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Advisory

Energie-Nederland

Financial and economic impact of a changing energy market

Strictly Private and Confidential
25 March 2013

IPA Energy + Water Economics

pwc

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Section 1
Executive Summary

Against the background of a large increase in capacity, relatively high gas prices, low demand growth and ambitious RES targets, Energie-Nederland wants to analyse the potential financial impact on conventional power

Market fundamentals have changed

Around 10 GW of new gas- and coal-fired capacity has come online or will become operational shortly. The respective investment decisions have been taken in the past decade, but since then the market fundamentals have changed dramatically. Average power prices have decreased and the difference between peak and baseload prices has declined. Furthermore, gas prices remain relatively high and a tax on coal has been introduced recently. As a result, margins are currently under strong pressure. In addition, the demand for electricity has weakened due to poor economic conditions, and the expectation for future demand growth is low. All these developments together create serious challenges for the profitability of conventional power plants.

Electricity is important for the ambitious renewable targets

As part of the EU's 20-20-20 targets, the Netherlands needs to supply 14% of their primary energy demand with renewable energy sources (RES) by 2020. The Dutch government recently agreed to increase this target to 16% of final energy demand, which currently amounts to 4.3%. A significant increase is therefore necessary to meet the target in 2020.

Electricity plays a crucial role in meeting the targets. Reaching the 14% or 16% RES target will necessitate the share of renewable electricity to increase from the current 10% (2012) to 37%-42% in 2020.

Given the importance of electricity in meeting the targets and the impact that substantial increases in renewables will have on the power system and the financial performance of conventional power plants, Energie-Nederland is interested to understand what the potential impact will be under different scenarios.

Our study addresses (i) the financial performance of conventional power plants, (ii) security of supply, and (iii) the economics of back-up and flexibility

Energie-Nederland has asked PricewaterhouseCoopers Advisory N.V. ("PwC") and IPA Energy + Water Economics ("IPA") to undertake a detailed study of the Dutch power market and to assess the financial implications for conventional power plants. This study is to provide insight into the potential implications of the 16% RES target without prescribing a particular scenario or outcome, or suggesting possible solutions. The key findings of this analysis are summarised in this report.

Our study focuses on the potential financial and economic impact of meeting the RES target under different market scenarios. We also address the potential impact on security of supply and the need for flexible back-up capacity in the period 2013-2020.

We perform an analysis of potential market prices that are required for the economic feasibility of flexible back-up generation capacity with a very limited load factor.

For the assessment of the financial impact of a changing energy market, we model the Dutch power market under various scenarios. We use a detailed model of Northwest Europe, where all power stations, interconnections, and constraints (i.e. RES potential) are accounted for.

In all scenarios, the 16% RES target is a binding constraint in our model. This means the model determines the least-cost option to meet this target, including wind onshore and offshore (up to the limit estimated by ECN[1]), dedicated biomass and co-firing of biomass, and other sources such as solar.

[1] ECN, *16% Hernieuwbare energie in 2020 - Wanneer aanbesteden?*, 2013

Fossil-fuelled power plants (coal and gas) are projected to suffer financially over the modelled period 2013-2020

We examine three different financial metrics

We examine three different financial metrics: (i) *Gross margin* measures the difference between electricity revenues and fuel costs, (ii) *EBITDA* measures the income before taking depreciation, interest and tax payments into account, and (iii) *EBT* measures the income available after depreciation and interest payments, but before taxes.[1]

Newest coal-fired plants due to come online perform financially better than the other existing fossil-fuelled power plants, but do not earn back their investment

We project that coal-fired power plants – due to come online in the next two years (newest coal) – will demonstrate the best financial performance on gross margin and EBITDA, when compared to other conventional power plants. This is driven by relatively high efficiency and our assumed low CO_2 prices. The older coal-fired power plants have lower gross margins and negative EBITDA due to relatively lower load factors and higher costs.

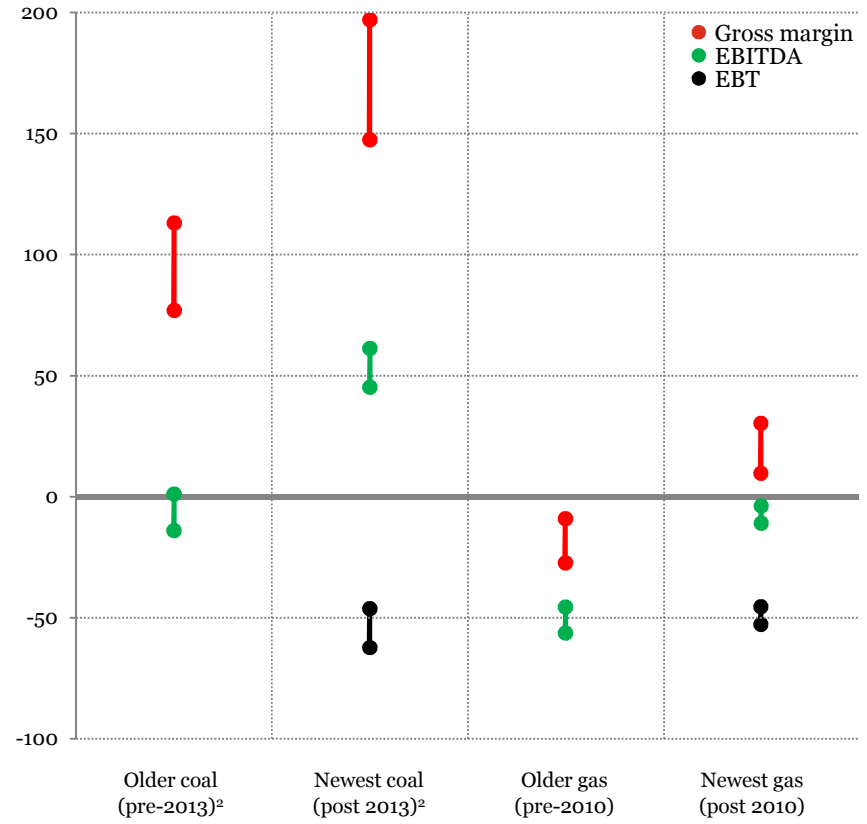
When capital costs are included (EBT) the returns are negative.

Gas-fired plants have negative EBITDA and EBT in all scenarios and do not earn back their investment

Gas-fired plants compete as price-setting technology and face relatively cheap import competition from Germany. The large gas-fired capacity base, including substantial must-run CHP, creates a long flat supply curve where prices are hardly influenced by changes in underlying costs, such as CO_2 prices.

The newest gas-fired plants have EBITDA negative or close to zero, and when capital costs are included, the returns are negative.

Indicative ranges of average financial metrics per year under all scenarios (in € per kW)



Source: PwC/IPA Analysis

[1] We only consider EBT of newest coal- and gas-fired plants, as we assume that some of older coal-/gas-fired power plants have already earned their capital costs back.

[2] Pre-2013 and post 2013 mean before and after 1 January 2013, respectively. Similar for pre-/post 2010.

In particular, gas-fired power plants suffer most from the lower power prices, lower peak-baseload spreads, relatively high gas prices and historically low CO_2 prices

The Dutch power market is currently characterised by substantial overcapacity which will remain in the medium run, while demand is expected to grow only modestly in the coming decade. This, combined with the increased share of renewable electricity from the domestic market and from the German market, further suppresses power prices in the Netherlands.

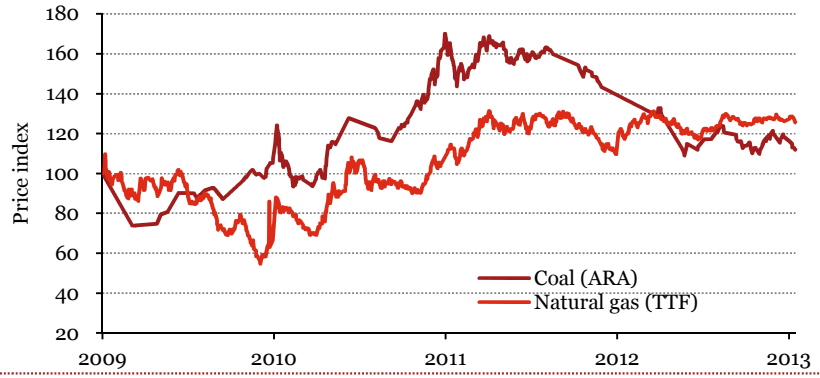
Part of the explanation for the underperformance of gas-fired power plants has been the declining trend of coal prices relative to gas prices. Some recently built gas plants have had load factors below 10%. A reduced number of operating hours requires higher peak prices in order to have a "healthy" financial performance. Unfortunately, peak prices relative to the baseload prices have dropped significantly in recent years, as the result of the increasing supply of RES during the peak hours.

At the same time historically low CO_2 prices limit the cost differences between coal and gas. Our scenario analysis however shows that an increase in CO_2 prices only marginally improves the financial performance of gas-fired power plants, due to the substantial over-capacity and increased RES share.

Gas-fired power plants switch places with coal-fired power plants if gas prices drop relative to coal prices. Our scenario analysis shows that a 40% reduction is needed for gas-fired power plants to outperform coal-fired power plants.

Further closure of must-run gas-fired power capacity (CHP) increases power prices and benefits the financial performance of gas-fired power plants, but the impact is limited as imports from Germany subsequently increase as well.

Historical price movement of coal and natural gas



Power price peak/base multiple

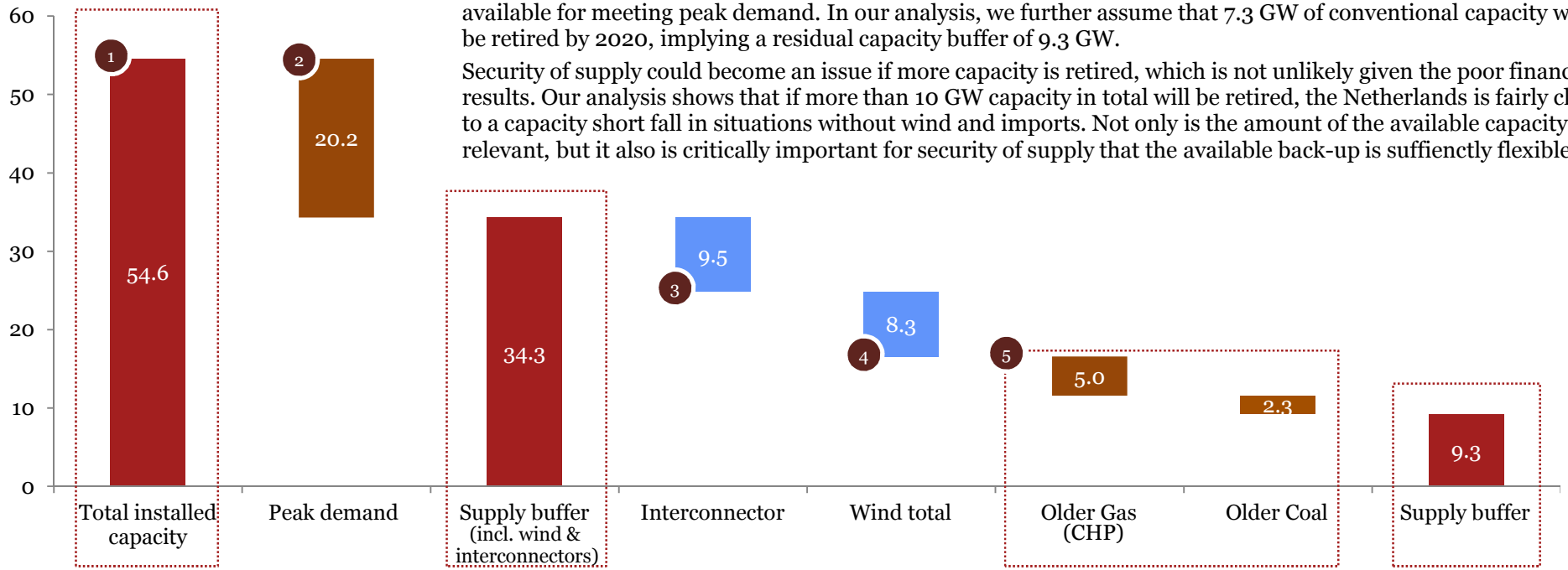
Sources: Bloomberg, Eurostat, PwC Analysis

Security of supply is not at risk due to the overcapacity in the current Dutch power market

Security of supply in 2020 (in GW)

Total peak demand in 2020 is projected to be just over 20 GW, while the total installed capacity (including wind and interconnection) is expected to be 55 GW. When all the interconnection capacity (9.5 GW) and a significant part of wind capacity (8 GW) are excluded, approximately 16.5 GW of residual dependable capacity still remains available for meeting peak demand. In our analysis, we further assume that 7.3 GW of conventional capacity will be retired by 2020, implying a residual capacity buffer of 9.3 GW.

Security of supply could become an issue if more capacity is retired, which is not unlikely given the poor financial results. Our analysis shows that if more than 10 GW capacity in total will be retired, the Netherlands is fairly close to a capacity short fall in situations without wind and imports. Not only is the amount of the available capacity relevant, but it also is critically important for security of supply that the available back-up is suffienctly flexible.



Assumptions

1. Total projected installed capacity in 2020 to reach 55 GW, including all potential interconnection capacity (9.5 GW)
2. Capacity needed for the peak demand is projected to be 20 GW in 2020, without considering the effect of demand side management
3. All available interconnection capacity is not dependable
4. 75% of the total wind capacity is considered as not dependable, and is therefore excluded from the reserve capacity
5. 5 GW gas-fired CHP and 2.3 GW older coal capacity will be retired by 2020. This obviously depends on the financial position and the decisions by the owners. The assumption of the retirement of 5 GW CHP by 2020 is not unlikely. A recent study of Productschap Tuinbouw/LTO (November 2012) shows that all existing CHPs would not able to generate sufficient returns to cover their costs in 2019 in some unfavourable scenarios. Must-run CHPs would be replaced by cheaper alternatives. In 2007, VEMW already indicated a potential reduction of 4.5 GW CHP by 2020 in its report "INDUSTRIËLE WARMTEKRACHTKOPPELING"

Current market prices are not sufficient to compensate the total costs for operating a CCGT with a limited load factor

A high price will be needed for recovering the total costs of back-up capacity with a limited load factor

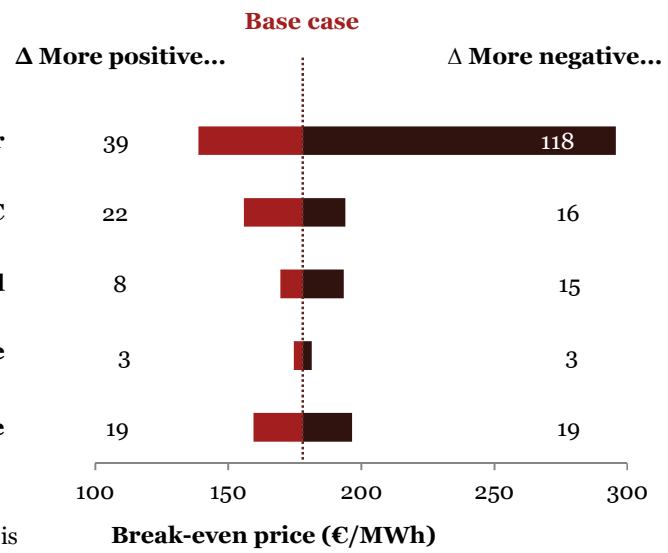
Some form of flexible back-up capacity will be required to act as a buffer to quickly meet peak demand. This can be a modern coal-fired or a new or existing gas-fired power plant with low ramp-up time and relatively high flexibility (CCGT or OCGT). It is not unusual to assume that this plant will only run for 5%-15% of the year.

Gas-fired power plants are currently the price-setting technology in the Dutch market. This is the result of relatively high gas prices (compared to coal prices) and low CO_2 prices (favouring coal-fired generation). The substantial increase in renewable capacity domestically in the next years, and imports of cheap renewable power from Germany, will suppress the financial position of gas-fired generation.

This is exacerbated by a large share of gas-fired generation capacity in the Dutch market, and significant must-run capacity for heat and steam production-leading to uneconomic dispatch and electricity production. Simultaneously, a certain amount of flexible generation is required to provide necessary back-up in situations where less or no renewables/imports capacity is available.

To assess the price levels that are needed to support the financial business case of a new CCGT, we have undertaken a high-level analysis of operational and capital costs assuming a load factor between 5% and 15% (i.e. 438 hours and 1,314 hours of the year). Based on our analysis, the break-even price (at 10% load factor) is significantly higher than the current market price and is estimated at around €180/MWh - this price is however very sensitive to the load factor.* Our sensitivity analysis also shows that a decrease of 5 percentage points in the load factor would increase the break-even price to almost €300/MWh.

Parameter	More positive for CCGT	Base case	More negative for CCGT
Load factor	15%	10%	5%
WACC	5%	8%	10%
Pay back period	25 yrs	20 yrs	15 yrs
CO_2 price	€0/t	€10/t	€20/t
Fuel price	€20/MWh	€30/MWh	€40/MWh



Source: PwC Analysis

* Estimated break-even prices are indicative, based on the assumed investment cost of €900/kW which is a reasonable approximation in the current market. Even by assuming a much lower capex (e.g. €500/kW), the break-even price will remain significantly higer than the current power prices.

Various domestic technical RES-options, statistical transfer with other EU member states and the CO_2 prices influence the costs for the Dutch tax payer

Given potential constraints of new wind capacity, biomass co-firing may be a necessary and relatively economical option to meet the RES targets in 2020

Our model determines the least-cost options to meet the 16% RES targets in 2020. Given our model assumptions, including potential constraints of new wind capacity as estimated by ECN, the scenario analysis indicates that biomass co-firing, like onshore and offshore wind, would be necessary for meeting the RES target.

In contrast to other RES technologies, a relatively limited amount of initial investment is required for biomass co-firing. However, the additional fuel cost for co-firing can be volatile, as it depends much on the acquisition prices of biomass. In an unfavourable biomass market, the additional costs per kWh of co-firing can be more expensive than, for instance, the cheapest SDE+ categories of onshore wind. In general, biomass co-firing is less expensive than offshore wind.

We examine different levels of co-firing in the scenario analysis, with co-firing percentages ranging from 10% to 40%. The least-cost approach of the model can lead to noticeable outcomes, where the load factor of coal-fired power plants will increase considerably from 2019 to 2020 in order to meet the RES target in 2020. Consequently, CO_2 emissions will increase as well in 2020. However, the average CO_2 emissions over the whole analysis period 2013-2020 will decrease slightly if the co-firing percentage is high.

Further analysis will be needed to determine what levels are technically and economically feasible, taking into account supply chain constraints for biomass, and additional capital and operational costs of higher co-firing (e.g. reduced thermal efficiency).

Statistical transfer is an option to realise a higher national RES target, without requiring extra domestic RES generation

The RES target can be met by purchasing the renewable electricity rights from neighbouring countries that have a surplus. This statistical transfer could release some pressure on realising domestic renewable capacity.

From a theoretical perspective, the price for acquiring the transfer rights should make up for the difference between the market power price and the integral cost of relatively cost-effective RES technologies (e.g. onshore wind). However, in a constrained market where a particular country has subsidised wind onshore and other more expensive technologies, it is likely that the difference with the more expensive technology will need to be paid to acquire the rights.

In the light of abundant generation capacity in the domestic market and potential build constraints of domestic RES generation capacity, statistical transfer might nevertheless be a useful and practical option. Furthermore, it requires no upfront investment.

Higher CO_2 prices potentially reduce the subsidies required to meet the RES targets

An increase in the CO_2 price has negative financial consequences for the gas- and coal-fired power plants, albeit with a stronger impact for the coal-fired power plants (given their higher CO_2 emissions per MWh).

The increased power price due to a higher CO_2 price will be partially passed on to consumers. This reduces the level of subsidy needed to cover the cost difference with RES. The increased CO_2 price has less effect when it is only applied to the Dutch market, as the cost differential will lead to increased imports from 2016 onwards.

Section 2
Overview of scenarios and results

We have defined scenarios in order to study the potential financial impact of changes in the energy market on conventional power generation

Financial impact analysis

We use different market scenarios to assess the impact on the financial performance of conventional power plants. For this purpose, we, together with Energie-Nederland, have specified eight main scenarios (see the table on the right side).

We have considered the following key outputs over the analysis period 2013-2020 for each main scenario:

- Installed capacity mix
- Fuel mix in generation
- CO_2 emissions
- Electricity prices
- Import and export of electricity
- Annual gross margin per kW of coal- and gas-fired power plants
- Annual EBITDA per kW of coal- and gas-fired power plants

Report structure

This report is structured as follows: We first elaborate the key outputs of Scenario II, which is considered as the reference scenario ("the base scenario"), in Section 3.

In Section 4, we reflect the main differences in the key outputs between the base scenario and the alternative scenarios.

Finally, we present detailed analyses of alternative scenarios and sensitivity analyses of Scenario II in the appendix.

