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Options for a Renewable Energy Supplier Obligation in the Netherlands

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Executive Summary

The government of the Netherlands has committed itself to achieving ambitious renewable energy targets by 2020, and has put in place a variety of policies intended to help the country achieve these targets.[1] The current study, which has been commissioned by the Ministry of Economic Affairs, Innovation, and Agriculture, considers the impacts of potential changes to existing policies. The policies include variants of the current SDE+ approach, as well as different variants of a Supplier Obligation with renewable energy certificate trading. The Supplier Obligation options would require electricity suppliers (and under some design alternatives, gas suppliers) to procure renewable energy equal to a certain proportion of their total energy supply, or alternatively, to buy a corresponding number of renewable energy certificates ("RECs"). The obligation could also extend to other large purchasers of energy apart from suppliers.

The above options were outlined initially in the *Energy Report* published in 2011, along with five criteria that the government would use to assess them. Our analysis combines quantitative modelling of the energy and (proposed) certificate markets with qualitative discussion of selected policy design options and implications for target delivery, social costs, and impact on consumers. The modelling quantifies various standard policy appraisal criteria, including the amount of renewable energy produced, total social costs, impacts on energy consumers (electricity, and possibly also gas consumers), and the level of profits, or "rents", earned by renewable energy producers. We also consider a number of issues qualitatively, including potential concerns related to market power, and the potential benefits of linking a tradable certificate system to other countries.

Our analysis is based on the results of energy market modelling informed by our own judgment. We use a power market model that also represents the decision to build various forms of renewable energy – whether to produce electricity or other qualifying forms of energy, such as heat or biomethane (so-called "green gas")

The various policies that we consider can be designed in different ways. If policy-makers had perfect information about technology costs and potential now and in the future, then it would be possible for them to design each of the policies in ways that would allow them to produce very similar outcomes. However, in the real world, policy-makers do not have perfect information – about renewable energy technologies, or about the investors and markets that support them. Which policy outcomes are robust, and which are variable, under conditions of uncertainty is likely to be one of the key sources of differences between the policies. To better capture the real-world operation of the policies, we model a range of different scenarios designed to provide insight into how they respond under conditions of uncertainty.

1 At the time when the analysis presented here was prepared, the government's renewable energy target had been set at 14 percent of energy use, but the new government has recently proposed that this target be increased to 16 percent.

Box 1
Scenarios Considered

	Scenario Name	Scenario Description
1	Perfect Information	- RES costs are known accurately now and in the future.
2	Low RES Cost	- RES costs are consistently overestimated. - Actual costs 20 percent lower than assumed.
3	Reduced Heat Potential	- RES costs are known with certainty now and in the future. - RES supply potential of heat and green gas is overestimated. - Actual potential 50 percent lower than assumed.
4	Volatile Gas Prices	- RES costs are known with certainty now and in the future. - Increased volatily in the wholesale market gas price.
5	High Wind Costs	- RES costs are known with certainty now and in the future. - Wind costs do not decline over time.
6	Range of WACCs	- WACC estimates varied to test sensitivity to policy risk premium.

We start with a "Perfect Information" scenario, which assumes that policy makers know precisely the costs of RES technologies now and in the future, including perfect information about cost heterogeneity, which policies can be designed to match precisely. We then consider scenarios in which we assume, for example, that costs are consistently overestimated, or that RES potential is significantly lower than projected, and model the impact of the policies – which are no longer precisely designed to match the state of the world.

Like the Perfect Information scenario, many of the sensitivity scenarios still represent a significant simplification of reality. For example, when we assume low RES costs, we assume that policy designers consistently over-estimate RES costs over the policy lifetime and never use "correct" values. We do not model a single "central" or "most likely" scenario. Instead, we use the results of the different scenarios to inform our overall evaluations of the policies. The most likely outcome – including policy-makers' responses to new information – is likely to lie somewhere in between the results for the different scenarios that we consider.

Box 2
Policies Analysed

	Policy Name	Policy Description
1	Current SDE+	- SDE+ support scheme as it was under Rutte 1 government.
2	SDE+ & cofiring	- As 1, complemented by subsidy required to incentivise biomass cofiring.
3	SDE+ & cofiring, high budget	- As 2, with annual budget up to €5.7 billion.
4	"Target-Achieving" SDE+	- As 3, with increased subsidies for offshore wind and dedicated biomass.
5	Uniform RECs	- REC-based policy with one REC per MWh for all technologies, target = 260 PJ.
6	Uniform RECs & bonus/malus	- REC-based policy with one REC per MWh for all technologies. - Expensive RES receives additional subsidy, inexpensive RES pays a charge.
7	Banded RECs	- Expensive RES receives more RECs per MWh than inexpensive RES.
8	Uniform RECs & banking	- As 5, but certificates may be banked and used for compliance in future years.
9	Uniform RECs & banking, 2030 target	- As 8, but target increases gradually after 2020, reaching 334 PJ in 2030.
10	Uniform RECs with buyout	- As 5, but with buyout prices set at different levels.
11	"Hybrid" Uniform RECs + SDE+	- As 10, but with SDE+-style support for expensive RES.

Main Conclusions

- First, we note that any policy change whose effects are not easy to understand may result in delays to investments, because investors will wait to observe the operation and impacts of the new policy become before they begin new projects. Repeated changes may also make investors wary that policies are not stable, and result in further delays.
- The SDE+, in the form and with the annual budget in place during the Rutte 1 government, was unlikely to achieve an overall RES target of 14 percent renewable energy.[2]
- In our Perfect Information scenario (which should not be confused with a “most likely” scenario), an expanded SDE+ would have the lowest impacts on consumers – but impacts are also relatively low for the Bonus/Malus REC policy, under which the REC market is combined with additional subsidies for expensive RES tech-nologies and charges for inexpensive ones.[3] The Uniform REC policy, in which all RES sources receive one REC per MWh (or GJ) of output, has a larger impact on consumers.
- A Uniform REC policy has the lowest resource costs – that is, the incremental cost of the technologies used to meet the RES target is the lowest. However, because even

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2 While the analysis presented here was finalized, the new Dutch government (Rutte 2) proposed a RES target of 16 percent in 2020 and increased the available budget. We have not assessed this new proposal. References in this report to the “Current SDE+” refer to the SDE+ as introduced in 2011 by the previous government (Rutte 1), which aimed to achieve a RES target of 14 percent.

At the time of our analysis the SDE+ annual budget ceiling was €1.7 billion. To make a meaningful comparison with REC policies, we assumed an additional €0.4-0.6 billion allocated under other policies to support biomass co-firing, amounting to a total budget ceiling around €2.1 billion.

3 As noted, with perfect information it should be possible to design the Bonus/Malus and Banded REC policies to closely match the SDE+.

inexpensive technologies receive the same support as the most expensive, the Uniform RECs policy leads to high excess profits, or "rents". This amounts to a significant transfer from energy consumers to RES producers.

- When there is a mismatch between policy design assumptions and reality, the SDE+ does *not* always impose the lowest burden on consumers, because other policies may be better able to scale back impacts when costs are lower than expected. On balance, however, the SDE+ performs reasonably well in limiting consumer impact in most scenarios. The REC options have more variable impacts on consumers, unless combined with a buyout price.

- REC variants that differentiate the support received – including a Banded REC system, a Bonus/Malus system, or some other "hybrid" (such as a combination of the SDE+ with a REC system for lower-cost technologies) – tend to produce results that are similar to the SDE+. The Banded REC system may be more difficult to manage, however, because there is no longer a one-to-one relationship between the number of RECs in the system and the amount of energy actually produced to achieve the RES target.

- In general, of the policies with output above or equal to 260 PJ, the "target-achieving" SDE+ policy (or a hybrid REC buy-out plus SDE+ policy, which has very similar outcomes) usually results in the lowest impact to consumers. These are followed by REC policy variants, with the Uniform REC policy appearing most expensive. This ranking is reversed, however, in the "Low Cost" RES scenario, where we assume that policy-makers over-estimate the cost of RES supply. Under this scenario, the Uniform REC policy (with or without banking) imposes lower costs on consumers than the target-achieving SDE+.

- The SDE+ could be made less expensive if it gave priority to technologies not on the basis of their *total* cost, but on the basis of *incremental* or resource cost.

- Under a REC system (including one with banking), if there is no increase in the RES target after 2020, the REC price will be prone to peaking in 2020 and then falling in 2021. This is because once new investment is no longer needed, the REC price is likely to fall back to the level of the short-run marginal cost of the marginal RES capacity. This short-run cost will not be sufficiently high to compensate capital investments in earlier years, implying the need for much higher prices before the sharp drop down to the short-run marginal cost.

- Concentrated ownership of assets that can be used to burn biomass could result in the exercise of short-run market power in a REC market, but it is less clear that this will have long-run detrimental impacts. Exercise of market power in the long-run would require limited competition and significant barriers to entry across other technologies as well, however. If these are features of RES supply in the Netherlands in the long-run they are also likely to make it possible to exert market power under the SDE+.

- Linking of REC markets tends to lower overall costs, but may not always result in lower impacts on consumers.

Additional conclusions are set out in the concluding chapter of the main report.

1 Introduction and Overview

1.1 Background

Like most European Member States, the Netherlands has committed to challenging renewable energy targets. These will require the Netherlands to derive 14 percent of its energy from renewable sources by 2020. This is likely to entail that on the order of 35 percent or more of electricity be derived from renewable sources by this year, with additional renewable energy anticipated from "green gas" (amounting to approximately 8-12 percent of gas supply), as well as 11 PJ anticipated from renewable heat technologies.

Achieving these targets will be costly, making it imperative that the policies designed to support renewables are cost-effective. The latest SDE+ policy for promoting renewables has been designed with various features intended to contain costs, including annual budget caps, competition between technologies, and multiple bidding rounds, but there is some concern about whether the policy will be able to achieve the above targets. The recent pace of uptake of renewables does not appear to be rapid enough to meet later targets.

The Government's 2011 *Energy Report* identified five key criteria that any alternative to the SDE+ should meet before it would be considered. These are:

1. Renewable energy supply must reach the targeted levels;
2. The policy must be more efficient than the SDE+ – i.e., it should cost less (for a given target);
3. Consumers should not be worse off than under the current system (again, assuming the same targets are met).
4. It should avoid excessive profits (typically referred to in the economics literature as "rents", or sometimes as "windfall profits") and market power. (This is related to the preceding point – all else being equal, higher profits implies higher producer surplus, and therefore lower consumer surplus.)
5. The desirability of moving towards a more harmonized regime across the EU.

In addition, it would be desirable for the policy to minimize complexity.

It is very likely that reliance on biomass co-incineration (or "co-firing") will need to increase in order to meet Government targets, but policy support for this renewable energy option has largely been phased out. Co-firing is not eligible for support under the SDE+. Ongoing agreements between the Government and coal generators are intended to spur continued use of this option, but the details regarding implementation of these agreements leave room for uncertainty. Co-firing is perceived to be among the lower-cost renewable energy sources, but because it has a positive short-run marginal cost and is dispatchable (unlike wind, for example, which has a very low short run marginal cost and is not dispatchable) it has raised concerns in connection with market power and excess profits.

1.2 Aims of Current Study

The current study analyses a number of different various options for a renewable energy supplier obligation in the Netherlands, combined with a tradable renewable energy certificate policy. The policy would oblige electricity suppliers (and under some design alternatives, gas suppliers) to procure renewable energy equal to a certain proportion of their total energy supply, or alternatively, to buy a corresponding number of renewable energy certificates ("RECs"). The obligation could also extend to other large purchasers of energy apart from suppliers.

