional measures at the remaining plants), the RES-E share decreases in the short-term by 2%, also due to lower co-firing of biomass.

  It has to be noted that closure of coal plants could free up funds from the subsidy budget. These funds could be used to subsidise RES-E somewhere else in the system. We don't take this possible indirect effect on RES-E policy into account since we assess decisions to be speculative. In our analysis, an increase of other RES-E following lower co-firing is therefore not included.

  The implementation of additional abatement measures at the plants in the *Scenarios 3c-e* leads to a medium-term increase of RES-E (prior to plant closure) due to higher co-firing of biomass as an element of the additional measures.

Figure 21. Renewable energy share of net-demand



Source: Frontier

Table 14 shows the absolute levels of electricity supply from wind, solar PV and biomass in the Reference Case as well as in the different policy scenarios.

Table 14. Development of net-electricity supply from RES-E

TWh	2018	2020	2025	2030	2035
Reference Case	26.6	41.1	55.4	53.9	65.9
Scenario 1a	26.6	41.0	60.2	62.3	73.0
Scenario 1b	26.6	41.0	63.7	66.5	73.7
Scenario 2	27.5	41.9	55.8	54.0	69.6
Scenario 3a	26.6	35.2	48.7	53.9	65.6
Scenario 3b	26.6	41.1	48.7	53.9	65.6
Scenario 3c	26.6	41.0	60.2	53.9	65.6
Scenario 3d	26.6	41.0	60.2	62.3	73.0
Scenario 3e	26.6	38.7	56.4	60.8	73.0
Scenario 3f	26.6	38.7	52.7	53.9	65.9

Source: Frontier

4.8 Other indicators

In this section, we describe the impact of the different policy measures on other indicators:

- Impact on other emissions (**Section 4.8.1**);
- Impact on heat networks (**Section 4.8.2**);
- Impact on innovation (**Section 4.8.3**);
- Effects on employment (**Section 4.8.4**).

4.8.1 Impact on other emissions

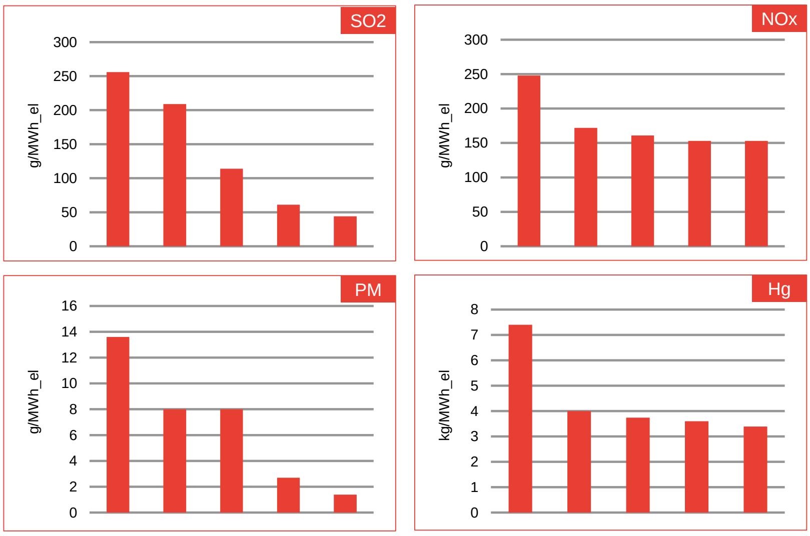
In the following, we assess the impact of the different policy measures on the emission of

- Sulphur-dioxide (SO2);
- Nitrogen Oxides (NOx);
- Particulate Matter (PM); as well as
- Mercury (Hg).

The assessment is based on plant specific emission factors provided by the plant operators. The decrease of emissions from coal-fired power generation at the five power plants is netted against an increase of emissions from other domestic generation (gas-fired power plants):

- **Other emissions from coal-fired power plants in The Netherlands** – The emissions of the above mentioned pollutants is determined by the specifics of the individual plants. **Figure 22** shows that there are significant differences between the five coal plants under consideration. For example, new plants emit significantly less SO_2 than older ones due to additional desulphurization of exhausts.

Figure 22. Emission factors of coal plants in the Netherlands



Source: *Frontier based on company information*
Emission factors are ranked from the largest to the smallest value.

- **Domestic substitution of emission from coal plants** – If power generation from the coal plants decreases due to either less utilisation or due to complete decommissioning, the omitted power supply has to be substituted by alternative production. The substitution takes partly place within The Netherlands and pre-dominantly by gas-plants. Therefore, the amount of additional emissions from gas-plants in The Netherlands needs to be taken into account. Other emissions from gas-plants partially depend on the technical capabilities of the specific plants. In our calculations, we assume a uniform emission factor for gas plants: [48]
  - 0 g SO_2/MWh_{el};
  - 155 g NOx/MWh_{el};
  - 0.7 g PM/MWh_{el}; and
  - 0.5 kg Hg/MWh_{el}.
- **Substitution of emission in other countries** – A share of reduced power generation from coal-fired power plants is served by higher imports / lower exports. Consequently, power generation and emissions in other countries increases. The specific emissions per unit of electricity produced depend on a multitude of factors including for example, country specific legal limitations for emissions and the age of the power plants affected. The exact specification of

[48] Partly based on Ministerie van Economische Zaken (20.04.2016): Beantwoording over het onderzoek 'Sluiting kolencentrales' van SEO in opdracht van Natuur & Milieu.

these emissions goes beyond the scope of this study and therefore we limit ourselves to general qualitative statements about this effect.

- **Other emissions from biomass co-firing –** Further, the emission of the coal plants depends on the assumed emission intensity of biomass co-firing. The emissions are, among other things, substantially determined by the type of biomass used for co-firing. Biomass, for example can lower the NOx or SO_2 emission of a co-firing plant.[49] Depending on the type of biomass used for co-firing up to 90% of particulate matter emission can be reduced. Co-firing of wood-chips (the pre-dominant form of co-firing in coal plants), however, is said to have a small impact on PM emissions, but reduces the emission of metals like mercury (Hg).[50]

  For the following calculations, we use indicative / exemplary values from secondary sources: Specific SO_2, NOx and PM emissions of biomass are based on CE Delft (2015).[51] Assumptions on mercury emissions of biomass are taken from Coa et al. (2008).[52]

Table 15 summarises the emission factors assumed in this analysis.

Table 15. Calculation of other emissions

	SO_2	NOx	PM	Hg
Coal (range) (g/MWh_{el})	44 – 256	153 - 248	1 – 14	0.004 – 0.007
Biomass co-firing (range) (g/MWh_{el})	7 - 39	34-55	0.6 - 6	0.0005-0.0011
Gas plants g/MWh_{el}	0	155	0.7	0.0005

Source: Frontier

Impact on other emissions

Figure 23 shows the development of other emissions in the different scenarios for the different gases.

- **Scenario 1: Additional abatement measures at the plants –** Scenario 1 is characterised by a significant increase in the share of biomass co-firing. The implementation of the additional abatement measures at the plants therefore influences the overall emission levels to the extent to which biomass co-firing lowers the emissions of the plants. In addition, if costs of abatement measures are borne by the companies, emissions decrease due to lower utilisation (partially offset by higher emission from gas-plants):

49 Henderson (2015): Cofiring of biomass in coal-fired power plants – European perspective; IEA Clean Coal Centre (2010): Profiles – Emission from co-firing coal, biomass and sewage sludge (PF 10-16)

50 Al-Naiema et al. (2015): Impacts of co-firing biomass on emissions of particulate matter to the atmosphere, Fuel, Vol. 162, p. 111-120.

51 CE Delft (2015): Kentallen voor grijze en 'niet-geoormerkte stroom' inclusief upstream-emissies, Delft, January 2015).

52 Cao et al. (2008): Mercury Emissions during Cofiring of Sub-bituminous Coal and Biomass; Environmental Science & Technology (2008), Vol. 42 (24), p. 9378-9384.

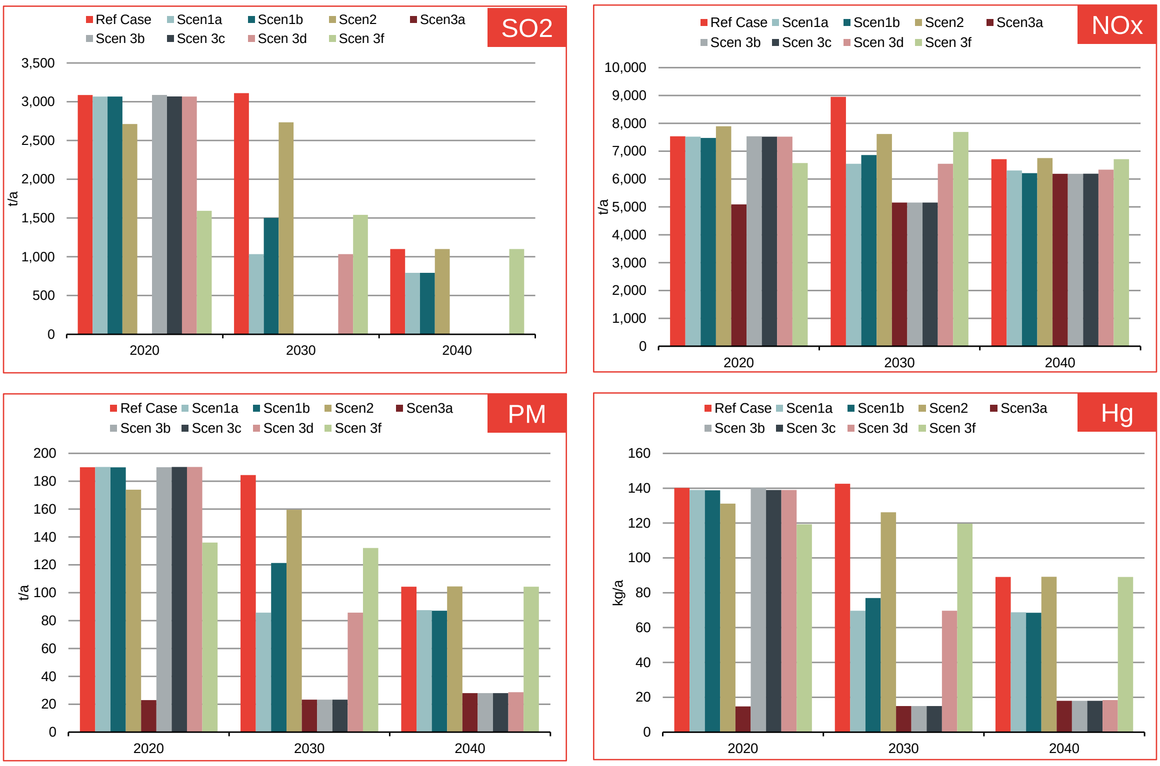
- High reduction of SO_2, PM and Hg due to biomass co-firing and no or limited additional emissions from gas plants;
- NOx emissions affected to limited extent due to compensating increase of gas-fired generation and emissions from these plants;

Due to the fact that scenarios 1a and 1b lead to limited additional generation in other modelled countries, it can be assumed that the increase of other emissions in these countries is also limited.

- **Scenario 2: Carbon price floor** - The carbon price floor increases gas-fired generation in The Netherlands in the short- to medium-term while utilisation of coal-plants decreases slightly. Consequently, emissions of all other pollutants decrease in the short- to medium-term. Due to the fact that the Carbon Floor Price leads to a significant reduction of CO_2 intensive power generation in other countries of the Pentalateral Forum, it can be assumed that other emissions in these countries (especially Germany) will decrease as well.
- **Scenario 3: Closure of coal plants** – Phasing out coal-fired generation reduces emission of SO_2, PM and Hg emission while NOx emissions are less affected, due to the relatively low emission factor of new coal plants compared to substituting gas plants. If additional abatement measures are implemented at the plants, the impact is determined by the assumed lowering impact of biomass co-firing.

  Due to the fact that early closure of coal plants in The Netherlands leads to increases in power generation in other modelled countries, it can be assumed that consequently emissions of the pollutants that are the subject of this analysis increase in those countries, too.

Figure 23. Impact on other emissions



Source: Frontier

Taking into account the above mentioned limitation in the context of this study, the resulting other emissions should be understood as an indicative estimation of the impact. Further research should be pursued to assess the impact of these factors further, in a national as well an international context.

4.8.2 Impact on heat networks

Some of the coal power plants currently provide heat to regional heat networks. Furthermore, additional heat supply can constitute a policy measure to reduce specific emissions of a power plant.

In all scenarios in which power plants close before the end of their lifetime, heat supplied from those power plants to regional heat networks will have to be replaced by other sources. This could be achieved by

- connecting the heat network to other heat networks with sufficient capacity to replace the heat from coal/biomass fired power plants;
- investing in new facilities to provide heat to heat networks. These are likely to be modern gas boilers;
- discontinue the provision of heat to industry and households by replacing it with local heat production.

All options will lead to additional costs as investments have to be made into expansion of heat network and new facilities to provide heat. We estimate that coal-fired power plants which might be closed before the end of their lifetime provide around ca. 2 TWh/a to heat networks. As an indicator for the cost of replacing these heat supplies, we have estimated the specific production costs of a gas boiler. Depending on the development of the gas price we estimate that the heat supply from gas boilers would cost between million 48.8 € and million 89.5 € per year.[53] These costs are not included in the system costs of the electricity supply discussed in chapter 4.3.

It has to be noted that some plant operators that are currently producing heat are planning to implement high shares of biomass-fired heat supply in the future. This (almost) carbon-neutral heat supply would no longer be at disposal if coal plants are closing before their assumed end-of lifetime. A replacement of biomass-fired heat supply by gas-boilers therefore might be not seen as an adequate replacement and more costly options might have to be considered, e.g. connecting heat networks to other existing low-carbon heat sources.

In some scenarios the power plant operators plan to increase the provision of heat to industry and households in order to reduce the specific emissions. In such a case, additional investments might have to be undertaken in order to fully utilise the additional heat provided by the power plant. This could include for example the cost of expanding the heat network. On the other hand, an increased heat supply from coal-fired power plants saves new investments into alternative heating technologies.

4.8.3 Impact on innovation

The policy measures can have a positive impact on innovation if the development of specific measures or technologies is fostered. At the same time, a negative impact can result from hindering the development of certain technologies:

- **Implementation of additional abatement measures can increase innovation –** The implementation of additional abatement measures can lead to higher innovation with regard to the development of CCS and biomass supply chains. The demonstration plant “ROAD” remains online longer than assumed in the Reference Case. Due to this increased utilisation, learning effects and cost savings might be realised with respect to the operation and the development of CCS installation at coal plants. In addition, the innovation potential related to the transportation and storage of carbon dioxide can be transferred to the implementation of CCS at gas plants. Furthermore, additional co-firing of sustainable biomass could lead to the development of biomass supply chains that comply with Dutch sustainability criteria for biomass (e.g. international implementation of Dutch sustainability criteria for biomass).
- **Closure of coal plants could lower innovation activities –** If the newest coal plants are closed earlier than expected, currently planned testing of CCS might not be realised.
- **Impact on innovation with respect to RES-E –** Some scenarios result in higher investment in wind-offshore and solar PV. In these scenarios, additional operation of RES-E could lead to higher learning effects for these

[53] This is based on specific investment costs between 70 and 130 €/kW, fixed operating and maintenance costs of 2%-5% of the investment cost, a lifetime between 35 and 40 years, an interest rate of 5% and full load hours between 2100 and 3200 hours. The efficiency of the gas boiler is assumed to be 95%. Costs for CO_2 and other emissions have not been included.

technologies. These effects, however, are deemed to be rather small due to the already achieved cost reductions and the relatively small impact of all scenarios on investments in RES-E.

4.8.4 Effects on the employment

The closure of the five coal plants under investigation can have direct and indirect effects on employment:

- **Direct employment effects**: Up to 1000 people[54] are directly employed at the five coal-fired plants. After closure of these plants, these employees would have to be transferred into other workplaces.
- **Multiplier effects**: The closure of the plants can have indirect effects on employment especially through multiplier effects:
  - The closure of the plants can have negative effects on suppliers of the coal plants.
  - Furthermore, spending power of employees in the affected regions is reduced after closure of the plants. This can have negative impacts on local commercial and service enterprises.
- **Compensating effects**: On the other hand, the substitution of coal-fired power generation with power supply from other sources can offset at least to some extent the impacts on employment at the coal plants. For example, employment can increase with reactivation of gas-fired power stations and the extension of RES-E. However, since power generation from RES-E and gas-fired power plants is in general less labour intense than power generation in coal plants, and some parts of the power generation is substituted by higher electricity imports/lower exports, these compensating effects cannot be expected to totally balance out the loss of employment at the coal plants (at least in the short term).

The quantification of the indirect effects is not subject of this study.

[54] Based on full-time-equivalents (FTE)

ANNEX A REFERENCE CASE ASSUMPTIONS

In this annexe, we provide detailed information on the assumptions of the Reference Case. As described in **section 2.2**, the Reference Case is based on the current and intended policy framework in The Netherlands and in North-Western Europe. It represents a scenario which is built upon a combination of current market expectations, e.g. regarding fuel prices and CO_2 prices, and political targets for example for the development of RES-E. However, we only take those policy decisions into account which are defined in an operational manner and are officially decided.

A.1 Fuel and CO_2 price assumptions

The fuel and CO_2 prices affect the variable costs of generation and therefore the power prices and profitability of generation units.

A.1.1 Fuel prices (coal and gas)

The coal and gas prices used in the context of this study are largely based on the assumptions underlying the report "*Frontier Economics (2015): Scenarios for the Dutch electricity supply system*". The decrease of oil and other fuel prices of the past two years is reflected in our assumptions. Based on current prices for power futures traded on power exchanges and the long-term outlook of the World Energy Outlook 2015, we assume that fuel prices will remain low in the short-term and increase gradually after 2018:

- **Short-term** (until 2018) development according to current market expectations – The short-term development is derived from future prices of the trading day 28 April 2016[55].
- **Medium- and long-term** (2019-2050) based on *Frontier Economics (2015)* and World Energy Outlook (2015, New Policies scenario).
  - The price development from 2019 until 2023 is modelled as linear interpolation between the last future price (2018) and the first year of price notation based on the WEO. Prices after 2023 are based on the oil price projection from the WEO 2015 (New Policies) [56].
  - In the long-run (after 2040) prices are based on the methodology described in *Frontier 2015* .

[55] Yearly futures; Coal: CIF ARA; Gas: TTF/NCG.

[56] The long-term (after 2023) development of coal and gas prices is derived from oil prices based on expected heat equivalence ratios (oil-to-gas and oil-to-coal). Heat equivalence ratios are defined as the price of fossil fuels in relation to the heat content, expressed as EUR/MWh_{th}. We assume a decreasing ratio for gas to oil in the long-run (gas becomes relatively cheaper in the long run) because of the on-going decoupling of oil and gas prices and higher availability of gas resources compared to oil resources (e.g. shale gas and LNG). For the coal/oil and coal/gas relationships, we assume as well a decreasing trend because of the higher availability of coal resources compared to gas or oil resources and a flatter marginal cost curve for coal production than for the other primary energies.

Figure 24. Fuel price development (Reference Case)

Source: Frontier

Note: prices are noted in real values (2015) and low calorific value

A.1.2 Price for CO_2 allowances

The European Emission Trading Scheme (EU ETS) has been characterised by an "oversupply" of CO2 emission certificates in past years. This oversupply can be attributed to a drop of demand due to the financial and economic crisis but also due to certificates from flexibility mechanisms (JI/CDM) and higher shares of RES-E in Europe that substitute conventional power generation and in return decrease the demand for emission certificates.[57] As the total supply of certificates in a "cap & trade" system like the EU ETS is fixed by the emission cap, the price has decreased substantially.