Definition of main scenarios

Scenario	Key Assumptions
I.	• 16% RES-target to be met by domestic RES generation by 2020 • CO_2 price flat at €10/t over 2013-2020 • Coal tax 2013-2020 • 10% co-firing (10% of all energy-input biomass), at coal-equivalent cost • ECN annual build limits for wind onshore and offshore
II. (the base scenario)	• Same as I, but with… • Decommissioning of 2.3 GW pre-1990 coal by 2016, and 5.0 GW pre-2010 gas from 2016 in 5-equal steps • 20% co-firing, at coal-equivalent cost
III.	• Same as II, but with… • 40% co-firing , at coal-equivalent cost
IV.	• Same as III, but with… • CO_2 price increases linearly to €25/t in 2020
V.	• Same as III, but with… • CO_2 price increases linearly to €25/t in 2020, for Netherlands only • CO_2 price flat at €10/t 2013-2020, for other countries • Coal tax only in 2013, but not in 2014-2020
VI.	• Same as II, but with… • 14% RES target to be met by domestic RES generation 2020 • 2% statistical transfer (cost difference calculation for wind onshore, wind offshore, and solar/PV)
VII.	• Same as II, but with… • Additional retirement of 3 less efficient pre-2010 gas
VIII.	• Same II, but with… • Capacity markets in the neighbouring countries

Overview of key findings per scenario (1/2)

Scenarios	Main findings	Page
Scenario I. *16% target* *No capacity retirement* *10% co-firing*	• All onshore and offshore wind generation potential will be realised to meet the 16% RES target, based on the ECN's maximum build estimates • 2 GW of dedicated biomass is also needed for meeting the RES target, next to wind and 10% biomass co-firing • With substantial gas-fired power as price-setter, the Netherlands becomes a net exporter by 2015 • The financial returns of most conventional power plants (except for newest coal), in terms of average annual EBITDA per kW over 2013-2020, are strongly negative, and are significantly poorer than in Scenario II • When taking capital costs into account (i.e. in terms of EBT per kW), all conventional power plants (including newest coal) have negative financial results	*31-35*
Scenario II. (base scenario) *Capacity retirement* *20% co-firing*	• The Netherlands will remain a net importer (except for 2015 and 2020) • Only newest coal has positive annual EBITDA per kW on average over 2013-2020 (but with negative EBT per kW), while less efficient older gas-fired power plants financially suffer most • The average annual EBITDA of exisitng coal and efficient newest gas plants are negative as well, but close to zero	*13-19*
Scenario III. *40% co-firing*	• Due to higher share of biomass co-firing, less offshore wind and dedicated biomass need to be built • This lower ramp-up of domestic generation makes the Netherlands to become a net importer in 2013-2020 • Prices are slightly higher than in the base case • With the extra co-firing costs still assumed to be paid for externally, the EBITDA for all coal plants improves slightly compared to the base scenario	*36-40*
Scenario IV. *CO_2 price to €25/t*	• Prices are higher than in all other scenarios, due to higher CO_2 price • Economics of older coal and older gas are worse as a result of increased CO_2 costs, while the financial performance of newest coal and newest gas improves slightly • The higher CO_2 price stimulates only a marginally greater amount of offshore wind and dedicated biomass generation	*41-45*
Scenario V. *CO_2 price to €25/t for NL only* *No coal tax*	• With a higher fossil cost base than its neighbours and increased interconnection capacity with Germany from 2016, the Netherlands becomes a much greater net importer from 2016 onwards than in Scenario II • Dutch power prices are slightly higher than in II, but lower than in IV due to increased imports • The removal of the coal tax actually benefits Dutch coal plants relative to gas in comparison to IV, widening the cost differential to the price-setting plant, and the average EBITDA for the existing plants is again slightly positive over 2013-2020 albeit not as much as II	*46-50*
Scenario VI. *14% target*	• As a result of a lower RES target, not all the offshore wind is built • And only 800 MW of dedicated biomass needs to built domestically • Dutch power prices are close to II, as are the economics of conventional plants, slightly lower on average in 2013-2020	*51- 55*

Overview of key findings per scenario (2/2)

Scenarios	Main findings	Page
Scenario VII. *Additional 3 GW gas closure*	• Electricity prices are relatively higher in the last years of the decade (2018-2020) compared to other scenarios • Financial performance of all types of plants improves slightly due to higher power prices • Import rises througout 2013-2020, mostly from Germany • Further closure of capacity after 2020 could lead to capacity shortfalls	*56-60*
Scenario VIII. *Capacity markets neighbouring countries*	• The export to GB reduces significantly due to the capacity premium in the GB, compared to Scenario II • The Netherlands will however remain a net importer (except for 2015 and 2020) • The financial performance of conventional power plants is similar to the situation in Scenario II	*61-65*

Detailed financials, prices and CO_2 emissions per scenario show slight variations across the different scenarios

Scenario	Average EBITDA 2013-2020 (€/kW)				Ave. E-price 2013-2020 (€/MWh)[1]	Ave. CO_2 emission NL electricity (mln tonnes)[2]	Average subsidy per MWh RES (€)	Average annual subsidy RES (bln €)[3]	Average annual import (TWh)	Average annual export (TWh)
	C1	C2	G1	G2						
I. *16% target No capacity retirement 10% co-firing*	(9)	45	(56)	(11)	51	53	44/75	1.5/2.6	14	23
II. *Capacity reduction 20% co-firing*	(0)	58	(49)	(5)	53	47	41/72	1.4/2.5	21	19
III. *40% co-firing*	1	61	(48)	(4)	53	45	43/71	1.4/2.3	24	18
IV. *CO_2 price to €25/t*	(14)	47	(45)	(4)	57	44	38/66	1.3/2.2	23	16
V. *CO_2 price to €25/t for NL only No coal tax*	(2)	54	(54)	(9)	54	43	42/70	1.4/2.3	29	19
VI. *14% target*	1	60	(48)	(4)	53	47	39/72 [4]	1.2/2.2 [4]	24	19
VII. *Additional retirement of 3 GW gas-fired capacity*	1	61	(47)	(4)	53	45	40/72	1.4/2.4	24	19
VIII. *Capacity markets in neighbouring countries*	(1)	56	(50)	(5)	53	46	41/73	1.4/2.5	21	19

C1 = Older coal power plants
C2 = Newest coal power plants
G1 = Older gas-fired power plants
G2 = Newest gas-fired power plants

[1] Weighted by generation volume per year
[2] The difference between scenarios involves the Dutch emissions only, and will have no impact on the emissions under EU ETS outside the Netherlands
[3] Only very high-level estimations of subsidies, based on SDE+ 2013 for wind and solar, and ECN's estimates for additional costs of co-firing biomass and simulated power prices
[4] Based on a 2% statistical transfer of onshore and offshore wind, using SDE+ 2013 assumptions

Section 3
Scenario II - the base scenario

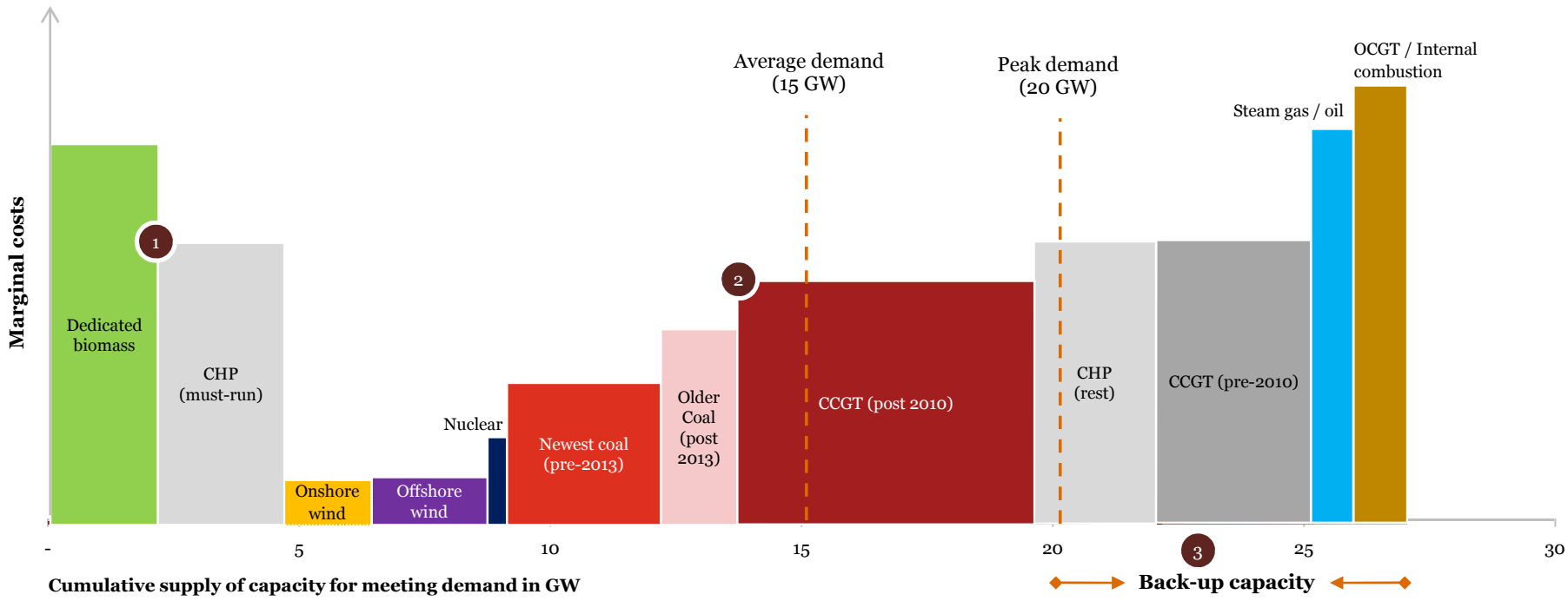
Key assumptions

- 16% RES target to be met by domestic RES generation 2020 (assumed to require 42% of electricity generation to be from RES)
- Flat CO_2 price of €10/t
- Coal tax 2013-2020
- 20% co-firing (20% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.3 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency)

Main findings

- The Netherlands will remain a net importer (except for 2015 and 2020)
- Only newest coal has positive annual EBITDA per kW on average over 2013-2020 (but with negative EBT per kW), while less efficient older gas-fired power plants financially suffer most
- The average annual EBITDA of exisitng coal and efficient newest gas plants are negative as well, but close to zero

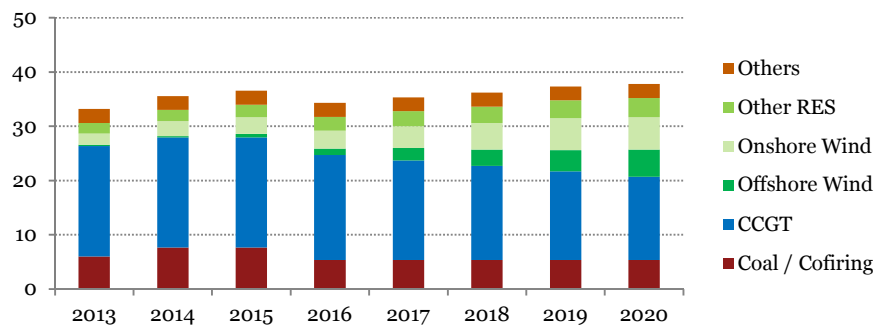
Stylised merit order 2020



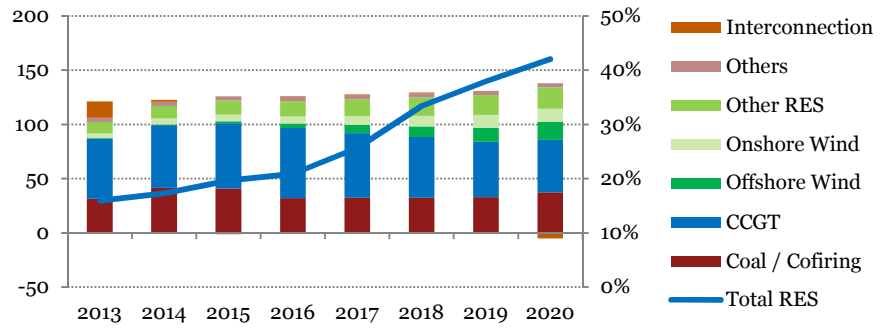
1. Dedicated biomass and must-run CHP act as the first suppliers to meet the demand, despite the relatively higher marginal costs of these plants. Therefore, the must-run capacity does not response to economical signals in the market. Dedicated biomass generation is employed, next to the 20% co-firing of biomass, to meet the 16% RES target in 2020, while the must-run CHP keeps running to meet the heat demand from industrial process and household
2. Gas-fired generation capacity due to its substantial share in the capacity mix remains price-setter. Consequently, the electricity price in this scenario will remain relatively stable
3. Despite the retirement of about 7 to 8 GW conventional generation capacity, the back-up capacity (of 7 GW) still remains high compared to the peak demand of 20 GW in 2020

Scenario II: installed capacity & generation

Scenario II: capacity mix excluding interconnection (in GW)



Scenario II: generation mix (in TWh LHS, RES in % RHS)



Source: PwC/IPA Analysis

Security of supply is not under pressure, despite of the closure of existing plants

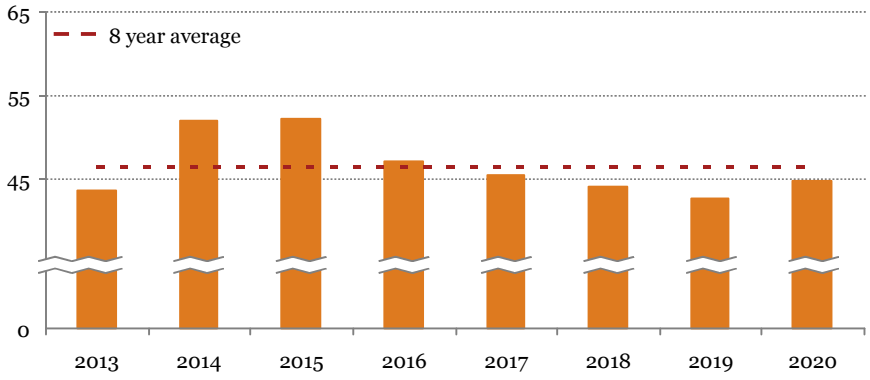
- The installed capacity will increase by 5 GW from 33 GW in 2013 to 38 GW in 2020
- The decrease in capacity from 2016 is due to the assumed closure of 2 GW of older coal power plants and 5 GW of less efficient gas-fired power plants (including cogeneration plants)
- The expected capacity over the period 2013-2020 is sufficient to cover the expected peak demand. The reserve margin based on dependable capacity is expected to be between 30-60%. This is considerably lower than the expected reserve margin in the case of no power plant closures, but still more than sufficient to meet the peak demand

Coal and gas remain dominant in the generation mix

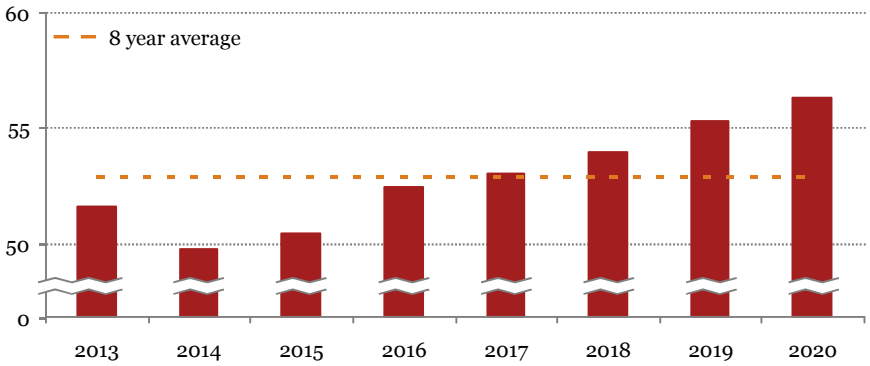
- Coal and gas remain important in the Dutch generation mix
- The target of 42% RES electricity will be met by increased co-firing in 2020, leading to higher generation output of coal-fired power plants
- The import and export of electricity are almost in balance
- The closure of coal-fired power plants results in an increase/decrease in gas-/coal-fired power generation

Scenario II: CO_2 emissions and electricity prices

Scenario II: CO_2 emissions (in tonnes mln.)



Scenario II: electricity price at 2013 price levels (in €/MWh)



Source: PwC/IPA Analysis

The new RES generation and the retirement of existing conventional capacity slow the increase in CO_2 emissions

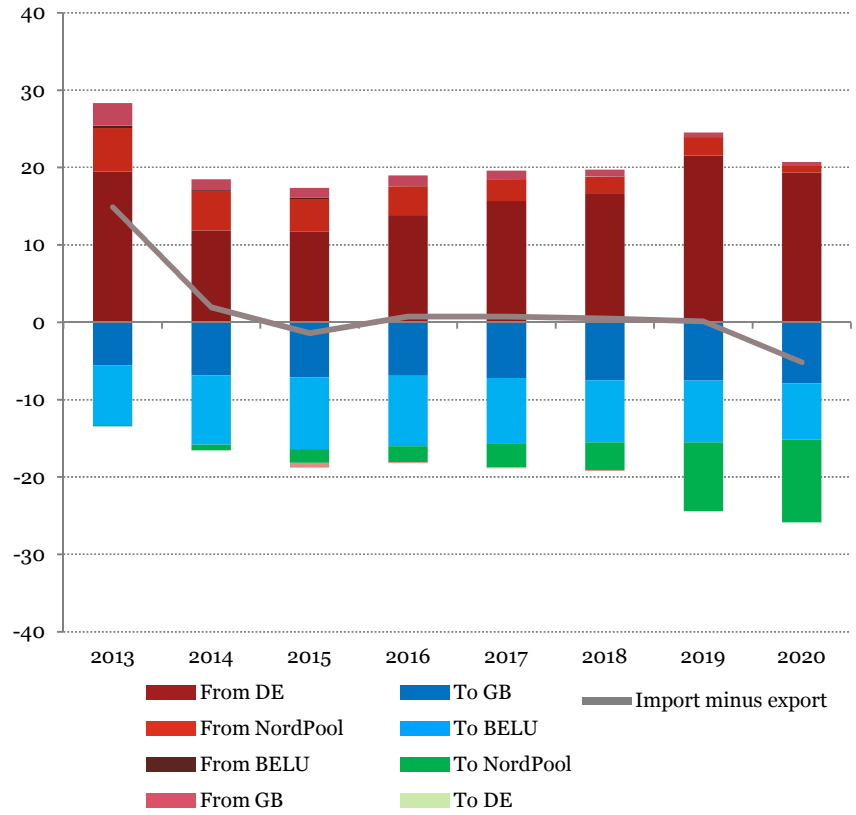
- CO_2 emissions from power generation in 2020 will remain at the same level as 2013 (i.e. around 45 mln. tonnes), despite the addition of newest coal-fired generation capacity from 2014 and 2015. This can be explained by
  - the addition of wind power generation
  - the closure of some coal and gas power plants from 2016
  - high co-firing share of biomass (20%)
- The increase of carbon emissions in 2020 is the consequence of the increased co-firing of biomass in coal-fired power plants for meeting the RES target

Electricity price increases from 2015 onwards after initially declining in 2014

- Recent APX day ahead power prices have moved between €50 to €60 MWh, which is also the case for the projected base load price in our analysis. We project an average power price of €53/MWh over 2013-2020
- The commissioning of highly efficient newest coal power plants in 2013 and 2014 contributes to a lower price level in 2014. However, the power price increases again in 2015, due to the expected increase of coal prices in that year
- The retirement of older coal-fired generation capacity, combined with the increasing fuel prices (in particular natural gas), leads to higher power prices from 2016 onwards

Scenario II: import and export

Scenario II: import to vs. export from the Dutch power market (TWh/year)



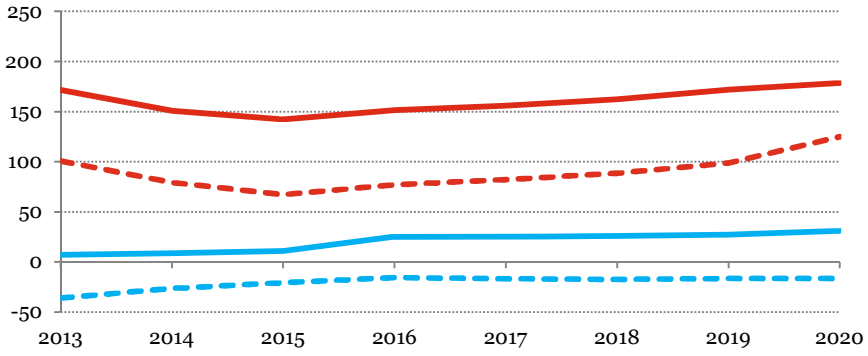
Source: PwC/IPA Analysis

Imports and exports are in balance over the period

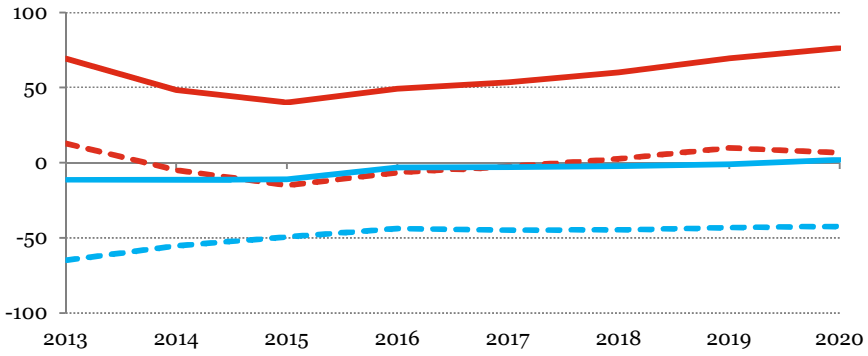
- In the period from November 2011 to November 2012, the Dutch market imported 26 TWh electricity from its neighbours, mainly from Germany. On the other hand, the Dutch power generators sold about 11 TWh to the foreign markets
- Germany will remain the largest supplier of electricity outside the domestic market, while Belgium, GB and NordPool will be the largest export markets for the Dutch electricity in 2020
- Exports increase between 2013 and 2015 with newest coal-fired generation coming online, while imports drop significantly in 2014. As a result, the Netherlands becomes a net exporter in 2015. From 2016 to 2019, imports increase gradually, as more than half of older coal capacity is retired from 2016
- The significant increase in export to NordPool in 2019 is due to the addition of new interconnection capacity of 700 MW
- Co-firing of biomass in coal power plants, which is needed to meet the target in 2020 in our model, will result in an oversupply of coal power in the Dutch market, leading to an increase in export in 2020. As a result of this, the Netherlands becomes a net exporter in 2020

Scenario II: financial performance

Scenario II: gross margin (€ per kW)



Scenario II: EBITDA (€ per kW)



Older Coal — Older Gas
Newest Coal — Newest Gas

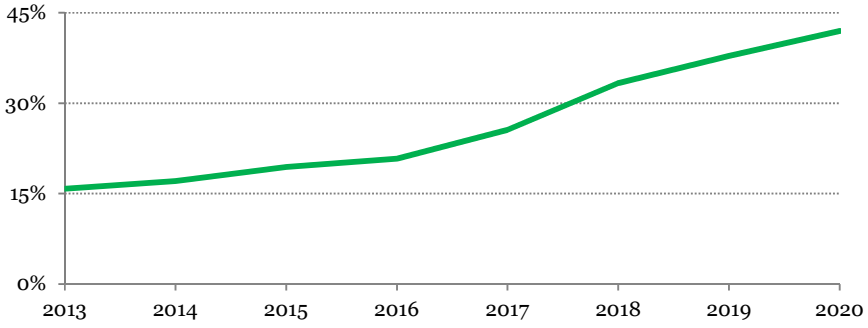
Source: PwC/IPA Analysis

Financial performance of less efficient coal and gas plants remains poor over 2013-2020

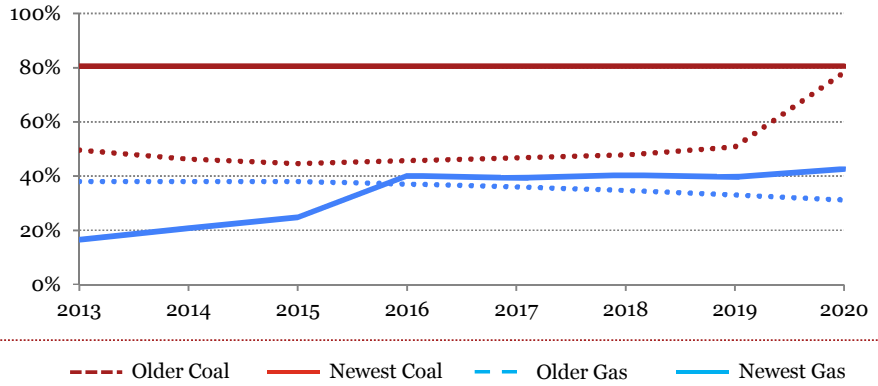
- The newest coal-fired power plants are expected to have the best financial performance in terms of annual gross margin and EBITDA per kW, but have negative average EBT per kW
- The older coal power plants also have positive gross margins due to relatively high electricity prices, but considerably lower than the newest coal due to lower efficiency
- Gross margins as well as EBITDA of gas-fired power plants built pre-2010 ("less efficient gas") remain negative. This is a result of the combination of relatively expensive natural gas and lower efficiency of these older plants
- Efficient gas-fired power plants built after 2010 have positive gross margins over all years, but no positive EBITDA on average. The EBITDA performance of these power plants is similar to the performance of older coal-fired power plants