Our analysis combines quantitative modelling of the energy and (proposed) certificate markets with qualitative discussion of selected policy design options and implications for target delivery, social costs, and impact on consumers. The modelling quantifies various standard policy appraisal criteria, including the amount of renewable energy produced, total social costs, impacts on energy consumers (electricity, and possibly also gas consumers), and the level of profits.

The policies that we consider include:

1. The policy baseline: SDE+ ;
2. A version of the SDE+ adding support for co-firing;
3. A "high budget" version of the SDE+ with co-firing support;
4. A "target-achieving" version of the SDE+ with various modifications to the current policy;
5. A target-achieving supplier obligation with a "pure" REC system (where 1 MWh = 1 REC);
6. A target-achieving supplier obligation with a "banded" REC system (different technologies receive different number of RECs per MWh); and
7. A target-achieving supplier obligation combined with separate "bonus" payments and "malus" charges to provide support in line with the costs of different technologies; and finally
8. A supplier obligation that allows the banking of certificates between years and imposes more stringent targets beyond 2020 up to the policy horizon of 2030;

Under the first three, the policies would not on their own deliver the targeted renewable energy output from electricity, heat, and biomethane ("green gas") technologies. The other variants of the policies broaden eligibility (and critically, the level of support available) to a wider range of technologies to bring the national renewable energy target within reach. Some of the variants also incorporate additional features to mitigate excess profits. Option 6 would do this via "banding" technologies, so that technologies would receive a number of RECs in proportion to their required level of "top-up" support. Option 7 would provide additional support to expensive technologies – and would limit supra-normal profits to low-cost technologies – through the implementation of a supplementary fixed subsidy / tax system (possibly related to the SDE). Option 8 has the effect of smoothing the certificate price over time, dampening the required support in 2020 itself. It does this through two mechanisms; on the one hand allowing some of the target to be met with certificates that have been saved from previous years and on the other hand creating additional incentives for renewable generators in the years beyond 2020.

We also consider the possibility of setting different buy-out prices for the Supplier Obligation. A low buy-out price has the effect of reducing the target achievable through a certificate system, and relies on supplementary support via some other mechanism.

2 Policy Appraisal – Conceptual Issues

2.1 Approach to Policy Modelling

2.1.1 General

Policy modelling often presupposes a world in which there is perfect information and where unexpected future developments do not occur. Under such assumptions, standard economic theory suggests that there need not be any significant difference between a quota-based policy and a subsidy-based policy. Each can be designed to achieve the same outcome – for example, by choosing a uniform feed-in tariff ("FIT") subsidy at the same level as the expected REC price, or by choosing REC "banding parameters" that provide support equal to the support provided by differentiated FITs. The equivalent policies will incentivise the same investor behaviour and achieve the same overall cost, subsidy, price impacts, etc.

Of course, in the real world we cannot assume that governments or investors have perfect information about the present or the future. Decisions are made taking risks and uncertainties into account. Different policy designs often do respond in different ways to unexpected developments, so if we wish to model the kinds of real world uncertainty that are likely to confront investors and policy-makers, we need an approach to modelling that will be able to capture the way the different policies – in our case, the SDE+ and different variants of a REC system – will respond to unexpected future outcomes, given policy designs that are based on our current imperfect information.

Our primary approach is to start from a base set of assumptions about future costs, prices, RES potentials, etc., and to develop the potential policy options with these expectations in mind. These policy options will be considered under the "Perfect Information" scenario. Inevitably, of course, some of these assumptions will turn out to be wrong. We model what happens under the different policy designs when the future differs from current expectations.

In particular, we consider how key indicators of policy success – including total resource costs (i.e. the incremental costs of delivering energy relative to the world without the policy), total "excess profits" from support payments or revenues, and distance from the renewable energy target – deviate from their expected levels when the different policies are confronted by unexpected developments.

There is a wide range of parameters that could turn out differently from current expectations. For example:

- Fossil fuel prices higher / lower than anticipated
- Biomass prices higher / lower than anticipated
- RES investment costs higher / lower than anticipated
- RES potentials higher / lower than anticipated (different technologies / bands)
- Wind capacity factors higher / lower than anticipated

We model a selection of these to illustrate their impacts on the different policy outcomes, presenting the results in Chapter 5 and discussing their implications for policy assessment.

In addition to modelling what happens when our current assumptions about factors that are inputs to the policy design turn out to be wrong, we also consider an alternative approach to modelling uncertainty. This approach focuses on the uncertainty facing potential investors in renewable energy technologies, and attempts to "parameterize" the risks that they face as a result of different policy designs. If a particular policy imposes greater risks on investors, we may expect that they will demand some "premium" return on their investment to compensate them for these risks. We consider the implications for the costs of particular policies if investors demand different levels of return under different policies.

For example, a significant amount of time has been devoted to comparing price- or subsidy-based instruments to quantity-based instruments. One of the frequently-cited advantages of price-based instruments is that unlike quota-based policies, they do not expose developers (and their financial backers) to market price risk for a new (often poorly understood) financial commodity. Subsidy-based regimes, it is often claimed, therefore are more "bankable" and consequently offer governments the possibility of achieving desired levels of renewables while paying a lower "risk premium" to investors to compensate them for the uncertainty associated with fluctuating certificate prices.

We use our modelling tools to assess how much difference this could make to the costs of different policies.[4] However, there is very little consensus about how to quantify the potential differences in risk premium that should be attributed to different policies – particularly the relatively complex designs being considered in the Netherlands.

Related to this is the extent to which any policy revisions that a government undertakes will *themselves* undermine investor confidence, leading to delays in investment, or possibly pushing up the return that investors seek before they are willing to invest in projects. This is something that will also need to be considered when weighing the advantages and disadvantages of the different policy options that the Government is considering.

In the remainder of this chapter we summarise some of the key features of the SDE+ and REC policy instruments and related variants, and assess them against a number of policy evaluation criteria, including robustness to uncertainty and economic efficiency.

2.2 Current SDE+ Regime: A Price-Based Subsidy Instrument

The current SDE+ regime in the Netherlands subsidises renewables by topping up power market prices to a predetermined level (or "base level"[5]) that varies for each technology, based on the levelised cost calculated for that technology. The SDE+ is therefore a form of a "contract for difference" (or "CFD") that aims to keep total revenues above a certain level.[6]

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4 Although there may be some merit in this line of reasoning, it may abstract too far from the reality of policy-making: for example, by failing to recognise that governments themselves will only bear so much risk, and may modify policies significantly – even retroactively – if unexpected outcomes materialize.

5 In Dutch: *basisbedrag*

6 The SDE+ system is a "price-based instrument". There are many other variants of such systems in place across Western Europe, although the SDE+ system is somewhat more complex than most of them. Other examples of price-based subsidy instruments include the system in Germany**,** which has provided extensive FiTs driving a significant expansion of wind Solar PV capacity over the past 5 years. A number of observers suggest the subsidy levels there are, however, extremely high by most standards. Because it is a fixed subsidy stream there is usually no "basis risk", in contrast to the Dutch system. The UK is also planning to introduce a CfD mechanism for subsidising renewables. This

Renewable energy producers receive a top-up payment to the base load power price (or for non-power RES, the relevant conventional counterfactual energy source[7]) for the duration of the support life (either 12 or 15 years) as follows, and as illustrated in Figure 2.1 below:

1. Each subsidised resource has a predetermined "base level" (the black horizontal line series, labelled "A"), which is fixed in nominal terms for the duration of the subsidy period (either 12 or 15 years), and is intended to reflect the levelised cost of the resource.
2. Each year over the lifetime of the subsidy, a top-up payment[8] is calculated and paid based on the difference between the realised power price index (the blue line labelled "P"[9]) and the base level (A), subject to a price floor (the green line labelled "C[10]"), as shown in Figure 2.1:
   - If the power price index (P) is above the base level (A) no subsidy is paid, because the power price on its own provides enough revenue to fully compensate the renewable energy source;
   - If the power price index is between the "price floor" (C) and the base level (A) the asset is paid a subsidy equal to (A) – (P); and
   - If the power price falls below the price floor, the asset is paid a subsidy of only (A) – (C), which prevents the total liabilities of the policy from exceeding a predetermined maximum.

Figure 2.1 shows a hypothetical stream of per-MWh payments that would be provided to a hypothetical renewables development under the SDE+ given a series of power prices over time.

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will top up revenues when they are below a price, similar to the SDE+ system, but claw back revenues when they are above the price. As in the SDE+ system the contract and subsidy stream is intended to be entirely separate from the power market, such that a significant amount of contract basis risk and balancing risk is intentionally left with the generator.

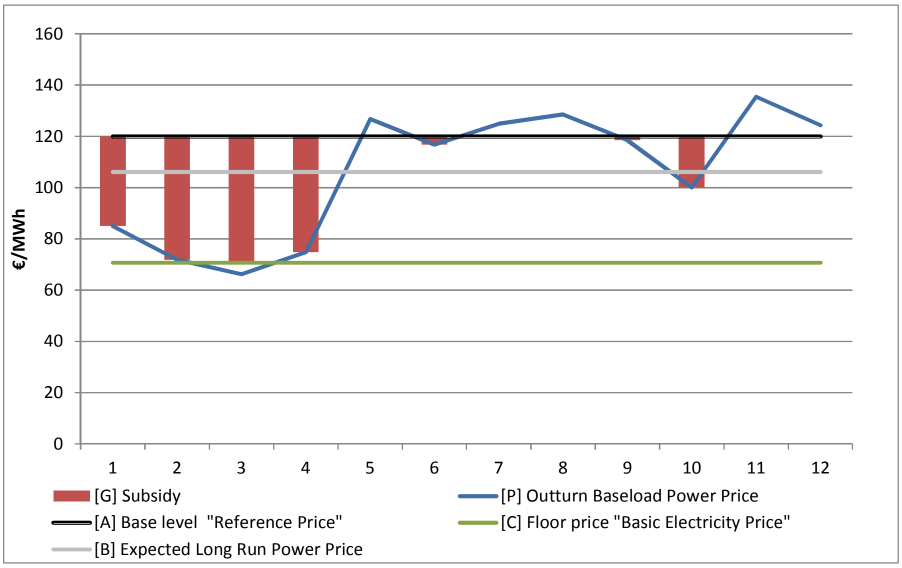
7 In the subsequent discussion, we focus on the power market, although the discussion applies equally to non-power energy sources markets supported by the SDE+, including renewable heat and "green gas" (biomethane) technologies.