Several measures have been proposed or have been introduced that aim at increasing the CO_2 price and therefore the incentives for CO2 reduction in the EU ETS:

- As a temporary measure, a 900 mn. certificates have been taken out of the market (so-called "Backloading") and will be (partially) fed back into the system at the end of this trading period (2020).
- The "Market Stability Reserve" represents a possible medium term option (from 2019) to stabilise pricing signals. This option has been backed by the Environment Committee of the European Parliament end of February 2015.

[57] European Commission (2012).

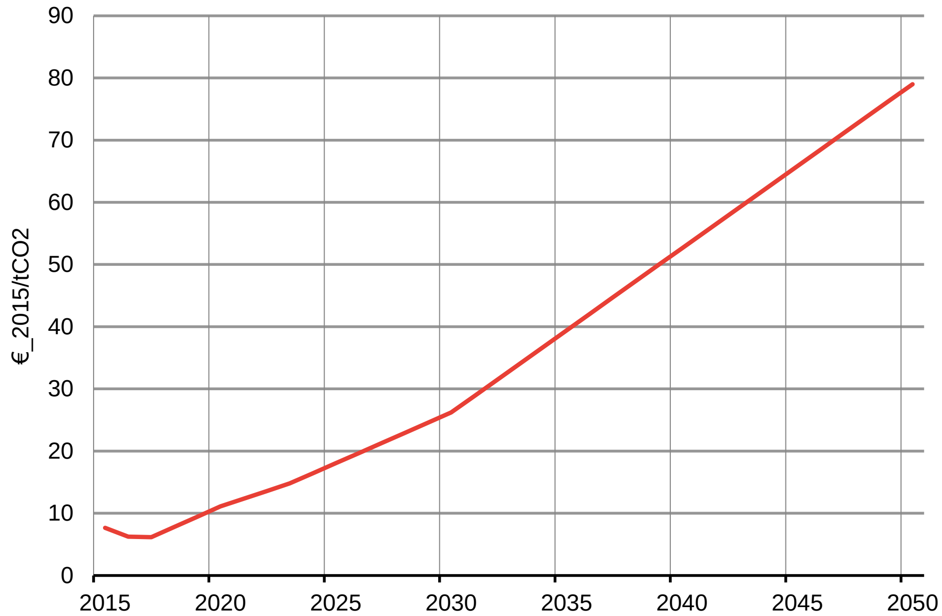
- For the trading period IV (2021-2030, the current proposal foresees and increase of the Linear Reduction Factor from 1.74%/a to 2.2 %/a[58] as well as an amendment of rules regarding free allocation and carbon leakage.

In total, we expect in the Reference Case that the EU ETS will maintain its role as the central instrument for climate change on the European level. Therefore, we expect the price to rise in the medium- to long-run after market reforms have been implemented.

We derive our CO_2 price assumptions according to the following logic:

- **Short-term** (until 2017) development according to current market expectations – We use CO_2 price futures (trading day 28 April 2016) to derive our short-term price projection.
- **Medium-term** (2018-2035) price development based on the “Nationale Energieverkenning” (National Energy Outlook) – We use the CO_2 price assumptions derived in the National Energy Outlook in 2016.[59]
- **Long-term price development** (after 2035) is calculated as a linear extrapolation of the price projection of the NEO 2016 for the years 2030 and 2035.

Figure 25. Assumed CO_2 price development



Source: Frontier based on ECN/PBL (2016)

Note: Prices are noted in real values (2015)

A.2 Power demand

Our assumption for the development of power demand is based on the demand projection used in the National Energy Outlook (Nationale Energieverkenning,

[58] Based on the emissions of 1990.

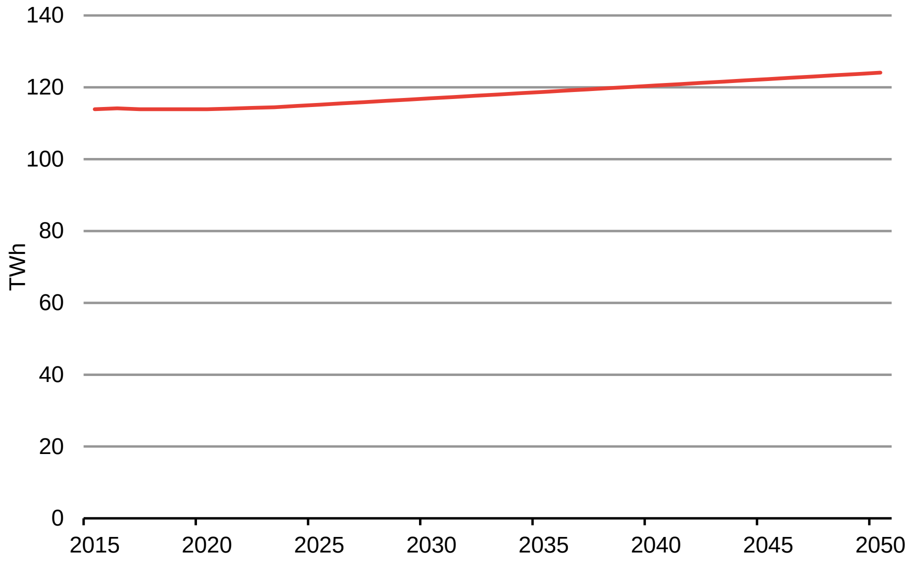
[59] ECN/PBL (2016, forthcoming), scenario “Voorgenomen beleid”.

NEV) published by ECN and PBL in 2015.[60] The NEV assumes a moderate growth of power consumption in the next years. Including network losses, net electricity consumption is assumed to increase from 114 TWh in 2015 to 121 TWh in 2040. This growth reflects the moderate average demand increase in the most recent years and takes two countervailing trends for the future into account:

- Increased demand due to growth of GDP; and
- Increased energy efficiency which leads to a decoupling of the formerly strong relationship between power demand and the GDP.

We base our assumptions on the assumed demand growth of the NEV until 2030 and use linear extrapolation for the years after 2030 (**Figure 26**).

Figure 26. Development of net-power demand



Source: Frontier based on ECN/PBL(2015)
Note: Net-demand including transmission losses, excluding own-consumption of generation

Power demand in other modelled European countries is derived from national forecasts, e.g. Transmission System Operators (TSO) forecasts (France: RTE, German net-work development plant). Net-demand in all modelled regions[61] is assumed to increase by 8.3% from 2,281 TWh in 2015 to 2,470 TWh in 2040.

[60] Net electricity consumption; "implemented and planned policies" (excluding own-production including grid losses)

[61] Modelled regions include: The Netherlands, Germany, Belgium, France, Denmark, Poland, Czech Republic, Austria, Switzerland, Italy and Great Britain.

Table 16. Net power demand (model-region)

TWh	2015	2018	2020	2025	2030	2035	2040
DE*	539	538	537	535	535	535	535
NL*	114	114	114	115	117	119	121
BE*	87	90	91	94	97	101	104
FR*	490	490	490	495	500	505	510
AT*	71	72	73	75	77	80	82
CH	65	66	67	68	69	70	69
CZ	66	68	70	73	75	78	81
PL	148	151	154	159	164	169	175
DK	35	35	35	36	36	36	37
GB	338	335	334	336	343	355	363
IT	328	333	337	350	364	379	394

Source: Frontier

Note: "Core-region" with endogenous optimisation of power plant park marked with (*)

A.3 Generation capacities

A.3.1 Conventional thermal generation capacities in The Netherlands

The Dutch power plant park is characterised by a large share of conventional generation capacities. Based on economic reasoning, the power market model optimises the existing power plant park through

- Retirement of power plants (before end of lifetime if economic);
- Mothballing of power plants;
- Reactivation of mothballed capacity; and
- Investment in new generation capacity.

In our modelling, mothballing and reactivation of power plants are associated with costs. Investment costs for conventional power plants are indicated in **Table 17**. Mothballing of power plants reduces the yearly fixed operation and maintenance costs of the power plant by 75%. The reactivation of a power plant is followed by a one-time payment of 25% of the yearly fixed operation and maintenance costs.[62]

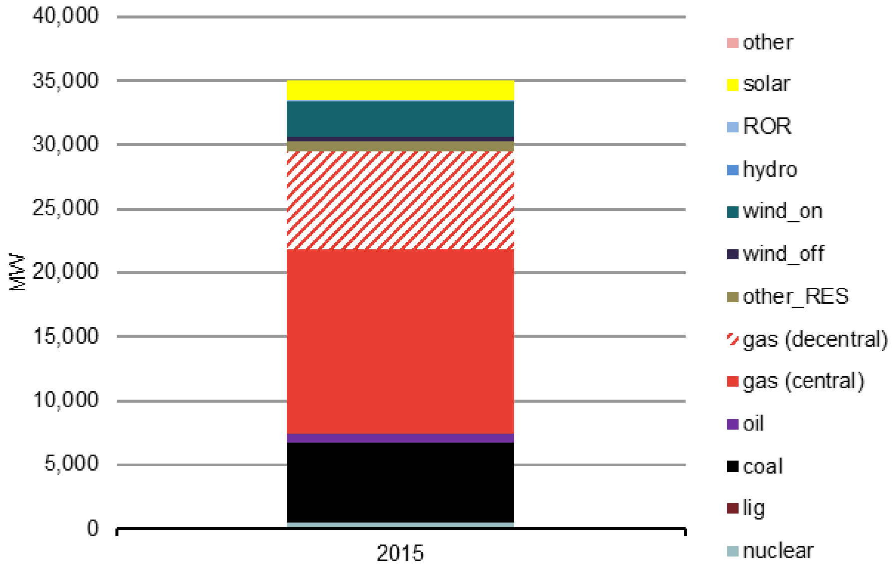
[62] The costs of reactivation depend in practice on a multitude of factors including plant specifics, company specific circumstances and the time period after which the plant is reactivated. However, alternative assumptions of costs for reactivation have a very limited on the results of this study since the reactivation costs are insignificant compared to the costs of the electricity system in total.

Development of thermal generation capacity

The assumptions regarding the existing power plant park are derived from Platts PowerVision database, a commercial database with information on retirements and additions of power plants and other publically available information e.g. on mothballing of specific units. Further adjustments of thermal capacity were derived from the Energy Agreement (regarding closure of coal-fired power plants) and the Monitoring Report published by the Dutch TSO, TenneT.[63]

In 2015, installed generation capacity amounts to ca. 35 GW, of which 29 GW are fossil fuel fired power plants (**Figure 27**).

Figure 27. Installed generation capacity (NL, 2015)



Source: Frontier

Note: Graph includes 4.3 GW of mothballed gas-fired power plants.

Our modelling takes into account known market entries (investment) until 2020 as well as known mothballing decisions and retirements based on the end of the technical lifetime of power plants as exogenous assumptions.[64] In the short-term, this includes

- Known retirement of 2.6 GW coal-fired power generation until June 2017 based on the Energy Agreement;
- Market entry of the coal-fired MPP3 power plant in 2016;and
- Known mothballing of 4.3 GW of gas-fired capacity;

In addition to those additions and retirements, the model simulates additional investment, earlier retirement of plants or on additional mothballing and reactivation of generation capacities.

[63] TenneT (2015).

[64] Our model does not include retrofitting to achieve a lifetime extension but allows for replacement investments.

Possible investment options in The Netherlands

The outlook of the future electricity system in The Netherlands is influenced by the technological development and the availability of new generation technologies, as for example carbon-capture and storage (CCS) for coal and gas plants as well as new storage solutions.[65] We include the following options in our modelling for investments in The Netherlands (**Table 17**):

- Hard coal - with and without CCS (as "integrated gasification combined cycle" (IGCC) technology);
- Natural gas – "combined cycle gas turbines" (CCGT) and "open cycle gas turbines" (OCGT);
- Nuclear power;
- Power storages - "compressed air energy storage" (CAES), "advanced adiabatic compressed air energy storage" (AACAES), and power-to-gas (and back to power).

Table 17 provides the assumed investment costs per MW. Beside investment costs, thermal efficiency, storage volume (if relevant) and other variable costs determine which technologies are built in the power market model.

Table 17. Investment options (conventional thermal and storage)

Technology / Fuel	Available in	Overnight investment cost (EUR/kW)	Fixed operation and maintenance (EUR/kW)
Hard coal	2018	1,750	26.25
Natural Gas (OCGT)	2018	450	6.75
Natural Gas (CCGT)	2018	750	11.25
Hard coal (IGCC) with CCS	2025	2,750	54.95
Natural Gas (CCGT) with CCS	2025	1,400	21
CAES	2025	806	16.12
AACAES	2030	1,300	26
Power-to-Gas (to-Power)	2030	1,650	45
Nuclear[66]	2035	4,600	69

Source: Frontier

65 Investment costs are derived from multiple source and previous project experience.

66 Nuclear investment as a potential replacement of the existing nuclear power station is included as an option. However, building a new nuclear power station may be controversial in the political debate. Since the replacement would take place only in the long term and the total capacity of the unit would be relatively moderate compared to the size of the electricity system the impact of this assumption on the model results is very limited.

Combined-heat and power generation

A large share of electricity supply in The Netherlands is produced in combined-heat and power (CHP) facilities, i.e. power plants with the primary use of heat generation either for

- industrial processes;
- district heating; or
- agriculture and horticulture.

In 2014, around 12 GW electrical capacities are characterised as conventional CHP capacities:

- 5 GW central generation capacities (gas and coal) mainly for district heating and industrial heat generation; and
- 6.8 GW of decentralised generation capacities mainly for agriculture and horticulture (green-houses) and industrial heat generation.

Electricity generation from conventional CHP amounted to ca. 43 TWh in 2014[67].

In our modelling of the electricity system, heat driven power generation from CHP is treated as exogenous generation, power market driven generation as dispatched generation:

- Power generation as a bi-product of heat-decoupling is treated as “must-run” generation that is fed into the system irrespective of power market developments.
- In addition to the electricity generation arising from heat production, certain CHP plants have flexibility and are dispatched like a “power-only” plant.

For the future development of conventional CHP generation, we apply the following assumptions:

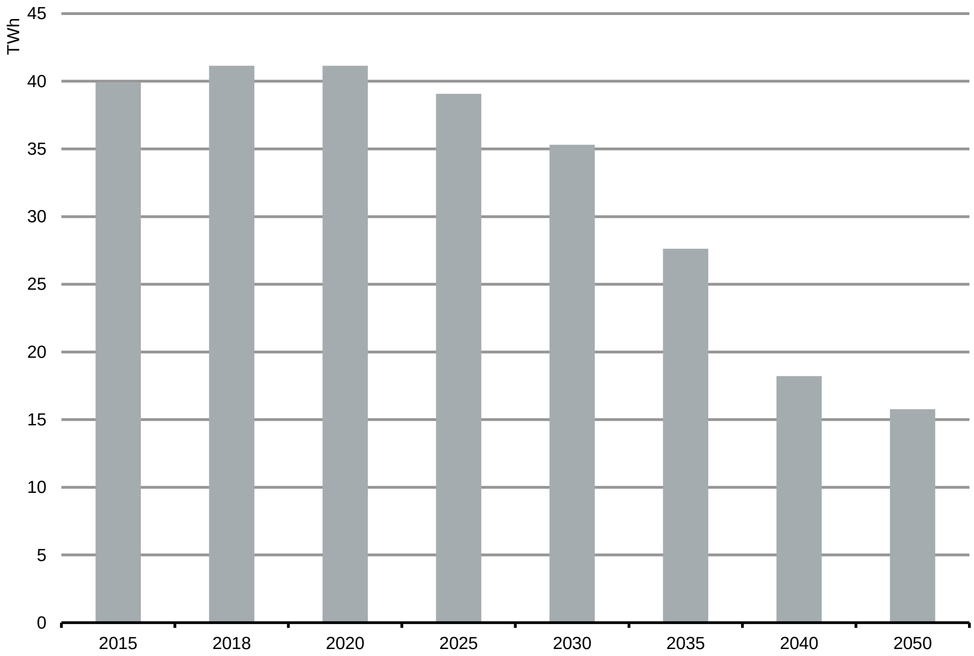
- **Long-term decrease of de-central generation:** Electricity supply from de-central CHP capacities, as for example greenhouses, is regarded as bi-product of heat-generation. We assume that the underlying economics of de-central CHP capacities will not change in the short-term. Therefore, generation from these capacities will remain constant until 2025. After that, replacement investment would become necessary. Due to a more difficult economic framework and increased penetration from alternative heat sources (e.g. geothermal), we assume that generation from de-central CHP units decreases in the long-run (2040) by more than 50% compared to 2015.
- **Decreasing central generation:** Central CHP capacities are influenced by power market economics to a greater extent. We assume that central conventional CHP installations can remain online until the end of their technical lifetime, but may be mothballed or retired beforehand. It has to be noted that we don’t model the new built of central conventional CHP installations endogenously since the specific circumstances of heat

[67] Based on CBS statline.

demand etca. (which are not part of the model) drive the economics of each single unit and therefore the decisions to renew or refrain from renewal of old units. The assumption of absent replacement investments is consistent with results of studies that have assessed the economic situation of conventional CHP plants.[68] Instead, we include the option of new-built gas-plants (OCGT and CCGT).

In total, must-run power generation from conventional CHP will decrease in the long-run from ca. 40 TWh in 2015 to ca. 15 TWh in 2050. This decrease is also in line with the political goals a decarbonisation of the power sector. At the same time, we expect CHP generation from renewable (biomass) plants to increase in the long-run as additional financial support is granted under the SDE (+) support scheme.[69]

Figure 28. Assumed development of central and de-central CHP "must-run" generation



Source: Frontier

De-rating factors for reserve margin calculation

We have used the following de-rating factors to calculate reserve margins as well the supply for the modelled capacity mechanisms in foreign countries (e.g. France).

[68] E.g. CE Delft / DNV GL (2014).

[69] ECN/PBL (2014), p. 100.

Table 18. De-rating factors

Power plant type	Capacity credit for CRM
Nuclear	93.1%
Lignite	89.6%
Hard Coal (with/without CCS)	89.6%
Gas (CCGT)	88.8%
Gas (OCGT)	82.1%
Oil	87.3%
Wind-offshore	11%
Wind-onshore	8%
Solar PV	2%
Biomass	65%
Run-of-river	48%
Pumped-Hydro-Storage	90%
Reservoir-Storage	85%
Power-to-Gas	85%
AACAES	85%
CAES	85%
DSR (load reduction)	90%

Source: Frontier

A.3.2 Renewable Energies

RES-E in The Netherlands

The current political targets expressed in the Energy Agreement foresee a significant growth of renewable energy supply in electricity supply. As the development of renewable energy sources in the electricity sector is very much driven by political initiatives and support schemes, we assume an exogenous growth path of RES-E capacities and generation based on:

- Current political targets for RES-E capacity; or
- Secondary sources on future RES-E development in The Netherlands.[70]

[70] ENTSO-E Scenario Outlook and Adequacy Forecast (SO&AF) RES-E capacities in other modelled countries are derived accordingly based on legal targets and / or secondary sources.