Scenario II: analysis of load factor

Scenario II: development of renewable electricity in the total electricity demand (in %)



Scenario II: load factor of different plant type (% of full year)



Source: PwC/IPA Analysis

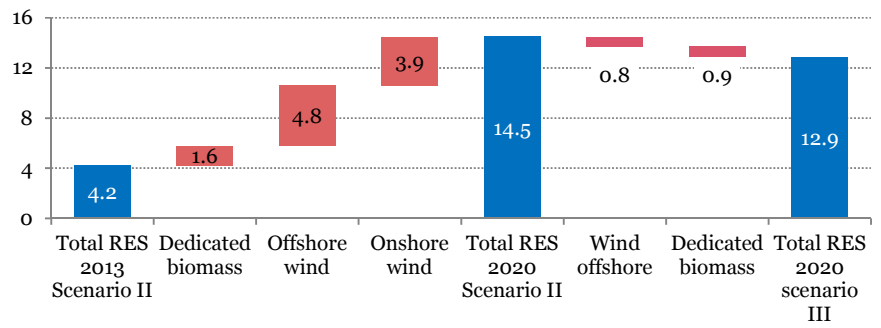
Newest coal-fired power plants have the highest load factor, while other conventional plants have relatively low running hours

- The newest coal-fired power plants have the most stable and high number of running hours (about 7,000 hours per year), as they have the lowest dispatch costs
- The older coal-fired power plants ("old coal") have much lower load factors (about 4,000 operating hours), as they are less efficient than the newest coal
- However, the average load factor of old coal will increase from 51% in 2019 to 78% in 2020, as a result of the catch-up of the 16% RES target in 2020 with the help of co-firing. Consequently, the share of RES electricity will increase from 38% to 42% of the total demand from 2019 to 2020. The jump in older coal generation in 2020 to meet the RES target through co-firing would be from out-of-merit running, which will need to be incentivized in the market through additional direct cost subsidies beyond just the incremental cost of switching from coal to biomass
- The less efficient gas-fired power plants built pre-2010, mainly consisting of gas-fired CHP (about 50% of which is considered as must-run CHP), have stable but relatively low load factors (around 3,000 running hours per year)
- The more efficient gas-fire power plants (built post 2010) have the lowest load factor in 2013-15 (1,800 running hours per year on average). However, we project a load factor of 40% (equivalent with 3,500 running hours per year) in 2016-2020 for these newer gas plants. The increase in the load factor is mainly due to the retirement of 7 to 8 GW less efficient existing capacity from 2016

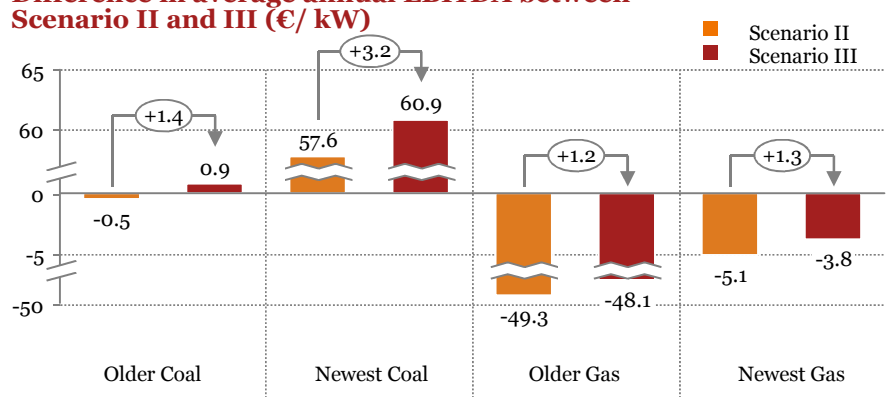
Section 4
Comparison analysis between the base and alternative scenarios

Scenario III: less domestic renewable capacity required as co-firing increases and the Netherlands reverts to being a net importer in 2014-2020

Scenario III: RES capacity development 2013 - 2020 compared to scenario II (in GW)



Difference in average annual EBITDA between Scenario II and III (€/ kW)



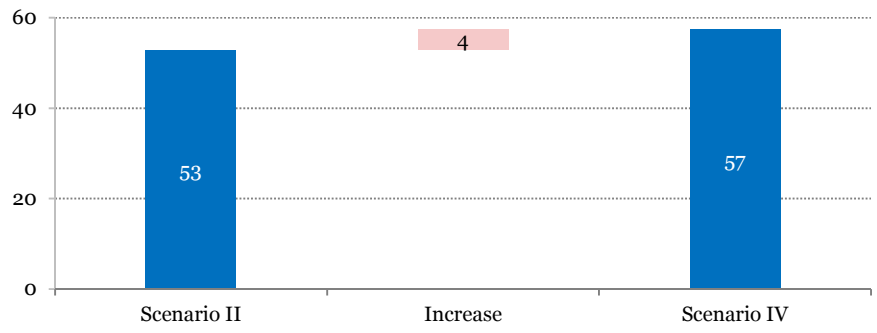
Co-firing increases to 40% in Scenario III

- In Scenario III we increase the co-firing percentage from 20% to 40% - assuming that all additional costs are compensated externally
- The increase in co-firing means that less domestic renewable capacity is required to meet the 2020 RES target, and the RES target is met by increasing the load factor of coal-fired generation
- In total 800 MW less wind offshore is required, and 900 MW less dedicated biomass capacity is built
- The decreased rate of domestic renewable capacity results in the Netherlands reverting to a net importer in 2013-2020, predominantly from Germany
- Electricity prices are slightly higher than Scenario II, whereas CO_2 emissions are lower due to the higher co-firing percentage (40% versus 20%)
- The financial performance improves for all players, but the EBITDA for newest coal-fired power plants has gained the largest increase in absolute amount by about €3 per kW (i.e. a 6% increase) compared to Scenario II, as power prices are slightly higher
- The annual subsidy costs do not differ significantly compared to Scenario II

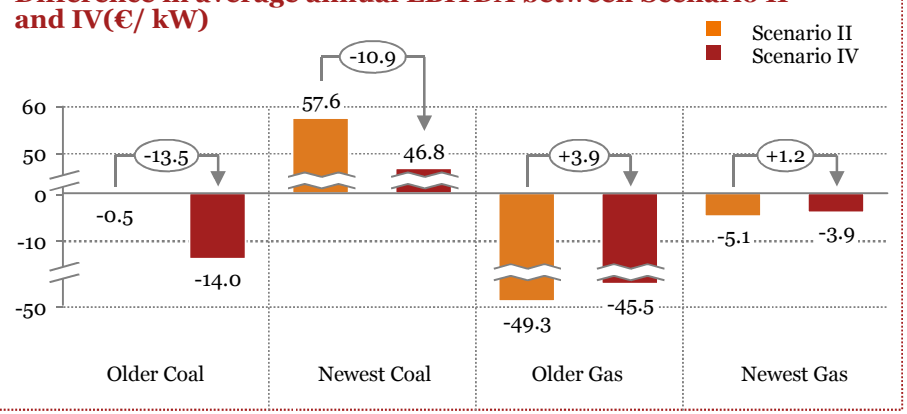
Source: PwC/IPA Analysis

Scenario IV: an increasing CO_2 price reduces the financial performance of coal plants (with negative returns for old plants) and potentially reduces the direct subsidy from the government for RES

Difference in average annual electricity price between Scenario II and IV (€/MWh)



Difference in average annual EBITDA between Scenario II and IV(€/ kW)



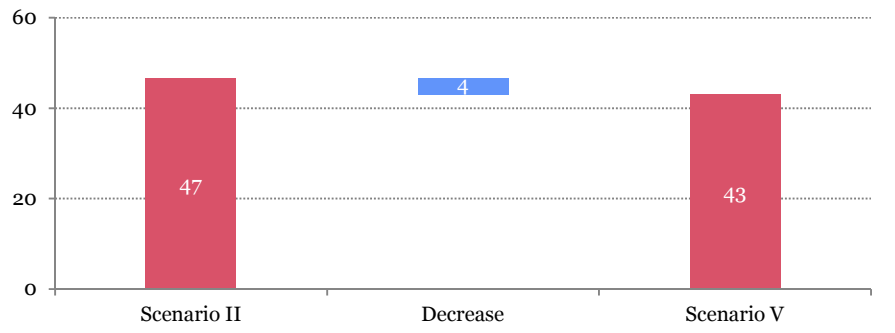
Source: PwC/IPA Analysis

The CO_2 price increases to €25/t in 2020 in Scenario IV

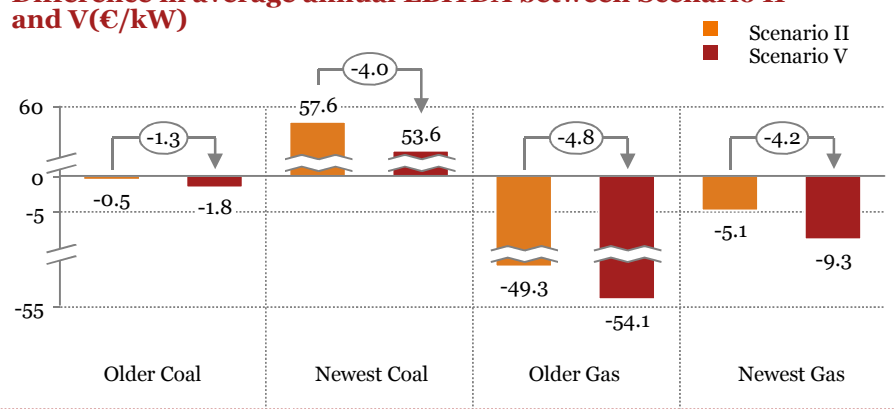
- In Scenario IV we increase the CO_2 price linearly from €10/t in 2013 to €25/t in 2020 (in Scenario II the CO_2 price remains flat at €10/t)
- The higher CO_2 price is reflected in the market price for electricity, increasing by €4/MWh compared to Scenario II
- The higher CO_2 price stimulates only a marginally greater amount of offshore wind and dedicated biomass build
- The higher CO_2 price implies higher costs for conventional power plants emitting CO_2. In particular, this affects the financial position of the coal-fired plants considerably
  - The old coal-fired plants have negative annual EBITDAs from 2014 onwards, ranging from -103 to -35 € per kW. The average EBITDA over 2013-2020 amounts to -€14/kW
  - The newest coal-fired plants see a 19% decrease in EBITDA per kW as a result of higher CO_2 prices. This is equivalent to €38 mln losses per year, based on 3.5 GW of newest coal capacity
- As gas-fired generation is the price-setter in the Netherlands there is only a marginal increase in the EBITDA, compared to Scenario II
- Dutch CO_2 emissions are second-lowest after Scenario V
- With higher electricity prices, the total subsidy costs to meet the RES target are potentially lower than in Scenario II

Scenario V: with a higher Netherlands-only CO_2 price and no coal tax, the increased imports hurt gas-fired power plants more than coal-fired generation. CO_2 emissions are lowest in this scenario

Difference in average annual CO_2 emissions between scenario II and V (in tonnes mln.)



Difference in average annual EBITDA between Scenario II and V(€/kW)



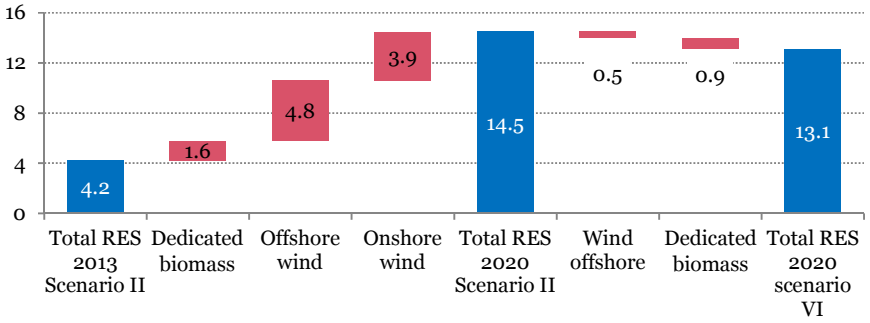
Source: PwC/IPA Analysis

The CO_2 price increases to €25/t in 2020 in Scenario V for the Netherlands only, and remains flat at €10/t for the other countries, and the coal tax is removed from 2014

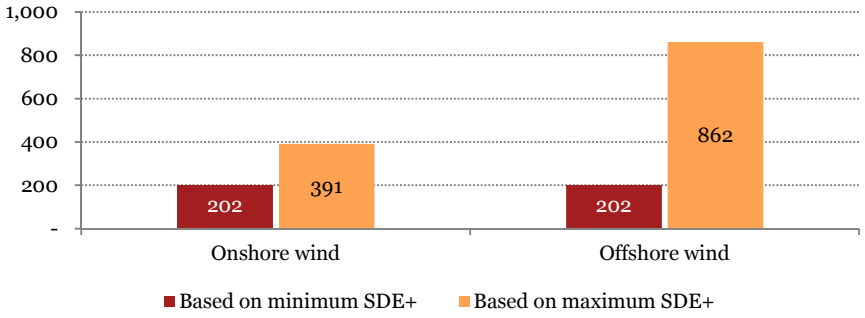
- In Scenario V, the CO_2 price is increased for the Netherlands only, with the CO_2 price remaining low and flat in the surrounding jurisdictions
- With a higher cost base than its neighbours and the increased interconnection capacity with Germany from 2016, the Netherlands becomes a much greater net importer from 2016 onwards, compared to the base scenario. In particular, the imports from Germany increase significantly from 2015 to 2016 (about 80%) in Scenario V
- Dutch power prices are slightly higher than in Scenario II, but lower than in IV due to increased imports
- There is no change in the renewable capacity mix compared to Scenario II
- CO_2 emissions in the Netherlands are lowest in this scenario as coal-fired generation is reduced. About 4 million tonnes carbon emissions per year are reduced compared to the base scenario
- The higher CO_2 price has a negative effect on the EBITDA of the coal-fired plants, but this is offset by the removal of the coal tax
- The financial position of the gas-fired power plants worsens substantially as they face increased CO_2 prices and lower load factors due to increased imports from Germany – decreasing the EBITDA per kW for high efficiency gas-fired plants by more than 80%. This is equivalent to €28 mln. financial losses, assuming 6.5 GW of high efficiency gas-fired capacity

Scenario VI: the target of 14% RES means less need for offshore wind and dedicated biomass. The lower domestic ramp-up of RES improves the financial position of conventional players slightly

Scenario III: RES capacity development 2013 - 2020 compared to scenario II (in GW)



Potential costs of 2% statistical transfer of wind energy (€ mln)



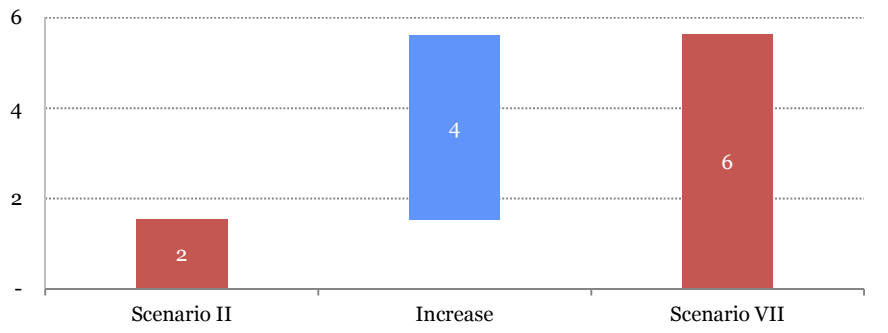
Source: PwC/IPA Analysis, Agentschap NL (SDE+ 2013)

RES target set at 14% in Scenario VI, with 2% statistical transfer

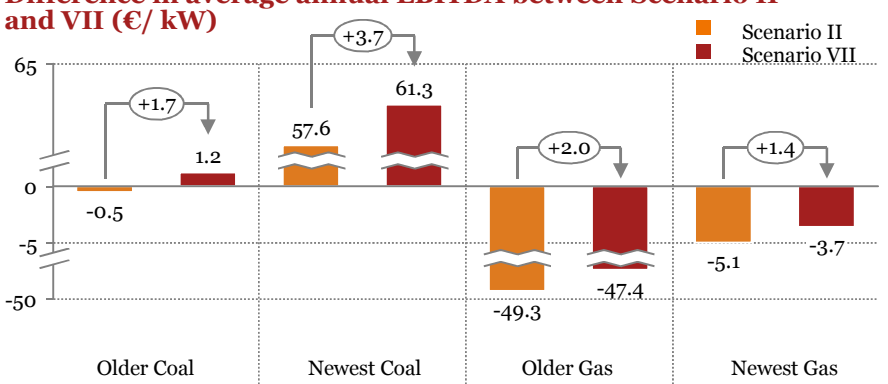
- In Scenario VI the RES target is reduced to 14% domestically, with 2% sourced through statistical transfer from abroad
- The lower target means not all offshore wind potential of 5 GW needs to be built, and less domestic dedicated biomass is needed to hit the 14% target in 2020
- The overall financial picture is similar to Scenario II, with slightly higher power prices on average
- Lowering the Dutch renewable capacity leads to more import from Germany, hurting gas-fired power plants (high efficient gas-fired plants in particular) more than coal-fired power plants
- The acquisition of renewable electricity rights from other countries requires a surplus in those countries and a willingness to sell them
- The market price for additional renewable capacity can be calculated as the difference between the market price for electricity and the levelised cost of RES. However, the actual cost of the RES does not have to be equal to the price that is necessary to acquire the rights – certainly if there is a net shortage in Europe: the price for RES certificates will typically be higher than the actual cost of RES
- The potential financial advantage of delaying capital expenditure by purchasing the rights at the last moment (in 2020) is not very substantial (up to €160mln assuming at 3% discount rate), compared to the entailed risk for ensuring the target is met

Scenario VII: higher power prices driven by the retirement of substantial existing capacity improve financial performance of all power plants

Difference in the average annual net import between Scenario II and VII (in TWh)



Difference in average annual EBITDA between Scenario II and VII (€/ kW)



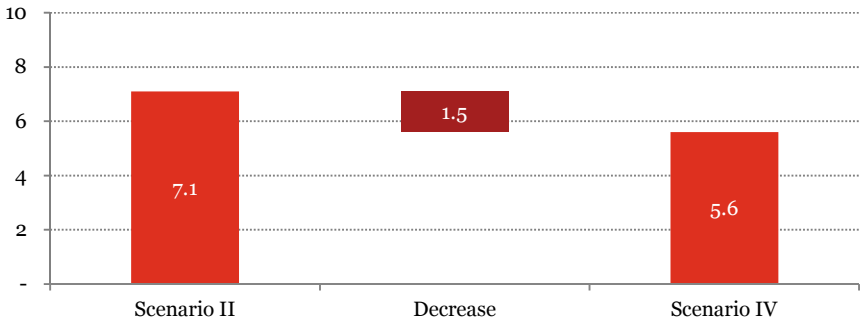
Source: PwC/IPA Analysis

Additional retirement of 3 GW older gas-fired generation in 2016-2020

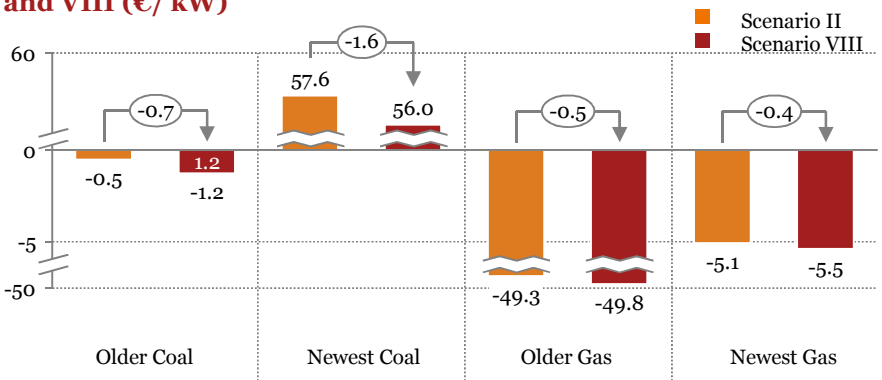
- As a result of the extra decommissioning of existing gas-fired capacity, the power prices in the Dutch market are driven up slightly after 2016
- Assuming a further 400 MW decommissioning in 2021-2025, new CCGTs are built with a corresponding capacity premium in the price (equal to Capex + fixed costs, which is around €10/MWh). This indicates that the Netherlands is fairly close to a capacity shortfall, in situations without wind and imports
- The higher power prices result in an increase in imports, mainly from Germany. The Netherlands will import about 9 TWh more from Germany in 2020 than in the base scenario
- The financial performance of each plant type improves due to the higher power prices. The increase in the average annual EBITDA ranges from €1 to €4 per kW
- Newest coal-fired generation has the largest financial gain from higher power prices
- In contrast to Scenario II, the older coal power plants do not only have positive gross margins, but also positive EBITDA on average throughout the years. In particular, older coal plants generate positive EBITDA results in 2018-2020
- Gross margins as well as EBITDAs of low efficiency gas-fired power plants built pre-2010 remain negative, despite some improvements
- High efficiency gas-fired power plants built after 2010 have positive gross margins over all years as in the base scenario, but negative EBITDA over 2013-2017. Only from 2018 onwards, do these power plants have slightly positive results

Scenario VIII: capacity payments in countries directly connected to the Dutch power market potentially reduce the export to these countries

Difference in the average annual export of electricity to GB between Scenario II and VIII (in TWh)



Difference in average annual EBITDA between Scenario II and VIII (€/ kW)



Source: PwC/IPA Analysis

Capacity mechanism in the surrounding countries

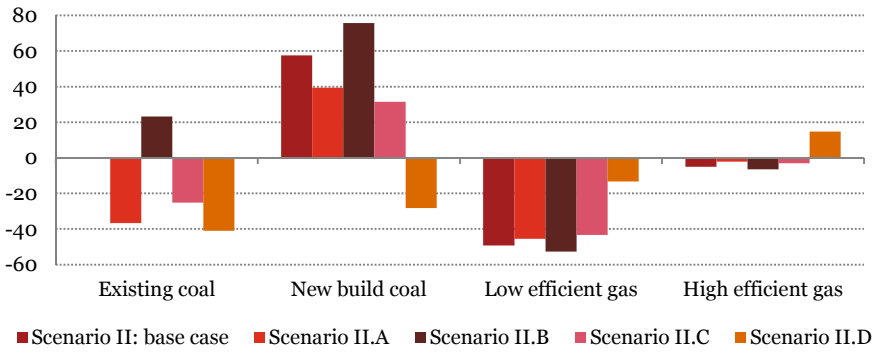
- With a capacity mechanism subsidising the fixed costs of plants that are not expected to run very much but are nonetheless needed for security of supply, the expectation is that wholesale electricity prices will drop to the short run marginal costs (SRMC). Therefore, the model has effectively already capatured the impact of capacity markets in Germany, France and Belgium/Luxembourg in all scenarios, as interconnector flows are based on SRMC, except for the GB and NordPool markets which are modelled as price curves
- For Scenario VIII, we only adjusted the GB price level to reflect the likely impact of a capacity market over there. As a result of this, prices in the Netherlands drop slightly. Exports to GB are however much reduced, with almost equal flows in both directions by 2020. Financials for all plants are marginally down, because of the lower prices.[1]
- In terms of what value might be available to Dutch power plants if they were able to participate in these capacity markets, we expect that capacity payments would fall somewhere between the fixed costs of existing CCGTs (ca. €12/kW/yr) and the capital + fixed costs for new OCGTs (ca. €50/kW/yr). It can possibly be as high as that for new CCGTs (ca. €100/kW/yr). The modelling already shows such a capacity premium for France and Belgium reflecting new CCGT build in those countries
- Based on a capacity premium range of €12-50/kW per year, a 500 MW CCGT can potentially generate an additional revenue of about €6-25 million per year

[1] Potential downside impact of capacity markets in Germany, France and Belgium/Luxembourg on Dutch power market in all runs is already included in the model outcomes we have

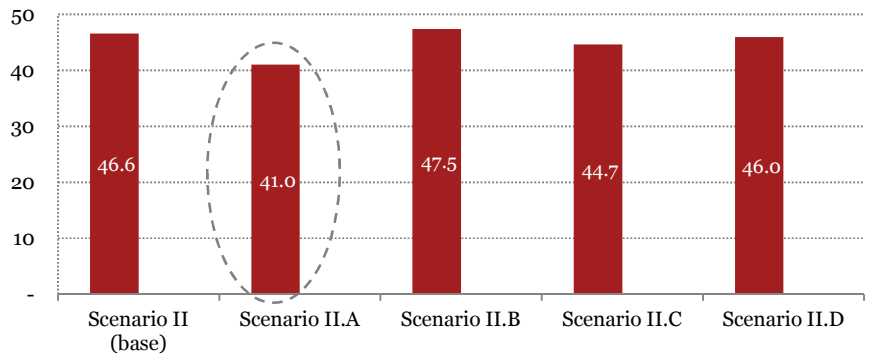
Appendix 1
Sensitivity analysis of Scenario II

The impact of different CO_2 prices, co-firing at costs and lower gas prices

Average annual EBITDA in different scenarios (€/kW)



CO_2 emissions under different scenarios (tonnes mln.)