8 In Dutch: *jaarlijkse subsidie*

9 In Dutch: *correctiebedrag*

10 In Dutch: *basiselectriciteitsprijs*

Figure 2.1
Example of SDE+ Subsidy Payments



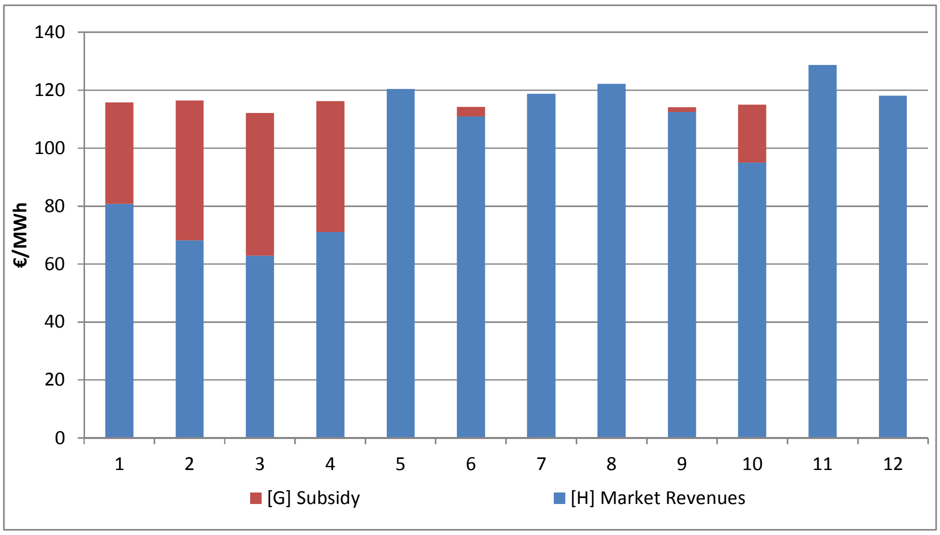
Source: NERA analysis

To receive support under the SDE+ system, potential RES projects participate in a first-come-first-serve application process that is designed to allow the government to select the most cost-effective RES projects for support, given the available budget:

1. In advance of each calendar year, the government sets a maximum "budget commitment" for subsidising eligible RES projects. The government also defines a "long-term average electricity price" and uses this to set the price floor that will apply throughout the life of projects that are granted support in that year. The floor is set to 2/3 of the "long-term average price".
2. Cheaper resources (i.e., ones with relatively low base levels) have priority access to the available budget compared to more expensive resources. This is implemented via an application process that is divided into 5 different chronological tranches, providing the lowest cost support during the period of Tranche 1, and then allowing larger per unit subsidies during Tranche 2, etc., until the budget is exhausted.
3. For each successful applicant, the Government commits a portion of the available annual budget equal to the maximum subsidy which could be required to support that applicant. This maximum represents a worst-case cost to the SDE+, and is equal to the difference between the price floor and the base level, multiplied by the expected output.

As a result of this subsidy structure, the per MWh revenues accruing to a given project may vary over time. Under "normal" conditions (that is, when the power price received by the project falls *between* the base level and price floor), total revenues (including both electricity revenues and SDE+ support) are equal to the base level (ignoring for the moment any basis risk, which we discuss below). However, in the event of very low power prices there is a risk that total revenues will be below the base level. Conversely, if power prices are high, total revenues may exceed the base level. This is illustrated in Figure 2.2.

Figure 2.2
Example of SDE+ Revenues to power asset



Source: NERA analysis

In addition to the variation of the average baseload power price (and the associated power price index), the total revenue received by renewable generators may fall short of the base level for another reason, which we refer to as "basis risk". The subsidy top-up payment is calculated with reference to a power market price index (the "basis"), usually the average power price. In practice, however, the average price received by intermittent renewable resources for their output may differ from the average price ("baseload price"). This is of particular concern for wind generators: wind output tends to be highly correlated among assets over a large area and high aggregate wind output tends to depress market prices so plants achieve less than average prices within each day or week. This effect is mitigated to some extent by the fact that wind output tends to be higher in the winter when prices are also higher. Our modelling, and the experience in other European and international power markets, suggests the former effect is likely to grow stronger over the next decade as wind penetration increases, leading to wind generators, on average, capturing below-average prices.[11]

An example of the contribution to the "budget commitment" for a wind power asset with a base level of €120/MWh is shown in Table 2.1. In this example, the total budget committed is €1.3m/MW installed capacity, assuming an expected annual 2200 full load hours per year

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[11] This is consistent with experience from other areas with high levels of wind penetration, such as western Denmark, where our analysis suggests the haircut off the base load price was typically 5-10% before the east-west interconnector was opened in 2009/2010.

In the UK, one proposal under their forthcoming Contract-for-Difference FIT scheme is to mitigate the increased risk for wind technologies of not capturing the baseload price by basing support on different reference prices. It is envisaged that a day-ahead based price be used for wind (wind generation forecasts tend to be fairly accurate by the day prior to delivery), whereas a long term baseload price would be used as the reference for other dispatchable technologies. The proposal also notes that such a system may even provide incentives for dispatchable plants to time their routine maintenance to coincide with lower current baseload prices.

Under the SDE+, a "disbalance factor" is applied to the relevant energy price that is used to determine the required support for wind projects.

and 12 year asset life. In the example below, we have assumed that the average revenues from the power market (H) are only 95 percent of the baseload power price, reflecting the lower-than-average price expected to be received by wind generators.

The actual total subsidy depends on the amount of electricity generated as well as the power price. In the illustrative example, the actual government expenditure is 34% of the committed budget, because the power price is significantly above the price floor for a majority of the simulated horizon.

Table 2.1
Example Subsidy Calculations

Allocated Budget		**Units**	**Amount**
[A]	Base Level	€/MWh	120
[B]	Expected Long Run Price	€/MWh	106
[C]=[B]*2/3	Floor Price (2/3 of above)	€/MWh	71
[D]=[A]-[C]	"Committed Budget" per MWh	€/MWh	49
[LH]	Expected Full Load Hours	MWh/MW	2,200
[E]	Years		12
[F]=[E]*[D]*[LH]	Total Max Budget Commitment	€/MW	1,300,995
Example Outturn Values			
[G]=Max([A]-Max([C],[P]),0)	Subsidy Payment	€/MWh	(Varying)
[LHR]	Realised Full Load Hours	MWh/MW	(Varying)
[I]=Sum([G]*[LHR])	Realised Budget Consumption	€/MW	445,463
[J]=Sum([H])/[F]	Percent Budget Consumption	%	34.2%

2.2.1 Assessment of the SDE+ system

The SDE+ system has a number of attractive characteristics:

- **Some degree of revenue certainty for investors:** the project developer has a moderate level of certainty about the amount of money that the project will receive, although there is still a downside risk associated with low power prices.
- **Certainty about maximum expenditure:** The future committed budget is known in advance. However, this maximum commitment is likely to be significantly higher than what is actually spent, and may bear little resemblance to what is actually paid out, assuming prices turn out as expected.
- **Limiting excess profits:** The SDE+ attempts to limit excess profits or "rents" in two ways: by capping the support that individual technologies are eligible for, and by imposing restrictions on the *timing* of the support levels offered to applicants – to provide incentives for lower-cost investments to bid early to ensure that they have the opportunity to receive the subsidy before the annual budget is fully allocated. Technologies with the lowest cost are offered lower subsidies per MWh than higher cost technologies, in theory

limiting "excess profits" or "economic rents" and reducing the budget requirement. [12] The policy's ability to limit rents by encouraging early application for support depends on whether or not applicants are confident that if they delaying their application, they will still receive funding.

- **Economic efficiency:** Technologies with lower resource costs are granted access to subsidies first (or may choose to apply earlier). In an ideal world with perfect information, this means the least expensive technologies are selected even when projects are offered different levels of support. This feature presupposes that costs are represented accurately, (and similarly, that there is limited heterogeneity of cost within each technology group).

There are, however, also a number of potential disadvantages to the system.

- **Unknown take-up:** If the pre-determined base levels are wrong or do not adequately capture the dispersion of costs for each resource type the take-up could be very different from what is projected. This could mean missing the country's renewable energy targets if the policy under-delivered. Also, there is no commitment to build by developers who are awarded subsidies. Historically, we understand that some investors may have viewed the SDE+ application process as a kind of "option" to receive the subsidy stream if circumstances were favourable, rather than a fixed commitment.[13] There is, therefore, uncertainty about actual take-up, even after the budget has been allocated.
- **Downside risk to investor:** The investor is exposed to downside risk in the event the power price index goes below the floor. This increased risk is likely to increase to required expected return on investments required by the investor (relative to a case where the downside risk were eliminated).
- **Unsuitable for technologies with significant fuel costs:** For resources which have significant fuel costs (or any other variable costs whose underlying prices fluctuate), such as biomass plants, the system as currently designed does not take into account variations to these costs. In the current setup, there is only limited support for biomass plants and none for biomass co-firing. Allowing for support to these resources may require that subsidy "base levels" be indexed to annual biomass prices, which is not part of the current SDE+ regime. The way this index was set would also mean that the allocative efficiency of the SDE+ (its ability to select the lowest cost technologies) could be reduced.[14]

Finally, the above discussion highlights the fact that many of the potential advantages of the SDE+ system depend on certain assumptions that may only partly hold in the real world. In particular:

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[12] The ability to pay different prices for similar outputs (or to charge different customers different prices) is sometimes referred to as "price discrimination".

[13] Producers must receive a licence before they are eligible to apply for subsidies. Investment in obtaining the licence can be seen as a sunk cost that raises the price of taking up the "option," and that may reduce speculative applications, but will not eliminate them

[14] For example, if renewable energy from biomass sources were relatively inexpensive at low biomass prices, but increasing biomass prices rendered this previously low-cost energy supply much more expensive, it would no longer be cost-effective to operate the biomass generation sources. It might be necessary to design a more complicated index mechanism that put a cap on biomass support in relation to the cost of alternative RES technologies.

- **Cost estimates and excess profits**: The ability of the SDE+ to limit the amount of excess profits depends on its ability to accurately estimate the costs of the set of projects that are actually supported by the SDE+ each year. There are two difficulties here:
  - First, the SDE+ subsidy levels may not be based on accurate estimates of the *average* cost of each technology band. In this case, if projected costs are lower than actual costs, the SDE+ will not be successful in stimulating the development of that technology.[15] If the projected costs are higher than actual costs, the SDE+ will lead to excess profits. In both cases, provided the government or its representatives are able to observe the "true costs" at a future date, the SDE+ can be corrected.
  - The second issue is more difficult to overcome. It arises because even if the SDE+ has the "correct" average cost of each technology, there is likely to be heterogeneity of costs across the set of projects of each technology that receive support. This heterogeneity may be significant. Even if the SDE+ were to offer a level of support that was exactly at the right level to support the "marginal" development within each technology group, all investments with lower cost would receive "excess profits". It is very unlikely that the cost heterogeneity that creates these profits could be eliminated. Thus the ability of the SDE+ to reduce such profits is likely to be over-stated, possibly significantly, if one ignores cost heterogeneity.
- **Price discrimination vs. "gaming" the application process**: As noted above, the application process is designed to reduce excess profits by subsidising cheaper technologies before more expensive ones, and possibly by supporting the cheaper projects within each technology group (thus addressing, to some extent, cost heterogeneity of projects). However, we have also noted that as more information about project costs and the outcomes of successive application processes becomes available, we might expect developers to become savvier about the timing of their applications, and to maximise the level of support that they may be able to achieve. There are a number of ways that applicants could modify their behaviour to increase the support they received from the policy, all of which would increase the cost to consumers of meeting the target, or compromise it all together.
  - Firstly, within each year, some technologies, such as onshore wind, have different base-levels of subsidies which are intended to discriminate within technologies. However, in the event that the budget is abundant for cheaper technologies (which it will be, given the level required to meet the target), investors in cheaper onshore wind, for example, might have an incentive to wait for higher onshore wind tranches than strictly required, thereby achieving a higher subsidy. In certain borderline cases they may even make inefficient economic decisions, for example by fitting smaller blades onto a large turbine, in order to fit into a lower load hour category.
  - Secondly, in the longer term, if it were perceived that the government would be likely to adjust SDE+ levels and budgets in the event of a shortfall of the target, pivotal players may have an incentive to deliberately delay investments from one year to the next with the expectation that the government would increase subsidy levels

[15] This may also mean that other, less expensive projects are not selected as eligible for support, leading to more expensive renewable technologies being supported than would be necessary.