In the Base Case, we assume a significant increase of renewable electricity supply from around 14 TWh in 2015 to more than 60 TWh in 2035. This corresponds to an increase of the share of renewable electricity of net demand from 12% in 2015 to approx. 50% in 2035. The development of renewable electricity supply is based on the following assumptions:

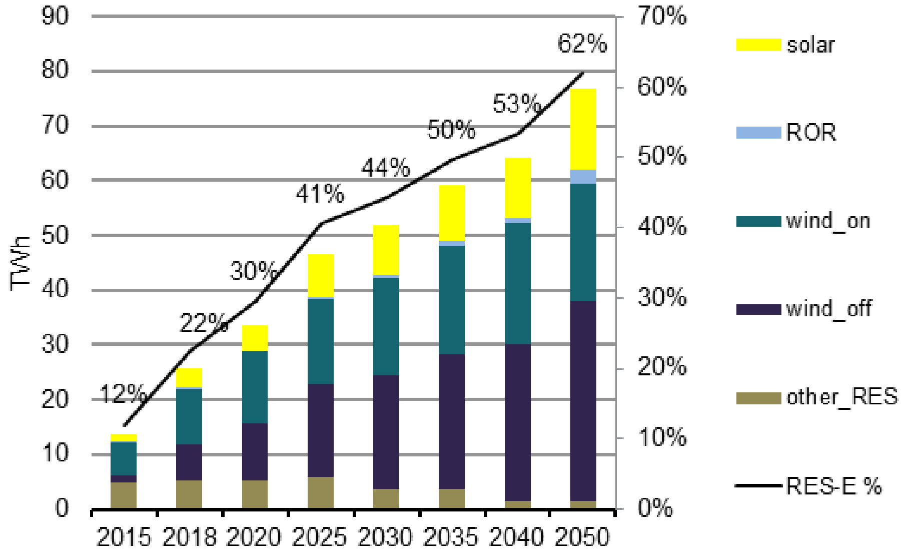
- **Wind-onshore** – According to the Energy Agreement, onshore wind power installations are expected to increase to 6 GW in 2020. Thereafter, we assume a yearly growth of wind-onshore installations by 200 MW/a, in line with growth expectations from ENTSO-E SO&AF (2014, Scenario B / Vision 3).
- **Wind-offshore** – According to the Energy Agreement, the installed capacity of wind-offshore turbines is planned to increase to 4450 MW in 2023. Thereafter, we assume an on-going growth of wind-offshore capacities to 6 GW in 2030 based on ENTSO-E SO&AF (2014, Vision 3).[71]
- **Solar PV** – There are no explicit political targets regarding the development of solar PV installations in The Netherlands. However, solar PV is eligible to the support scheme SDE (+) and, in addition, small scale installations are benefiting from net-metering.[72] Therefore, we assume increasing solar PV capacity based on the following information:
  - We use the National Energy Outlook for the period until 2023 (increase from ca. 1.5 GW in 2015 to ca. 9.6 GW in 2023).
  - After 2023, we assume that changes to the current legal framework of net-metering will reduce the benefits of small-scale solar PV installations, and growth will slow down to ca. 250 MW/a (based on ENTSO-E SO&AF (2014, Vision 3).
- **Other RES-E (biomass) –** Biomass in The Netherlands is used in dedicated biomass/-gas power plants as well as in co-firing of coal-fired power plants:
  - In the short-run (until 2028), co-firing of biomass is subject to subsidies (SDE+) and a 25 PJ/a limit on total amount of biomass co-fired. In the long-run, we assume that biomass co-firing in coal plants will take place if it is economical based on the assumed prices of biomass, CO_2 and coal.
  - Power generation from dedicated biomass/-gas generation units will remain more or less constant (based on NEV 2015).

Figure 29 shows the assumed growth of renewable electricity supply in The Netherlands.

[71] Capacity development after 2030 is derived based on a linear trend of the previous years.

[72] Net-metering applies to consumers that are connected to the distribution grid and reduces the burden of energy taxes to the amount of net electricity consumption, i.e. no energy taxes have to be paid on the auto-produced electricity.

Figure 29. Development of RES-E in The Netherlands



Source: Frontier

Note: RES-E share of net-demand / excluding biomass co-firing in coal plants.

In addition to the exogenous expansion of RES-E described above, we allow for endogenous investment in RES-E after 2035. Based on the assumed levelised costs of electricity[73], the model can decide to invest in wind-onshore, offshore or solar PV. We limit the additional investment potentials to yearly growth-rate described above, i.e.:

- 200 MW/a for wind-onshore;
- 220 MW/a for wind-offshore; and
- 250 MW/a for solar PV.

The cost-assumptions shown in **Table 19** are used to calculate the costs of RES-E investment and operation as well as modelling the endogenous investment in RES-E (after 2035).

Table 19. Levelised costs of electricity (RES-E)

EUR (real, 2015) / MWh	2015	2018	2020	2025	2030	2035	2040	2050
Wind-offshore	83.5	77.0	70.5	66.7	59.2	59.2	57.5	52.7
Wind-onshore	64.0	63.1	62.2	61.3	59.7	59.7	59.4	58.5
Solar PV	120.9	113.2	105.5	97.2	80.6	80.6	78.0	69.9

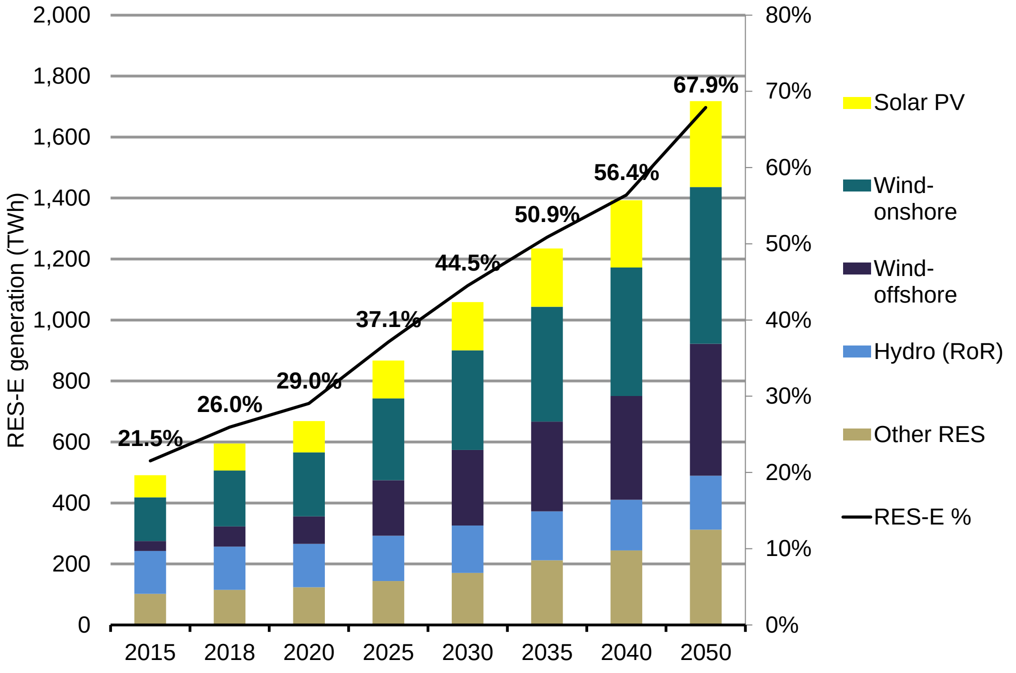
Source: Frontier based on ECN (2014), WEO 2014

[73] Levelised costs of electricity according to Frontier (2015).

Renewable energy sources in foreign modelled countries

As in The Netherlands, the development of renewable energy sources in other modelled countries has been derived from the current political framework (e.g. EEG 2014) or for example TSO forecasts.

Figure 30. RES-E in the model-region



Source: Frontier

Note: RES-E % share of net-demand; Other RES without biomass co-firing.

A.4 Interconnection capacities

Increasing interconnection capacity between countries in Europe is an important cornerstone of the European internal electricity market. Therefore, the development of cross-border connections is an important assumption and influences the outcomes of the power market modelling significantly. It has to be noted that the modelling of interconnectors does not take internal congestions inside the modelled countries into account. Availability of interconnectors is further not influenced by loop or transit flows and flow-based market coupling is not incorporated in the model since the modelling of interconnections is based on Net Transfer Capacities (NTC) due to restrictions regarding computational time of the model.

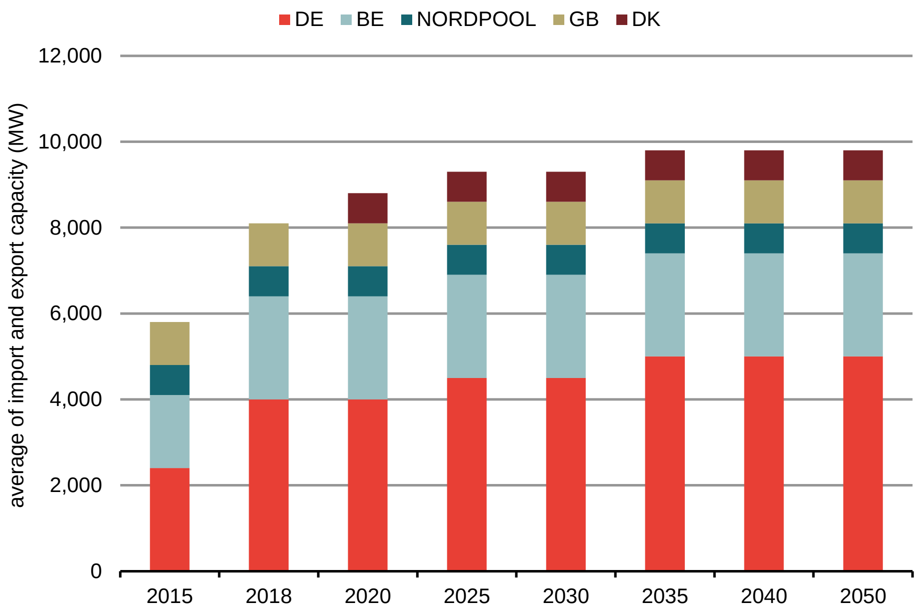
Interconnection capacities of The Netherlands

The Netherlands is a country with high interconnection to its neighbouring countries, notably Germany and Belgium. Additional interconnections are in place to Great Britain (BritNed) and Norway (NorNed). In 2015, total cross-border capacity from/to The Netherlands amounted to almost 6 GW, approximately one third of peak load.

Based on our assumptions, cross-border capacity will increase further in the next years: Our assumptions regarding the development of interconnection capacity are based on ENTSO-E's Ten-Year-Network-Development-Plan.[74] In addition, we have confirmed the development of power interconnectors to and from The Netherlands with TenneT's monitoring report.[75] **Figure 31** shows the average of import and export capacity to/from The Netherlands[76]:

- Interconnections to Germany will increase in 2018 and 2021 to a total of 4.5 GW in 2021. Additional interconnection to Germany is assumed to come online after 2030 (+ 500 MW).
- Interconnections to Belgium will increase to 2.4 GW by 2018.
- Interconnection to Denmark (Cobra Cable) will be established by 2019.

Figure 31. Assumed development of interconnection capacity (NL)



Source: Frontier based on TYNDP 2014 and TenneT (2015)

[74] We assume that projects that are in the earlier planning phases will come online with a certain delay: "design and permitting" + 2 years; "planning" + 5 years; "under consideration" + 15 years.

[75] TenneT (2015).

[76] Assumptions regarding interconnectors across Europe are included in Annexe 2.

ANNEX B REFERENCE CASE RESULTS

In this annexe, we summarise the resulting market outcomes for the Reference Case in detail:

- Electricity generation and capacities (**Section B.1**);
- Power exchange (**Section B.2**);
- Power sector carbon dioxide emission (**Section B.3**); and
- Development of power prices (**Section B.4**).

The modelling outcomes are based on the assumptions described in **ANNEX A.**

B.1 Electricity generation and capacities

B.1.1 The Netherlands

Electricity generation and the development of operational capacities in The Netherlands in the Reference Case is characterised by the following key trends:

- Additional mothballing of gas-fired power plants in the short-term, investment in new capacities in the long-run;
- Increasing share of RES-E in the medium- and long-run;
- Change of the importing positions from being a net-importer of power to becoming a net-exporter to power.

Additional mothballing in the short-term, new investment in capacities in the long-run

Operation capacities in The Netherlands are decreasing in the short-term due to mothballing of gas-fired power plants but increase again in the medium to long run based on the assumed growth of RES-E as well as the reactivation of mothballed plants and new investments:

- **Additional short-term mothballing of ca. 4 GW** – In the period of 2015 to 2018, additional 4 GW of gas-fired power plants are mothballed in The Netherlands. This result is driven by the existence of short-term overcapacities in Central-Western Europe, a slow recovery of power demand following the economic and financial crisis in Europe, as well as consistently low fuel prices.[77]

  Until 2025, scarcity of generation capacities in CWE increases significantly with the completion of the German nuclear phase-out until 2023 and the nuclear phase-out in Belgium until 2025. Additional tightening of the market is

[77] Mothballing of plants may be lower if reactivation costs are assumed to be higher. Most capacities not mothballed can be expected to stay operational instead in the relevant time period since new built of capacities as a potential replacement after 2020 would be much more costly than keeping the plants operational in the short and medium term.

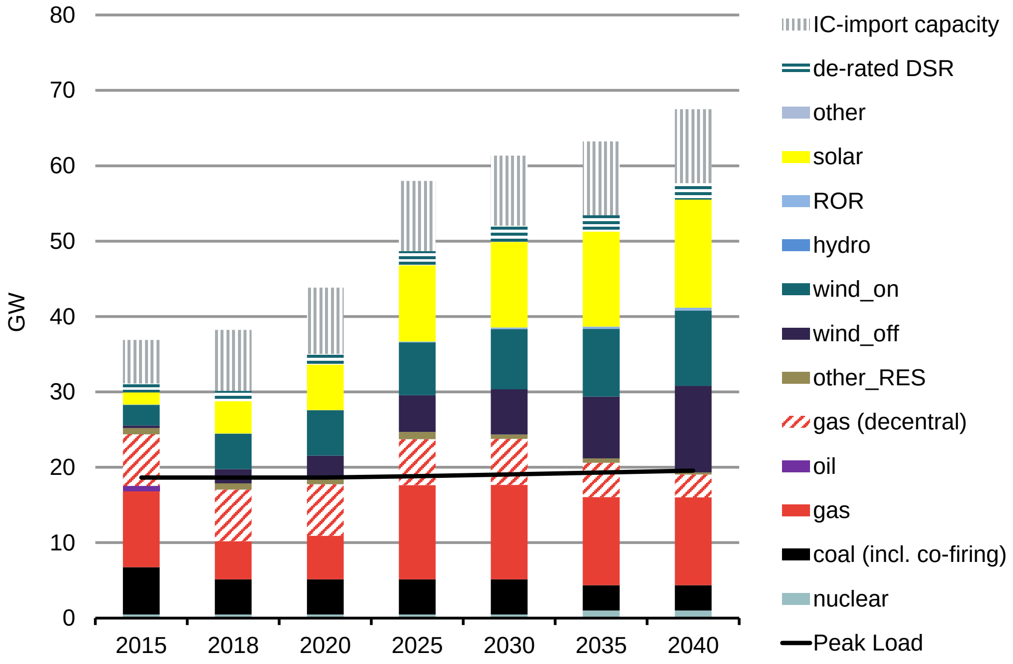
induced by the introduction of the capacity reserve in Germany[78] which, in the short-term, leads to decommissioning of lignite plants. Therefore, with increasing tightening of the market, in the medium term from 2018 until 2025, the majority of mothballed capacities is reactivated and re-enters the market.

- **Investment in new capacities in the long-run** – In addition to the assumed growth of renewables, new generation capacities enter the Dutch power market in the long-run:
  - The decommissioned Borssele nuclear power plant is replaced with a new investment of 1 GW in 2035;[79]
  - With increasing CO_2 prices, gas-fired generation becomes more economical as compared to other fossil fuels. Consequently, required replacement investments take place in 2035 (1 GW OCGT) and in 2040 (2 GW CCGT); and
  - The long-term market environment with high CO_2 prices is favourable for RES-E. Therefore, additional investment of 1 GW wind-offshore in 2035 and 2 GW wind-offshore in 2040 as well as 500 MW of solar PV in 2040 come online (on top of the assumed exogenous capacity additions which are politically driven).
- **Dutch coal plants stay online until the end of their assumed lifetime** – The five remaining Dutch coal plants (coal plants not closed before 2018) stay online until the end of their assumed lifetime in the reference Case. Utilisation of these plants decreases in the long-run. However, market-based co-firing, which becomes profitable in the long-run (2040), keeps running-hours sufficiently high.

[78] Current plans forsee that ca. 5% of peak demand should be contracted as reserve. In the short-term, 2.7 GW of lignite-fired generation will cease operation and enter the reserve before being decommissioned after 2021.

[79] If this replacement doesn't take place due to political reasons we expect that additional gas-fired capacity and/or some additional RES-E capacities would be built instead in the Netherlands. Furthermore, exports to foreign countries might decrease to some extent.

Figure 32. Development of operational capacities NL (Reference Case)



Source: Frontier

Note: operational capacities excl. mothballed capacities, not de-rated

Increasing shares of renewable energy sources in the medium and long-term

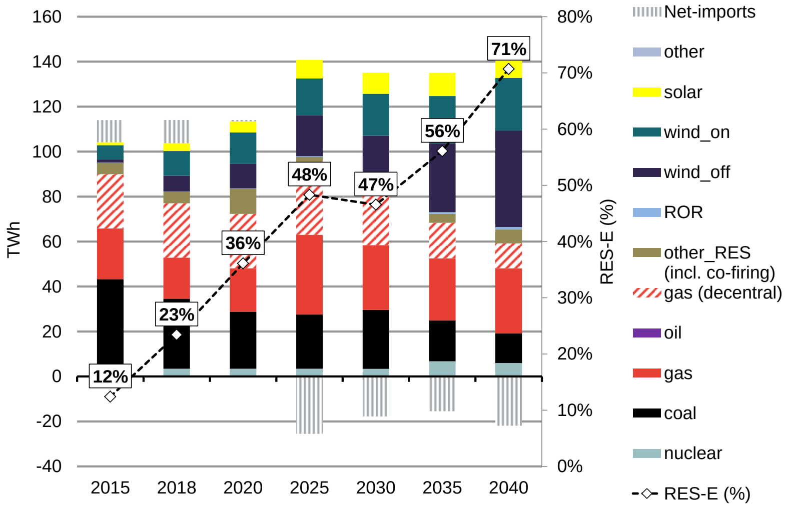
The development of electricity generation in The Netherlands is mainly driven by a significant increase in the share of RES-E power production:

- **Significant increase of RES-E** – According to the current political targets and long-term vision of the European and Dutch power sector, renewable energy sources play an increasingly important role in the power system. This development is reflected in the assumptions of the Reference Case. The renewable share of net demand increases from ca. 12% today to almost 50% in 2025. After 2025, due to the assumed phase out of-subsidies for biomass co-firing in the Dutch coal plants, the renewable share decreases slightly to 47% temporarily. With additional investments in RES-E, the share increases to 71% of net-demand in 2040.

  Electricity supply from wind-offshore installations records the largest increase in power generation from ca. 1.3 TWh in 2015 to more than 40 TWh in 2040. Wind-onshore power generation increases from ca. 6 TWh in 2015 to 23 TWh in 2040 and solar PV generation from 1 TWh (2015) to 12 TWh (2040). Co-firing of biomass in coal plants ceases after the assumed phase-out of subsidies in 2028 and increases again in 2035 and 2040 due to improved economics.

- **Changing import position in the medium-term** – With increasing scarcity in neighbouring countries and an increase of renewable energy sources, The Netherlands move from being a net-importer of power in the short-term to becoming a net-exporter of power after 2025.

Figure 33. Development of electricity supply in The Netherlands (Reference Case)



Source: Frontier

B.1.2 CWE and neighbouring countries

In the following tables, we provide information on the development of operational capacities and power generation in the most important countries of the Central-Western European market (The Netherlands, France, Germany, Belgium, Austria), Great Britain and Denmark.[80]

[80] Great-Britain and Denmark are not part of the “core-regions” of the model, i.e. plant dispatch is modelled with a lower level of detail and capacity development is assumed exogenously.