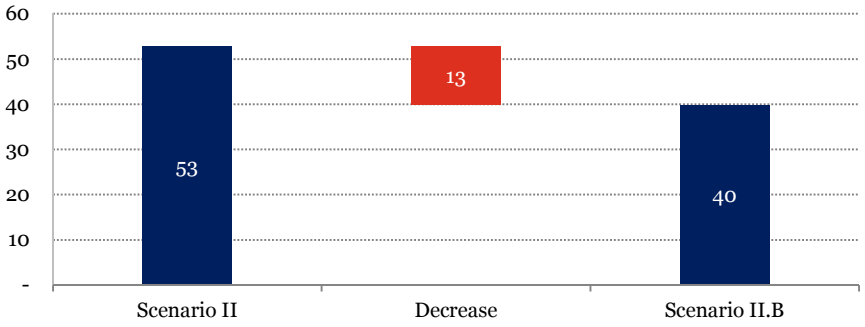


Source: PwC/IPA Analysis

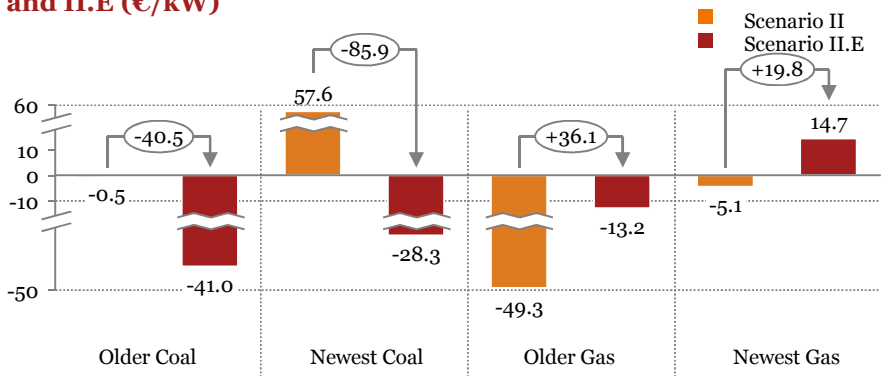
- To assess the sensitivity of the outcome of Scenario II, we have changed the following key parameters in Scenario II:
  - Scenario II.A: 20% co-firing at cost instead of full compensation (i.e. additional costs of co-firing compared to the coal consumption are not compensated externally)
  - Scenario II.B: no costs for CO_2 emissions
  - Scenario II.C: linear increase up to €40/t in 2020
  - Scenario II.D: 40% lower gas price, compared to Scenario II
- Main observation from the sensitivity analysis
  - Significant changes in CO_2, gas prices and co-firing costs have considerable impact on the financial performance of coal-fired plants. Existing and newest coal show the best performance in II.B (no CO_2 costs), and the worst performance in II.D (lower gas price)
  - Older coal plants have negative EBITDA on average in most cases, except if there are no costs for carbon emissions. newest coal plants would in most cases have positive average EBITDA (but negative average EBT per kW), except for when the gas prices are so low, such that even low efficiency gas-fired power plants are cheaper than any coal power plant
  - CO_2 prices and the cost of co-firing have limited impact on the financial results of gas-fired power plants, while the significant reduction in the gas prices will have a much greater effect. Low efficiency gas plants have negative EBITDA in all cases, even when the financial performance is significantly improved by much lower gas prices in II.D. More efficient gas plants would have positive EBITDA on average, only if the gas prices drop considerably
  - A higher CO_2 price has a reduced effect on the CO_2 emissions (-4%). However, the largest reduction (-12%) in the carbon emissions would be achieved in II.A (co-firing at costs)

A substantial decrease of the gas prices improves the gas-fired power plants significantly

Difference in the average electricity price between Scenario II and II.B (in €/MWh)



Difference in average EBITDA between Scenario II and II.E (€/kW)



Source: PwC/IPA Analysis

- A 40% reduction in the gas prices is substantial, which can be considered as the result of a potential shale gas revolution in Europe. We analyse the impact of 40% lower gas prices (compared to the price assumption in the base scenario, see slide 72) on the financials of conventional power plants in more details
- As the consequence of the much lower gas prices, the generation shifts from coal to gas, and the large amount of CCGT/CHP capacity stretches right across the annual demand range so that coal-fired plants hardly run after 2015 until capacity is progressively removed – before suddenly turning on in 2020 for the biomass co-firing to meet the renewables target
- Due to lower fuel costs, power prices are down to €40/MWh through the period, at the average short run marginal costs of the gas plants
- Due to the combined effect of the lower power price and much reduced running hours, both existing and newest coal power plants suffer considerably from financial losses, resulting in heavily negative EBITDAs. The newest coal only covers its short run marginal costs when it does run
- The financial performance of all gas-fired power plants improves considerably, as the load factors increase significantly (50% increase in running hours both for older and newer gas-fired plants). The low efficiency gas would gain a better financial performance than coal-fired power plants, although the average EBITDA through the period is still negative
- The newer CCGTs with higher efficiency will outperform all other conventional power plants, and have positive EBITDAs on average

Appendix 2
Detailed analysis of alternative scenarios

Appendix 2.1
Scenario I

Key assumptions

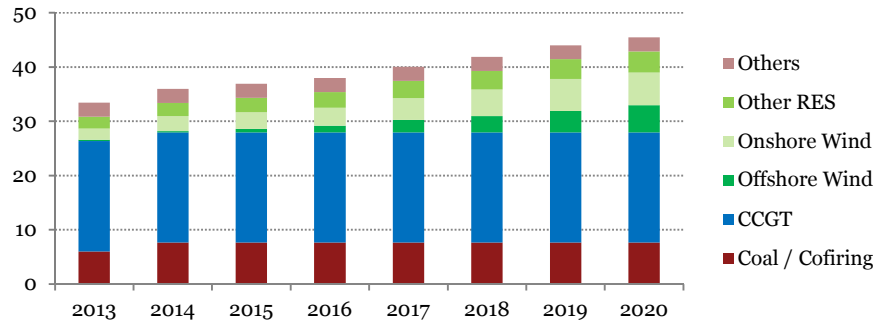
- 16% RES target to be met by domestic RES generation 2020
- CO_2 price flat at €10/t 2013-2020
- Coal tax 2013-2020
- ECN annual build limits for wind onshore and offshore
- 10% co-firing (10% of all energy-input biomass, at coal-equivalent cost)

Main findings

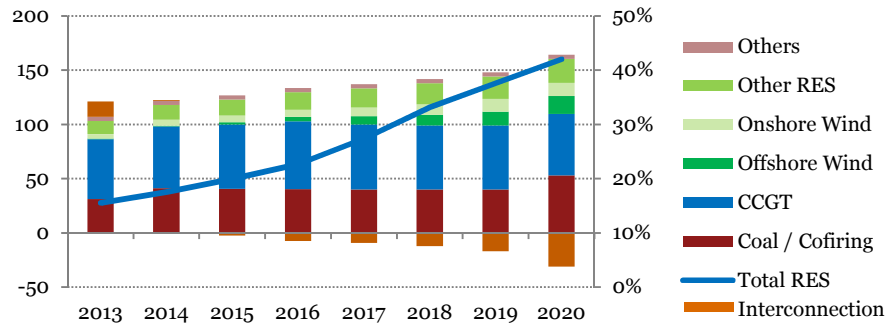
- All onshore and offshore wind generation potential will be realised to meet the 16% RES target, based on the ECN's maximum build estimates
- 2 GW of dedicated biomass is also needed for meeting the RES target, next to wind and 10% biomass co-firing
- With substantial gas-fired power as price-setter, the Netherlands becomes a net exporter by 2015
- The financial returns of most conventional power plants (except for newest coal), in terms of average annual EBITDA per kW over 2013-2020, are strongly negative, and are significantly poorer than in Scenario II
- When taking capital costs into account (i.e. in terms of EBT per kW), all conventional power plants, including newest coal, have negative financial results

Scenario I: installed capacity & generation

Scenario I: capacity mix excluding interconnection (in GW)



Scenario I: generation mix (in TWh LHS, RES in % RHS)



Source: PwC/IPA Analysis, CBS Statline

Security of supply is not under pressure

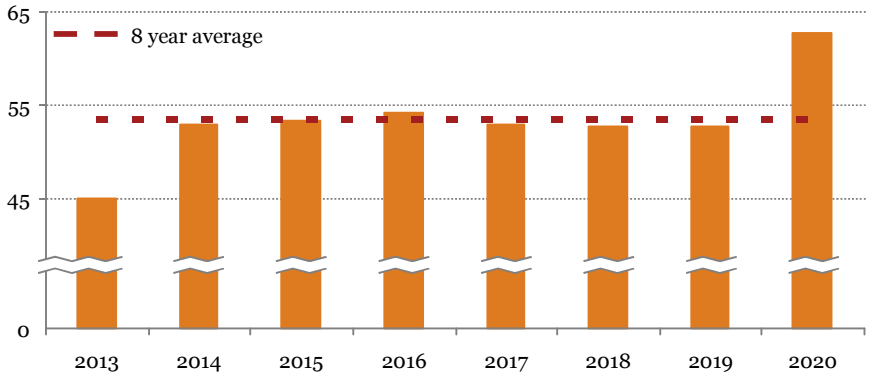
- According to CBS, total installed capacity in the Dutch market was 28 GW in 2011. This amount will increase to 45 GW in 2020 in this scenario
- The increase is mainly due to the addition of
  - three newest coal power plants (3.5 GW)
  - new onshore and offshore wind capacity (8.7 GW)
  - 100% dedicated biomass plants (2 GW)
- The expected capacity over the period 2013-2020 is more than sufficient to cover the expected peak demand. The reserve margin, based on dependable capacity, is expected to be between 50-70%

Coal and gas remain dominant in the generation mix

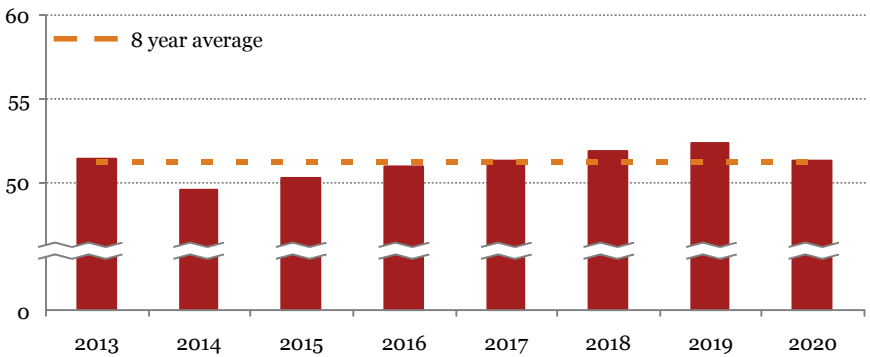
- According to CBS, total electricity demand in the Netherlands was 122 TWh in 2011
- Based on the forecast data of Eurelectric and ENTSO-E, power demand is projected to be 132 TWh in 2020 (equivalent to an average annual growth of 1,3% from 2013 to 2020)
- From 2015 onwards, the Netherlands will become a net exporter
- The relatively stable and high share of gas power is due to must-run generation of existing gas-fired cogeneration plants with an average annual output of 46 TWh
- Coal generation increases in 2020 due to the RES target, which is partially met by co-firing biomass

Scenario I: CO_2 emissions and electricity prices

Scenario I: CO_2 emissions (in tonnes mln.)



Scenario I: electricity price 2013 price levels (in €/MWh)



Source: PwC/IPA Analysis

CO_2 emission will increase as a result of increased co-firing in coal power plants

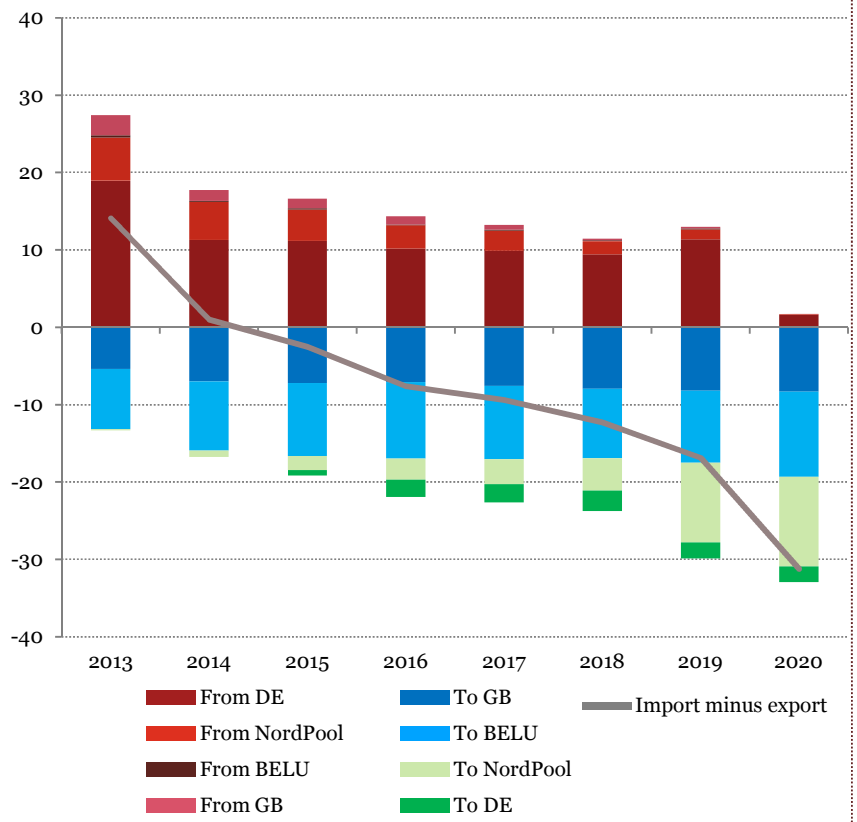
- According to the Dutch emission authority, the production of electricity and gas was responsible for 45 mln. tonnes CO_2 emission in the Netherlands in 2011
- CO_2 emission from power generation is expected to increase to 64 mln. tonnes in 2020, with an increase of approximately 40% compared to 2013
- The increase in CO_2 emissions is entirely due to
  - three newest coal power plants in 2013 and 2014
  - the considerable increase in the coal power generation in 2020 for meeting the 16% RES target through co-firing

Electricity price remains relatively stable

- The commissioning of efficient newest coal power plants in 2013 and 2014, combined with the decreased gas prices, contributes to a lower power price level in 2014
- The power prices increase again over 2015-2019, as the fuel prices (both coal and natural gas) start to increase from 2015 onwards
- The prices drop in 2020, due to increased coal-fired generation in that year in order to meet the RES target

Scenario I: import and export

Scenario I: import to vs. export from the Dutch power market (TWh/year)



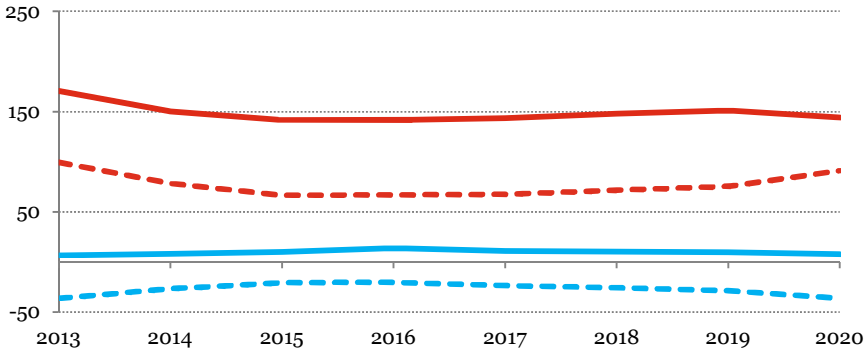
Source: PwC/IPA Analysis

The Netherlands will become a net exporter

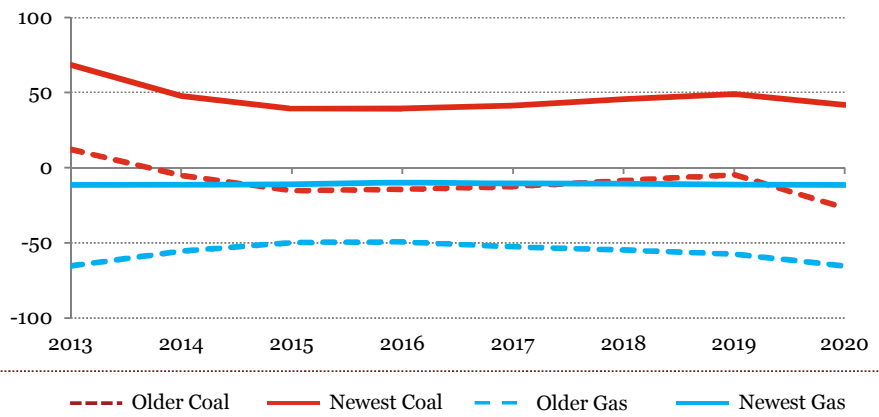
- The Netherlands will become a net exporting country from 2015 onwards
- This relates to the addition of the three highly efficient coal power plants in 2013 and 2014, resulting in a considerable generation surplus for the Dutch market
- The catch-up of RES generation by means of co-firing in 2020 for meeting the 16% RES target will result in an considerable oversupply of electricity, increasing the export further in that year
- Germany remains a net exporter to the Dutch market, although in a much lower level fashion in 2020
- Great Britain and Belgium / Luxembourg remain stable net importers from the Dutch market. NordPool will become the largest importer of the Dutch power generators

Scenario I: financial performance

Scenario I: gross margin (€ per kW)



Scenario I: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Financial performance of less efficient older coal and gas plants is under pressure

- With respect to gross margin and EBITDA, the newest coal power plants are expected to have the best performance. The existing less efficient coal power plants also have positive margins, but considerably lower than the newest coal. This is explained by the difference in efficiency
- Due to the relatively high fixed O&M costs of older coal power plants, the EBITDA of these plants becomes negative, despite of positive gross margins
- We make a distinction between gas-fired power plants built before and after 2010, due to the significant difference in the efficiency
- Gross margins as well as the EBITDA of gas-fired power plants built pre-2010 ("less efficient gas") are expected to be negative. This is a result of the combination of relatively expensive natural gas and lower efficiency of these "old" plants, in combination with a low load factor

Appendix 2.2
Scenario III

Key assumptions

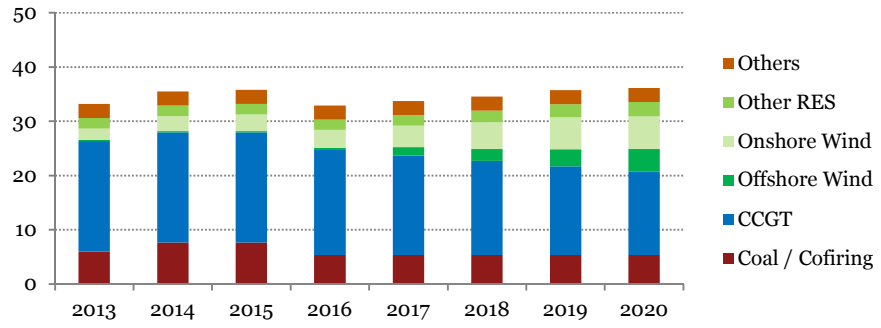
- 16% RES target to be met by domestic RES generation 2020
- Flat CO_2 price of €10/t
- Coal tax 2013-2020
- 40% co-firing (40% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.2 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency)

Main findings

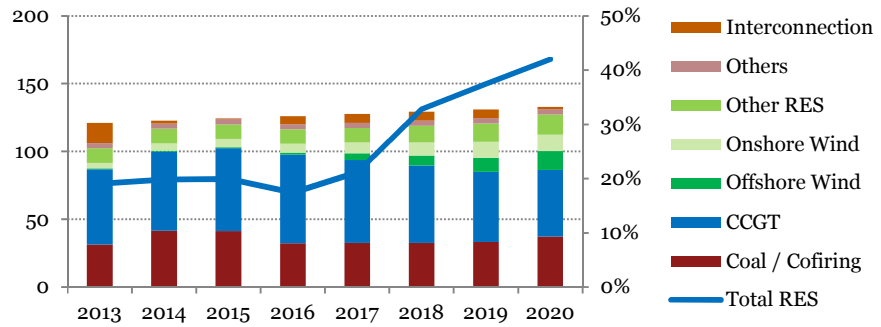
- Due to higher share of biomass co-firing, less offshore wind and dedicated biomass need to be built
- This lower ramp-up of domestic generation makes the Netherlands to become a net importer in 2013-2020
- Prices are slightly higher than in the base case
- With the extra co-firing costs still assumed to be paid for externally, the EBITDA for all coal plants improves slightly compared to the base scenario

Scenario III: installed capacity & generation

Scenario III: capacity mix excluding interconnection (in GW)



Scenario III: generation mix (in TWh LHS, RES in % RHS)



Source: PwC/IPA Analysis

Security of supply is not an issue, despite the decreasing trend of reserve margins from 2014 onwards

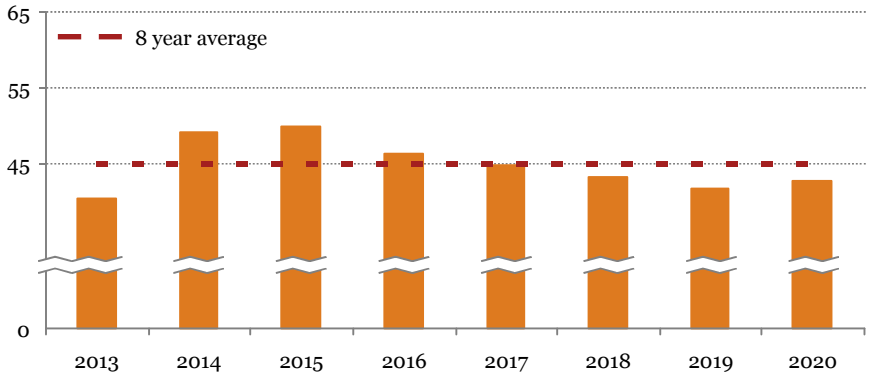
- The installed capacity will increase from 33 GW in 2013 to 36 GW in 2020 in this scenario
- The decrease in capacity in 2016 is due to the assumed closure of 2 GW older coal power plants and 5 GW less efficient gas-fired power plants (including cogeneration plants)
- The expected capacity over the period 2013-2020 is more than sufficient to cover the expected peak demand, despite the closure as mentioned above. The reserve margin is expected to be between 29-60%, which is still considered to be high

Gas remains important in the Dutch generation mix

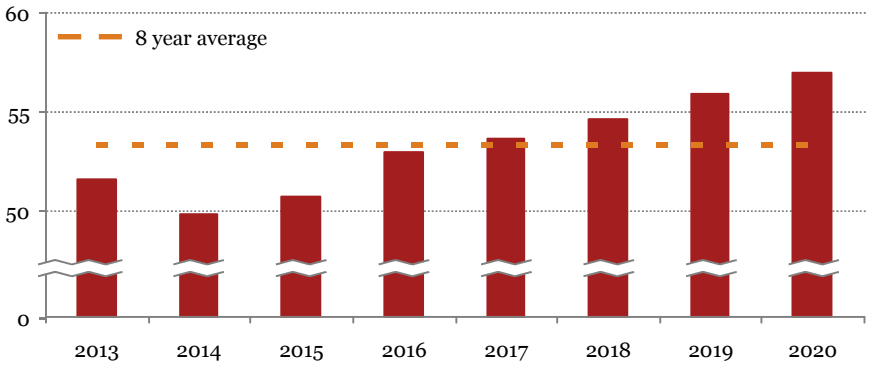
- Coal-fired generation increases in 2014, as newest coal-fired plants come online in 2013 and 2014
- The increase of gas-fired power generation from 2015 to 2016 is explained by the closure of the older coal power plants from 2016
- The Netherlands remains a net importer of electricity from 2015 onwards, as electricity prices remain relatively high

Scenario III: CO_2 emissions and electricity prices

Scenario III: CO_2 emissions (in tonnes mln.)