(essentially holding the government to ransom). We discuss this below in Chapter 6 (section 8), where we consider market power more generally.

– Finally, given relatively limited commitment costs of applying for SDE+, some market participants may speculatively submit applications with little expectation of actually utilising the investment.[16] These players may effectively see the subsidy allocation as a “real option” for investment rather than a firm commitment. The design of the SDE+ means these allocations might crowd out other potential projects which would have gone ahead and hence compromise meeting the target all together.

- **Influence on cost estimates**: If the determination of SDE+ base levels relies on information from a few existing developers in the Netherlands, these developers may have lower incentives to drive their own costs down, because this will ultimately reduce the SDE+ support that they can expect to receive. This might result in higher costs over the longer term, although the magnitude of such an effect may not be very great.

2.3 Supplier Obligation: A Quantity-Based Support Instrument

The proposed Supplier Obligation in the Netherlands would be a quantity-based “quota” or “certificate” system. In their simplest form, such systems work as follows:

1. Renewable energy sources receive one renewable energy certificate (or “green certificate” or “quota”) for every unit of energy they generate;
2. Suppliers of energy to end-users are required to surrender a target quantity of certificates per unit of energy they deliver[17] (where the overall target is set by the government);
3. Energy suppliers can buy these certificates from renewable energy suppliers directly or on a certificate market; and
4. Renewable energy generators receive revenue from REC sales in addition to revenues from the power market.

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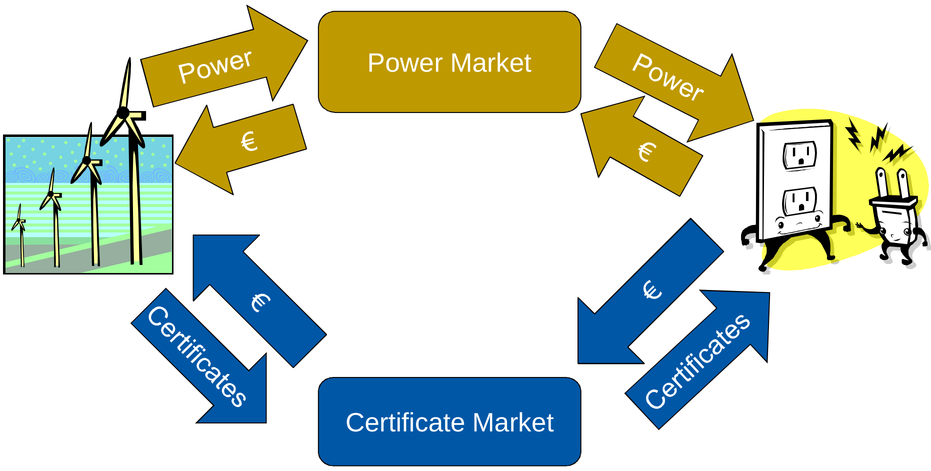
[16] Commitment costs include the costs of planning applications, licensing and the like, but these are small in comparison to the costs of constructing the project itself.

[17] Other parties in the energy supply chain may face the obligation instead of suppliers, but targets are most commonly imposed on suppliers. We have not been asked to consider other forms of obligation.

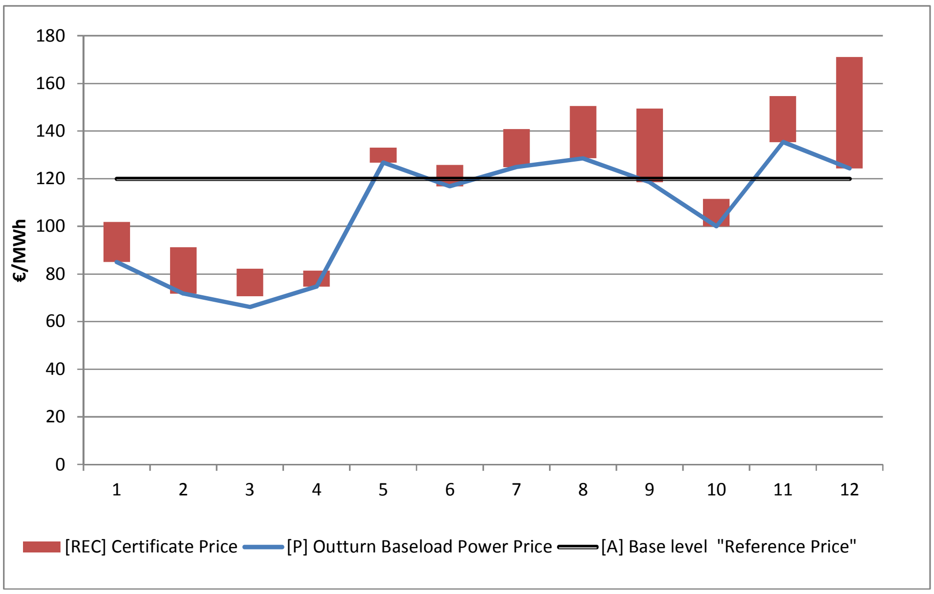
Figure 2.3
Power and REC Market



In theory, this means the REC price should increases to the level that is required to encourage investment in (and operation of) sufficient renewable energy capacity to meet the target.

As suggested by the discussion above, the revenues accruing to a RES producer are the sum of power market revenues and revenues from certificates, as shown in Figure 2.4. As with the SDE+, the revenues to the generator from the power market may differ from the average power price. The expectation is that the REC price adjusts dynamically over time to ensure that renewable operators (and investors) are nevertheless willing to provide energy to the market.

Figure 2.4
Example of REC Subsidy Payments



2.3.1 Assessment of a Supplier Obligation

Certificate-based systems that award one REC per MWh have a number of advantages:

- **Uptake is known:** The quantity is set in advance, so is far more certain to be achieved than under a price-based system.[18]
- **Economic efficiency:** It is economically "efficient", minimising social costs. In other words, the cheapest resources are built before more expensive resources, because any source with a cost below the expected REC price is willing to invest and generate, irrespective of which technology it is. This is not the same as minimising costs to consumers, however. The "least social cost" property is achieved because least cost investments are most *profitable* for investors, but there is no "discrimination," so there may be significant transfers from consumers to investors, who may earn excess profits.[19]
- **Well understood:** Certificate systems are easy to understand and can offer a relatively straightforward framework for investors.[20] However, ease of understanding does not mean they are free from risk and uncertainty.
- **Protection against volatile electricity prices:** Because a target typically must be achieved each year, movements in the average annual electricity price (or in underlying factors that influence it, such as the gas price) are unlikely to change significantly the financial position of renewables sources, because the REC price will automatically adjust to provide total revenues necessary to achieve the target. This differs from the effects under the SDE+, notably when the electricity price falls below the SDE+ price floor.

However, certificate systems also have various disadvantages that have been highlighted in many of their real-world implementations:

- **Volatile and uncertain REC prices:** The REC price can be very volatile—increasing dramatically if supply is unexpectedly low, and falling (in theory to near zero) if supply approaches or exceeds the target. This exposes both buyers and sellers of RECs to significant price risks. As a consequence, many independent developers have found it difficult to secure bank loans on the basis of future REC revenues – driving up investment costs, and creating a system that favours established businesses, and possibly vertically integrated arrangements.
- **Risk exposure of sunk costs:** The price of RECs always reflects the *marginal* cost of renewable energy which means once an investor has constructed a renewable asset, it is exposed to subsequent fluctuations in the price for both power and RECs. For example, commodity price fluctuations tend to feed directly into power prices, so if gas prices drop,

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18 However, introducing either banking or a buy-out price into the Supplier Obligation scheme may undermine the likelihood of the target being achieved. This is discussed in more detail within the results section of the report in sections 5.2.9 and 5.2.10.

19 In essence, the certificate price reflects the marginal cost of generating from renewable energy over conventional sources of generation, so offers a price signal for the cost of renewable energy. All renewable energy sources can earn this price, irrespective of how low their own costs are.

20 In the UK, where the renewable support policy is moving from a certificate based system to a Contracts for Differences FIT system, opponents to the change cited the increased comfort investors took from a well-understood mechanism, as reflected in the current Renewable obligation regime. See DECC, *Planning our Electric Future: A White Paper for Secure, Affordable and Low-Carbon Electricity*, July 2011.

power revenues to renewable generators will drop off. As noted above, such price fluctuations may be compensated by opposite REC price movements, but if the costs of other renewable energy inputs also fall, REC prices may not need to rise as much to incentivise *new* capacity. This has the potential to leave older assets with stranded costs that they cannot hope to recover. Similarly RES producers are also exposed to technological progress, or other developments which make new renewable energy cheaper. For example, if the cost of constructing offshore wind turbines fell unexpectedly, this would be likely to incentivise more new investment and increase the supply of RECs, leading to a drop in the REC price, which would then leave existing producers (who had invested expecting higher prices to prevail) unable to recover their investments.

- **Potential for excess profits due to lack of discrimination:** Under a "pure" REC system, level of support provided per MWh is uniform across resources, i.e. there is no price discrimination. Cheap resources tend to be paid significantly more than their cost, giving rise to excess profits. Although this means the system is "economically efficient" (that is, cheap resources are most profitable and therefore constructed first), it also means that consumers pay more than they would have to for many resources if these could be paid the minimum subsidy required to give them incentives to generate. Variants to the "pure" REC regime modify this design.
- **Potential for Exercising Market Power:** Certain types of new entrant renewable energy potential in the Netherlands are scarce and relatively concentrated among a few market participants. Energy suppliers that would have greatest incentives to exercise market power would own both high marginal cost assets, such as coal plants that could co-fire biomass plants, and low marginal cost assets, such as wind turbines. Under some circumstances, incumbent generators have both the ability and incentive to withhold output from the high marginal cost plants and thereby push the REC price above its competitive level. In normal competitive markets, the threat of new entry capacity would provide a limit to such actions in the long term, but with limited potential new entrant capacity, there may not be less opportunity to check the exercise of market power. We discuss these issues in more detail in Chapter 6.

These perceived disadvantages have led policy-makers to vary the design of "pure" quantity-based policies, some of which we discuss below.

2.3.2 Supplier Obligation: REC system variations

- **"Support Discrimination": Technology differentiation through banding or bonus/malus payments**: In general, economic theory suggests that the most economically "efficient" approach (in the sense that the resource cost to society as a whole would be minimised) to policy design would be to offer *one* certificate to every MWh of output from *any* qualifying technology. However, as noted above, this may result in very significant "excess profits" being earned by low cost projects, which would be willing to invest even at significantly lower profit levels. Under such circumstances, consumers would be paying more than necessary for the output being produced. One option commonly in use is to "band" the technologies such that more expensive resources receive more RECs than cheaper technology. Another option, with similar characteristics, is to introduce bonus/malus payments However, this entails a trade-off between efficiency and distributional outcomes, as the risk of banding is that the technology bands are set incorrectly. Banding and other forms of support discrimination also entail greater administrative effort.

The Renewables Obligation scheme in the UK was first established in 2002 as a technology-neutral certificate-based scheme. However, this was changed to a banded scheme in 2009 (after two years of discussions and consultation). As well as mitigating excess rents, an additional motivation for this was to diversify the range of technologies offering renewable energy. Such diversification may improve the longer term security of supply across the network.