Table 20. Reference Case: Operational capacities and electricity supply by fuel type (The Netherlands)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Nuclear	0	0	0	0	0	1	1
Coal	6	5	5	5	5	3	3
Gas	10	5	6	13	13	12	12
Gas (decentral)	7	7	7	6	6	5	3
Oil	1	0	0	0	0	0	0
Wind-offshore	0	2	3	5	6	8	12
Wind-onshore	3	5	6	7	8	9	10
Solar PV	2	4	6	10	11	13	14
Other RES (excl. co-firing)	1	1	1	1	1	1	1
Hydro (Run of river)	0	0	0	0	0	0	0
Net electricity supply (TWh)							
Nuclear	4	3	3	3	3	7	6
Coal	40	31	25	24	26	18	13
Gas	23	18	19	35	29	28	29
Gas (decentral)	24	24	24	22	22	16	11
Oil	0	0	0	0	0	0	0
Wind-offshore	1	7	11	18	22	31	43
Wind-onshore	6	11	14	16	19	21	23
Solar PV	1	3	5	8	9	10	12
Other RES (incl. co-firing of biomass)	5	5	11	12	4	4	6
Hydro (Run of river)	0	0	0	0	1	1	1

Source: Frontier

Table 21. Reference Case: Operational capacities and electricity supply by fuel type (Germany)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Nuclear	12	9	8	0	0	0	0
Lignite	20	19	13	10	9	9	5
Coal	26	22	21	16	10	7	6
Gas	23	14	15	15	15	16	18
Oil	3	0	0	0	0	0	0
Wind-offshore	2	4	6	10	14	20	28
Wind-onshore	35	43	48	60	73	80	88
Solar PV	38	46	51	55	56	58	61
Other RES	8	8	8	8	9	9	10
Hydro (Run of river)	4	4	4	4	4	4	4
Hydro (Storage)	10	10	10	11	11	11	12
Net electricity supply (TWh)							
Nuclear	87	69	59	0	0	0	0
Lignite	139	129	91	67	56	53	29
Coal	110	111	108	92	55	36	25
Gas	61	65	67	71	71	67	68
Oil	0	0	0	0	0	0	0
Wind-offshore	7	16	21	37	53	74	105
Wind-onshore	67	81	91	115	139	153	168
Solar PV	35	42	46	50	52	53	56
Other RES	46	48	49	51	53	56	58
Hydro (Run of river)	17	18	18	19	19	20	21
Hydro (Storage)	9	10	10	11	12	13	15

Source: Frontier

Table 22. Reference Case: Operational capacities and electricity supply by fuel type (Belgium)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Nuclear	6	6	6	4	0	0	0
Coal	0	0	0	0	0	0	1
Gas	4	2	2	3	3	3	7
Oil	1	0	0	0	0	0	0
Wind-offshore	1	1	2	2	4	5	6
Wind-onshore	1	2	3	4	5	5	6
Solar PV	3	4	4	5	6	6	7
Other RES	1	1	2	2	2	2	2
Hydro (Run of river)	0	0	0	0	0	0	0
Hydro (Storage)	1	1	1	2	2	2	2
Net electricity supply (TWh)							
Nuclear	42	42	42	28	0	0	0
Coal	3	0	0	0	0	0	7
Gas	7	6	6	9	7	7	23
Oil	0	0	0	0	0	0	0
Wind-offshore	2	4	5	7	13	16	18
Wind-onshore	3	5	6	9	11	12	13
Solar PV	2	3	3	4	5	5	5
Other RES	3	8	10	14	14	14	14
Hydro (Run of river)	0	0	0	0	0	0	0
Hydro (Storage)	2	1	1	2	2	2	3

Source: Frontier

Table 23. Reference Case: Operational capacities and electricity supply by fuel type (Austria)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Coal	1	1	1	1	0	0	0
Gas	3	0	0	3	3	3	3
Gas (decentral)	2	2	2	2	2	2	2
Oil	0	0	0	0	0	0	0
Wind-onshore	2	3	3	4	5	7	8
Solar PV	1	1	2	3	4	5	6
Other RES	1	1	1	1	1	1	2
Hydro (Run of river)	6	6	6	6	6	6	6
Hydro (Storage)	7	7	7	7	7	7	8
Net electricity supply (TWh)							
Coal	3	3	3	4	0	0	0
Gas	1	0	1	8	7	7	7
Gas (decentral)	8	8	8	8	8	8	8
Oil	0	0	0	0	0	0	0
Wind-onshore	4	5	6	9	11	13	15
Solar PV	1	1	1	3	4	5	6
Other RES	4	5	5	6	7	8	10
Hydro (Run of river)	32	32	33	33	34	35	36
Hydro (Storage)	11	11	11	11	12	12	13

Source: Frontier

Table 24. Reference Case: Operational capacities and electricity supply by fuel type (France)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Nuclear	63	63	63	63	60	49	17
Coal	4	2	2	2	2	2	1
Gas	6	11	11	11	11	11	41
Oil	7	4	3	1	0	1	1
Wind-offshore	0	2	3	4	9	15	20
Wind-onshore	9	12	15	20	28	37	45
Solar PV	5	7	9	13	30	47	64
Other RES	1	1	1	1	2	3	4
Hydro (Run of river)	10	10	10	11	12	13	13
Hydro (Storage)	13	13	13	14	16	17	19
Net electricity supply (TWh)							
Nuclear	411	409	408	407	380	304	100
Coal	24	15	14	13	8	8	4
Gas	11	15	17	20	16	16	56
Oil	0	0	0	0	0	0	0
Wind-offshore	0	5	9	11	29	47	64
Wind-onshore	19	26	31	42	60	79	97
Solar PV	6	9	11	16	37	58	79
Other RES	7	7	7	7	14	20	27
Hydro (Run of river)	30	30	30	33	36	38	39
Hydro (Storage)	26	27	26	29	33	36	39

Source: Frontier

Table 25. Reference Case: Operational capacities and electricity supply by fuel type (Great Britain)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Nuclear	10	9	9	6	11	14	14
Coal	19	17	16	6	2	5	5
Gas	31	31	31	38	40	41	42
Oil	1	0	0	0	0	0	0
Wind-offshore	5	8	10	25	29	30	31
Wind-onshore	7	11	13	18	19	19	20
Solar PV	5	7	14	19	23	26	27
Other RES	0	1	1	1	2	4	5
Hydro (Run of river)	1	1	1	1	1	1	1
Hydro (Storage)	3	3	3	3	3	3	3
Net electricity supply (TWh)							
Nuclear	70	67	66	47	80	97	83
Coal	132	106	87	26	6	12	15
Gas	61	56	50	46	33	27	43
Oil	0	0	0	0	0	0	0
Wind-offshore	19	30	38	100	118	123	125
Wind-onshore	17	25	30	42	44	45	46
Solar PV	3	5	10	14	17	18	19
Other RES	3	4	5	7	9	24	32
Hydro (Run of river)	3	3	3	3	3	3	3
Hydro (Storage)	2	2	2	3	4	4	5

Source: Frontier

Table 26. Reference Case: Operational capacities and electricity supply by fuel type (Denmark)

	2015	2018	2020	2025	2030	2035	2040
Operational capacities (GW)							
Coal	1	1	1	1	0	0	0
Gas	2	2	1	1	1	1	1
Oil	1	1	1	0	0	0	0
Wind-offshore	1	2	3	3	4	5	5
Wind-onshore	4	4	4	4	5	5	6
Solar PV	1	1	1	1	2	3	3
Other RES	2	2	2	3	3	3	3
Hydro (Run of river)	0	0	0	0	0	0	0
Hydro (Storage)	0	0	0	0	0	0	0
Net electricity supply (TWh)							
Coal	6	6	5	3	0	0	0
Gas	0	1	1	2	1	1	1
Oil	0	0	0	0	0	0	0
Wind-offshore	5	9	11	13	16	18	20
Wind-onshore	9	9	9	9	11	13	14
Solar PV	0	1	1	1	2	2	2
Other RES	9	12	14	16	16	17	17
Hydro (Run of river)	0	0	0	0	0	0	0
Hydro (Storage)	0	0	0	0	0	0	0

Source: Frontier

B.2 Power exchange

The power exchange between countries is on the one hand affected by changing supply structures in the interconnected countries and on the other hand by the expansion of interconnector capacities between regions. In the following, we describe the development of power imports and exports from and into The Netherlands and in CWE.

B.2.1 The Netherlands

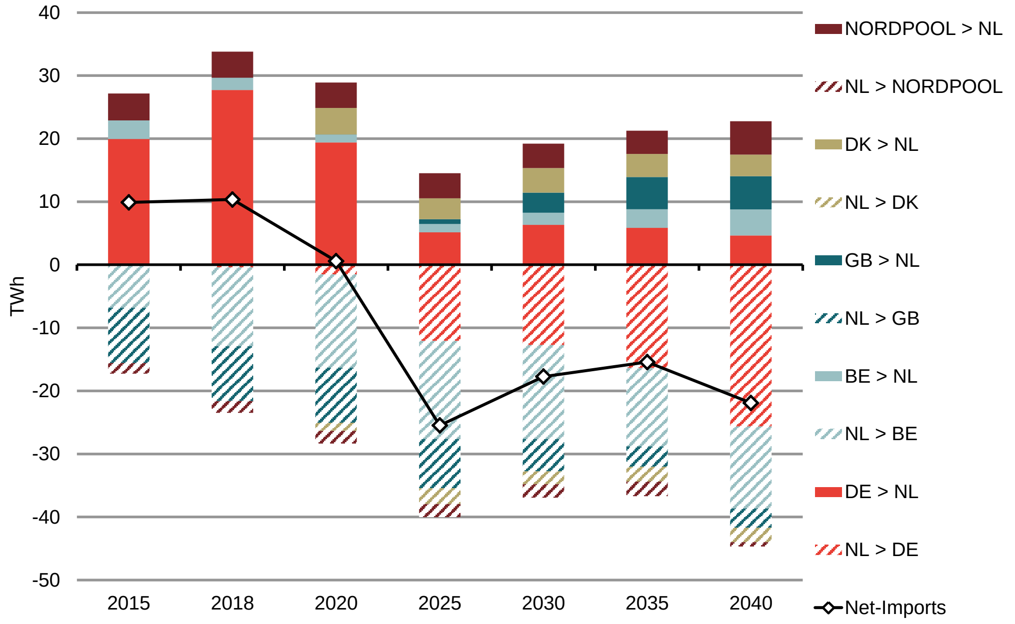
In recent years, The Netherlands have been importing more power than they have exported due to the high share of gas-fired generation which is comparably more expensive than low-cost but more carbon-intensive power generation for example in Germany. The level of net-imports since 2010 ranged between ca. 3 TWh in 2010 to 18 TWh in 2013. In 2015, historical net-imports amounted to ca. 9 TWh.[81]

As described in **Section B.1.1**, the net-importing position of The Netherlands is changing to a net-exporting position in the medium- to long-term:

- **Net-imports of power in the short-term –** Until 2020, The Netherlands remain net-importer of power by 10 TWh in 2018 and by a marginal amount of ca. 1 TWh in 2020.
- **Increased tightening of the market in CWE leads to lower imports**–In the model, electricity imports from Germany amount to more than 20 TWh in 2018. After the nuclear phase-out in Germany, the introduction of the lignite and capacity reserve as well as more RES-E production in NL, this position changes significantly to only 5 TWh of imports from Germany and more than 10 TWh exports to Germany (2025). From 2025 until 2040 Dutch the net-exports to Germany amount to between 15 and 25 TWh/a (**Figure 34**).

[81] CBS Statline, Electricity balance sheet; supply and consumption 2010-2015.

Figure 34. Imports/Exports NL (Reference Case)



Source: Frontier

Note: Positive values represent imports to The Netherlands, negative values exports from The Netherlands to other countries

B.2.2 CWE and neighbouring countries

Table 27 provides model results on the net-imports (positive values) and net-exports (negative-values) of selected countries in the CWE region..

Table 27. Net-imports in other countries (Reference Case)

	2015	2018	2020	2025	2030	2035	2040
DE*	-40.4	-49.2	-22.1	23.3	23.7	9.3	-0.9
FR*	-46.9	-50.2	-58.9	-78.7	-106.6	-92.0	15.5
NL*	9.9	10.3	0.6	-25.5	-17.7	-15.4	-21.9
BE*	24.6	21.3	17.0	22.6	46.5	45.8	22.7
GB	25.8	34.2	42.8	49.4	30.5	3.3	-4.5
AT*	7.6	8.0	5.8	-5.2	-3.1	-6.1	-6.6
CH	-4.0	-3.0	-2.5	-3.1	-1.0	1.2	-5.7
DK	5.0	-1.3	-5.4	-8.1	-11.4	-14.7	-17.5

Source: Frontier

*Note: * core-region with endogenous investment/divestment*

B.3 Power sector related CO_2 emissions

In this section, we describe the development of power sector related carbon emissions in The Netherlands and in the other modelled countries. Emissions from CHP-installations are taken into account based on the plant specific emission-intensity.[82]

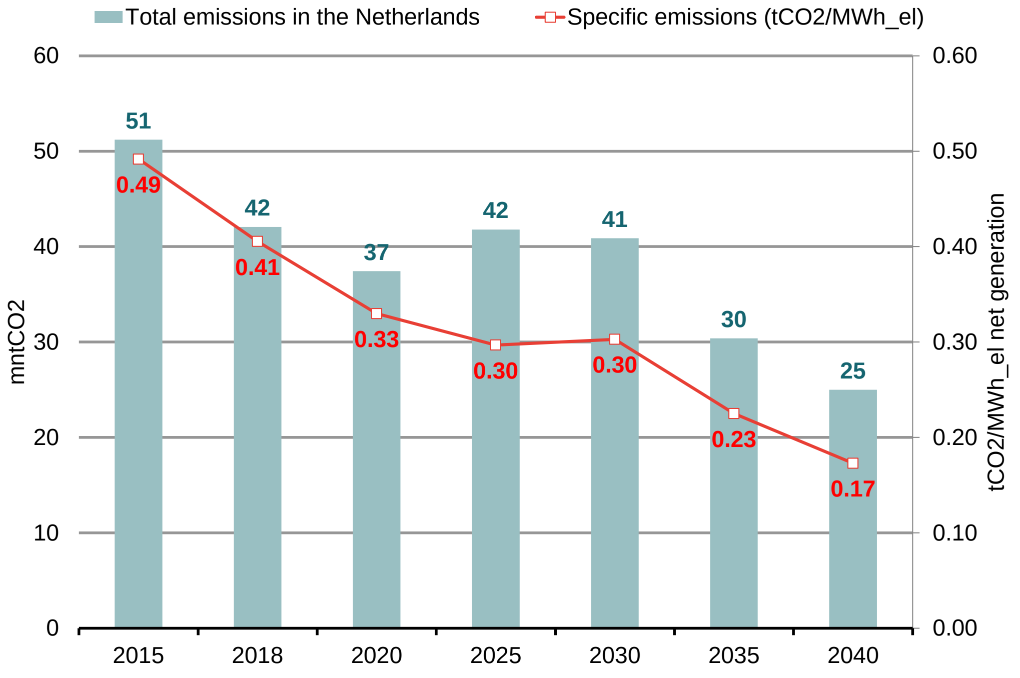
B.3.1 The Netherlands

The development of the Dutch electricity system in the Reference Case is characterised by a strong increase of RES-E. Accordingly, the power related carbon emissions decrease significantly from 51 mn. tCO_2 in 2015 to 25 mn. tCO_2 in 2040. The following developing of CO2 emissions can be taken from the model results:

- Short-term decrease of carbon dioxide emissions by ca. 27% to 37 mn. tCO2 in 2020 after closure of the 1980's coal-fired power stations in The Netherlands until 2018.
- Medium-term increase to 42 mn. tCO_2 with higher exports of power to neighbouring countries.
- Long-term decrease by 51% from 2015 until 2040 to 25 mn. tCO_2.

The specific CO2 emissions per unit of electricity produced in the Dutch electricity system decreases (almost) steadily (**Figure 35**).

Figure 35. Power sector CO_2 emission NL



Source: Frontier

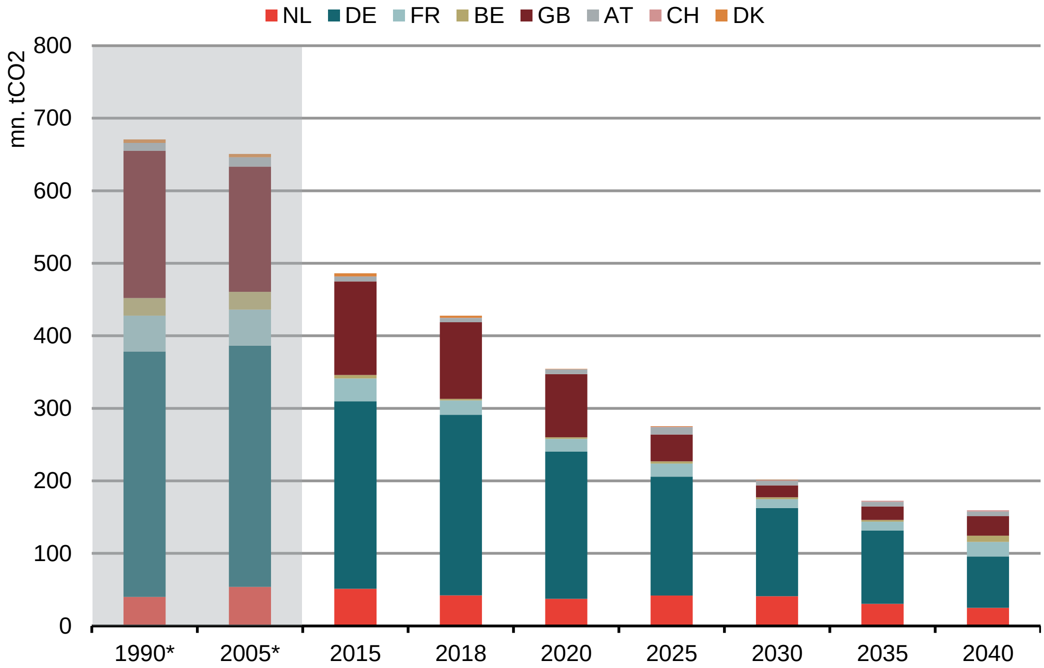
Note: Including emissions from CHP
Specific emissions calculated based on total net electricity generation

[82] De-central CHP units are included based on an emission intensity of 483 gCO_2/kWh_el

B.3.2 CWE and neighbouring countries

As in The Netherlands, power supply in the European market (modelled countries) is moving towards carbon-neutrality in the long-term. In the following, we provide information on the development of carbon dioxide emissions in CWE as well as in Great Britain and Denmark as interconnected country to The Netherlands.[83] Overall emissions from these countries decrease by ca. 67% from 2015 until 2040.[84]

Figure 36. CO_2 emissions in the Reference Case (CWE and neighbouring countries)



Source: Frontier

*Note: * 1990/2005 based on UNFCCC data (1.A.1.a - Public Electricity and Heat Production)*

B.4 Development of power prices

In this section, we describe the development of wholesale power prices in The Netherlands as well as in the neighbouring countries.

B.4.1 The Netherlands

In the past years, power prices in CWE and in The Netherlands have decreased in line with low fuel and CO_2 prices, shrinking power demand in some countries and overcapacities in the generation sector. The development of Dutch power prices is described by the following trends:

83 Great-Britain and Denmark are not part of the "core-region", i.e. plant dispatch is modelled with a lower level of detail and capacity development is assumed exogenously.