Scenario III: electricity at 2013 price levels (in € / MWh)



Source: PwC/IPA Analysis

Slight increase in CO_2 emissions in 2020 compared to 2013

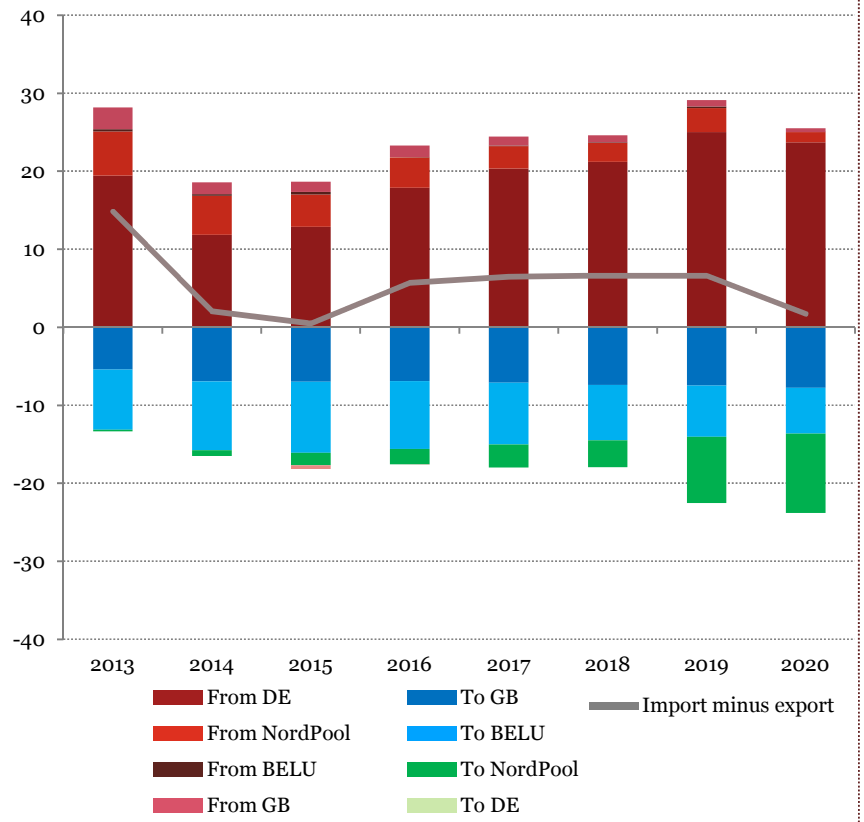
- CO_2 emissions increase in 2014, as the newest coal-fired power plants come online in 2013 and 2014
- The carbon emissions decrease again in 2016-2019, as a result of the retirement of older coal-fired power plants from 2016
- The slight increase in CO_2 emissions in 2020 is the result of increased co-firing to meet the RES target

Electricity price increases from 2014 onwards

- The electricity price ranges from €49 to €57 per MWh, with an average of €53 per MWh, which is slightly higher than the average price from Scenario II
- The electricity price drops in 2014, as the natural gas price is expected to decrease in that year. Also the commissioning of efficient newest coal power plants in 2013 and 2014 contributes to a lower price level
- However, the electricity prices move up again from 2015 onwards. This is partially due to the retirement of old coal-fired generation capacity from 2016 and the increasing fuel prices

Scenario III: import and export

Scenario III: import to vs. export from the Dutch power market (TWh/year)



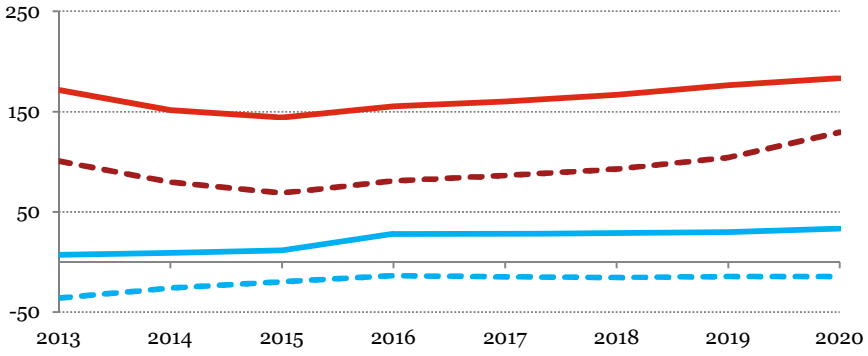
Source: PwC/IPA Analysis

The Netherlands will remain a net importer over the period 2013-2020

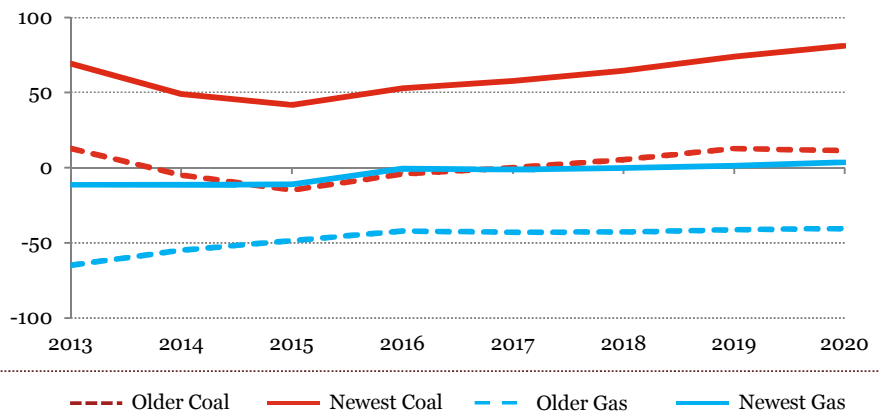
- The import will decrease significantly from 2013 to 2014 by 34%, which is mainly at expense of the import from Germany
- The import picks up again after 2015, due to the retirement of capacity in The Netherlands from 2016 onwards
- From 2016 onwards the Netherlands will be a net importer again. This relates to increasing electricity prices in the Dutch power market after 2016, reducing the export and increasing the import
- Germany exports by far the most electricity to the Dutch market, while the NordPool connection will become the largest importer of Dutch power generation after 2018

Scenario III: financial performance

Scenario III: gross margin (€ per kW)



Scenario III: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Financial performance of all power plants improves slightly compared to Scenario II

- The newest coal power plants significantly outperform the other conventional plants. Their EBITDA is on average 6% higher compared to Scenario II
- The older coal-fired power plants have slightly higher gross margins than in Scenario II. Their average EBITDA becomes even positive, whilst the EBITDA in Scenario II is below the zero line
- The EBITDA of all gas-fired power plants remains negative, although they are expected to show some slight improvements compared to Scenario II
- Efficient gas-fried power plants (built after 2010) show a similar EBITDA performance as the older coal power plants

Appendix 2.3
Scenario IV

Key assumptions

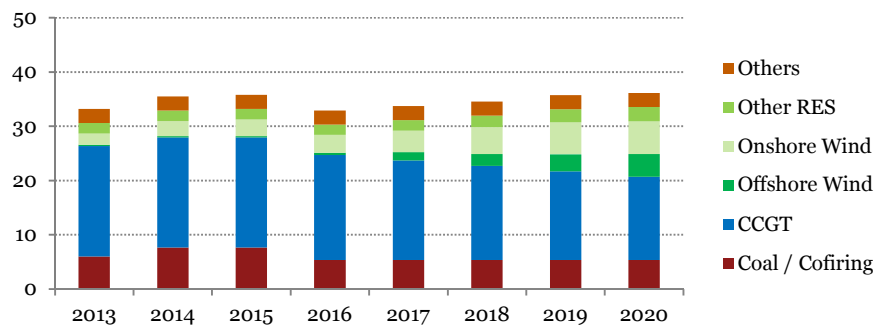
- 16% RES target to be met by domestic RES generation 2020
- CO_2 price increases linearly to €25/t in 2020
- Coal tax 2013-2020
- 40% co-firing (40% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.2 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency)

Main findings

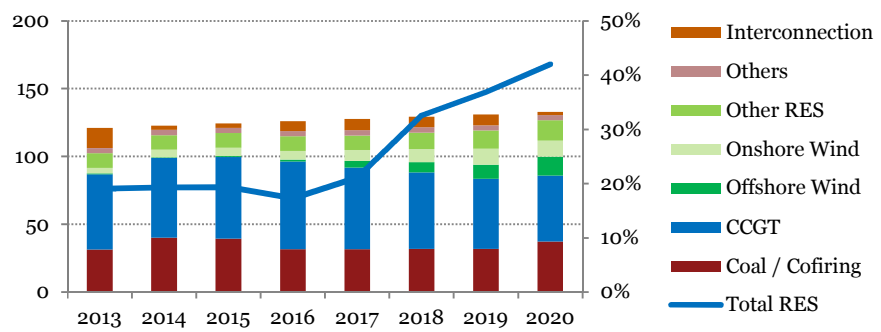
- Prices are higher than in all other scenarios, due to higher CO_2 price
- Economics of older coal and older gas are worse as a result of increased CO_2 costs, while the financial performance of newest coal and newest gas improves slightly
- The higher CO_2 price stimulates only a marginally greater amount of offshore wind and dedicated biomass generation

Scenario IV: installed capacity & generation

Scenario IV: capacity mix excluding interconnection (in GW)



Scenario IV: generation mix (in TWh LHS, RES in % RHS)



Source: PwC/IPA Analysis

The increased CO_2 price does not increase new wind and biomass capacity

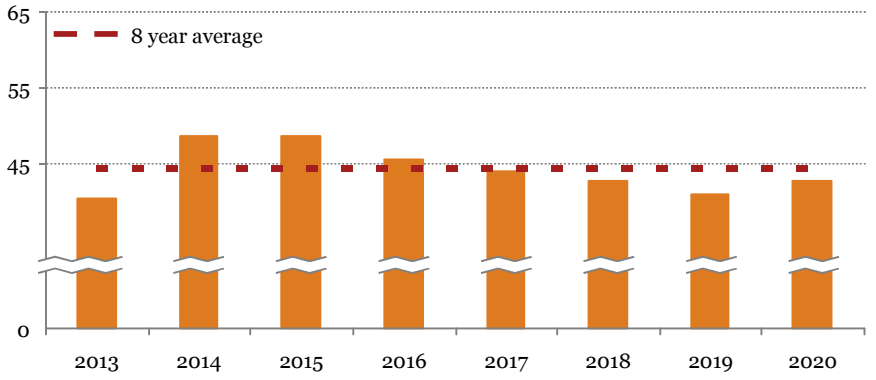
- The installed capacity will increase from 33 GW in 2013 to 36 GW in 2020
- The relatively higher CO_2 prices have limited positive effect on development of wind and dedicated biomass capacity
- The decrease of the capacity in 2016 is due to the assumed closure of 2 GW older coal power plants and 5 GW of the least efficient gas-fired power plants (including cogeneration plants)
- The reserve margin is expected to be between 29-60%, which is still relatively high

Gas share remains high

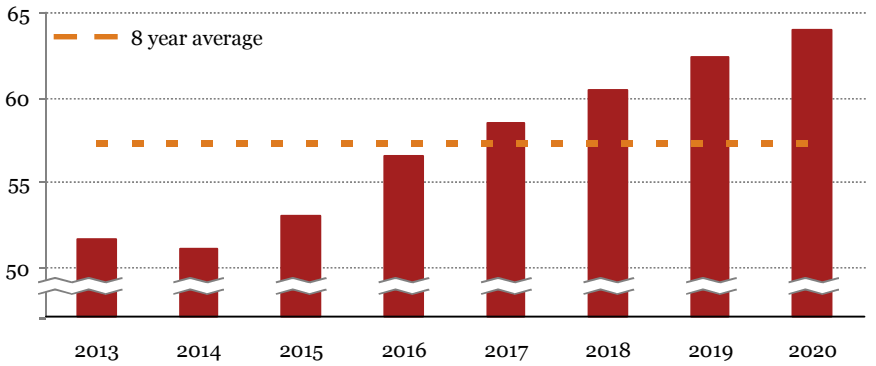
- The newest coal-fired power plants result in a higher share of coal-fired generation in the generation mix in 2014 and 2015
- The increase of gas-fired power generation from 60 GWh in 2015 to 65 GWh in 2016 is explained by the closure of the older coal power plants from that year
- Due to increased co-firing of biomass for meeting the 16% RES target in 2020, the generation output from (old/new) coal-fired power plants will increase by almost 20% from 2019 to 2020

Scenario IV: CO_2 emissions and electricity prices

Scenario IV: CO_2 emissions (in tonnes mln.)



Scenario IV: electricity price at 2013 price levels (in €/MWh)



Source: PwC/IPA Analysis

Higher CO_2 prices has limited impact on the CO_2 emission

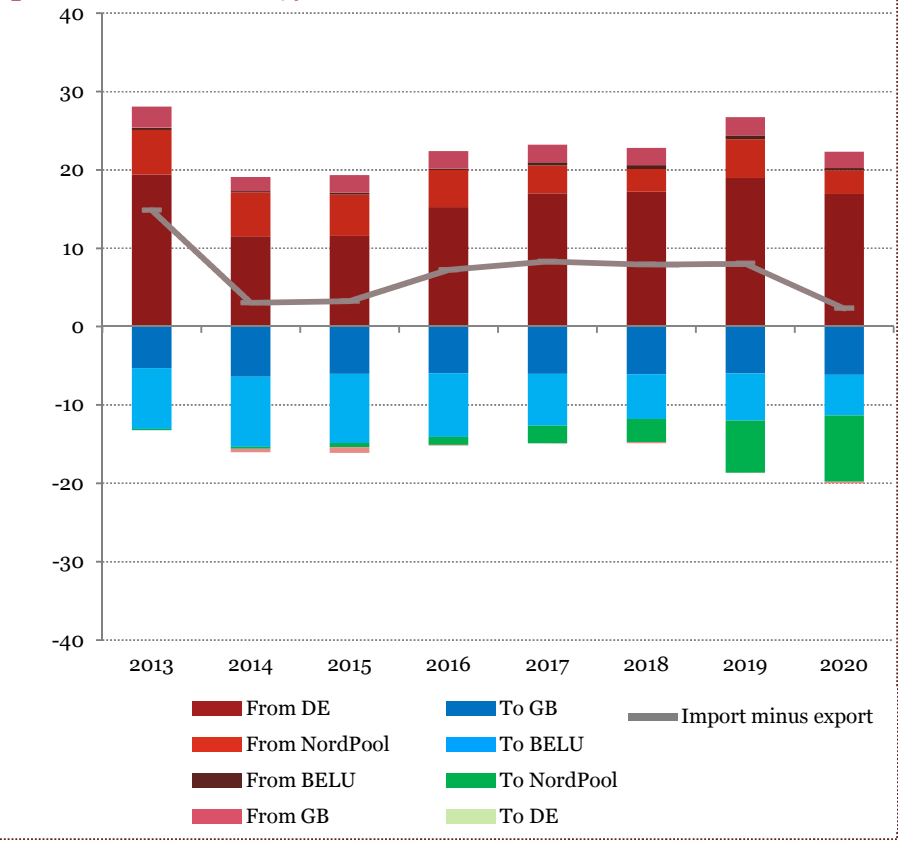
- CO_2 emissions of power generation in 2020 is expected to remain at the level of 2013 (43 mln. tonnes in 2020 vs. 40 in 2013), despite of the increased CO_2 price
- The small difference in CO_2 emissions between 2013 and 2020 is the consequence of the following:
  - the surrounding countries experience the same higher CO_2 price effect as the Netherlands, thus no significant increase in import is expected to replace domestic generation
  - newest coal power plants result in additional CO_2 emissions, which are however offset by high co-firing share of biomass (40%) and the retirement of older coal-fired plants

Electricity price increases from 2014 onwards

- The electricity price ranges from €50 to €64 per MWh, with an average of €57 per MWh. This price is the highest amongst all other scenarios, due to higher CO_2 prices (up to €25/t in 2020)
- The electricity price drops in 2014, as the natural gas price decreases in that year and the commissioning of newest coal-fired power plants
- However, the electricity price moves up again from 2015 onwards. This is partially due to the closure of existing older coal power plants from 2016

Scenario IV: import and export

Scenario IV: import to vs. export from the Dutch power market (TWh/year)



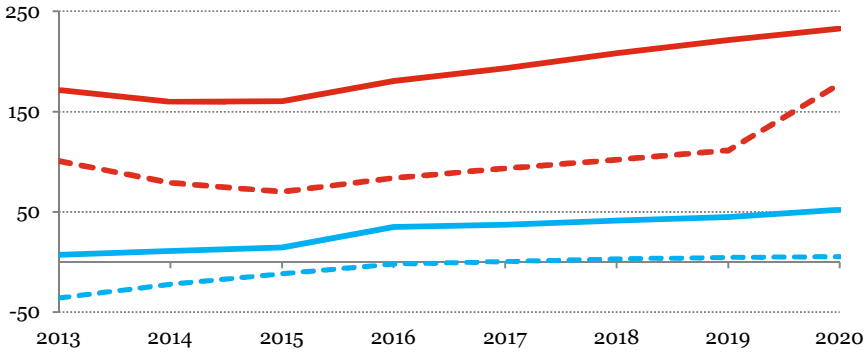
Source: PwC/IPA Analysis

The higher CO_2 price increases the Dutch import slightly compared to Scenario II

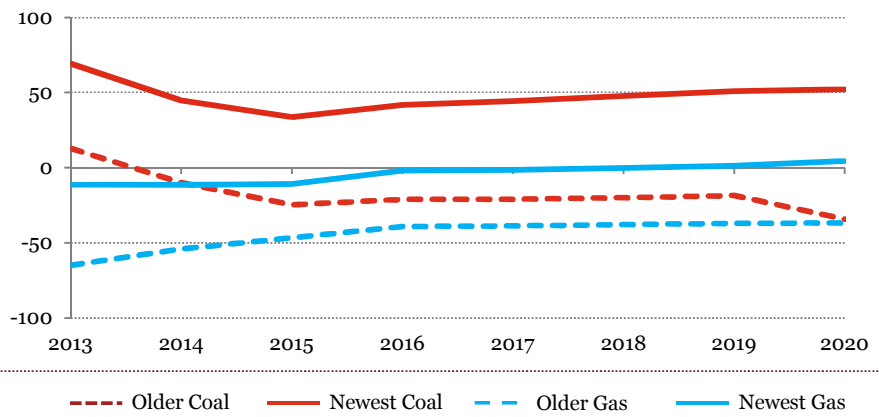
- The Netherlands will remain a net importing country in 2013-2020, albeit the net imported amount of electricity will be lower than the level of 2013, from 2014 onwards
- The net import will increase again in 2016, after a dip in 2014 and 2015. The increase is due to the assumed removal of older less efficient generation capacity from the Dutch market from 2016
- The decline in the import and increase in the export in 2020 is the result of the "sudden jump" in the coal-fired power generation in 2020, as the RES target needs to be met by co-firing
- Germany exports by far the most electricity to the Dutch market, while the GB, Belgium and Luxemburg will be the largest importing countries for the Dutch power generation. The export to NordPool is expected to increase from 2018 onwards, and NordPool will become the largest exporting market for The Netherlands in 2019 and 2020

Scenario IV: financial performance

Scenario IV: gross margin (€ per kW)



Scenario IV: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Older coal-fired power plants financially suffer the most from the higher CO_2 price

- With respect to gross margin and EBITDA, the newest coal power plants are expected to have the best financial performance due to relatively high efficiency. However, the returns are suppressed by higher CO_2 prices
- The financial performance of the older coal plants suffers the most from higher CO_2 costs, as these power plants emit the most of CO_2 emissions per kWh
- The gross margin for efficient CCGT remains positive between 2013 and 2020, due to the increased electricity prices
- But the increased price is not sufficient to cover the fuel and operational costs of less efficient gas-fire power plants, resulting in a strongly negative EBITDA for these power plants
- Efficient gas-fired power plants which are built after 2010 show a slightly better EBITDA performance than the older coal power plants after 2014, which is not the case in Scenario II. This is explained by the higher CO_2 price in Scenario IV, suppressing EBITDA of coal-fired power plants significantly
- The gross margin of older coal-fired power plants will increase from 2019 to 2020, while the EBITDA is expected to drop in the same period. The reason for this is the high CO_2 prices