- **Price smoothing through banking:** The option of setting aside RECs earned in one year for use against a future target can be one way of avoiding dramatic fluctuations in certificate prices. Banking is likely to be helpful in smoothing annual variations in wind output, for example. Like headroom (see below), in cases where targets are met, banking is a mechanism that keeps supply of certificates below demand. However, banking also allows for price stabilisation in the opposite circumstance (i.e. when prices are driven up because of a failure to achieve the target), provided there is a pool of previously banked certificates. This latter circumstance also illustrates how banking can serve as a buffer against the penalty or buy-out price. In general, the longer certificates may be banked, the closer will be the links between certificate prices for different compliance years, and in competitive markets, the greater the expected efficiency. However, because banking has the effect of restricting the number of allowances in circulation in a given year, it must be considered carefully if there are concerns about market power. Banking also needs to be considered carefully in light of the fact that renewable energy targets apply to 2020, so that underachievement in 2020 that is "topped up" via recourse to a pool of banked certificates may not be recognised as acceptable at the European level.
- **Price cap through a buy-out**: One of the risks to consumers is that if the REC target is set out of reach, the REC price will increase dramatically. Often, target-based systems include a "buy-out" price, i.e. a price at which end-user energy suppliers can avoid surrendering certificates. This is closely connected with the volume of renewables that will be delivered, and if the target is always out of reach, can be expected to form the basis for the certificate market clearing price – which may in turn have implications for the level of windfall profits or "rents". The buy-out level is also connected to incentives for banking – a higher buy-out price may provide greater incentives to bank certificates now to guard against the risk of missing a future target. The inclusion of a buy-out price risks that the target RES output will not be achieved. If the buy-out price does limit REC prices, so that energy suppliers elect to not surrender certificates corresponding to their obligation in 2020, then output will be below the desired level. This puts at risk one of the key strengths of the REC type policy. However, it may be reasonable where government does not wish to expose consumers to escalating costs, driven by an increasing REC price. As such, a well designed buy-out price can provide government with a tool to manage the trade-off between a firm commitment to achieving a target level of RES output and mitigating the potential cost impact of a supplier obligation policy that is passed through to consumers.[21]

[21] One possible option for managing this trade-off between sacrificing attainment of the target and imposing too high a burden on consumers would be to publish ex ante a variable buy-out level. This could be set in such a way that the buy-out price increases in proportion to the distance from the target trajectory for renewable energy output.

- **Price floors**: One of the key risks to renewable generators in a REC system is that the REC supply increases more than expected, causing REC prices to fall dramatically, or even to zero. One option to overcome this is to provide for minimum "headroom" between actual production and the target, such that the target is deliberately kept out of reach, such that it must be met through either banked certificates or buy-outs.[22] The effect is higher certificate prices, and because the target is re-adjusted, it also means the renewables output is no longer fixed. Mechanisms by which the headroom is periodically adjusted automatically, depending on the "distance to target", may be worth considering. Another way of ensuring that the price does not fall below a certain level is to set a "floor" price that would guarantee a minimum level of support. Price floors may be difficult to implement in a market that allows free trading of RECs – unless the government is willing to act as a buyer of last resort at the floor price.

[22] For example, headroom is added to the target renewables output target in the UK based ROC scheme. See: DECC publication, *Calculating the level of the Renewables Obligation*, 2009.

2.4 Summary of Efficiency and Risks

The previous section highlights some of the differences between the REC and SDE+ systems with respect to the exposure to risks within the power and renewable energy markets. We can distinguish these between (i) risks to investors; and (ii) risks to the government/consumer:

2.4.1 Risks to investors and suppliers

- **Commodity price risks:** Commodity price changes affect power (and heat) prices, which account for part of the revenue received by generators under a REC scheme. Generators are also exposed to these fluctuations, but in a different way, under the SDE+. They may actually face greater downside risk under the SDE+ because of the electricity floor price.
- **Technological progress risk:** Under the REC, there is a risk that falling costs of new entrant renewable capacity could force REC prices lower, which could then reduce the revenues received by projects that were built in previous years below their expected levels. Investors under a REC regime may therefore have greater incentives to recover their investments sooner than those under the SDE+ regime.
- **Basis risk ("Haircut risk"):** Exposure to increasing market volatility, and the risk that generators can not capture the baseload price. The exposure for REC and SDE+ generators are similar. In contrast to a fixed FiT system as observed in for example Germany, both systems have similar properties in relation to the economic efficiency of *dispatch* decisions, i.e. there are incentives to generate when it is most valuable but this does leave assets with the risk of taking a haircut on the baseload price. The REC scheme will dynamically adapt to this.
- **Regulatory risk:** A banded REC system is likely to be subject to banding reviews that occur every few years. Such changes to the level of banding or to the renewable target may have an impact on the REC price. Under the SDE+, there is an equivalent annual calculation of the necessary base price and the associated expected support levels. For the SDE+, however, this review does not affect the level of support that is available to projects that have already secured their subsidies. This would be different under a REC system, because re-banding has the potential to change the supply and demand balance within the entire REC market, and thus affect the support received by existing renewable energy capacity, even when the number of RECs received by existing capacity is "grandfathered".

2.4.2 Risks to the Government and consumers

For the government/consumers, there are also a number of risks

- **Renewables Target:** Under the pure REC, the target will be met by definition, subject to only limited buy-out and banking of certificates. Under the SDE+ , the uptake is uncertain so the government takes on risk.
- **Budget risk:** To the extent the SDE+ is financed through the government budget, this can vary, and the government is exposed to budget risk. If the SDE+ payments were placed directly on power consumers instead, they would act as a "natural hedge": In the event of

low power prices, the subsidy payments would increase, partly neutralising the change and vice versa.

- **Risk on the total price paid for electricity:** The REC scheme offers only protection through the buy-out price.

An important difference between the REC scheme and the SDE+ support regime is that under the REC system, generators are exposed to both REC and power price fluctuations while in the SDE+, generators are exposed only to variations in the power price – and then only when this price is above the base level or below the floor. Which of the two policy systems results in more volatile *total* revenue to investors will depend on a variety of different factors, including the volatility of various commodity prices and the power price, the level of the SDE+ floor price, and the degree of (negative) correlation between REC prices and power prices. It is not evident that one or the other of the two policy approaches has a wider distribution of possible total investment values – whether the “up-side”, the “down-side”, or both.

Another key difference between the two types of policy is that under an undifferentiated REC system, there is more certainty about meeting the target, because the support level automatically increases (with the REC price) in response to a shortfall. Under the SDE+, in contrast, development of new capacity (and operation of existing capacity) depends on subsidy levels that are set based on cost expectations, but that do not adjust automatically in response to any market development. The SDE+ therefore shifts the risk to the government that targets will not be achieved.

Note that some REC variants do not provide as much certainty about the achievement of the target. If a REC policy includes a buy-out price, then there is no longer a guarantee that the target will be met. Additionally, under the banded REC system, it is no longer straightforward to translate the number of RECs issued into the desired level of RES output in MWh or PJ, because there is no longer a one-to-one correspondence between RECs and energy output.[23] Similarly, when banking is allowed, the certainty that a target will be achieved in any particular year is reduced.

It has been suggested that REC-based policies may lead to greater innovation by RES developers. This argument needs to be understood first in the context of the global innovation that is occurring in the field of renewable energy. Given the size of the Netherlands, it seems unlikely that national policy can make much difference to global innovation in this field. Thus the innovation that might be influenced by the Netherlands’s RES policy should be understood as local innovation and cost reduction. With this in mind, if policy-makers are committed to minimising rents (by differentiating support through whatever policy mechanism), this may reduce incentives to innovate, because investors may fear that cost reductions will be met with corresponding reductions in the level of support that is offered. It is possible that a Uniform REC system, because it implicitly signals that high rents will be tolerated, could therefore provide greater incentives for innovation.

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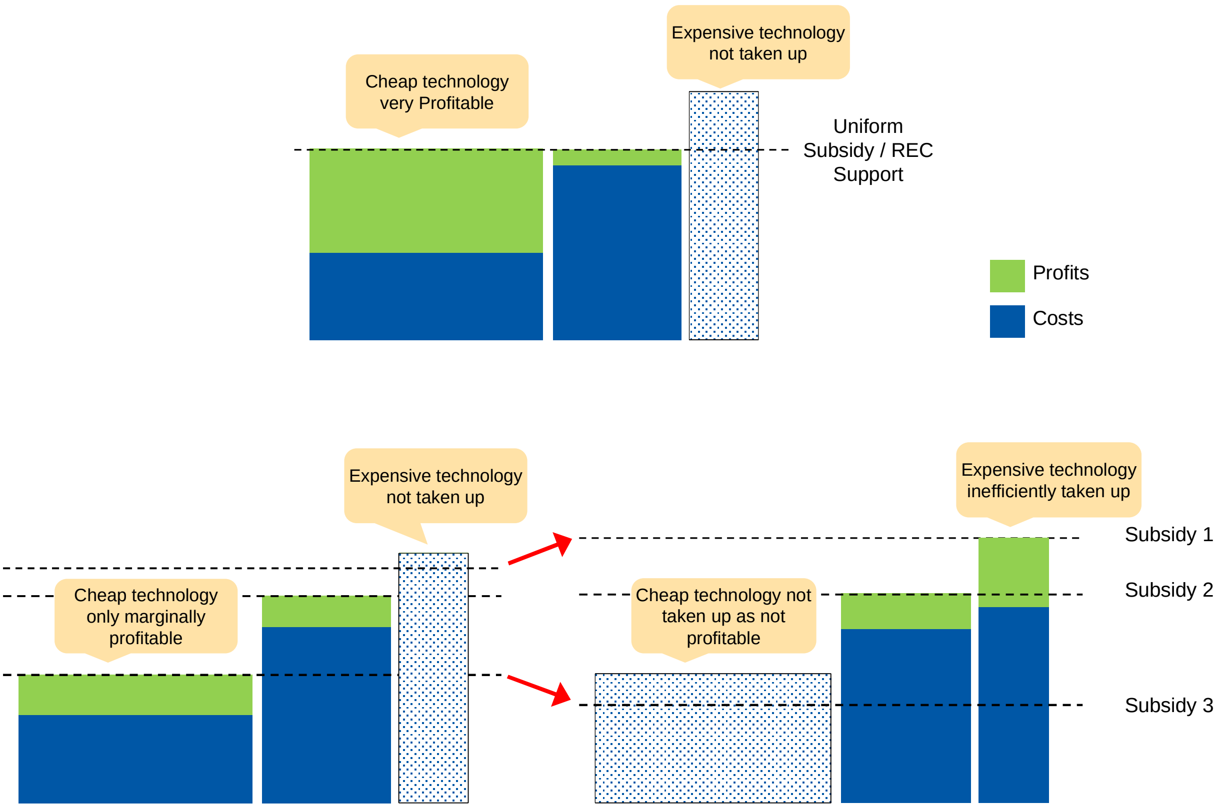
23 Because the bonus / malus policy retains the one-to-one correspondence between output and RECs (and provides a separate “top-up” payment), it also provides more certainty about the target.

There is one other significant trade-off from the Government's perspective, which arises once we take into account the fact that information about technology costs is likely to be inaccurate or incomplete. Although with perfect information, the SDE+ variants (or a banded REC or REC + bonus / malus policy) will deliver the least-cost technologies required to meet the target at the lowest subsidy cost, this is no longer true once the policy design is not perfectly aligned to real-world costs and other technology parameters. This is illustrated in Figure 2.5.