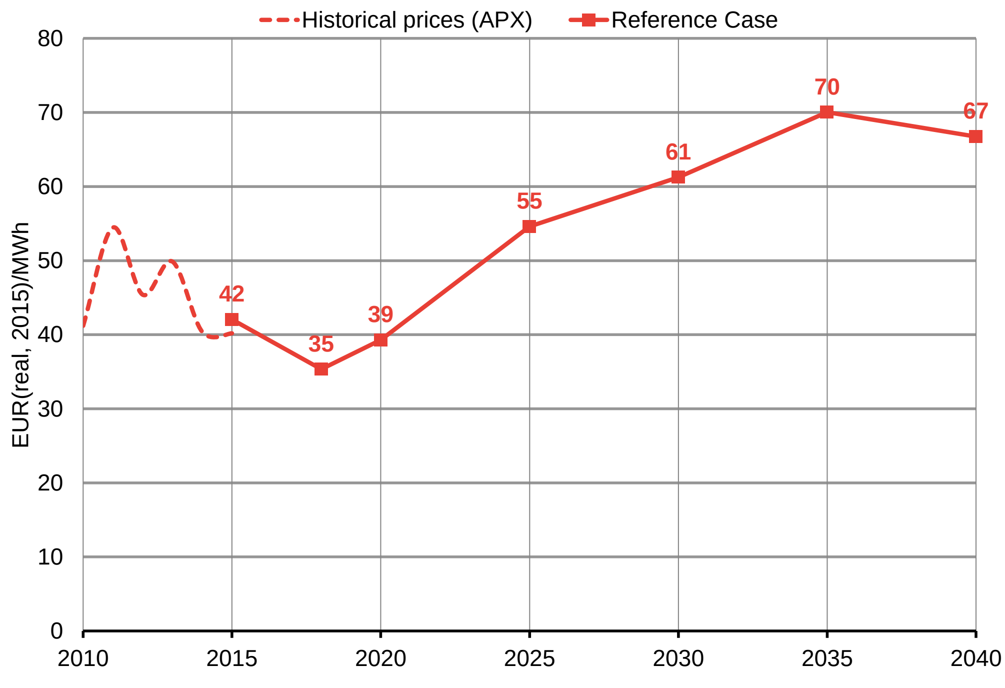
84 Historical emissions based on UNFCCC data (1.A.1.a - Public Electricity and Heat Production) are comparable only to a limited extent (due to different definitions of included installations).

Increasing price levels in the medium-to long-term

- **Low price levels in the short-term (until 2020)** – Due to low fuel prices and remaining overcapacities, prices will remain below 40 EUR(real, 2015)/MWh until 2020.
- **Increase of price levels in the medium-term (2030)** – Increasing tightening of the market (e.g. DE/BE nuclear phase-out) on the one hand and increasing CO_2 and fuel prices on the other hand lead to a medium increase of power prices in The Netherlands to 55 EUR(real, 2015)/MWh in 2025 and 61 EUR(real, 2015)/MWh in 2030.

  Prices increase to 70 EUR(real, 2015)/MWh in 2035 with rising CO_2 and fuel prices as well as a changing supply structure with lower shares of cheap base-load generation (nuclear / lignite). After 2035, prices decrease slightly to 67 EUR(real, 2015)/MWh as renewable shares continue to rise and growing interconnection capacities level out power production (including RES-E) and power prices more equally across countries.

Figure 37. Wholesale price development in The Netherlands (Reference Case)

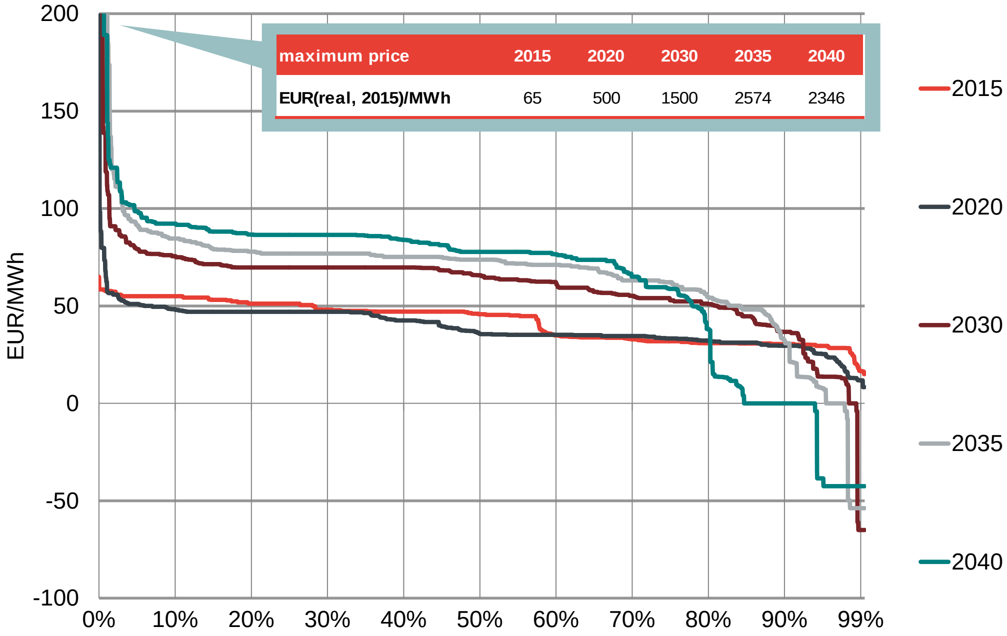


Source: Frontier

Increasing price volatility in the long-run

The share of electricity produced from intermittent renewable energy sources increases significantly in the long-run compared to today. Consequently, the share of hours with a tighter supply-demand balance in the electricity market and corresponding high price levels is expected to increase. At the same time, the share of hours with an oversupply of renewable energy sources and corresponding low (or even negative) price levels is also increasing (**Figure 38**).[85]

Figure 38. Price duration curve NL (Reference Case)



Source: Frontier

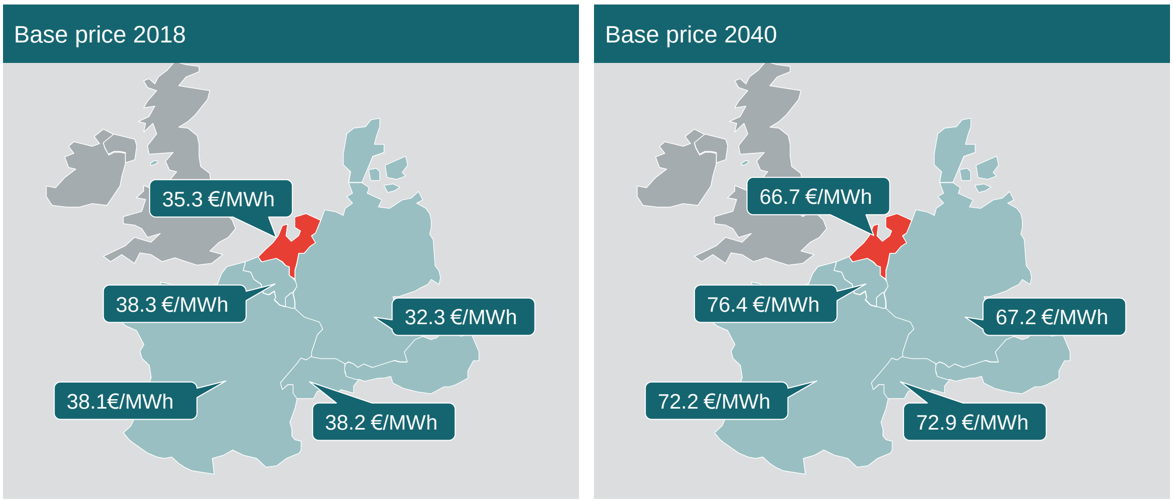
B.4.2 CWE and neighbouring countries

As in the Netherlands, wholesale power prices are expected to increase in the whole Central-Western European region in the medium and long term due to the same underlying market drivers. In addition, prices in CWE are expected to become increasingly integrated following an increase of interconnection capacity and a converging supply structure across countries (increase in RES-E, lower levels of cheap base-load generation).

- **Price increase in Central-Western Europe** – Wholesale power prices in neighbouring countries to the Netherlands are increasing to levels of 60 – 76 EUR(real, 2015)/MWh for base-load (**Figure 39**). Belgium is the country in CWE (excluding GB) with the highest price level in the short- and in the long-run.

[85] We assume that negative prices occur in hours in which RES-E in-feed from RES-E exceeds demand (curtailment costs).

Figure 39. Comparison of base prices CWE (Reference Case) 2018 – 2040



Source: Frontier

Note: Prices noted in real values (base year 2015)

- **Integration of prices between Germany and The Netherlands in the medium-term –** Interconnection capacity between Germany and The Netherlands is assumed to increase in the medium-term. In addition, the cost structure of both electricity supply sectors converges. Therefore, the base price difference between both countries decrease from 7 EUR(real, 2015)/MWh (modelled) in 2015 to 0.5 EUR(real, 2015)/MWh in 2020. After 2020, base price differences remain below 0.5 EUR(real, 2015)/MWh.[86]

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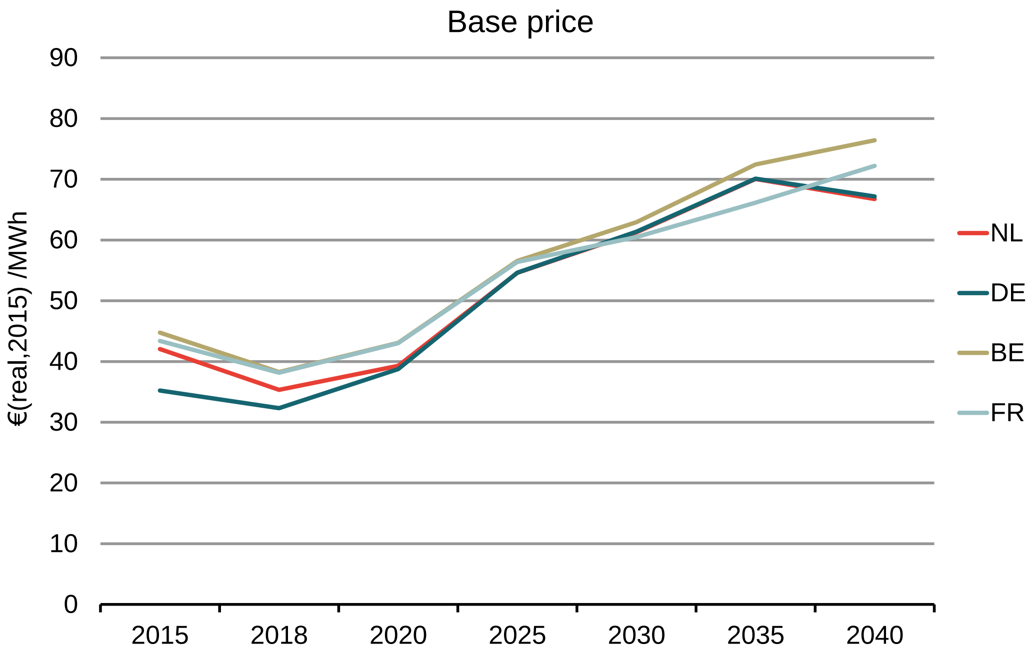
[86] It has to be noted that the price difference between countries/regions is to a high extend driven by the assumptions on the availability of interconnection capacity. For example, if the assumed extension of IC capacity between the Netherlands and Germany may not come in operation, price differences in 2020 will be higher than displayed. Furthermore, the availability of IC capacity can be lower if the short term impact of RES-E infeed in Germany on grid capacity is included. On the other hand, Flow Based Market Coupling can increase available IC capacity. Therefore, the numbers provided should be interpreted as indications.

Figure 40. Development of base prices in selected countries



Source: Frontier

ANNEX C DETAILED RESULTS OF THE POLICY SCENARIOS

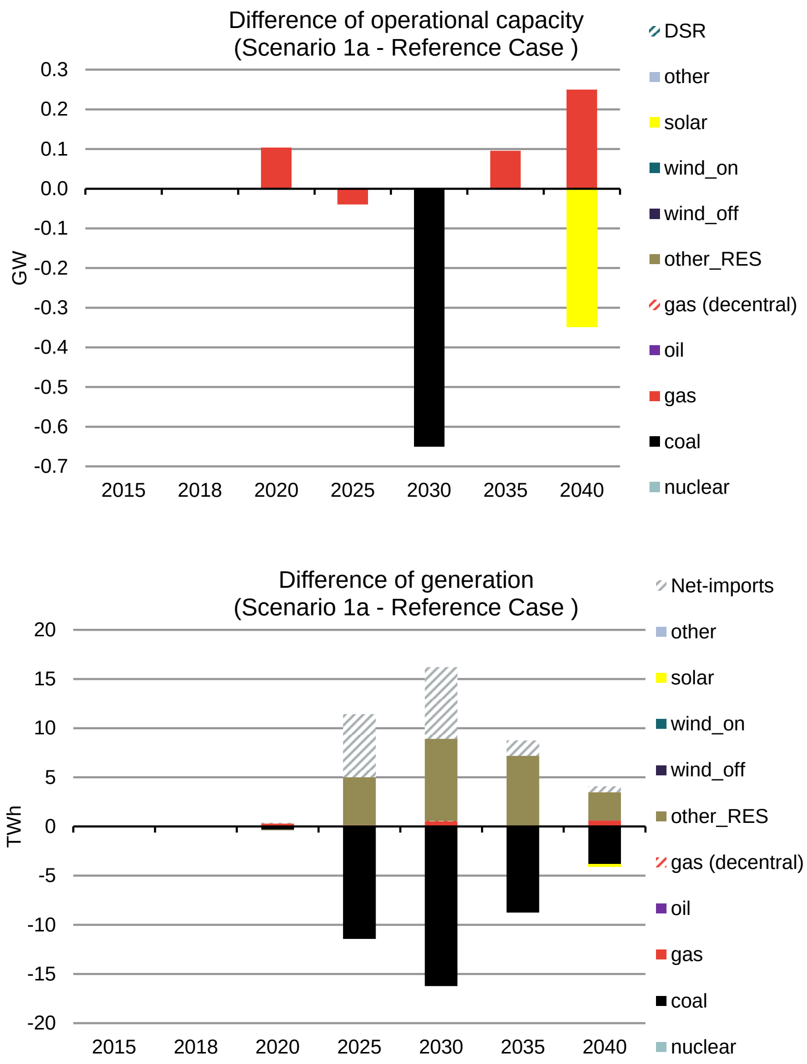
In this section, we provide more detailed information on the results of modelling the impact of the different policy measures compared to the Reference Case. For each policy scenario, we will report:

- Impact on capacities and electricity supply in The Netherlands;
- Impact on capacities and electricity supply in the model region; and
- Impact on imports and exports of power from and to The Netherlands.

C.1 Scenario 1a

The figures below illustrate the impact of the implementation of additional abatement measures at the coal plants without state compensation for associated costs (Scenario 1a) on the electricity supply in The Netherlands and in all modelled countries.

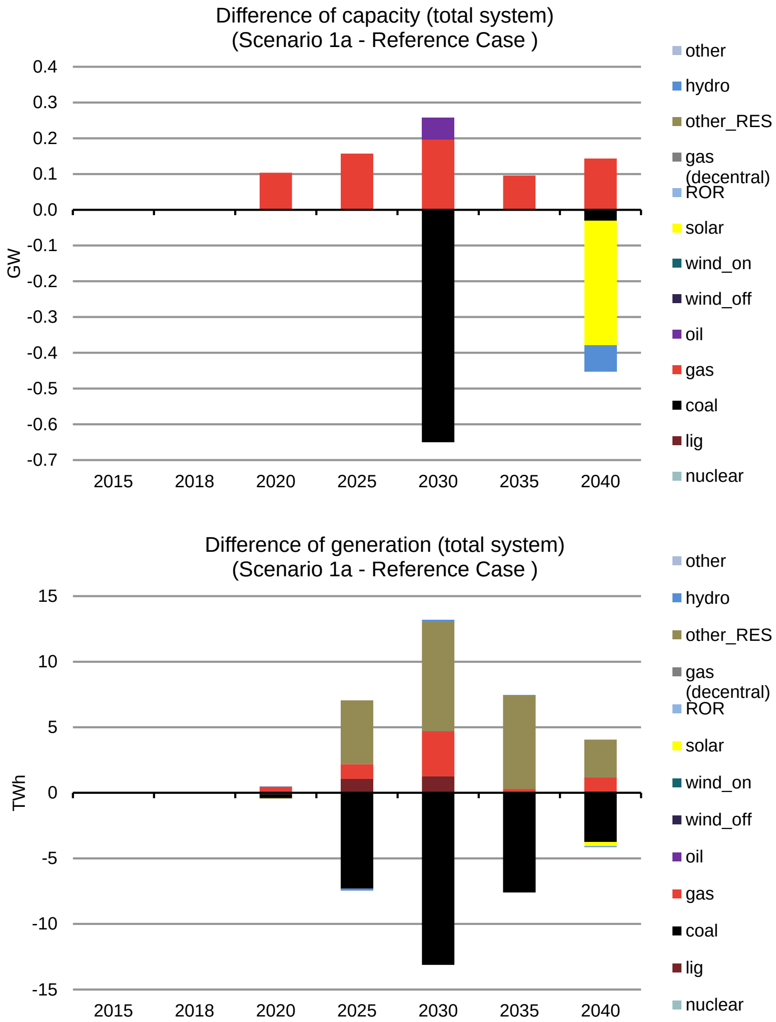
Figure 41. Impact on the Dutch electricity supply (Scenario 1a)



Source: Frontier

Note: Difference to the Reference Case

Figure 42. Impact on electricity supply (model-region) (Scenario 1a)

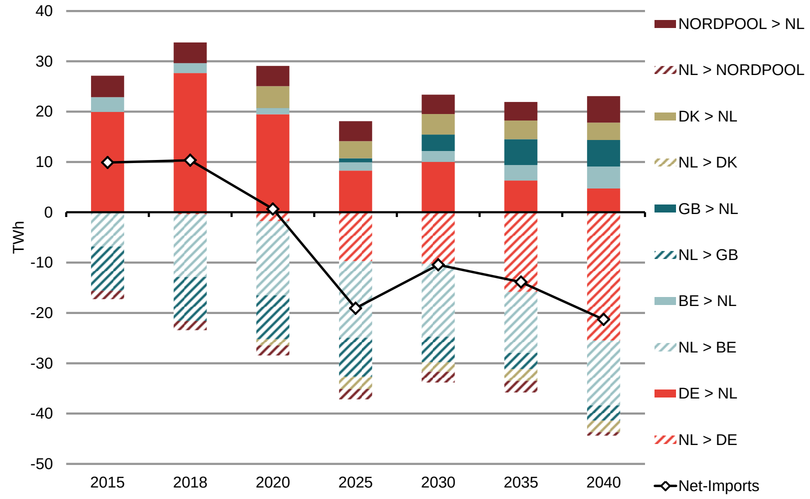


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 43. Imports/ Exports of power (NL) Scenario 1a



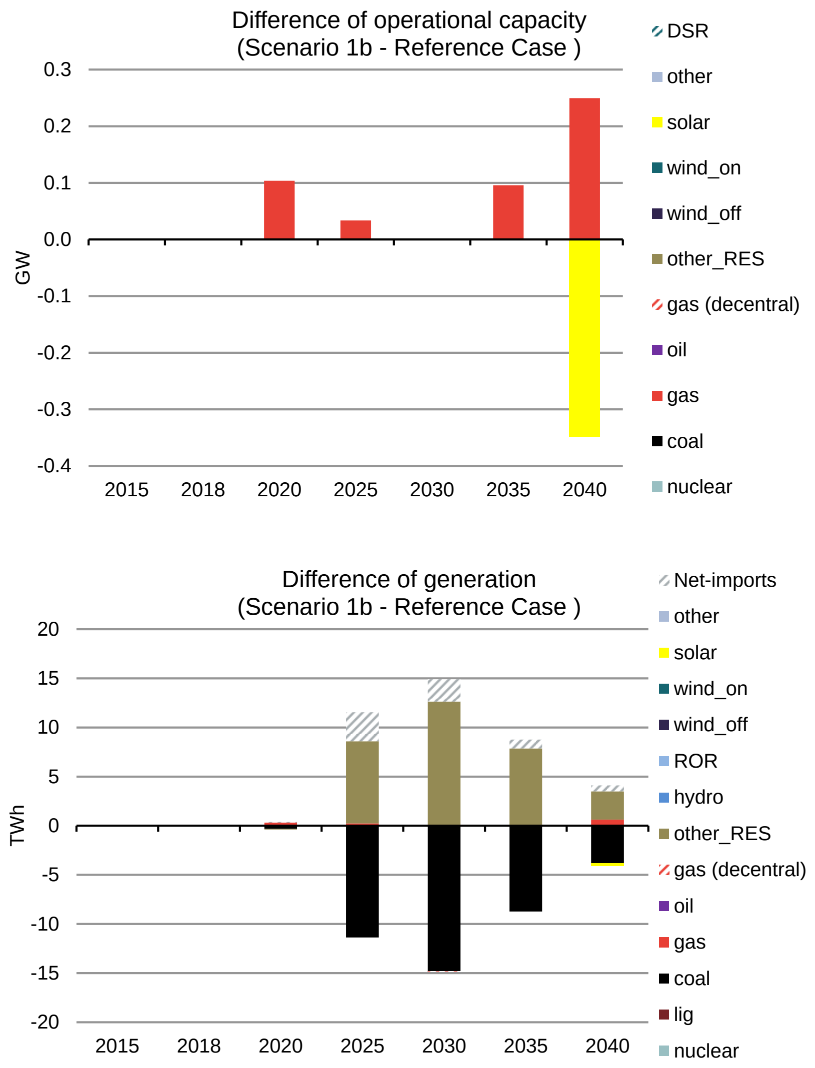
Source: Frontier

Note: Difference to the Reference Case

C.2 Scenario 1b

The figures below illustrate the impact of the implementation of additional abatement measures at the coal plants with state compensation for associated costs (Scenario 1b) on the electricity supply in The Netherlands and in all modelled countries.