Appendix 2.4
Scenario V

Key assumptions

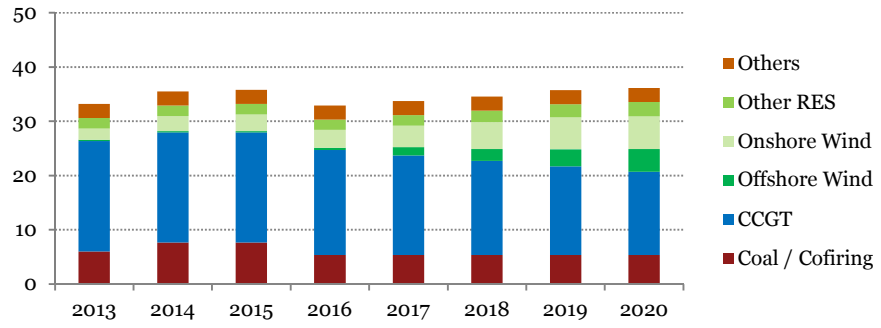
- 16% RES target to be met by domestic RES generation 2020
- CO_2 price increases linearly to €25/t in 2020, for Netherlands only
- CO_2 price flat at €10/t 2013-2020, for other countries
- Coal tax 2013, no coal tax 2014-2020
- 40% co-firing (40% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.2 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency)

Main findings

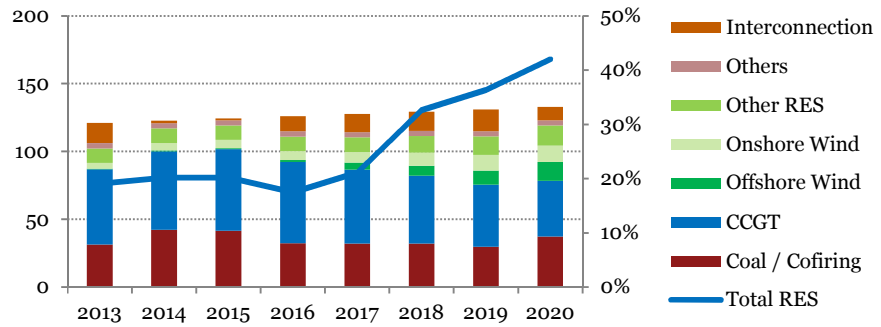
- With a higher fossil cost base than its neighbours and increased interconnection capacity with Germany from 2016, the Netherlands becomes a much greater net importer from 2016 onwards than in Scenario II
- Dutch power prices are slightly higher than in II, but lower than in IV due to increased imports
- The removal of the coal tax actually benefits Dutch coal plants relative to gas in comparison to IV, widening the cost differential to the price-setting plant, and the average EBITDA for the existing plants is again slightly positive over 2013-2020 albeit not as much as II

Scenario V: installed capacity & generation

Scenario V: capacity mix excluding interconnection (in GW)



Scenario V: generation mix (in TWh LHS, RES in % RHS)



Source: PwC/IPA Analysis

A higher CO_2 price in the Netherlands than other countries does not increase new wind and biomass capacity

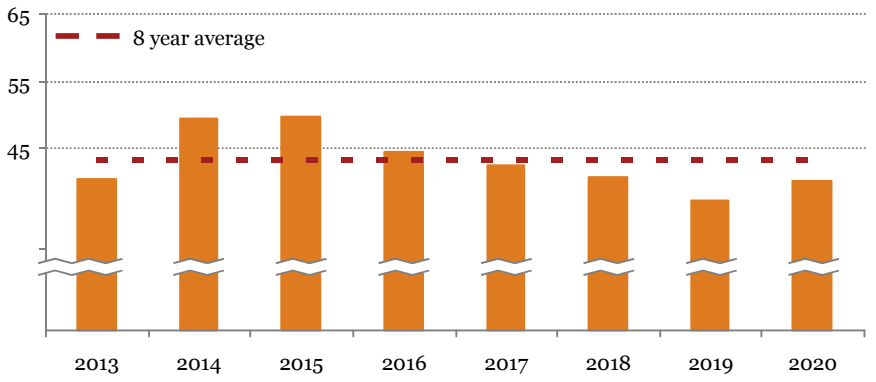
- The installed capacity will increase by 3 GW over 2013-2020
- The decrease of capacity in 2016 is due to the assumed closure of 2 GW older coal power plants and 5 GW of less efficient gas-fired power plants (including cogeneration plants)
- As in other scenarios, the expected capacity over the period 2013-2020 is sufficient to cover the expected peak demand: the reserve margin remains above 29% for all years

Coal and gas remain dominant in the generation mix

- The relatively high and stable share of gas-fired generation relates to must-run capacity of CHP
- The relatively higher CO_2 price in the Dutch market makes Dutch electricity more expensive compared to the neighbouring countries, leading to a decrease in export and an increase in import
- The closure of coal power plants in 2016 contributes to an increase in gas-fired power generation. But the share of gas power drops in 2020, as the result of the increase of co-firing to meet the RES target in that year

Scenario V: CO_2 emissions and electricity prices

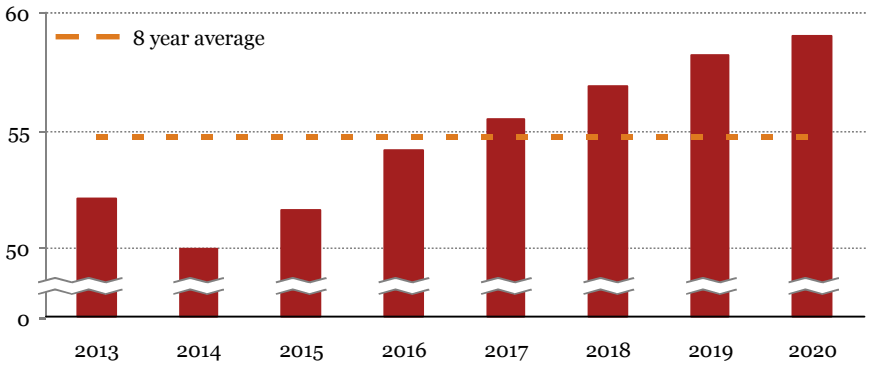
Scenario V: CO_2 emissions (in tonnes mln.)



CO_2 emissions will be reduced by 8% compared to Scenario II due to the higher CO_2

- The average annual CO_2 emissions are lower than all other scenarios, due to higher CO_2 prices in the Dutch market compared to CO_2 prices applied in other countries
- CO_2 emissions are expected to increase in 2014 and 2015 due to the newest coal power plants to be commissioned in 2013 and 2014

Scenario V: electricity price at 2013 price levels (in €/MWh)



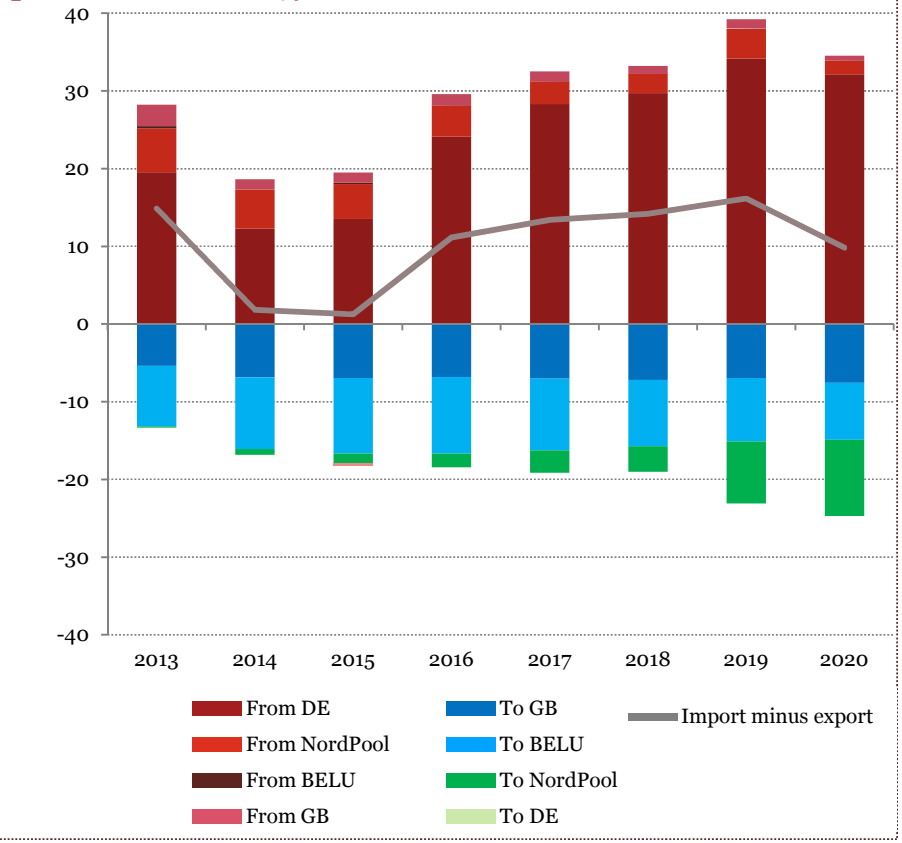
Electricity price increases from 2014 onwards

- The electricity price ranges from €49 to €59 per MWh, with an average of €54 per MWh
- The movement of power prices is similar to Scenario II

Source: PwC/IPA Analysis

Scenario V: import and export

Scenario V: import to vs. export from the Dutch power market (TWh/year)



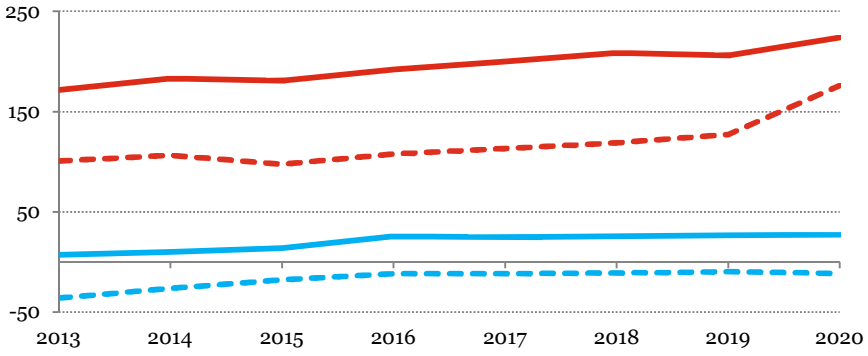
Source: PwC/IPA Analysis

The import to the Dutch market increases significantly compared to Scenario II, while the export remains stable

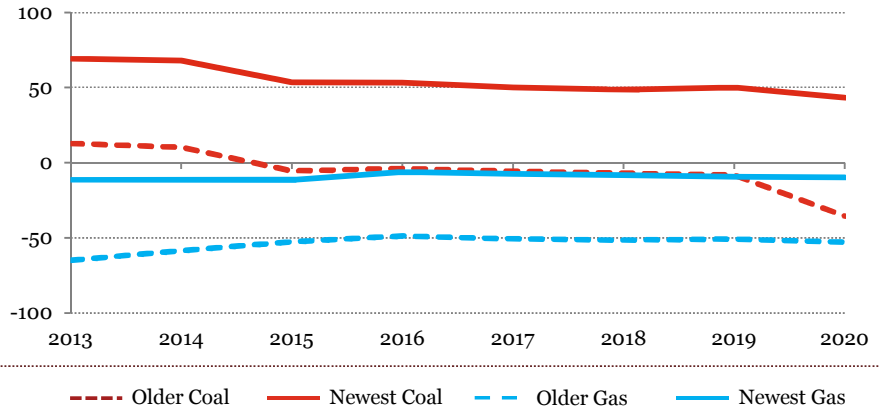
- Also in this scenario, the Netherlands will remain a net importing country during the period 2013-2020. The net imports increase significantly from 2016 to 2019. This can be explained by the national CO_2 price which is higher than in neighbouring countries (€25/t vs. €10/t in 2020) and the increased interconnection capacity with Germany from 2016
- The decrease in the net import in 2014 and 2015 is the result of the addition of newest coal-fired power plants
- The increase in the net import in 2016 is due to the assumed removal of less efficient capacities from the Dutch market in 2016
- The decline in the import and increase in the export in 2020 is the result of the "sudden jump" in the coal-fired power generation in 2020 for meeting the RES target in that year

Scenario V: financial performance

Scenario V: gross margin (€ per kW)



Scenario V: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Financial performance of all coal power plants decreases compared to Scenario II

- Newest coal-fired power plants are still the best performers of all power plant types. However, their earnings suffer from a higher CO_2 price compared to Scenario II
- The financial performance of older coal-fired plants suffers from higher CO_2 prices. In particular, the EBITDA in 2020 drops by almost 34% compared to Scenario II
- All gas powered plants show the second poorest financial performance amongst all scenarios. This relates to the significant increase of imports, mainly from Germany, which are driven by higher electricity prices in the Dutch market

Appendix 2.5
Scenario VI

Key assumptions

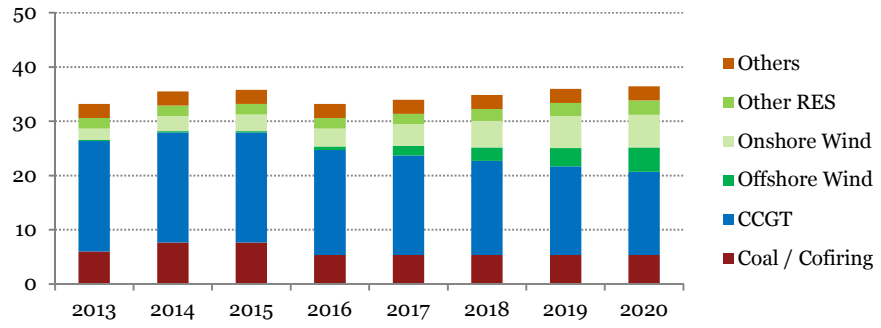
- 16% RES target in 2020 to be met through 14% domestic generation and 2% statistical transfers from other EU member states (cost difference calculation for wind onshore and wind offshore)
- Flat CO_2 price of €10/t
- Coal tax 2013-2020
- 20% co-firing (20% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.2 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency)

Main findings

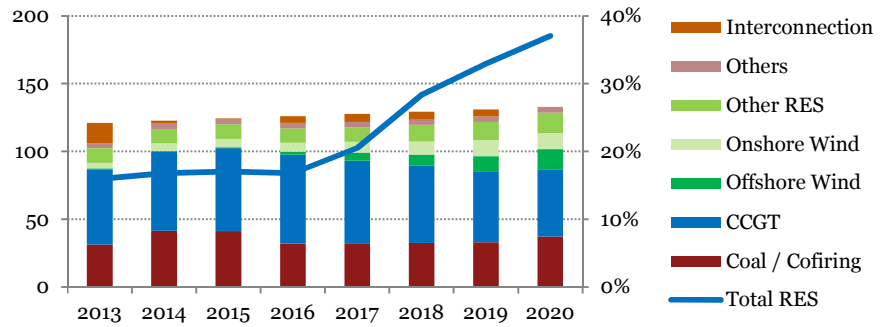
- As a result of a lower RES target, not all the offshore wind is built
- And only 800 MW of dedicated biomass needs to built domestically
- Dutch power prices are close to II, as are the economics of conventional plants, slightly lower on average in 2013-2020

Scenario VI: installed capacity & generation

Scenario VI: capacity mix excluding interconnection (in GW)



Scenario VI: generation mix (in TWh LHS, RES in % RHS)



Source: PwC/IPA Analysis

A lower domestic RES target requires less RES capacities

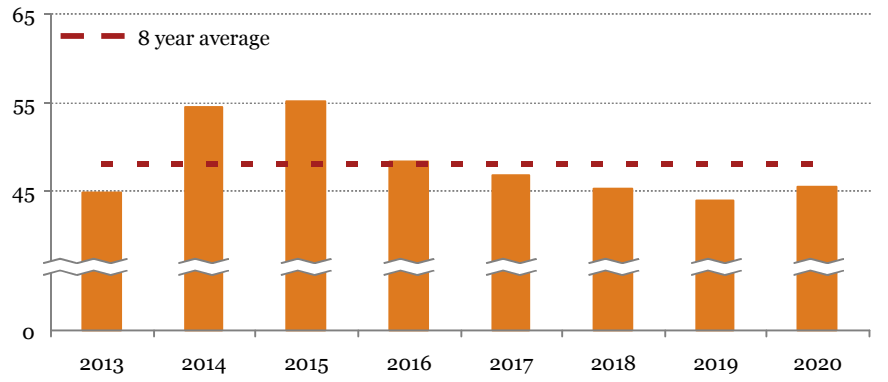
- The installed capacity will increase by 3 GW over 2013-2020, including the closure from 2016
- Due to a lower RES target (14% vs. 16%), less wind (0.5 GW) and dedicated biomass capacity (0.9 GW) will be required
- The decrease of capacity in 2016 is due to the assumed closure of 2 GW older coal power plants and 5 GW of less efficient gas-fired power plants (including cogeneration plants)
- The reserve margin, based on dependable capacity, remains above 29% throughout all years

Coal and gas remain dominant in the generation mix

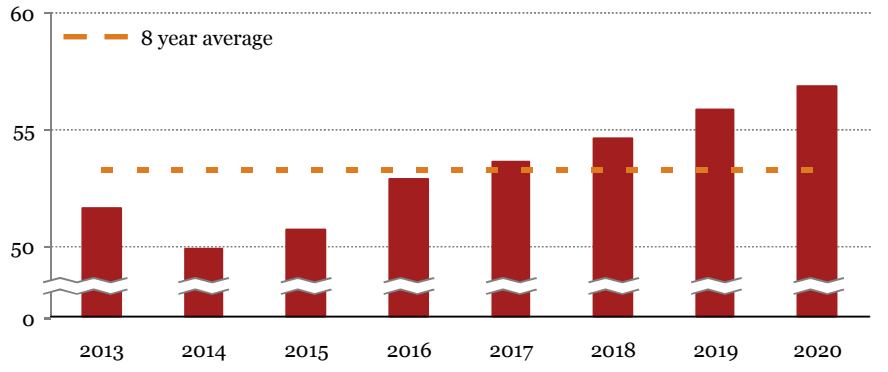
- Coal and gas remain very important in the Dutch generation mix. The relatively high share of gas-fired generation relates to must-run of CHP
- The closure of coal power plants contributes to an increase in gas-fired power generation in 2016

Scenario VI: CO_2 emissions and electricity prices

Scenario VI: CO_2 emissions (in tonnes mln.)



Scenario VI: electricity price at 2013 price levels (in €/MWh)



Source: PwC/IPA Analysis

Lowering the domestic RES target has limited impact on CO_2 emissions

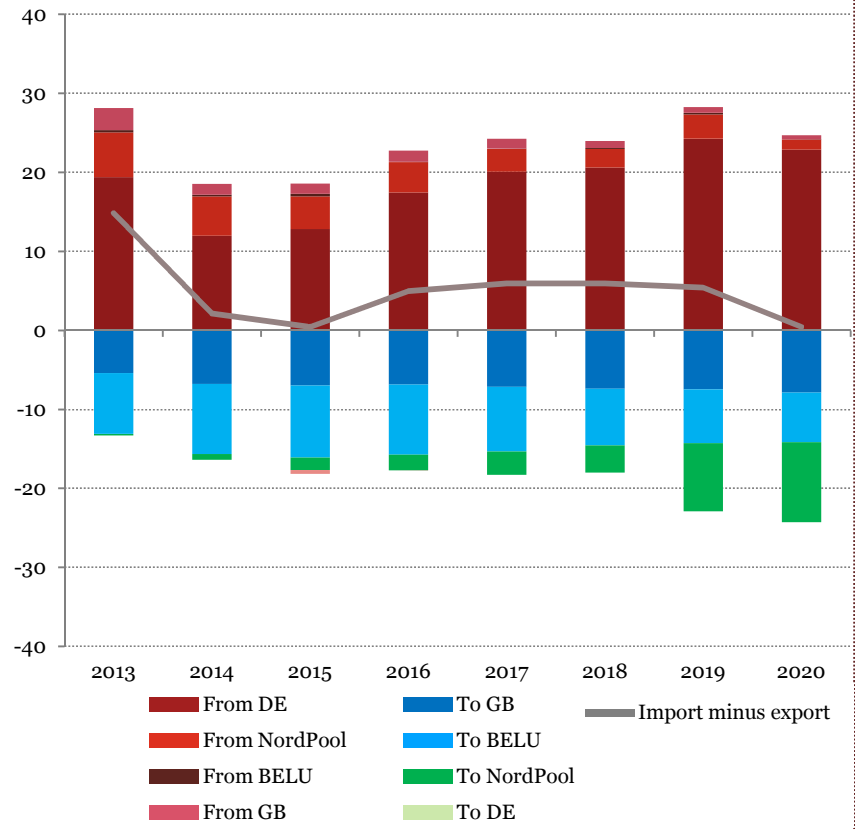
- Compared to Scenario II, CO_2 emissions are broadly unchanged, as the reduced domestic generation from renewable sources is largely replaced by imports

Electricity price increases from 2014 onwards

- The electricity price ranges from €49 to €57 per MWh, with an average of €53 per MWh
- The movement of the power prices is similar to the base scenario

Scenario VI: import and export

Scenario VI: Import to vs. export from the Dutch power market (TWh/year)



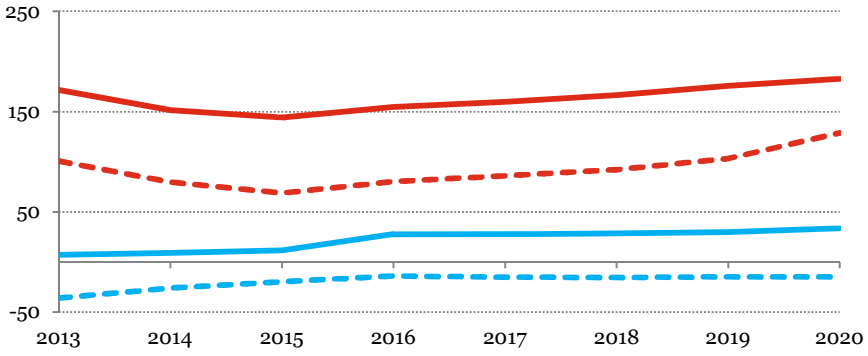
Source: PwC/IPA Analysis

The Netherlands will remain a net importer

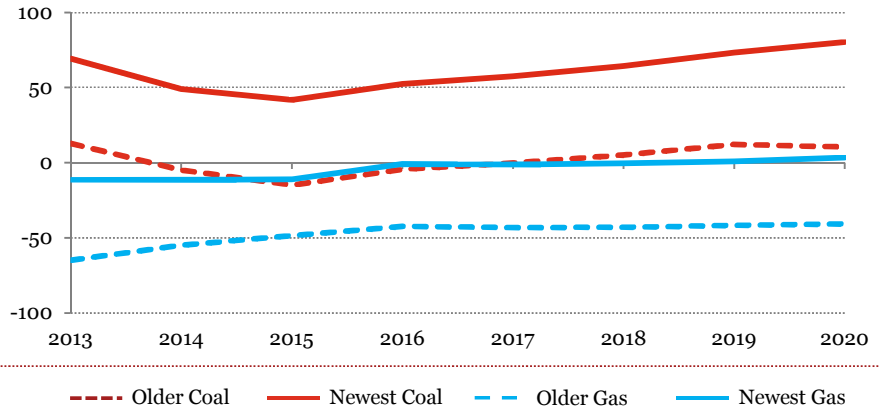
- The import/export profile in this scenario is similar to Scenario II, as the electricity price changes slightly compared to Scenario II
- However, the average annual import increases with approximately 10% compared to Scenario II, while the export decreases on average by 4%
- The import from Germany increases consistently from 2014 to 2019, after a dip in 2014. Germany remains the largest exporter to the Dutch power market
- NordPool will become the largest export market for Dutch power generation