The top chart in the figure shows a RES supply curve with three RES technologies – one with low cost, one medium cost, and one high cost. The coloured areas of the chart indicate the subsidies paid (or other policy-related revenues received). The blue reflects support that is required to cover actual resource costs, and the green represents profits above this level. The top panel shows that under the REC policy, excess profits are relatively high, but the cheapest technologies are supported, whether or not the Government knows the true costs and potential of the RES options. The bottom two panels illustrate the differences between an SDE+ policy that precisely matches subsidies to actual technology costs and one that gets the subsidy levels wrong. In the first case (the left panel), excess profits are reduced significantly, while the target is still met at the lowest cost. The right panel illustrates the impact of having incorrect information about technology costs – in this case, the lowest cost technology is not given enough support to encourage investment, and either the target is not met or it is met at a much higher cost.

Figure 2.5
Illustration of Trade-Off between Excess Profits and Inefficiency



As discussed above, while large inaccuracies in the subsidy level may be detected relatively quickly, and the levels may be adjusted within a year or two, inaccuracies that result from the heterogeneity of projects may simply be impossible to correct.

2.5 Applying Different Risk Premia to Policies

As noted above, differences in risk exposure under different policy regimes may lead investors to apply different investment criteria (such as hurdle rates, or required rates of return) when selecting investments.

There are obvious differences, for example, between a fixed feed-in tariff ("FIT") and a premium FIT, because under the fixed FIT, renewable energy producers are not exposed to fluctuations in the price of electricity. They are therefore less risky. More subtle differences may exist between premium FIT policies and certificate policies, and between both of these and the SDE+. For example, under the SDE+, if electricity prices drop below a certain level, there is a risk that renewables generators will not be able to cover their capital costs; under a certificate-based policy, similar circumstances may occur, but when power prices rise (or fall) there may be compensating changes in the certificate market in the opposite direction that change the distribution of possible revenue profiles.

One way that the differences in risk have been represented in market and policy studies is by assuming that the "hurdle rate" that investors use to screen projects is higher under policy regimes that are perceived to be riskier. This is equivalent to assuming that the opportunity cost of capital, often represented as a weighted average cost of capital (WACC), is higher under such policy regimes. Although there are various examples of studies that make such assumptions there is no consensus about how big a difference to the WACC policy differences are likely to make.

Various policy makers and researchers have considered how to quantify the differences in risk exposure under different policy regimes.

- In general, analysts tend to agree that certificate markets expose investors to significant risk, because for an individual project, there is uncertainty about the level of both the power price and the certificate price, although there is reason to think that the two prices will be negatively correlated, so that fluctuations in the two may offset each other to some extent.
  - REC price uncertainty can be mitigated to some extent by the imposition of price caps (or buy-out prices) and floors (for example, via dynamically adjusting the target level).[24]
- A premium FIT policy reduces the variability of the "renewable revenue stream" (compared to a REC system) but remains exposed to changes in the power price, and total revenues may be more volatile than under a certificate scheme, because of the negative correlation noted above.
- A fixed FIT policy is typically taken to provide the greatest level of certainty to investors. However, it also requires the following caveat: recent experience suggests

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[24] In the UK Renewables Obligation this is referred to as "guaranteed headroom".

even FIT regimes are subject to significant risk, as governments may drastically revise FIT levels, not only for new investments, but even retroactively for investments that have already been made.

  - Governments have also passed taxes to take back revenues earned by renewable generators from FITs, which exposes investors to substantial risk – particularly if developments have changed hands since original construction.
  - This exposure to policy risk is directly related to the fact that under FIT regimes, the government takes upon itself the *quantity* risk – that is, the risk that the level of investment in renewable energy projects is either greater or less than originally expected. Recent experience has demonstrated that governments will not always accept the downside financial risks associated with higher-than-expected investment.

– Contracts for difference ("CFDs", of which the SDE+ offers a certain variant) are similar to fixed FITs, but details of how the CFD is defined and the payment calculated can create additional risks for investors, including the basis risk discussed above, and the risk associated with the price floor under the SDE+.

There is, therefore, some consensus regarding the relative levels of risk that different policy regimes impose compared to other policy regimes, but the comparisons are not always clear-cut. Furthermore, the (qualified) consensus about the relative ranking of investor risk exposure is not easily quantified. So while it seems reasonable to suppose that the WACC demanded by investors under a fixed FIT regime will be somewhat lower than the WACC demanded by investors under a REC regime, there is no consensus about the magnitude of the difference.

Nevertheless, various analysts have made assumptions about the levels of WACC that are applicable under different policy regimes. Few of these are backed up by formal analysis or quantification of the estimates, but we nevertheless summarise a selection of typical estimates below:

- A European Wind Energy Association publication[25] assessed the characteristics of different types of renewable energy support policies based in part on surveys of industry experts. The study distinguished between "generic" policies (which are assumed to involve greater uncertainty because they are less well established, providing for less transparent procedures about policy revision and less market information) and "advanced" policies (which are characterised as being better developed, more well established, and having more transparency and rules for how revisions may be introduced). The WACC estimates vary substantially, with "advanced" fixed FIT policies having the lowest WACC (at 6.5 percent) and "generic" certificate systems tied with "generic investment subsidies" at 12 percent – a difference of 550 basis points. Interestingly, however, the study judged well-designed certificate systems (WACC of 8.6 percent) to be less risky than "generic" fixed FIT regimes (with a WACC of 9.1 percent). "Tendering systems" – which could be one way of describing the SDE+ – fall somewhere

25 European Wind Energy Association (2005) Support Schemes for Renewable Energy, A Comparative Analysis of Different Payment Mechanisms in the EU, European Wind Energy Association.

in between – with a difference relative to a REC system, under the "advanced" policy description, on the order of 100 basis points.[26]

- A study for the UK government[27] suggested a 60 basis point difference between investors' WACCs under a hybrid certificate regime like the UK Renewables Obligation and a CfD regime. The study also suggested a range of 40-80 basis points, depending on assumptions about the level of return demanded by equity investors (which in turn may vary by technology). The study attributes the difference primarily to the higher levels of debt financing (as opposed to equity financing) that it assumes would be afforded because of the greater revenue certainty provided by the CfD regime.
- Two recent studies in the Netherlands also make assumptions about the differences between different policy regimes:
  - One study for Energie Nederland[28] assumed a post-tax nominal WACC of 6-7 percent across all technologies in modelling the earlier SDE scheme in the Netherlands, with the higher WACC rate applied to offshore wind. The study assumes the same WACCs under the different policies considered.
  - Another study, also carried out for Energie Nederland,[29] assumed nominal WACCs of 6-8 percent per year (again, varying by technology) to model the SDE scheme, and assumed no difference under a certificate-based scheme. The study judged the SDE to have levels of risk similar to certificate based policies because of the downside risk associated with unexpectedly low power prices under the SDE. The study does suggest lower WACCs for a FIT regime, in the order of 100 basis points.

In summary, the selection of studies surveyed above suggests no real consensus about the difference in risk premium or WACC that might be demanded under a REC system, relative to the current SDE+ or some future variation on it. The range of estimates suggests that the WACC under a REC system could be no different from that under the SDE+, or that it might as high as 150 basis points higher.

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[26] These estimates were adopted in the Green-X project assumptions on the discount rate for various support schemes. (Presented in Fraunhofer Institute Systems and Innovation Research report (2006), *Monitoring and evaluation of policy instruments to support renewable electricity in EU Member States*.)

[27] CEPA (2011). "Note on impacts of the CfD support package on costs and availability of capital and of existing discounts in Power Purchase Agreements.", submitted to DECC

[28] Frontier Economics, *Study on market design for a renewable quota scheme.* May 2011

[29] Energy Research Centre of the Netherlands, *Cost-benefit analysis of alternative support schemes for renewable electricity in the Netherlands*, March 2011

3 Modelling Implementation and Assumptions

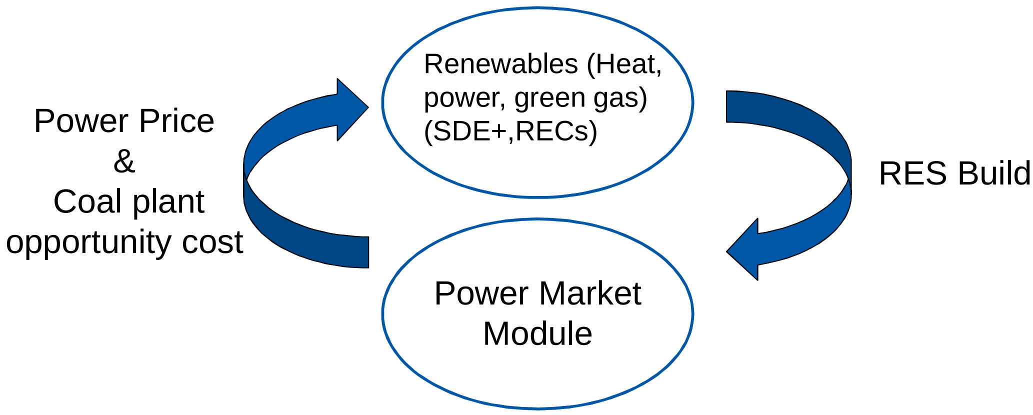
3.1 Overview of Modelling Methodology

For this assignment we have applied our power market and renewables model, EESyM. The model integrates our power market model and a tailored module for the Dutch renewable energy subsidy regime into one framework, iterating between the two modules as shown in Figure 3.1:

- First, the power market module estimates equilibrium power prices, given existing capacity, estimated existing renewables output, new entrant costs and commodity prices. This module passes power prices and coal plant opportunity costs for different power market situations to the renewables module;
- Then, the renewables module reads the power prices and opportunity costs, and decides which renewables to build, subject to the maximum annual construction limits and maximum total capacity constraints set out in section 4.6. This module explicitly models each year's new renewable capacity as a separate vintage, and takes into account the life of the subsidy and the life of the asset separately (if different). The module passes the renewables output back to the power market model;
- The power market module determines a new price path, given the output from renewables, taking into account the intermittent output profile of the renewables.

The iterative procedure is repeated twice, which we have found is adequate to sustain a stable equilibrium.

Figure 3.1
EESyM Modules



3.2 EESyM Power Market Module

We have used NERA's power market model to simulate the Dutch power market, complemented by a separate renewable energy module to ensure appropriate modelling of the renewable energy investment decision given quota obligations or subsidy payments. EESyM is a comprehensive production cost model of European electricity market, which we keep up-to-date using data drawn from Platts *Powervision* database as well as information gathered through local information sources and our various assignments.

The EESyM market module simulates the most important western European power markets for the Netherlands up to 2035.