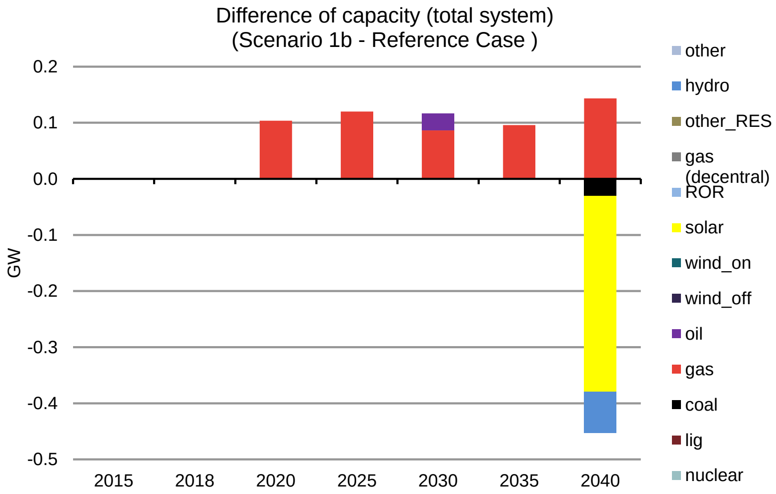
Figure 44. Impact on the Dutch electricity supply (Scenario 1b)

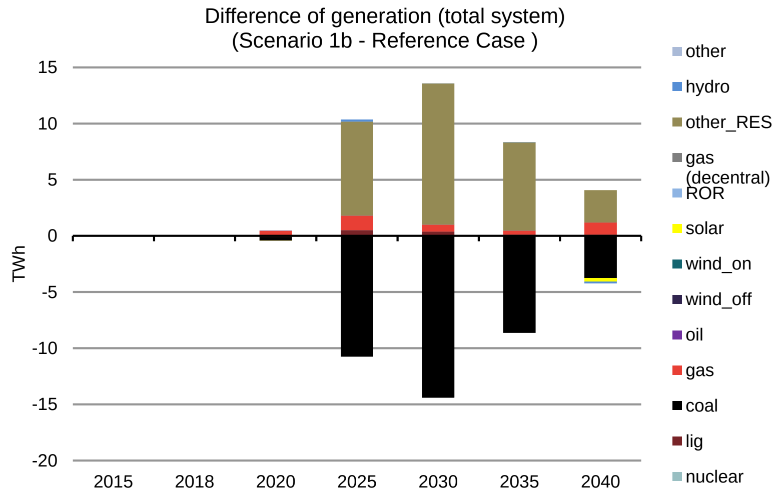


Source: Frontier

Note: Difference to the Reference Case

Figure 45. Impact on electricity supply (model-region) (Scenario 1b)

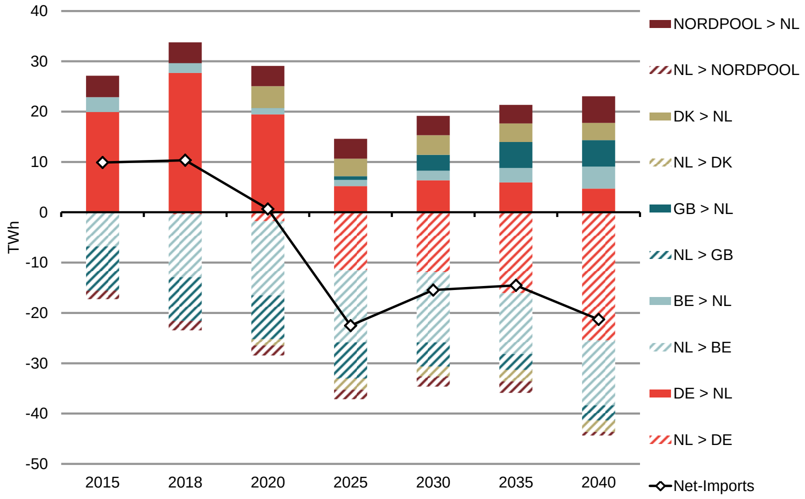




Source: Frontier
Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 46. Imports/ Exports of power (NL) Scenario 1b



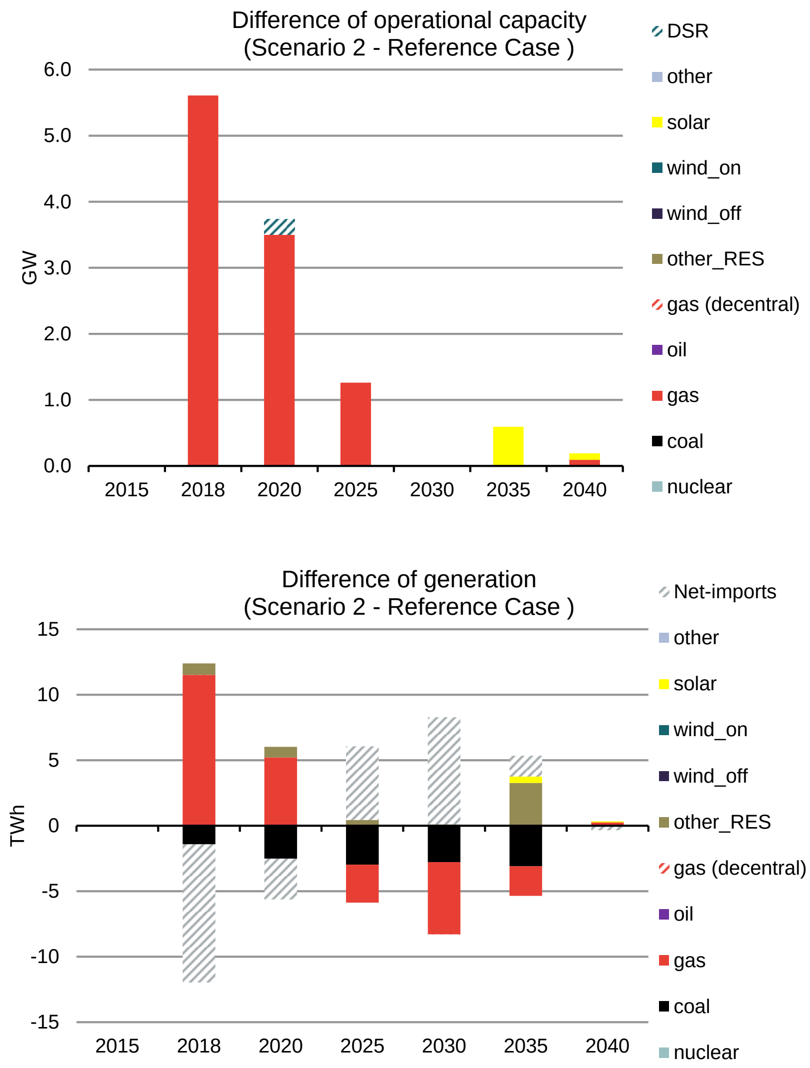
Source: Frontier

Note: Difference to the Reference Case

C.3 Scenario 2

The figures below illustrate the impact of the implementation of a Carbon Floor Price (Scenario 2) on the electricity supply in The Netherlands and in all modelled countries.

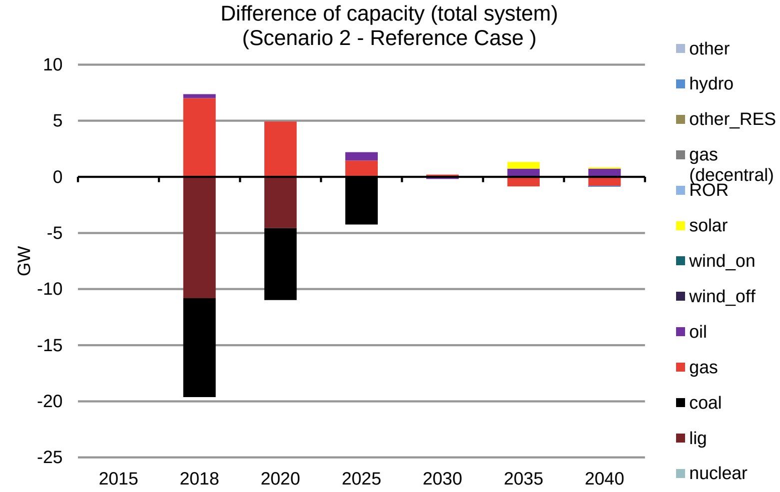
Figure 47. Impact on the Dutch electricity supply (Scenario 2)

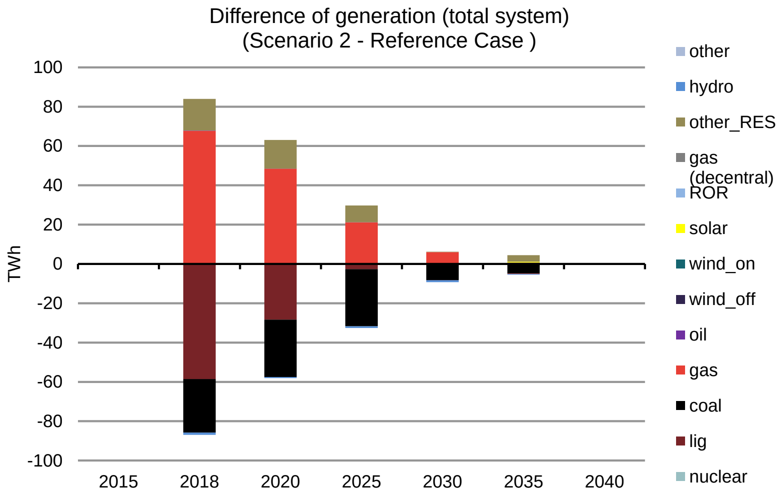


Source: Frontier

Note: Difference to the Reference Case

Figure 48. Impact on electricity supply (model-region) (Scenario 2)



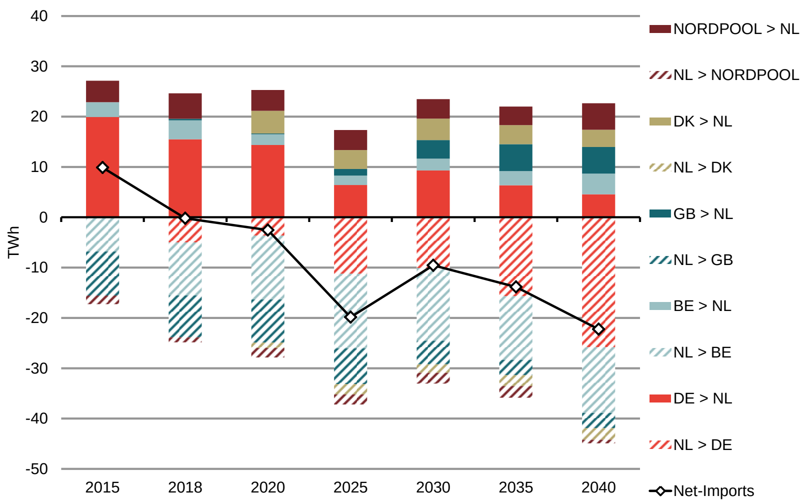


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 49. Imports/ Exports of power (NL) Scenario 2



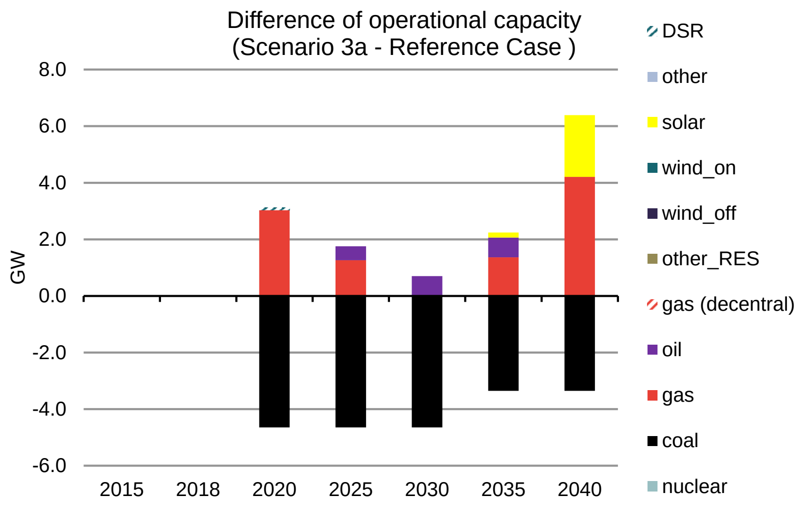
Source: Frontier

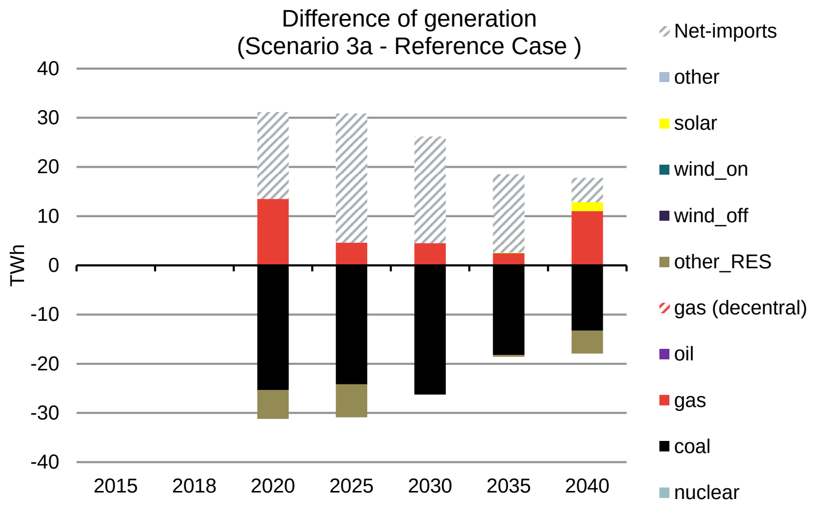
Note: Difference to the Reference Case

C.4 Scenario 3a

The figures below illustrate the impact closure of all coal-fired plants until 2020 on the electricity supply in The Netherlands and in all modelled countries.

Figure 50. Impact on the Dutch electricity supply (Scenario 3a)

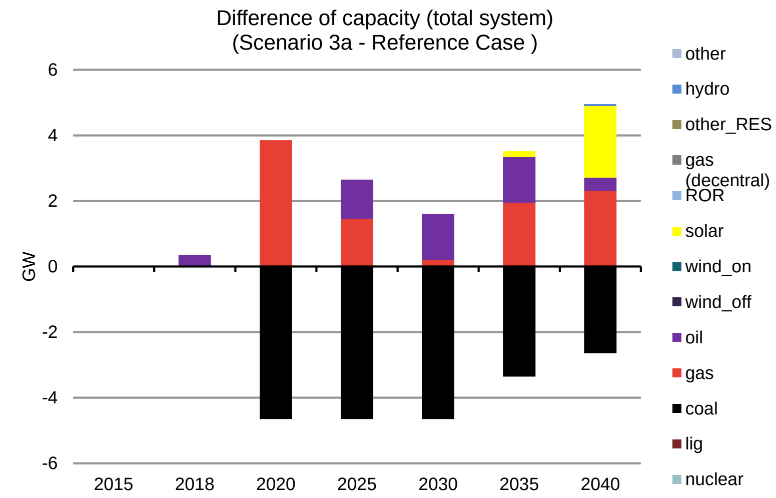


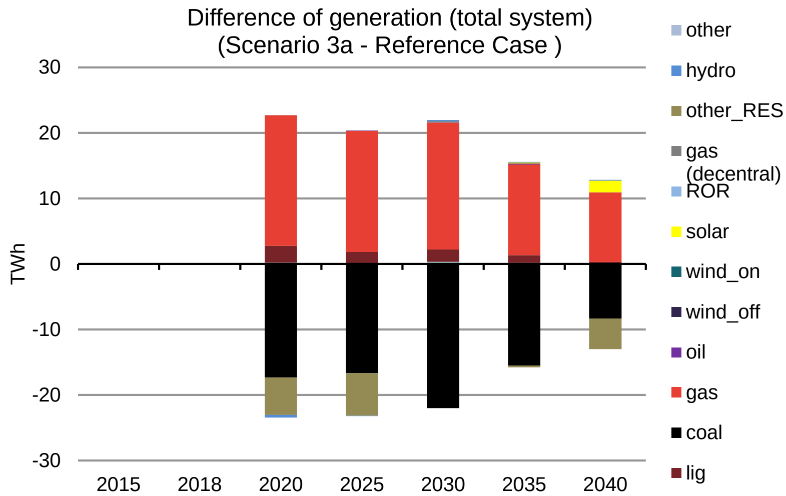


Source: Frontier

Note: Difference to the Reference Case

Figure 51. Impact on electricity supply (model-region) (Scenario 3a)



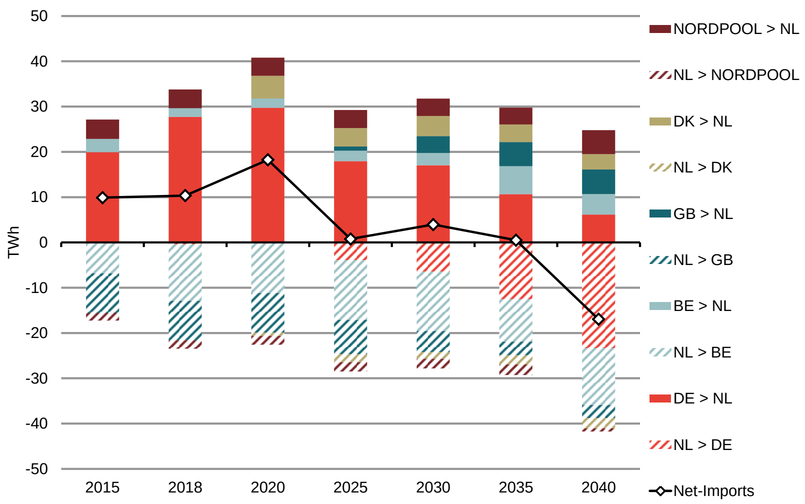


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 52. Imports/ Exports of power (NL) Scenario 3a



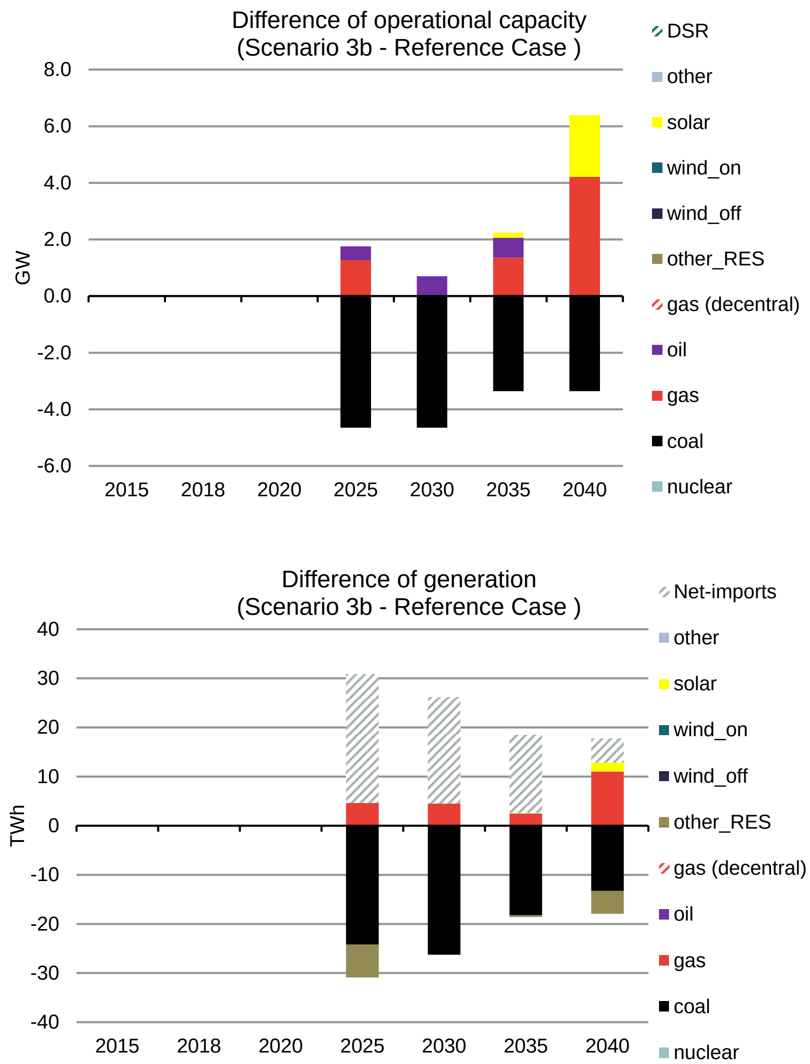
Source: Frontier

Note: Difference to the Reference Case

C.5 Scenario 3b

The figures below illustrate the impact closure of all coal-fired plants until 2025 on the electricity supply in The Netherlands and in all modelled countries.