Scenario VI: financial performance

Scenario VI: gross margin (€ per kW)



Scenario VI: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Financial performance of all power plants improves slightly compared to Scenario II

- The earnings of newest coal power plants will increase slightly compared to Scenario II due to the slightly higher electricity price
- As a result of increasing electricity prices, the EBITDA of all power plants improves. The EBITDA of the older coal-fired power plants even becomes positive after 2017
- But the increased price is not sufficient to cover the fuel and operational costs of less efficient gas-fired power plants, resulting in negative EBITDAs for these respective plants

Appendix 2.6
Scenario VII

Key assumptions

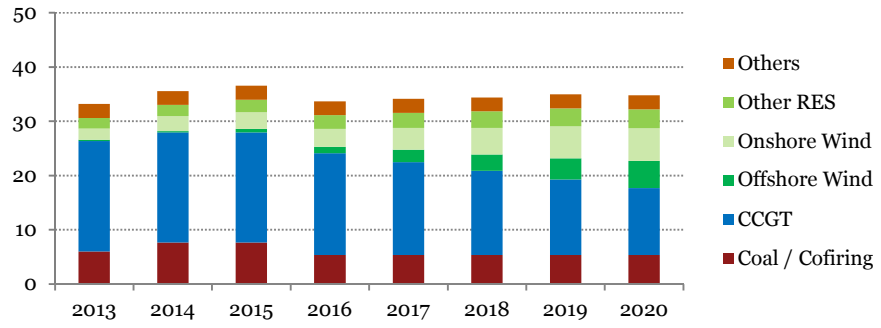
- 16% RES target to be met by domestic RES generation 2020
- Flat CO_2 price of €10/t
- Coal tax 2013-2020
- 20% co-firing (20% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.3 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency) + additional 3 GW Gas Cogen closure (1.6 GW/year between 2016-2020)

Main findings

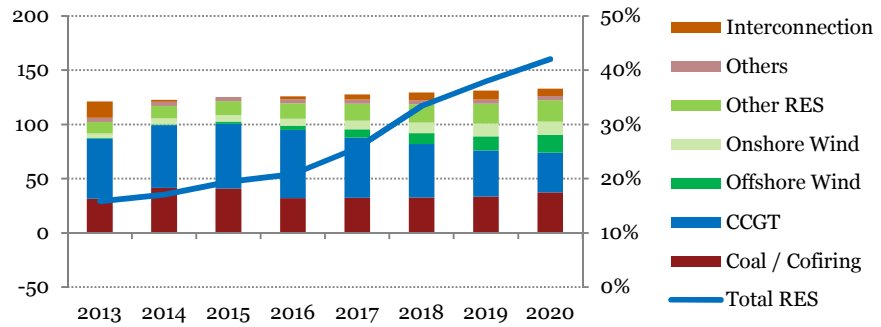
- Electricity prices are relatively higher in the last years of the decade (2018-2020) compared to other scenarios
- Financial performance of all types of plants improves slightly due to higher power prices
- Import rises througout 2013-2020, mostly from Germany
- Further closure of capacity after 2020 could lead to capacity shortfalls

Scenario VII: installed capacity & generation

Scenario VII: capacity mix excluding interconnection (in GW)



Scenario VII: generation mix in TWh LHS, RES % RHS



Source: PwC/IPA Analysis

Reserve margin drops significantly over 2013-2020, as additional capacity is retired

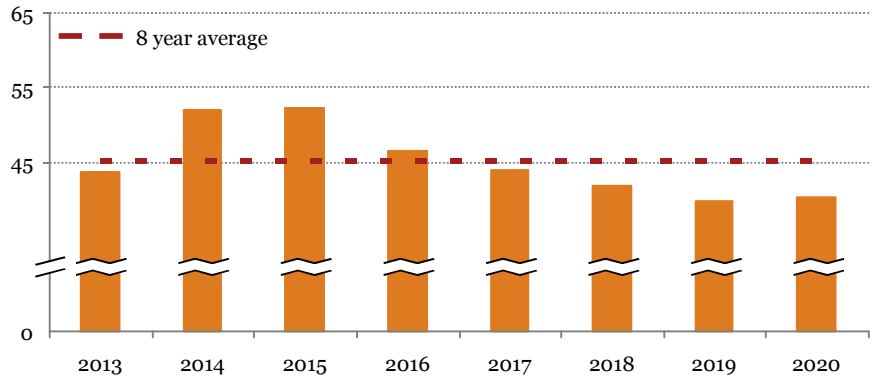
- The total installed capacity of 35 GW in 2020 is slightly higher than in 2013. The addition of conventional and RES capacity is almost completely offset by the retirement of more than 10 GW existing conventional capacity
- As the result of the substantial capacity reduction, the reserve margin drops dramatically from 50% in 2013 to 20% in 2020. Although 20% margin is still considered to be high, a further closure from 2020 onwards could seriously threat the security of supply

Coal will overtake the leading position of natural gas in the generation mix

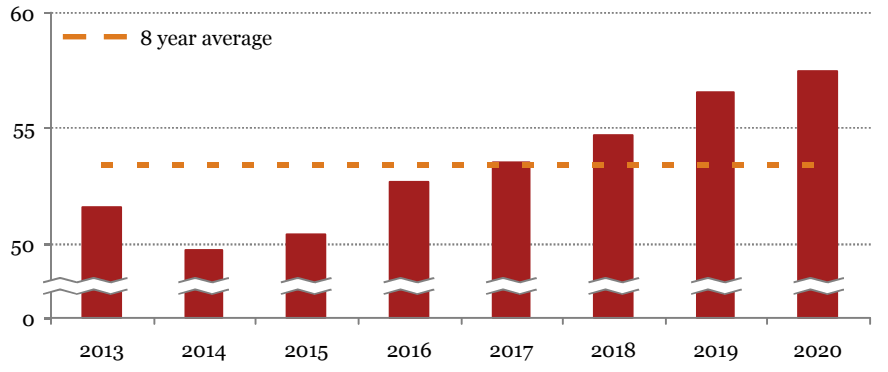
- Due to the closure of 8 GW gas-fired capacity, the generation output from gas-fired power plants drops by almost 40% (from 63 GW in 2016 to 37 GW in 2020) over 2016-2020
- The generation of coal-fired power plants increases by 17% in the same period, and contributes the highest share (30%) to the generation mix, including imports and exports in 2020

Scenario VII: CO_2 emissions and electricity prices

Scenario VII: CO_2 emissions (in tonne mln.)



Scenario VII: electricity price at 2013 price levels (in €/MWh)



Source: PwC/IPA Analysis

CO_2 emissions will decrease due to the closure of conventional power plants

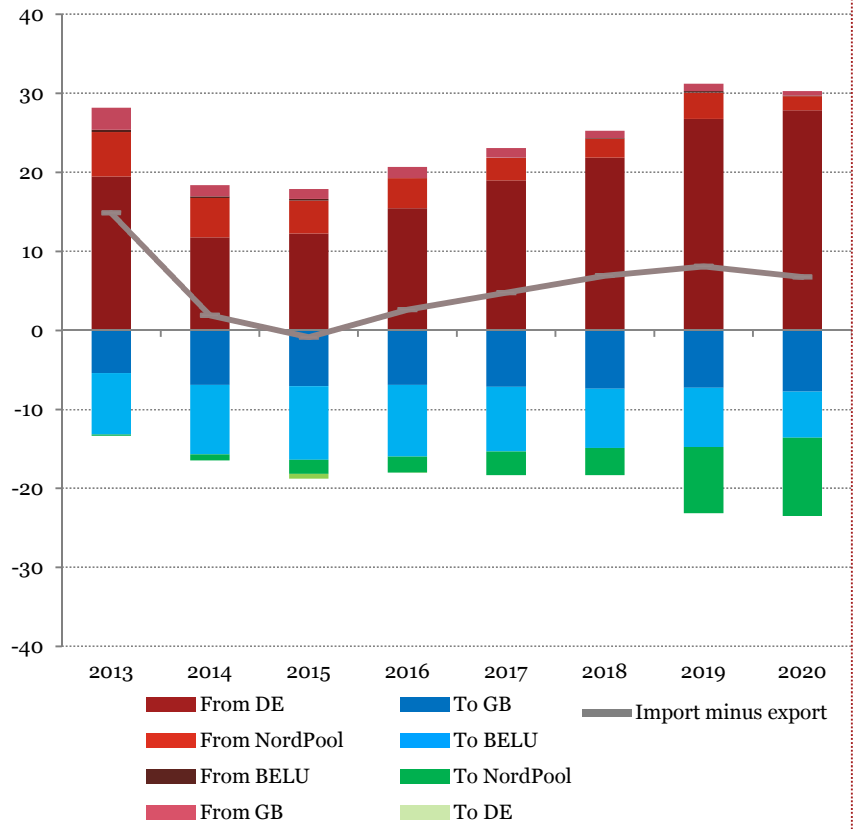
- CO_2 emissions of gas-fired power plants will be reduced by about 40% over 2013-2020 by the closure of more than 10 GW existing capacity from 2016
- However, a substantial part of this reduction is offset by the addition of coal-fired power generation capacity
- The overall CO_2 emissions in 2020 are 8% lower than in 2013

Electricity price increases from 2016 onwards after initially declining

- The average power price over the entire period of 2013-2020 is slightly higher than in Scenario II
- The effect of the retirement of gas-fired capacity from 2016 on the power prices is in particular observable in 2019-2020. The power prices per MWh in 2019 and 2020 are about €1/MWh higher than the corresponding prices in Scenario II

Scenario VII: import and export

Scenario VII: Import to vs. export from the Dutch power market (TWh/year)



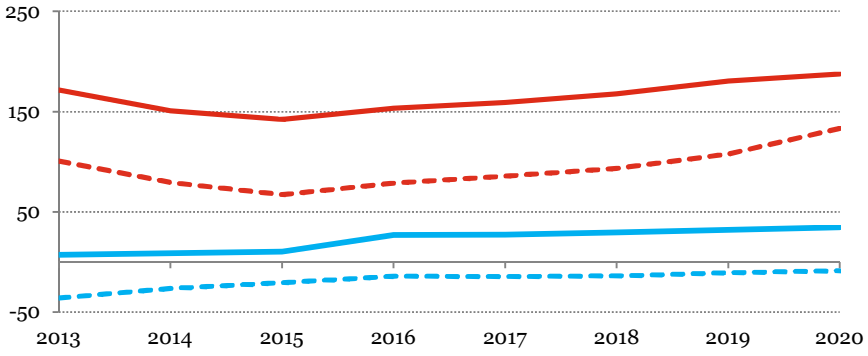
Source: PwC/IPA Analysis

The Netherland will remain to be a net importer

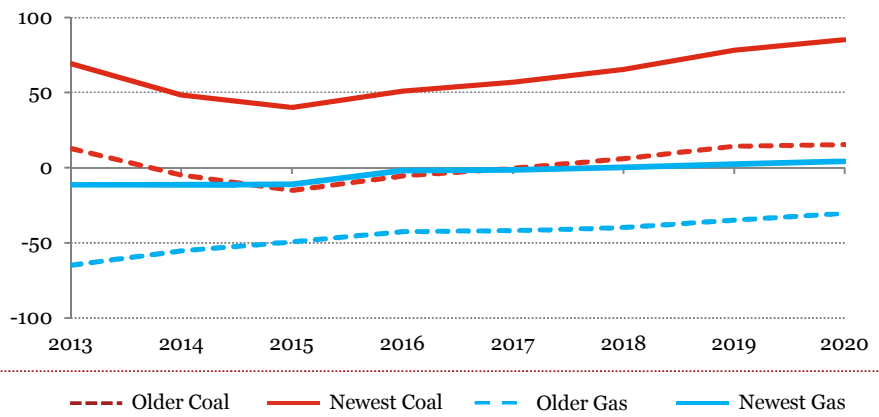
- Since the retirement of existing capacity will become effective from 2016, the import and export over 2013-2015 remain unchanged compared to the situation of Scenario II: exports increase between 2013 and 2015 as newest coal-fired generation comes online
- From 2016 onwards, the Netherlands imports more as older coal- and gas-fired generation capacity start to retire. Due to the price rise in the Dutch market from 2016 onwards, the import increases faster than the export (46% increase of import vs. 30% increase of export)
- This results in an net import of 7 TWh in 2020. The increase in the imports comes mostly from Germany

Scenario VII: financial performance

Scenario VII: gross margin (€ per kW)



Scenario VII: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Financial performance of all power plants improves slightly compared to the base scenario

- As the average power price in this scenario is slightly higher than in Scenario II, the average annual gross margin and EBITDA of all conventional power plants increase slightly compared to the financial performance in Scenario II
- The increase in the average EBITDA ranges from €1 to €4 per kW. In particular, newest coal has the largest financial gains from higher power prices
- In contrast to Scenario II, the older coal power plants have not only positive gross margin but also positive EBITDA on average throughout the years. In particular, older coal plants generate positive EBITDA results in 2018-2020
- Gross margins as well as EBITDA of gas-fired power plants built pre-2010 remain negative, despite some improvements
- Efficient gas-fired power plants built after 2010 have positive gross margins over all years as in the base scenario, but negative EBITDAs over 2013-2017. Only from 2018 onwards, these power plants have slightly positive results. But on average from 2013 to 2020, the annual EBITDA of these newer gas plants is still slightly negative

Appendix 2.7
Scenario VIII

Key assumptions

- 16% RES target to be met by domestic RES generation 2020
- Flat CO_2 price of €10/t
- Coal tax 2013-2020
- 20% co-firing (20% of all energy-input biomass, at coal-equivalent cost)
- Decommissioning of 2.3 GW old coal by 2016 and 5.0 GW gas from 2016 in 5-equal steps (based on efficiency)
- Capacity markets in the neighouring countries[1]

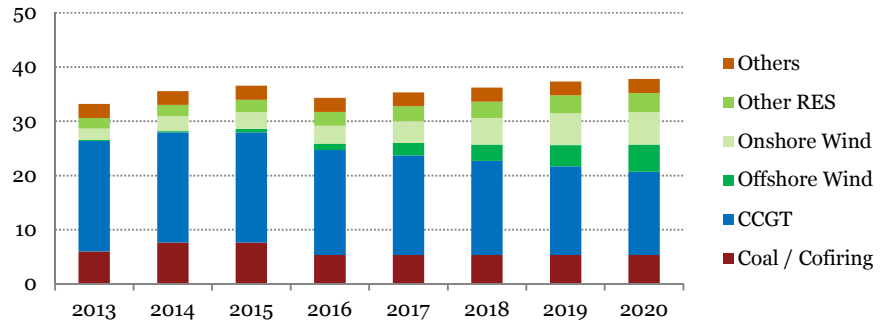
Main findings

- The export to GB reduces significantly due to the capacity premium in the GB, compared to Scenario II
- The Netherlands will however remain a net importer (except for 2015 and 2020)
- The financial performance of conventional power plants is similar to the situation in Scenario II

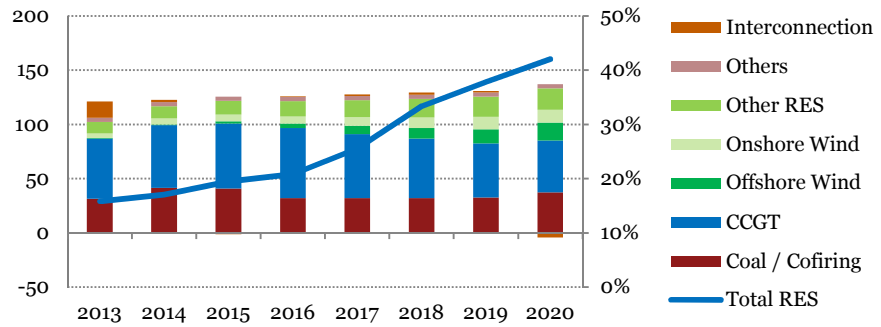
[1] Since ECLIPSE is an economic optimisation rather than a simulation model, we can not directly reflect specific implementations of capacity markets. To an extent the model is effectively already treating the following interconnected markets with separate capacity market: Germany, France and Belgium/Luxembourg, because interconnector flows are based on short-run marginal cost (SRMC) dispatch. In modelling terms, we capture the impact of capacity payments in these countries already in all scenarios we analysed so far, except for the GB and NordPool markets which are modelled as price curves instead of SRMC. For Scenario VIII, we only adjusted the price level at which the GB price would be expected to settle to reflect the likely impact of a capacity market over there. The impact on the Dutch market of Scenario VIII is hence only related to assumed changes in the GB market.

Scenario VIII: installed capacity & generation

Scenario VIII: capacity mix excluding interconnection (in GW)



Scenario VIII: generation mix in TWh LHS, RES % RHS



Source: PwC/IPA Analysis

The Netherlands has sufficient capacity, without the substantial retirement of existing capacity

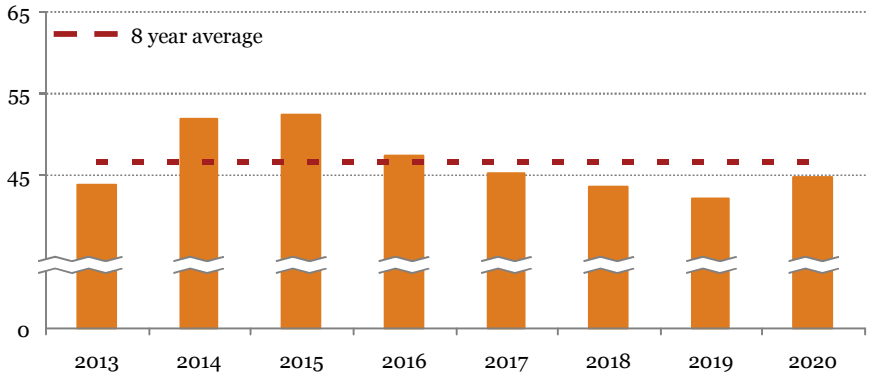
- The installed capacity is projected to be 38 GW in 2020, almost twice of the expected peak demand
- The reserve margin based on dependable capacity is expected to be between 30-60%. This is considered to be sufficiently high, as a reserve margin usually ranges between 10-20%

Gas keeps the leading position in the generation mix

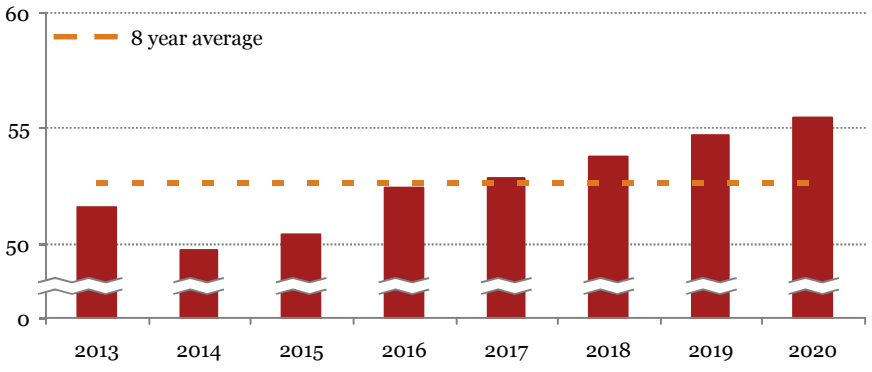
- Both coal and gas remain important in the Dutch generation mix. Gas will remain the biggest contributor to the total power supply in 2020, despite the decrease of gas share from 46% in 2013 to 36% in 2020 as the results of the closure of some existing gas-fired generation capacity
- The share of coal-fired generation in the total generation mix remains relatively stable from 2016 onwards, varying between 25% and 28%. The increase in 2020 is due to the higher output of coal-fired power for meeting the 16% RES target in that year

Scenario VIII: CO_2 emissions and electricity prices

Scenario VIII: CO_2 emissions (in tonne mln.)