3.2.1 Power Market model overview

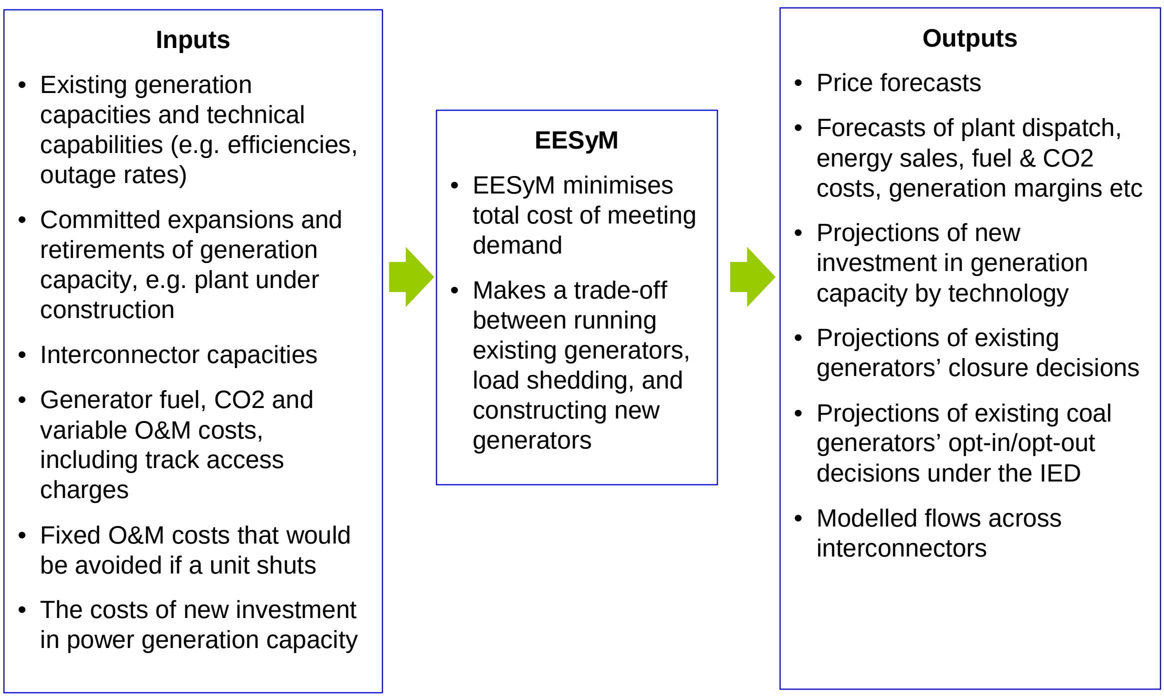
EESyM is a mathematical programming model which solves for the optimal market price of electricity, the optimal investments, and production by plant types in any given year.

The model simulates optimal despatch by minimising the net present value of the capacity and energy costs of meeting system demand in each market over a number of years, taking account of interconnection constraints between the markets. EESyM uses a load duration curve representation of demand in each market, as explained in the previous section. EESyM optimizes the dispatch by assigning the least cost solution for any point of the load duration curve.

The model can also simultaneously optimise new construction and decommissioning of plant given data about new plant options and the Operation & Maintenance costs of existing plant or, as an alternative, on the basis of standard economic lives.

A picture of the model flow is shown in Figure 2.1, below.

Figure 3.2
Model Flow

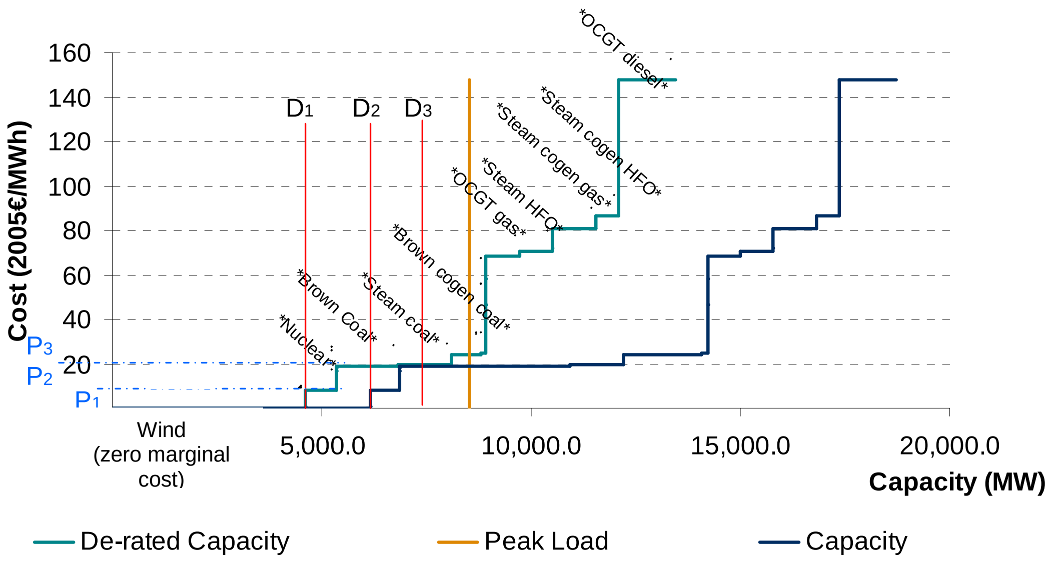


3.2.2 Illustration of power market modelling

When markets are competitive, the price of electricity in each hour is determined by the cost of the marginal generator needed to meet the load in that hour. To determine the price of electricity in each hour, EESyM uses a linear (mixed integer) program to find the least-cost way of using available capacity to meeting electricity demand. It matches generation arranged by 'merit order' against demand. The price in each hour, or type of hour, is given by the marginal cost in that hour, as explained below.

As an example, Figure 3.3 shows three different levels of demand, D_1, D_2 and D_3 together with a sample merit order curve. The price of electricity in those hours is the variable cost of the "marginal" generator on the system. The "marginal" generator is the most expensive type of generation required to meet demand in a particular hour, assuming a least-cost (merit order) pattern of generation. For the three levels of demand, D_1, D_2 and D_3, the corresponding prices are P_1, P_2 and P_3. Note that the first two prices differ very little, despite the large difference in demand, because the marginal generator in both cases has very similar variable costs. The line defined as "Peak Load" illustrates a sample level of maximum demand. The marginal generator at this level of demand is the same as at demand D_3, so P_3 is the maximum price that will be achieved under the given cost assumptions.

Figure 3.3
Example Supply-Demand Optimization



An important variable in the context of the Netherlands is the output from intermittent generation capacity such as wind. Variations to wind output mean that the merit order also shifts. The least-cost solution takes this into account by varying wind availability. This is calibrated to a historical aggregate wind output shape for the Netherlands.

To achieve a least-cost usage of generation capacity overall, EESyM finds a global minimum, subject to the constraints applying across several hours. It also simultaneously optimises new entrant capacity required to meet demand at least cost, and co-optimises the most important surrounding power markets as set out in section 4.3.

In practice, to reduce the number of calculations involved, rather than simulating all hours of the year up to the end of the modelling horizon, we sample representative hours on a quarterly basis. We do this in such a way that we sample both high and low intermittent generation situations under both high and low demand. This procedure is further outlined in Appendix B.

3.2.3 Model Inputs

The main types of inputs to the model for each market are:

- a forecast of peak annual system demand in MW,
- the system load duration curve represented in terms of a number of load periods each with a specified load level relative to peak demand,
- required capacity reserve margin or generation security margin,
- the discount rate (used to calculate the NPV of system costs)
- fuel and CO2 prices,
- net available capacity (MW) and expected life time, by type of plant,
- plant thermal efficiencies or heat rates, by type of plant,
- non-fuel variable costs, by type of plant,
- fixed Operation & Maintenance costs, by type of plant,
- capital costs of new plant, by type of plant,
- emission rates, by type of plant, and
- the annualised costs of new plant.

The model selects new capacity from options presented to it, and despatches new and existing plant capacity which is on the system in each year.

The model always ensures that demand is met at minimum cost in terms of Net Present Value (NPV), subject to any constraints on dispatch which are specified (e.g., interconnection limits). The specification of additional constraints – for example, future limits on fossil-fired generation – can easily be imposed.

We discuss details of our input assumptions in chapter 4.

3.2.4 Model Outputs

The main outputs produced by the model for each forecast year are as follows:

- electricity prices (based on the underlying merit order and demand profile);
- generation costs;
- construction of new plant in MW, by plant type;
- annual electricity generation in GWh and load factors, by plant type as well as for selected individual plant;
- annual fuel burn, by fuel type; and
- annual emissions of CO_2.

The figures below provide sample outputs from the model.

Figure 3.4
Electricity Market: Selected Production Costs, Prices, ad Spark Spread

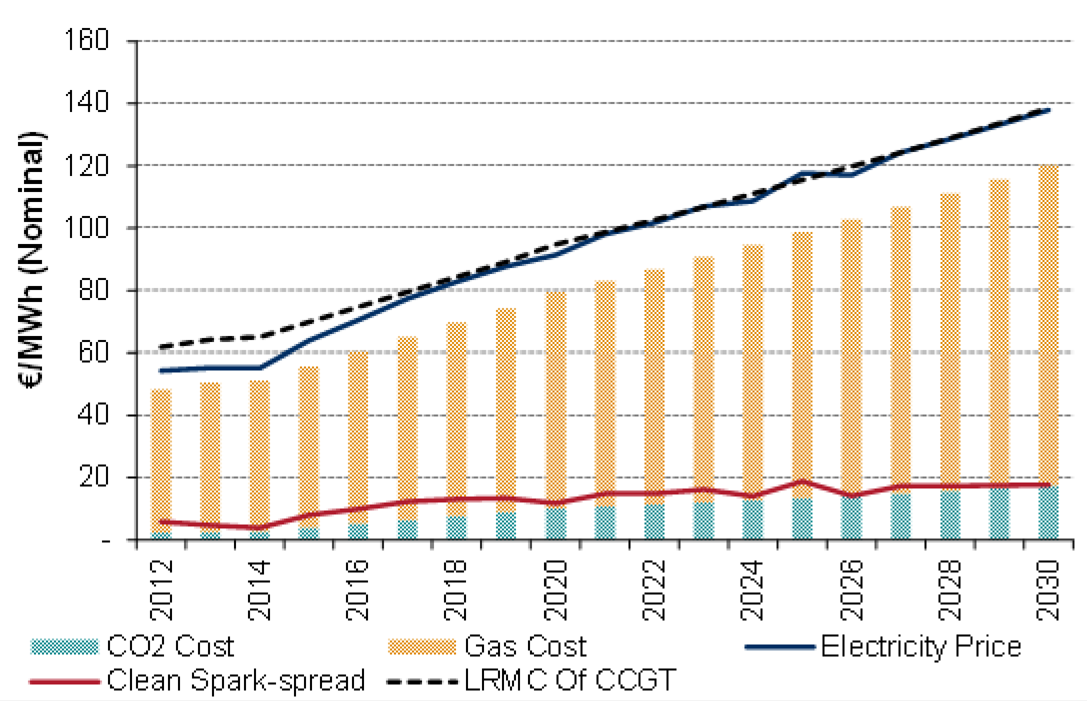


Figure 3.4 provides an illustration of the baseload wholesale electricity price predicted by the model, which converges to the underlying cost of new entrant gas-fired CCGT plants in later years. The next figure, Figure 3.5, shows the electricity generating capacity installed over time, with new renewable and potential gas investment highlighted in green. Finally, Figure 3.6 shows the associated electricity output over time. (Note that these results do not correspond to any particular policy scenario that we present in later chapters.)