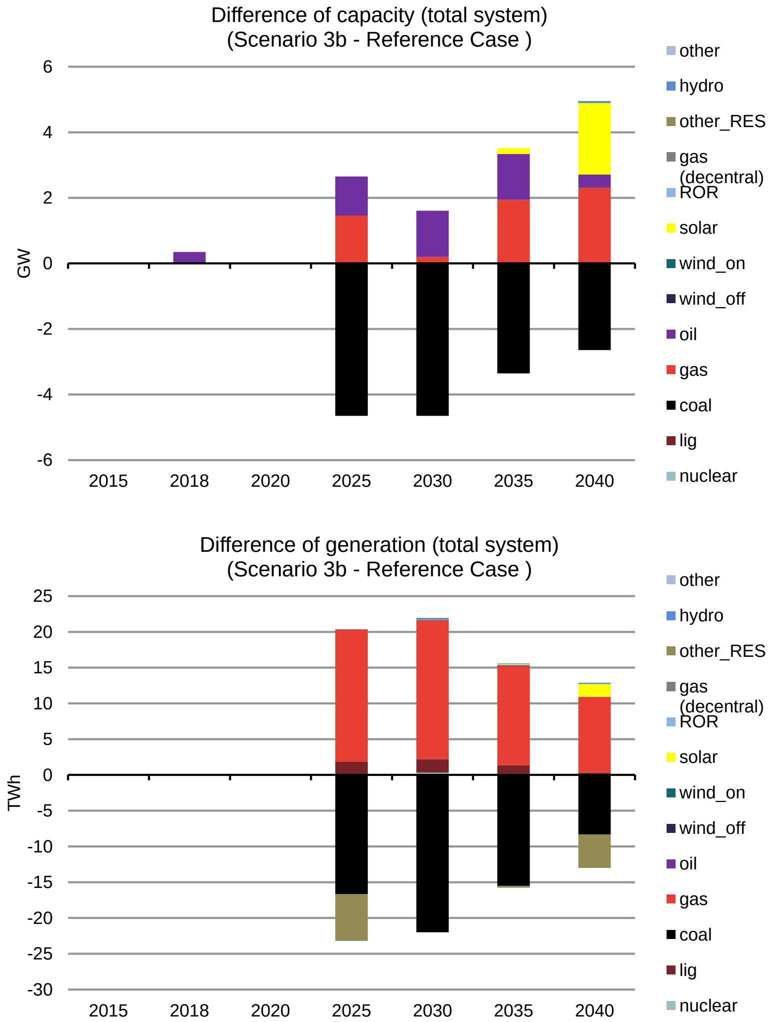
Figure 53. Impact on the Dutch electricity supply (Scenario 3b)



Source: Frontier

Note: Difference to the Reference Case

Figure 54. Impact on electricity supply (model-region) (Scenario 3b)

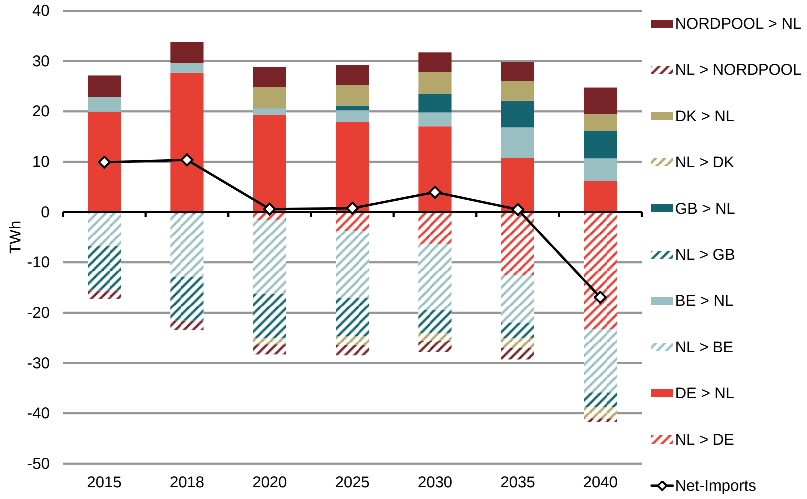


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 55. Imports/ Exports of power (NL) Scenario 3b



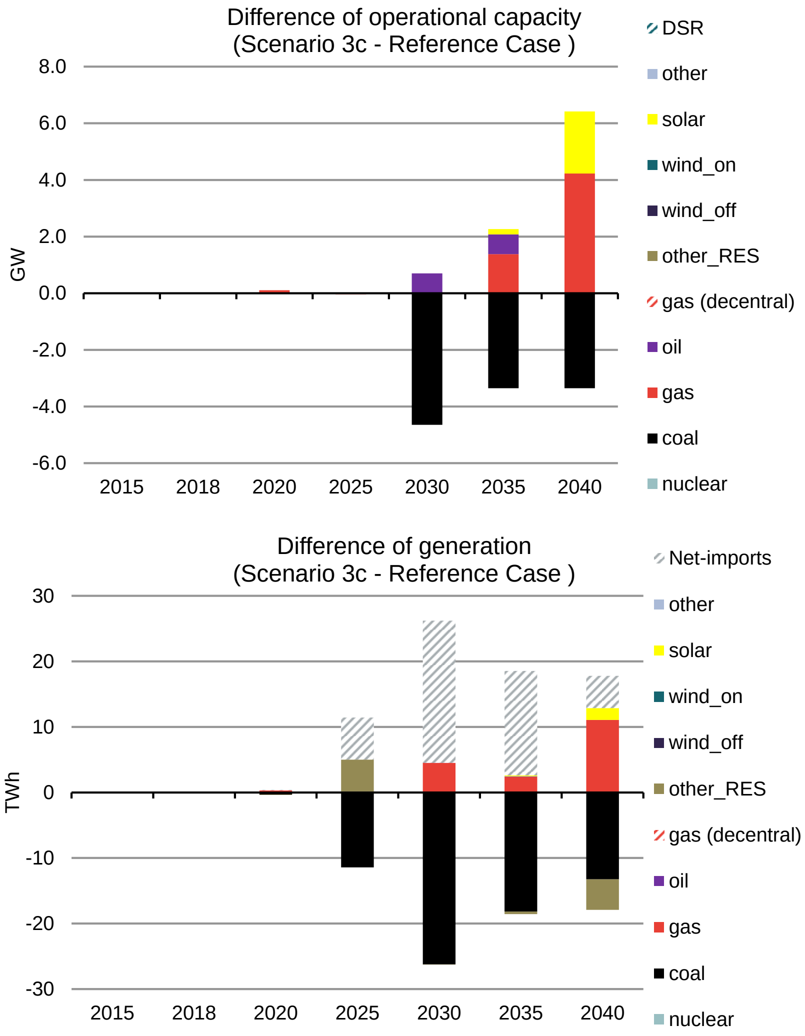
Source: Frontier

Note: Difference to the Reference Case

C.6 Scenario 3c

The figures below illustrate the impact closure of all coal-fired plants until 2030 and the implementation of additional measures on the electricity supply in The Netherlands and in all modelled countries.

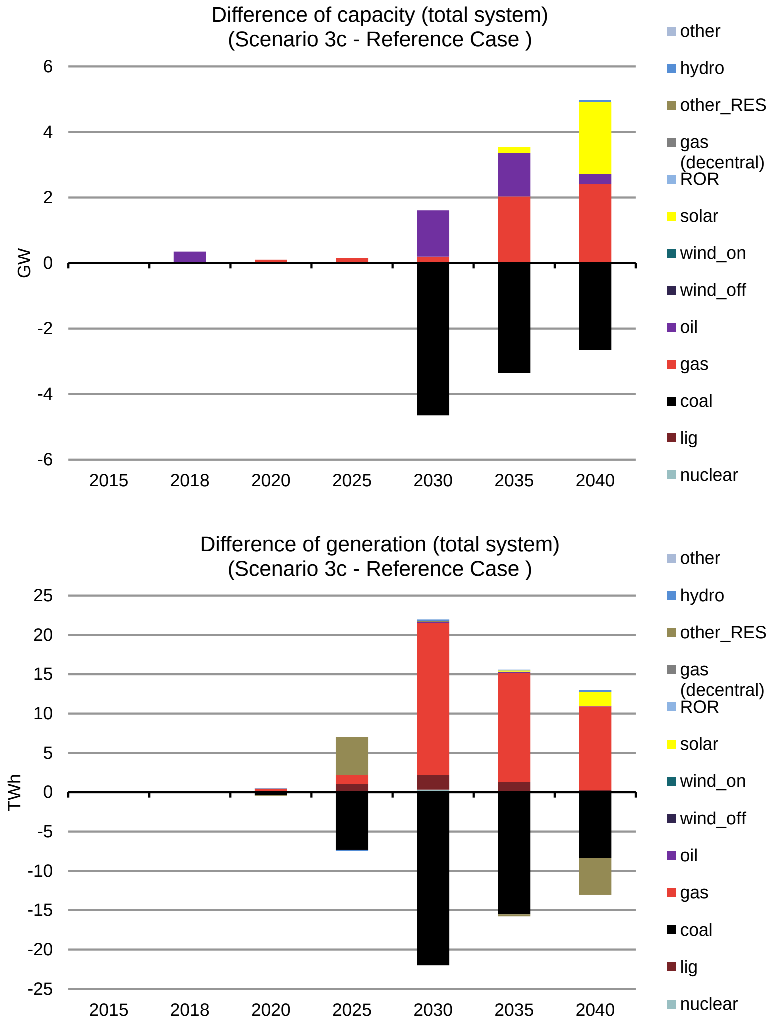
Figure 56. Impact on the Dutch electricity supply (Scenario 3c)



Source: Frontier

Note: Difference to the Reference Case

Figure 57. Impact on electricity supply (model-region) (Scenario 3c)

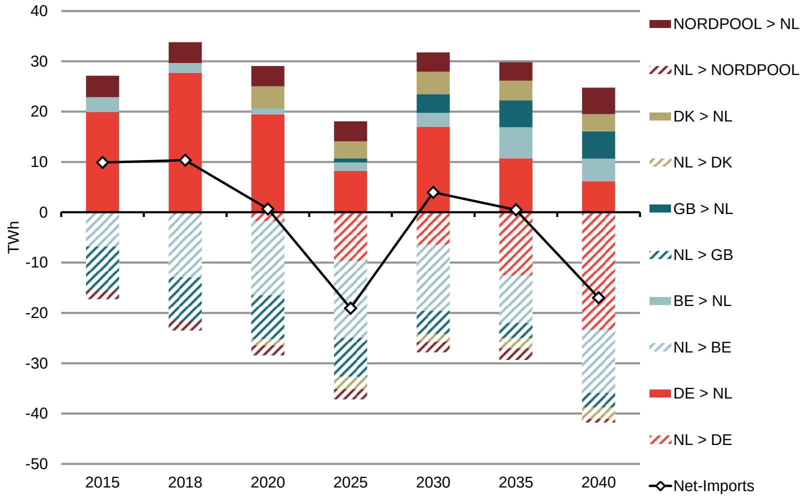


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 58. Imports/ Exports of power (NL) Scenario 3c



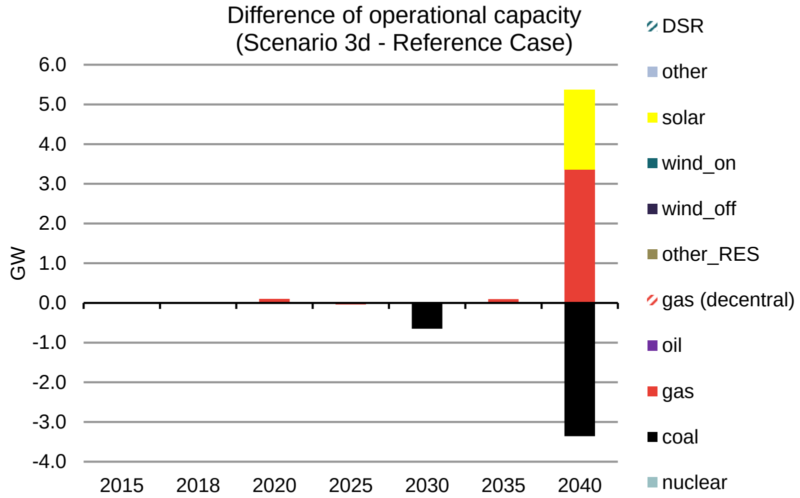
Source: Frontier

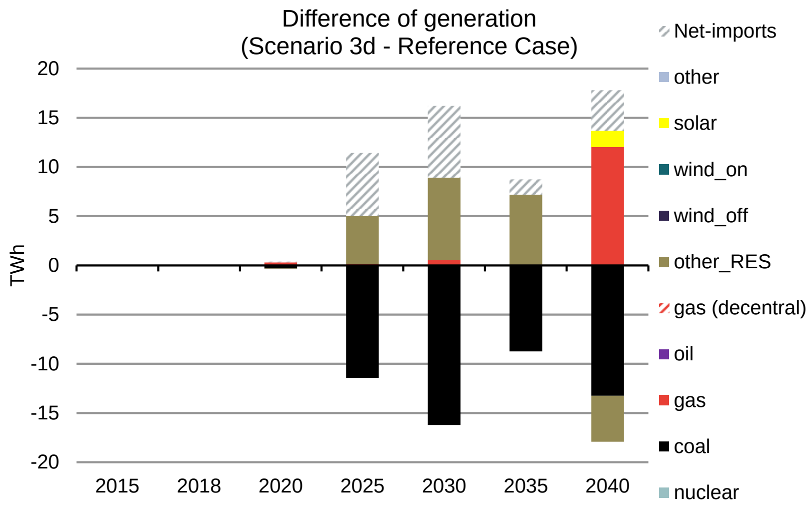
Note: Difference to the Reference Case

C.7 Scenario 3d

The figures below illustrate the impact closure of all coal-fired plants until 2040 and the implementation of additional measures on the electricity supply in The Netherlands and in all modelled countries.

Figure 59. Impact on the Dutch electricity supply (Scenario 3d)

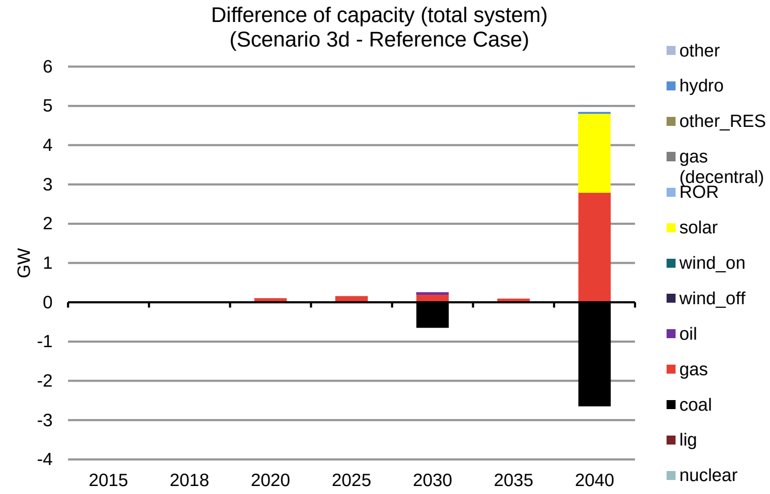


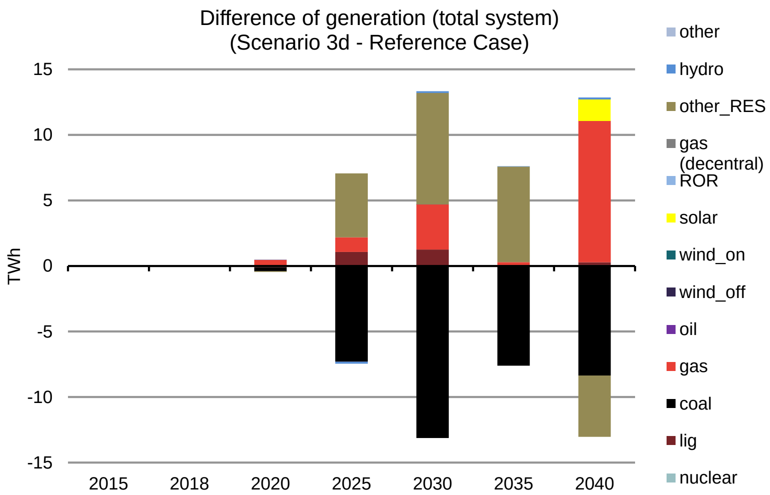


Source: Frontier

Note: Difference to the Reference Case

Figure 60. Impact on electricity supply (model-region) (Scenario 3d)



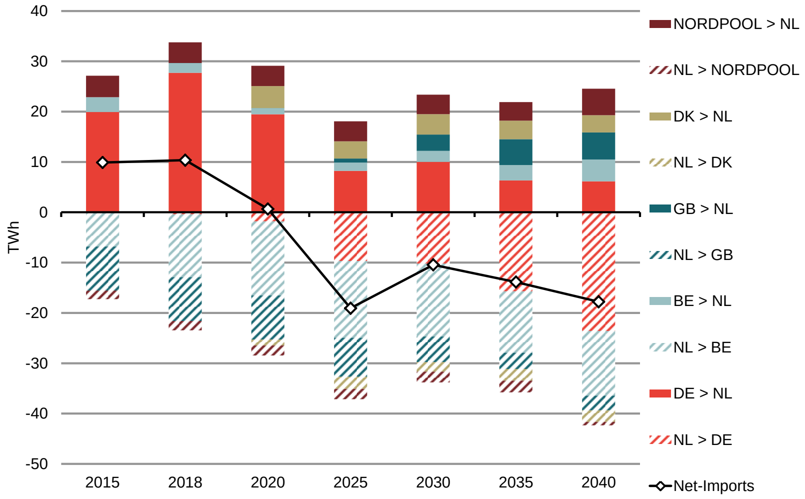


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 61. Imports/ Exports of power (NL) Scenario 3d



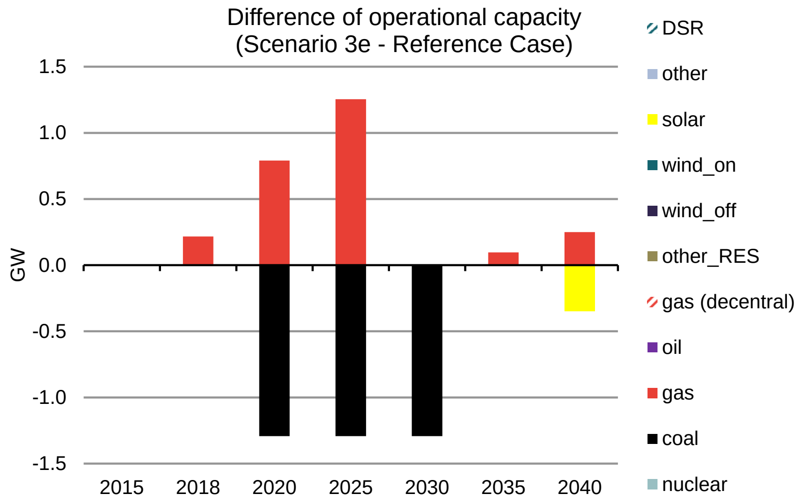
Source: Frontier

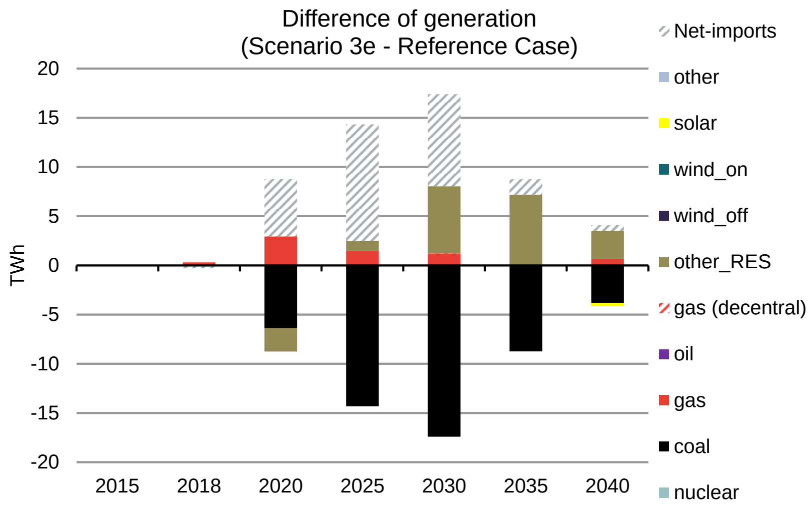
Note: Difference to the Reference Case

C.8 Scenario 3e

The figures below illustrate the impact of a closure of the two oldest coal-fired plants until 2020 and the implementation of additional measures at the remaining plants (from 2025) on the electricity supply in The Netherlands and in all modelled countries.