Scenario VIII: electricity price at 2013 price levels (in €/MWh)



Source: PwC/IPA Analysis

The new RES generation and the retirement of existing conventional capacity slow the increase in CO_2 emissions

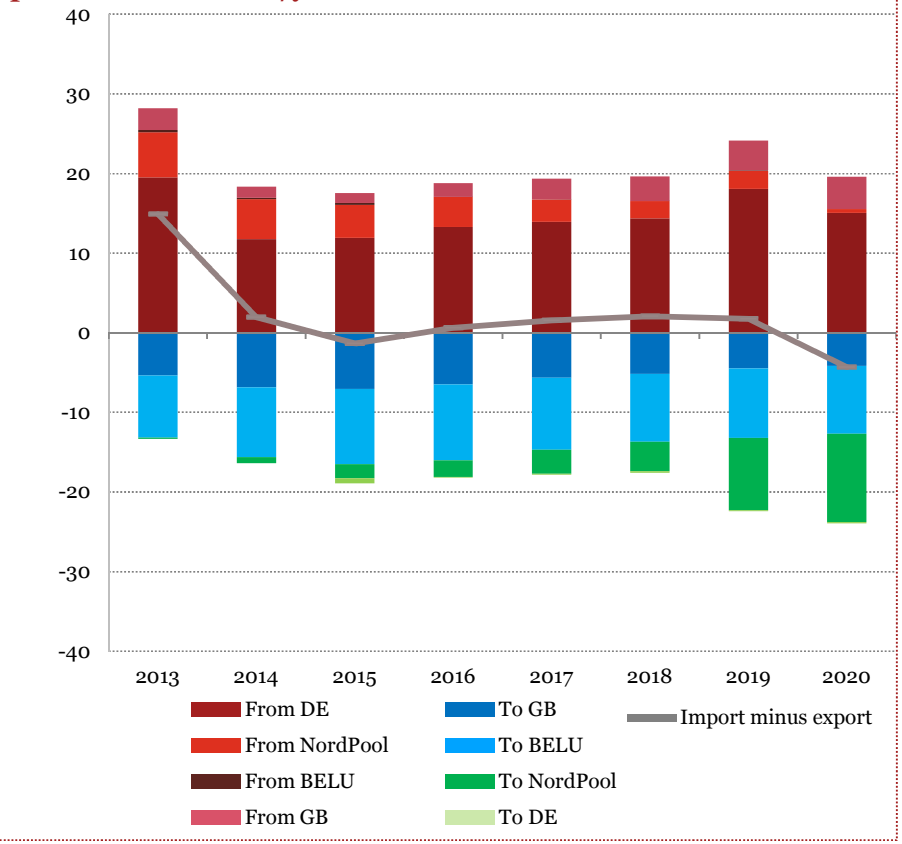
- CO_2 emissions from power generation in 2020 will remain at the same level as 2013 (i.e. around 45 mln. tonnes), despite the addition of newest coal-fired generation capacity from 2014 and 2015
- This is the consequence of
  - the addition of wind power generation
  - the closure of some coal and gas power plants from 2016
  - high co-firing share of biomass (20%)

Electricity price increases from 2016 onwards after initially declining

- The average power price is €53/MWh over 2013-2020, which is not significantly different from the base scenario
- However, the power prices in the Dutch market over 2017-2020 are lower than the corresponding prices in Scenario II. This relates to the reduced export to the GB market, as the wholesale power prices over there will decrease as the result of the introduction of capacity premiums for covering fixed costs

Scenario VIII: import and export

Scenario VIII: Import to vs. export from the Dutch power market (TWh/year)



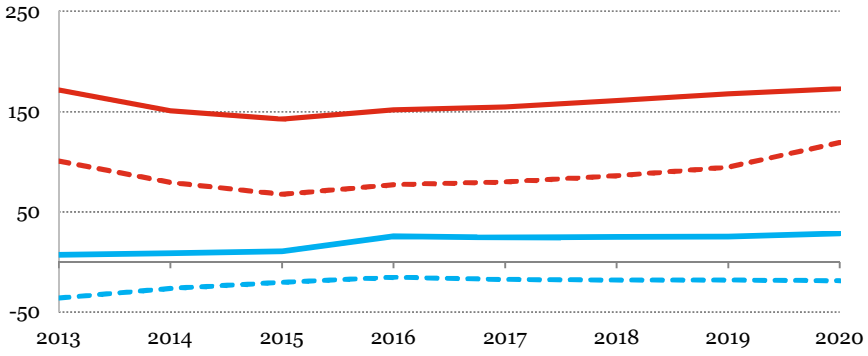
Source: PwC/IPA Analysis

Imports and exports are in balance over the period

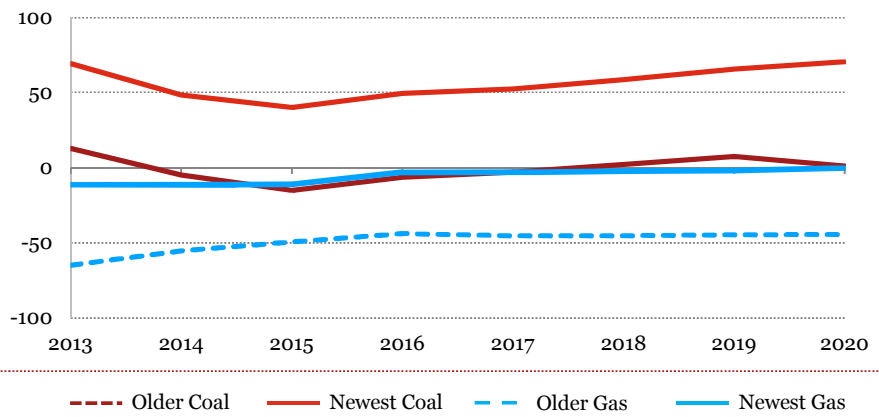
- The net import is this scenario is very similar to the situation in the base scenario, as only the price level in the GB market in Scenario VIII is changed to reflect capacity payments over there: exports increase between 2013 and 2015 with newest coal-fired generation coming online. From 2016 onwards, the Netherlands imports more, as some of old coal-fired generation will be retired
- However, the exports to the GB market are considerably lower than in Scenario II (4 TWh vs. 8 TWh in 2020). As mentioned earlier, this is the effect of the lower whole power prices in GB resulted from the capacity market in GB
- The reduced export amount to GB is mostly offset by the increasing export to Belgium and Luxemburg and to NordPool

Scenario VIII: financial performance

Scenario VIII: gross margin (€ per kW)



Scenario VIII: EBITDA (€ per kW)



Source: PwC/IPA Analysis

Financial performance of coal- and gas-fired plants is similar to the base scenario

- The newest coal-fired power plants will have the best financial performance in terms of gross margin and EBITDA
- The older coal power plants also have positive gross margins due to higher electricity prices, but considerably lower than the newest coal due to lower efficiency
- Gross margins as well as EBITDA of less gas-fired power plants built pre-2010 remain negative. This is a result of the combination of relatively expensive natural gas and lower efficiency of these “old” plants
- Efficient gas-fired power plants built after 2010 have positive gross margins over all years, but almost no positive EBITDAs. The EBITDA performance of these power plants is similar to the performance of old coal-fired power plants

Appendix 3
Methodology

We use the ECLIPSE market modelling platform to simulate the Dutch power market …

The ECLIPSE market model

In order to estimate the impact of the increased use of renewable electricity production in coming years, we used a proven simulation model of the Dutch power market ("ECLIPSE").

ECLIPSE applies deterministic linear programming optimisation that satisfies the given demand in the Dutch market with at least overall cost, including fuel, O&M and new build CAPEX.

We simulated the key metrics of the Dutch power market (i.e. the power price, installed capacity, generation mix, CO_2 emission, gross margins and EBITDA) by incorporating key economic and environmental constraints facing participants in the real world. In particular, we have taken the existing and planned interconnections between North-West European power markets.

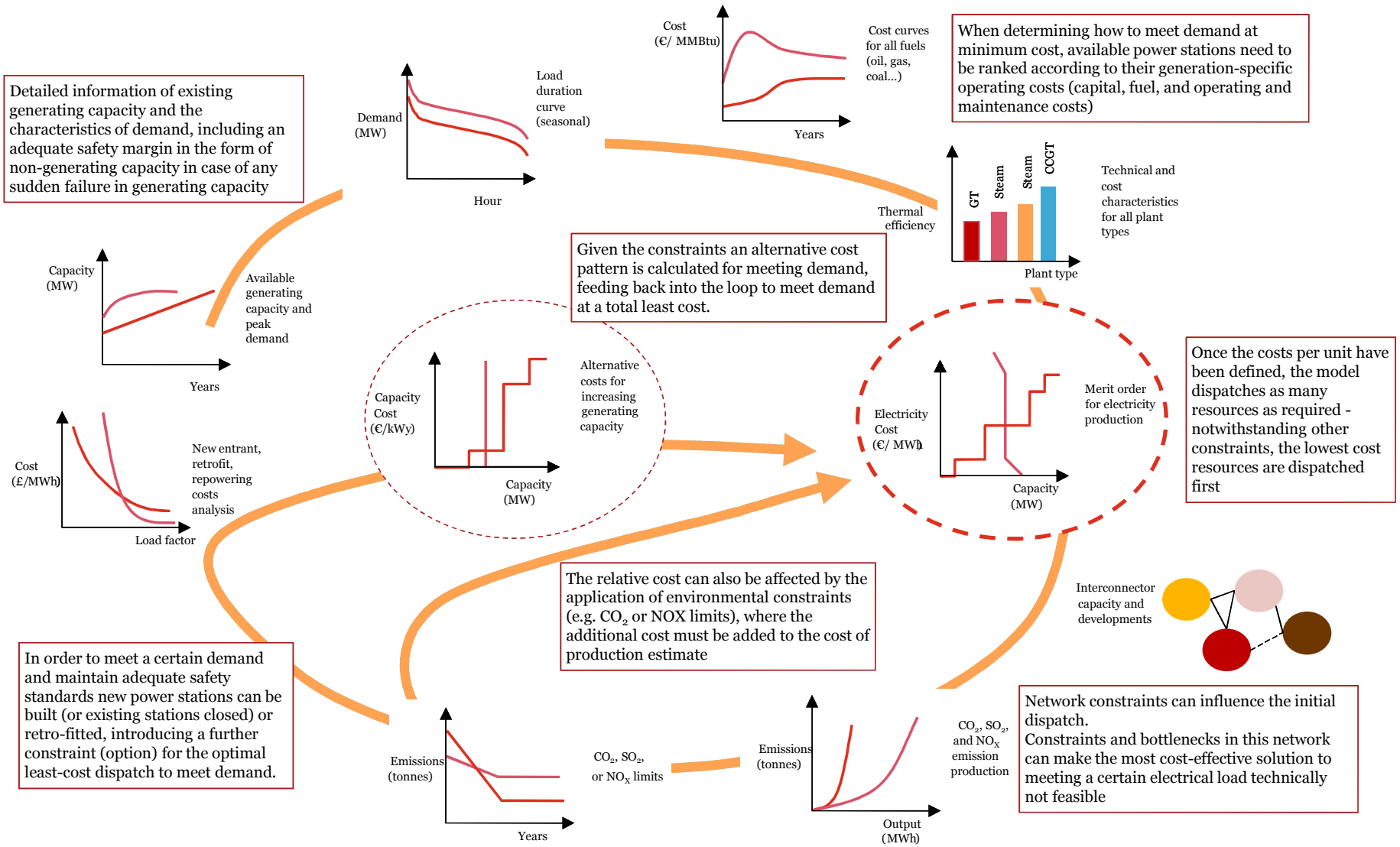
More specifically, the model carried out a series of integrated tasks:

- Extracting detailed information of the characteristics of (peak) demand and existing generation capacity
- Identifying generation-specific operational costs of plants in the system
- Initial dispatching of resources to meet the demand
- Applying environmental, fuel and cogeneration constraints
- Applying network capacity constraints
- Applying entry and exit constraints

Assumptions made around key model inputs

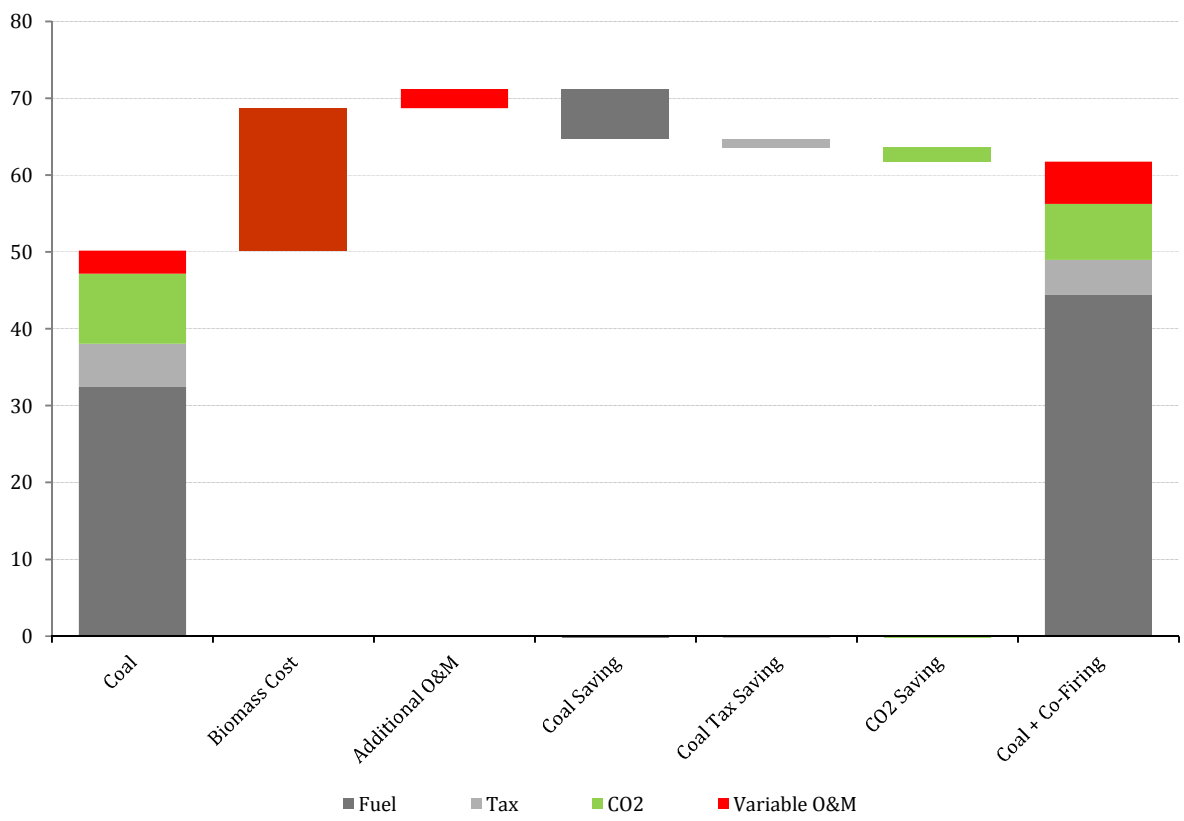
- Detailed electricity demand forecasts for the forecast horizon
- Minimum capacity reserve margin required to maintain security of supply (including taking into account only national dependable sources)
- List of existing facilities, including view on their technical characteristics and costs
- Possible decommissioning profile (including nuclear phase-out) and development of committed and proposed new capacity
- Technological, capital investment and financing inputs for other new builds
- Cost-estimates and time-horizon for zero-carbon thermal technologies
- Future prices of fuel, commodity and carbon in northwest Europe
- Review of governmental policies of EUAs on power plant economics
- Breakdown of LRMC and SRMC of new builds in the Netherlands
- Use of interconnectors for the exchange of hourly power and capacity
- Macroeconomic data, such as inflation and exchange rates

Basic set-up of model



Modelling of biomass co-firing costs

Short-Run Marginal Cost of Biomass Co-Firing (€/MWh)



Source: PwC/IPA Analysis, ECN

Biomass co-firing *at cost*

- To model biomass co-firing, we adjusted the short run marginal costs of the coal plant by adding the cost of biomass fuel for the co-firing percentage and the additional €2.50/MWh O&M costs, but removing the coal, tax and CO_2emission allowance costs for the saved fuel

Biomass co-firing *at coal-equivalent cost*

- For the coal equivalence cases (i.e. the additional costs are to be paid for externally), we just left the short run marginal costs at the pure coal cost, but made sure that the model knew to count the co-firing share of the generation towards the renewables target and the correct CO_2 emissions

Appendix 4
Key assumptions and Scenarios

Key assumptions of fuel price, new capacities and subsidy

Table 1: Fuel prices		
Fuel	**Assumption**	**Source**
Crude Oil	• Using CME forward curve (23rd January 2013) for 2013 and 2014. After 2014, follows EIA Reference Case, reaching 110 USD/bbl in 2020	Annual Energy Outlook ("AEO"), from US Energy Information Authority ("EIA").
Coal	• Using the forward curve of API#2 Coal from Spectron Group (23rd January 2013) until 2016, and flat in real terms thereafter at 104 USD/tonne	Spectron Group (23rd January 2013)
Natural Gas	• Based on the forward market (23rd of January 2013) relationship between TTF and Brent prices, equal to 60% of Brent (in energy equivalent terms)	IPA
HFO, Distillate	• Distillate: Based on the relationship between the forward curve of European Gasoil Swap Futures and Brent crude oil futures using data from ICE, equal to 124% of Brent (in energy equivalent terms). • HFO: Based on the relationship between the forward curve of Daily Settlements for European 1% Fuel Oil (Platts) Barges FOB Rotterdam Calendar Swap Futures and Brent crude oil futures, equal to 86% of Brent (in energy equivalent terms).	ICE, Platts
Biomass	Depending on % co-firing, the substitution costs are constant up to 2020: • <20% co-firing wood pellets (coal plant on coastal location): €33 per MWh • <20% co-firing wood pellets (coal plant on inland location): €36 per MWh • >21% co-firing wood pellets (coal plant on coastal location): €38 per MWh • >21% co-firing wood pellets (coal plant on inland location): €41 per MWh Additional O&M (€2.5 per MWh) as results of co-firing will be included in the substitution costs	Based on ECN, Apr. 2011, *Roadmap VNMI Inzet van hernieuwbare energie;* and ECN 2007

Key assumptions of fuel price, new capacities and subsidy

Table 2: Newly built conventional power plants and interconnections

Year	Plant	Technology	Type	Max. Capacity in MW
2013	BEC Delfzijl	Biomass	Biomass	49
2013	MPP-3	Steam Turbine & Generator	Coal	1,070
2014	Eemshaven		Coal	1,600
2013	Rotterdam		Coal	800
2016	Germany	AC	Interconnection	1,500
2019	Denmark	HVDC	Interconnection	700

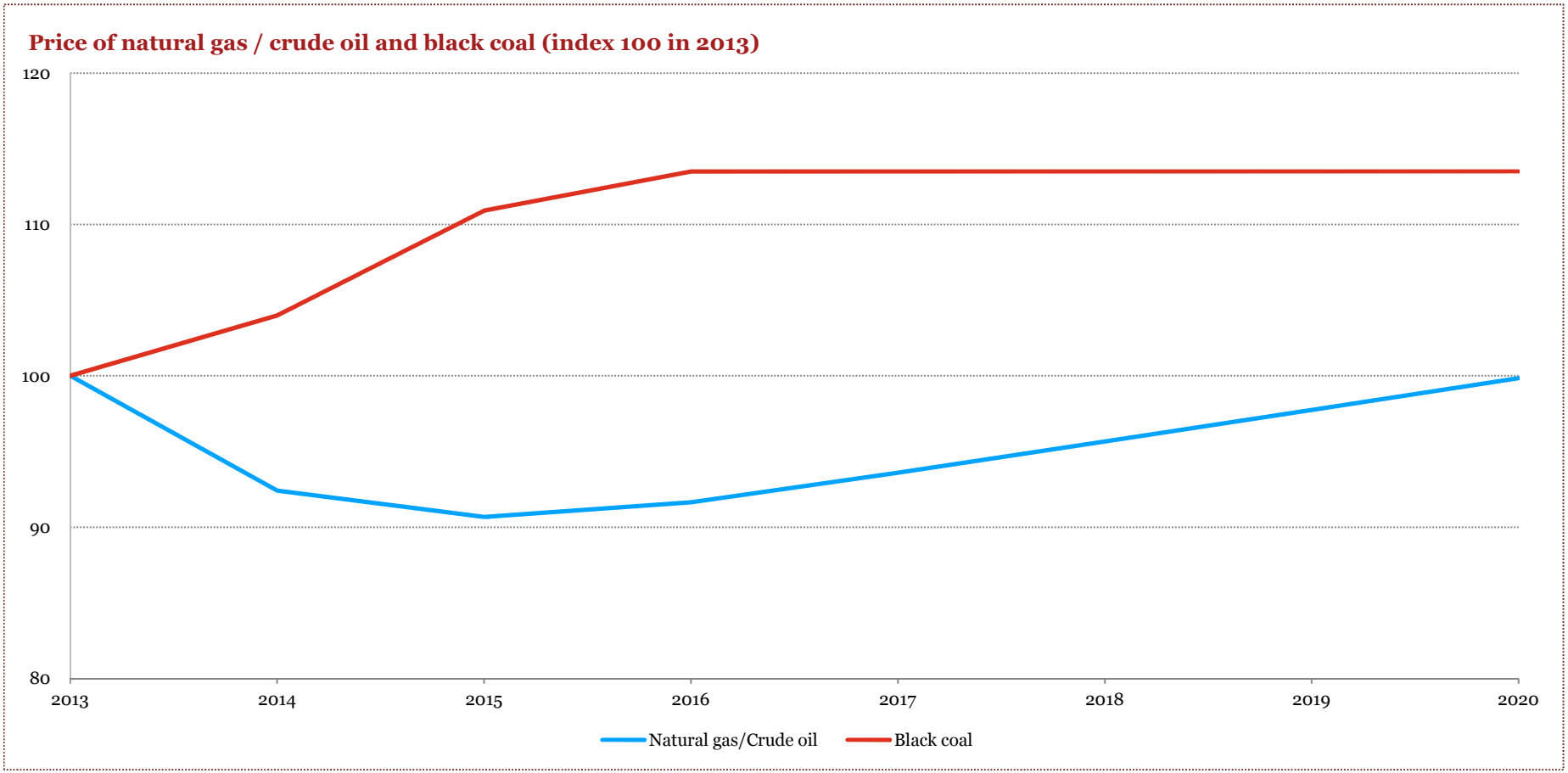
Table 3: Assumption of potential RES subsidy in €/MWh

Technology	Range subsidy €/MWh$_e$	Source
Co-firing biomass[1]	45/55	ECN, Apr. 2011, Roadmap VNMI Inzet van hernieuwbare energie; and ECN 2007 ; PwC/IPA
Onshore wind[2]	30/60	SDE+ 2013
Offshore wind	30/130	SDE+ 2013

[1] Very high-level estimations. Subsidy needed for co-firing depends much on the actual prices of biomass which are volatile in general. We used the substitution costs of co-firing as estimated by ECN. It is however not clear to us which price of biomass is explicitely used by ECN. Additional capex of co-firing is also not included in these substitution costs, which would however be a relatively small amount. The range for additional costs of co-firing as given by other sources (e.g. IEA, IRENA) is in general lower and much broader than the ECN's estimation.

[2] Based on the cheapest and most expensive phases of SDE+ 2013, Agentschap NL

Assumption of fuel price movement in the model



Source: Energy Information Administration, IPA/PwC analysis

Key assumptions of each scenario

		RES share in 2020		CO_2 price (per tonne)				Coal tax (per tonne)		Co-firing biomass				Plant closure			Gas price
		Model optimisation 14% NL + 2% statistical transfer	Model optimisation 16% NL	€0 flat	€10 flat	linear to €25 in 2020	linear to €40 in 2020	€14.03 2013, and zero 2014-2020	€14.03 2013-2020	10% co-firing, at coal-equivalent cost	20% co-firing at coal-equivalent cost	40% co-firing at coal-equivalent cost	20% co-firing (at cost)	Coal (2.3 GW per 2016)	Gas (5 GW in steps from 2016)	Extra gas (3 GW in steps from 2016)	40% decrease, compared to Scenario II
Main Scenarios	I.		✓		✓				✓	✓							
	II.		✓		✓				✓		✓			✓	✓		
	III.		✓		✓				✓			✓		✓	✓		
	IV.		✓			✓			✓			✓		✓	✓		
	V.		✓		✓(1)	✓(1)		✓				✓		✓	✓		
	VI.	✓			✓				✓		✓			✓	✓		
	VII.		✓		✓				✓		✓			✓	✓	✓	
	VIII.(2)		✓		✓				✓		✓			✓	✓		
Sensitivity	II. A		✓		✓				✓				✓	✓	✓		
	II. B		✓	✓					✓		✓			✓	✓		
	II. C		✓				✓		✓		✓			✓	✓		
	II.D		✓		✓				✓		✓			✓	✓		✓

[1] In Scenario V we assume a CO_2 tax for the Netherlands of €25/t increasing linearly up to 2020, for the other countries in the model we assume a flat CO_2 price of €10/t between 2013-2020

[2] The only difference with Scenario II is the inclusion of a capacity market in the GB

Appendix 5
Glossary

Glossary of terms

Generation related terms	
Average demand	The average demand as shown on the merit order charts is the demand level as if the load duration was completely flat throughout the year, calculated as the total annual energy demand divided by 8,760 hours
Dependable/Derated capacity	The net available installed capacity, after the adjustment of the portion of capacity which is considered not to be available for meeting the peak demand
Reserve margin	Calculated as: (dependable capacity/peak demand) – 1
Oversupply capacity	The difference between dependable capacity - 110%*peak demand
x% co-firing	x% of the total input energy comes from biomass, the remaining part (1-x%) from coal
Less/Low efficient gas	Gas-fired power plants built pre-2010, including co-generation
High efficient gas	Gas-fired power plants built in the period 2010-2012
Older coal	Older coal-fired power plants in operation
Newest coal	New builds of coal-fired power plants, to be commissioned from 2013

Financial and economic terminology	
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EBT	Earnings Before Taxes, but after Interest, Depreciation and Amortization
Gross margin	Difference between the energy revenue and the fuel costs
Levelised generating cost	The total cost of a certain generation technology per unit generation output, including all variable (fuel, CO_2, operation) and fixed costs (maintenance, costs of invested capital)
RES subsidy costs	The difference between the market price of electricity and the levelised costs of RES