Figure 62. Impact on the Dutch electricity supply (Scenario 3e)

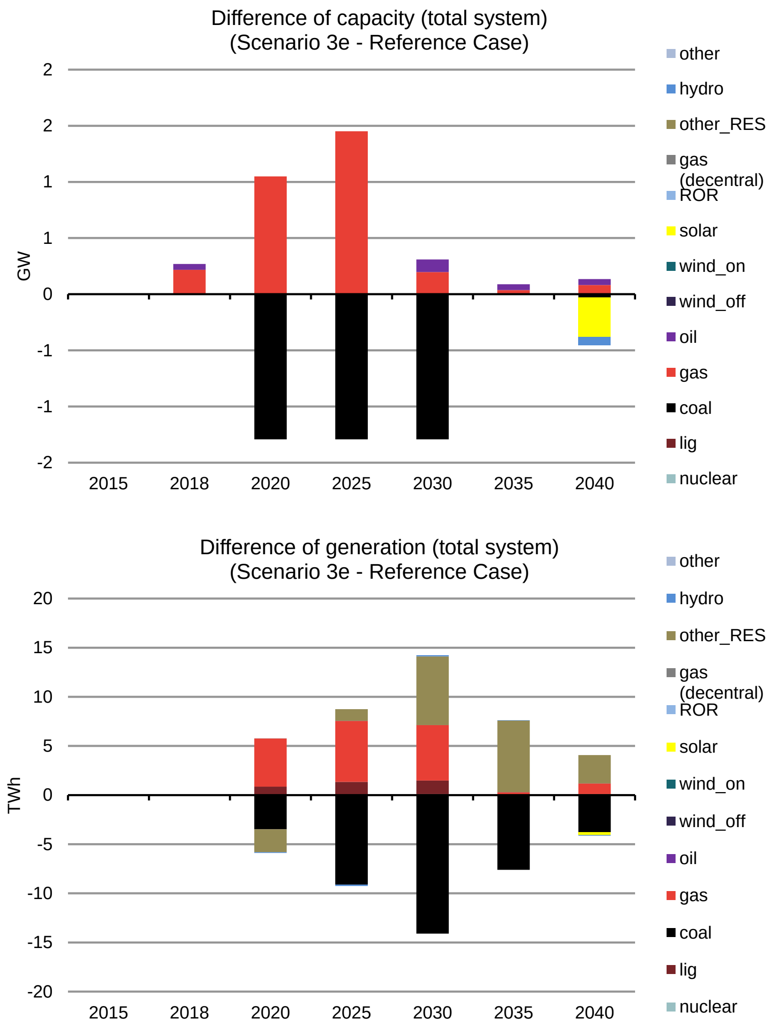




Source: Frontier

Note: Difference to the Reference Case

Figure 63. Impact on electricity supply (model-region) (Scenario 3e)

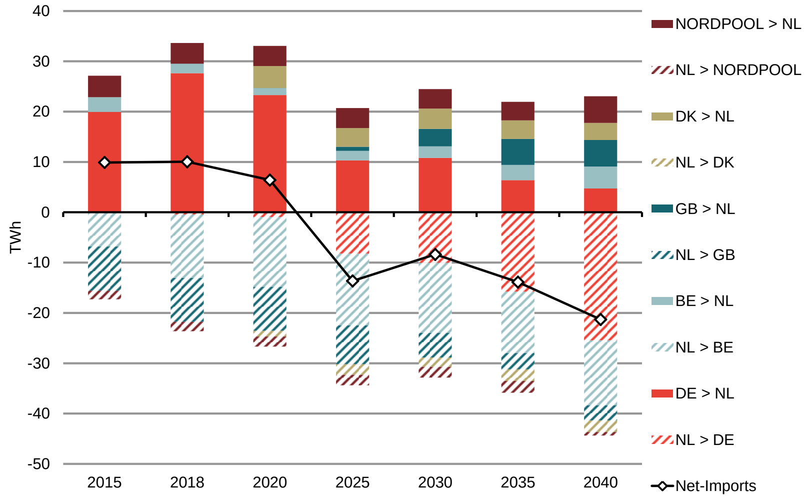


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 64. Imports/ Exports of power (NL) Scenario 3e



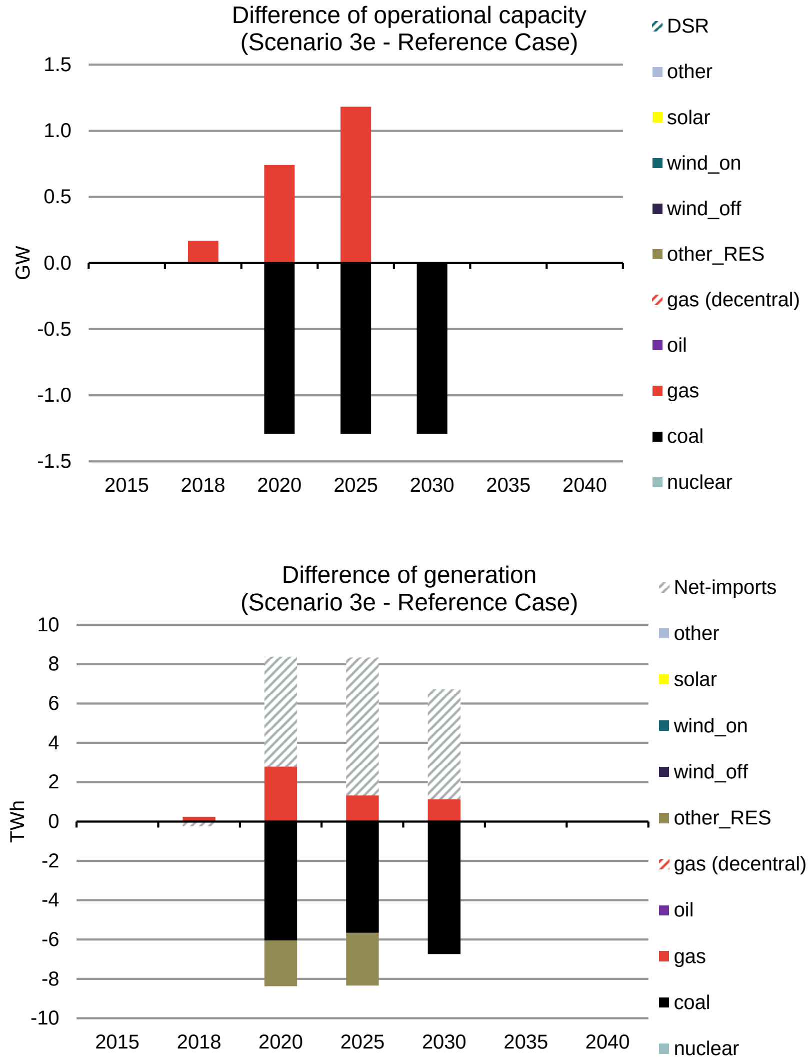
Source: Frontier

Note: Difference to the Reference Case

C.9 Scenario 3f

The figures below illustrate the impact of a closure of the two oldest coal-fired plants until 2020 on the electricity supply in The Netherlands and in all modelled countries.

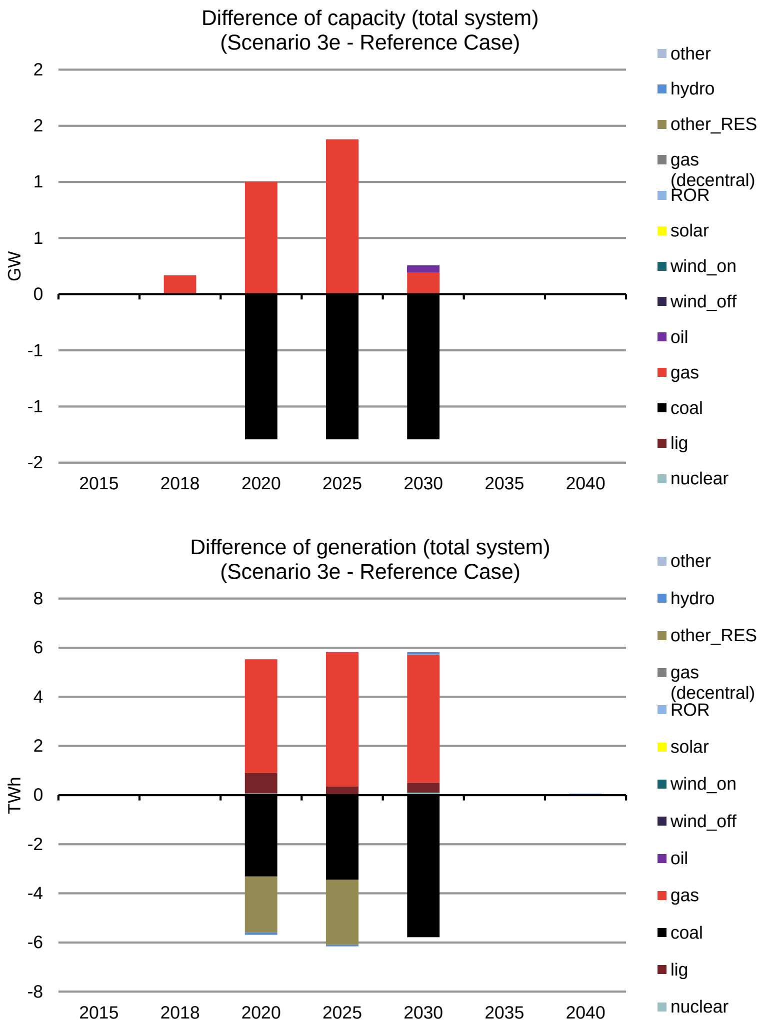
Figure 65. Impact on the Dutch electricity supply (Scenario 3f)



Source: Frontier

Note: Difference to the Reference Case

Figure 66. Impact on electricity supply (model-region) (Scenario 3f)

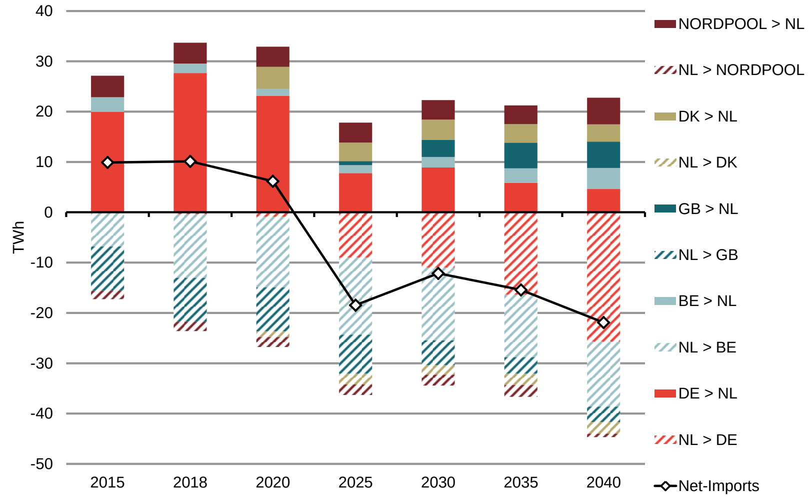


Source: Frontier

Note: Difference to the Reference Case

The figure below shows the level of imports and exports to and from The Netherlands.

Figure 67. Imports/ Exports of power (NL) Scenario 3f



Source: Frontier

Note: Difference to the Reference Case

ANNEX D MODEL DESCRIPTION

This section provides a technical description of the European power market model used in this study. The combined investment and dispatch model of the European power market is based on a linear optimisation problem[87]. The model optimises the hourly dispatch of the power plants as well as the development of installed capacity based on representative hours and selected photo-years. It is formulated in GAMS, and draws on extensive Excel databases for inputs and outputs. The model has the following characteristics:

- **Objective function –** The objective function is to minimize total costs[88] of the electricity supply in Europe. The model minimizes total costs subject to the following constraints:
  - Energy supply and consumption must be balanced in every hour in every regions;
  - Power exchange between modelled regions is limited by interconnection capacity;
  - Technical and economic constraints for power plants, storages, Demand-Side Response (DSR) as well as renewable energy sources.
- **Investment options** – In order to meet future demand at the least cost, the model optimises the power plant park in the so-called "core-regions"[89] of our model through either:
  - Investing in new capacities subject to technical and economic parameters and availability of different technological options;
  - Closing of existing power plants in the case of overcapacity; or
  - Mothballing plants and reactivation at a later point in time in order to save fixed operation and maintenance costs.
- **Temporal resolution** – The model is an integrated investment- and dispatch model. Therefore, the time frame for optimisation follows the technical lifetime of power plants. The time horizon for our analysis is from 2015 until 2049 with an hourly resolution of 4032 representative hours per photo-year.[90]
- **Geographical scope –** Our model focusses on Central-Western Europe as core-regions. Other neighbouring countries are included as non-core regions or satellite regions. This differentiation allows to model the power plant park of the core-region on a very detailed (unit-based) basis, but power exchange with other regions that are modelled with lower granularity and level of detail are at the same time included:

87 The optimisation problem is solved with the commercial Solver CPLEX.

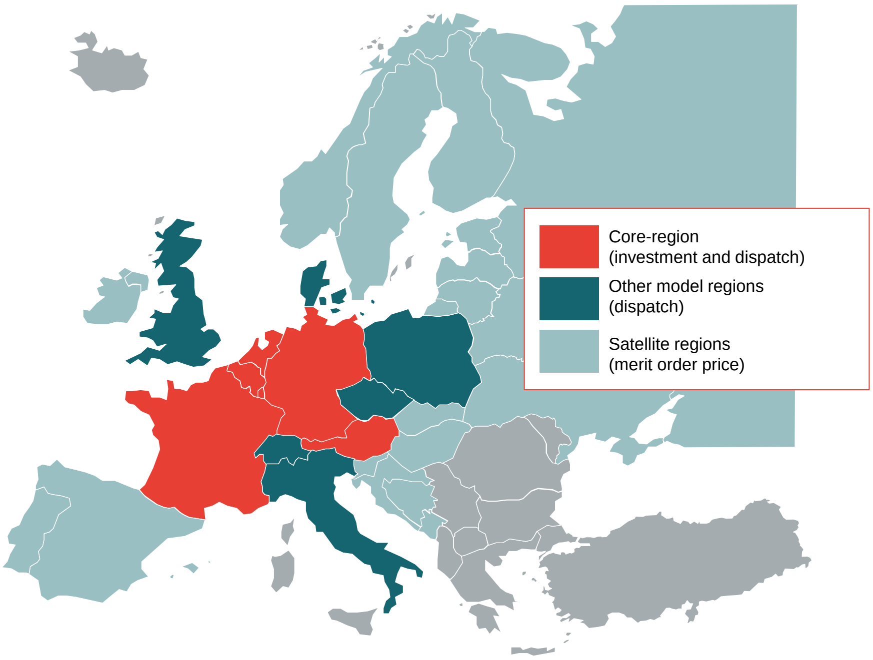
88 Total costs are minimized as net present value (NPV) today. This includes a discounting of future costs, i.e. comparable to an investment appraisal where short-term profits and costs are treated with higher time preference. We use an interest rate of 5% for the discounting of future costs and profits as well as for the calculation of investment costs of different power plants.

89 The core-regions of our model are the Netherlands, Belgium, Germany, Austria and France.

90 Analysed photo-years: 2018, 2020,2025, 2030, 2035, 2040

- **Core-regions:** The Netherlands, Belgium, Germany, Austria and France. The power plant park is modelled on a very detailed (unit-based) level, the dispatch of power plants and DSR as well as investment or divestment decisions are endogenously optimised (countries coloured in red, **Figure 68**).
- **Other model regions:** Great Britain, Denmark, Poland, Czech Republic, Switzerland, Italy. The power plant park is modelled as aggregated blocks. Capacity is set exogenously, i.e. investment and divestment decisions are not optimised (countries coloured in dark blue, **Figure 68**).
- **Satellite regions:** Other adjacent regions - for example South-Eastern Europe, the Noordpool region and Spain - are modelled as satellite regions. Power can be traded with those regions based on an exogenous price (countries coloured in light blue, **Figure 68**).

Figure 68. Geographical scope of the model



Source: Frontier

- **Security of Supply and Loss-of-load –** Demand has to be balanced in every hour and in every region. Through system-cost-minimisation, the model derives the efficient development of generation capacities and power plant dispatch (subject to additional technical and economic constraints). In order to fulfil the hourly energy balance, the model can also chose “involuntary load curtailment”, i.e. not to meet demand in every hour. This involuntary load curtailment or Loss-of-Load induces additional costs that are included in the objective function, the “Value-of-lost-Load”. Hence, we indirectly model the incentives for market participants to balance their supply obligations on then one hand side with actual power deliveries on the other hand side. The level of incentive to be balanced is given by the assumption on the Value of Lost

Load, which can be interpreted as the penalty for suppliers for the non-delivery of electricity to consumers[91]

[91] Assumed Value-of-lost-Load: 15.000 €/MWh. Our estimation is based on ENTSO-E (2013); Frontier Economics/Format Services (2014).

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