Figure 3.5
Installed Electrical Capacity and Peak Demand

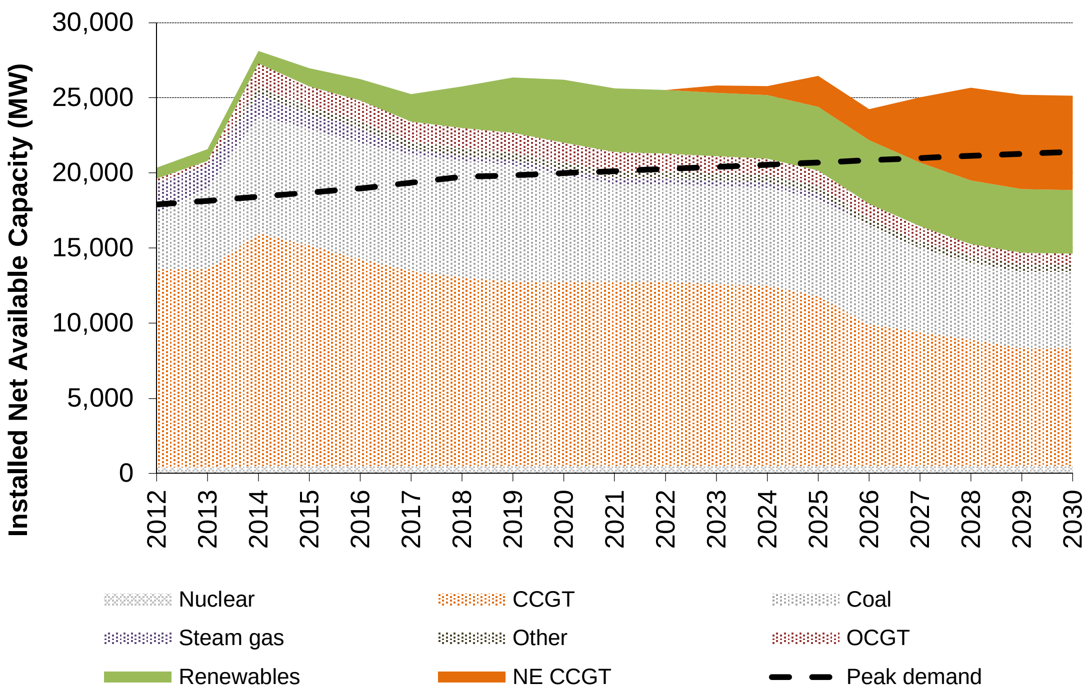
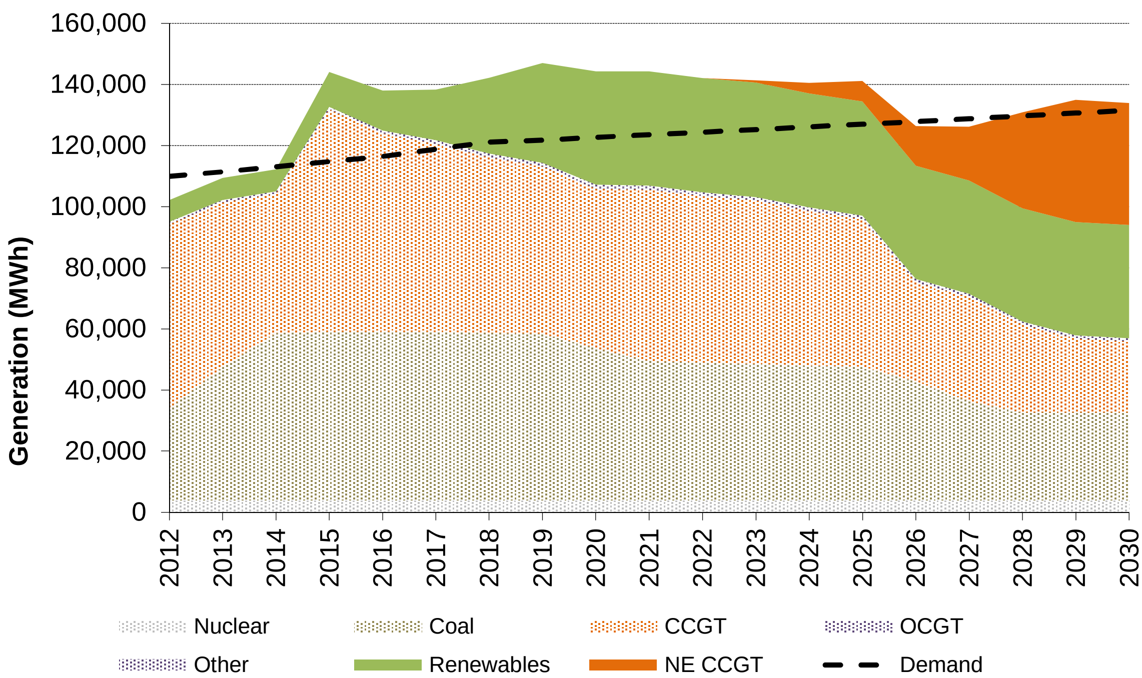


Figure 3.6
Electricity Generation and Demand



We then complement the basic power module outputs with additional results from the renewable energy module, which is discussed in the next section.

3.3 Renewable Energy Support Module

3.3.1 REC Renewables Model

We have applied EESyM's standard REC module for analysing the likely construction of capacity under different variants of a certificate scheme (RECs). The REC model works, in a similar manner to the power model, by minimizing the total resource cost of meeting the REC target. The REC price is determined as the "shadow price" of REC demand, i.e. the marginal cost of increasing REC demand by one unit. In short, the REC module works as follows:

- Each renewable generation capacity receives a prespecified number of REC's per unit of output;
- The model minimises cost of supplying the required number of RECs st. taking into account the net cost of generation, net of power market revenues.

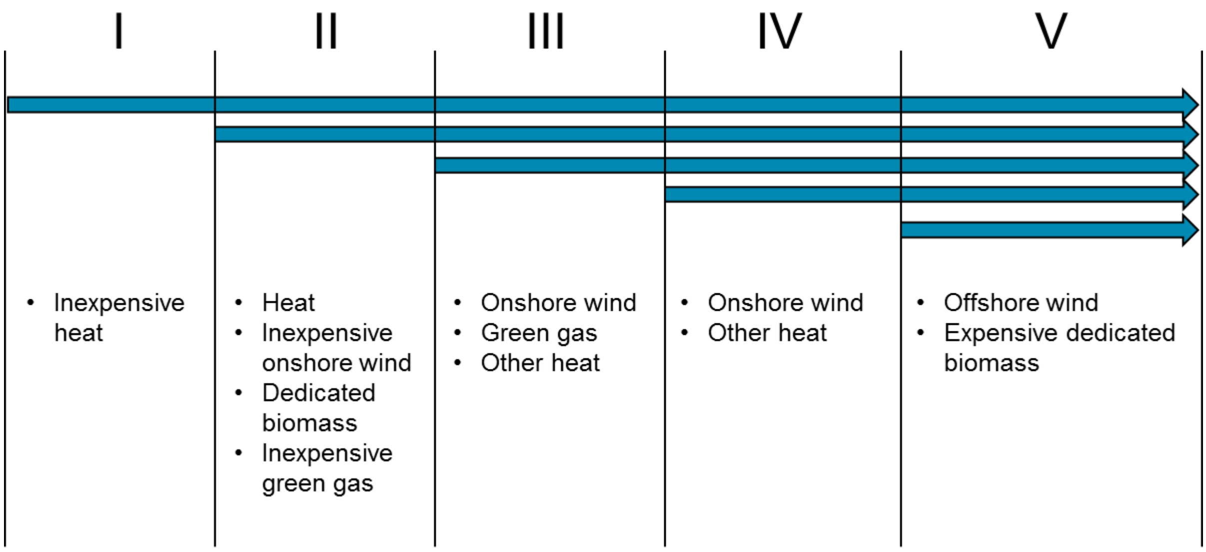
The REC module models representative situations for each quarter, which means that resources with significant marginal costs, such as biomass plants, are only dispatched if the revenues from the power market plus the value from the REC market can cover their dispatch (i.e. marginal operating) costs.

3.3.2 SDE+ Module

As a baseline for comparison of the different REC setups, for this project we have tailored our EESyM's renewables module to incorporate the specific characteristics of SDE+ subsidy regime, to resemble the scheme as close as possible. This module works by constructing new assets assuming investors wish to maximise profits, taking into account the following properties:

- SDE+ payments are granted as a top up to the average baseload power price, according to the formula set out in section 2.2.
- The revenues to investors are captured price in the power market plus the realized SDE+ top-up payment
- The committed budget for each vintage is subject to a budget constraint. The budget is allocated in a prioritised order where only cheap resources can participate in the first rounds, as depicted in Figure 3.7.

Figure 3.7
SDE+ Module



4 Input Assumptions

This section set outs the input assumptions applied in our modelling, including our assumptions in relation to:

- Demand/supply;
- Interconnections with other regions; and
- Cost and potential of new entrant renewable and conventional generation capacity.

4.1 Demand

4.1.1 Demand and sector breakdown

Over the period 2000-2011 Dutch electricity consumption (including losses) grew at about 1.1 percent per year on average, as Table 4.1 shows.

Table 4.1
Electricity Consumption and Peak Demand (2000-2030)

		Actuals				*Projection*				*Growth Rate*	
	Units	**2000**	**2005**	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**	**Historic**	**Projected**
Gross Consumption	TWh	104.6	114.7	117.1	118.1	122.3	130.7	135.3	140.2	1.11%	0.9%
Peak Load	GW	.	.	18.4	18.0	18.7	20.0	20.7	21.4		0.9%

*Source: Historic figures: ENTSO-E*30*; Projection: Tennet, table 2.1*

In 2011, hourly demand peaked at 18.05GW according to data from ENTSO-E. Peak load typically occurs in the winter (December, January or February).

For our modelling of the Dutch power market, we assume power consumption will grow as forecast by TenneT until 2019 (about 1.2 percent per year), and will thereafter grow more slowly, at 0.7 percent per year. On average, this implies that consumption will grow at an annual rate of 0.9 percent between now and 2030. We assume peak load will grow in line with consumption.

Because our modelling outputs include estimated impacts on consumer energy bills, we also make use of information about the share of demand accounted for by different consumer types. Table 4.2 shows a breakdown of the final net electricity consumption for the period 2000-2010.[31] Over this period, consumption by the residential and services sectors increased by 1.3 percent and 1.6 percent on average annually. Industrial consumption, which accounts for the largest share of demand, dropped significantly in 2009 due to the economic recession, and has not yet recovered even to its 2000 level. Agriculture has also seen significant growth, but because of its limited weight this contributes less to the overall growth. The difference

[30] ENTSO-E Country Packages, 2000-2011, ENTSO-E http://www.entsoe.eu/db-query/country-packages/production-consumption-exchange-package/

[31] At time of writing, detailed information of this kind for 2011-2012 was not yet available.

between the consumption data in Table 4.1 and Table 4.2 is mainly due to network losses that are not included in the final net energy consumption of Table 4.2.

Table 4.2
Final Electricity Consumption by Sector (TWh)

Final Power Consumption	Units	2000	2005	2006	2007	2008	2009	2010	Average Growth, 2000-2010
Industrial	TWh	40.8	41.6	41.6	42.3	42.2	36.3	39.1	-0.4%
Transport	TWh	1.6	1.6	1.6	1.6	1.6	1.7	1.7	0.6%
Residential	TWh	21.8	24.2	24.8	24.3	24.8	24.2	24.7	1.3%
Services	TWh	29.3	30.6	32.4	35.1	32.7	33.7	34.3	1.6%
Agriculture/Forestry	TWh	4.2	6.5	5.6	5.2	7.8	8.1	7.1	5.3%
Net Consumption	TWh	97.8	104.5	106.0	108.5	109.1	104.0	106.9	0.9%

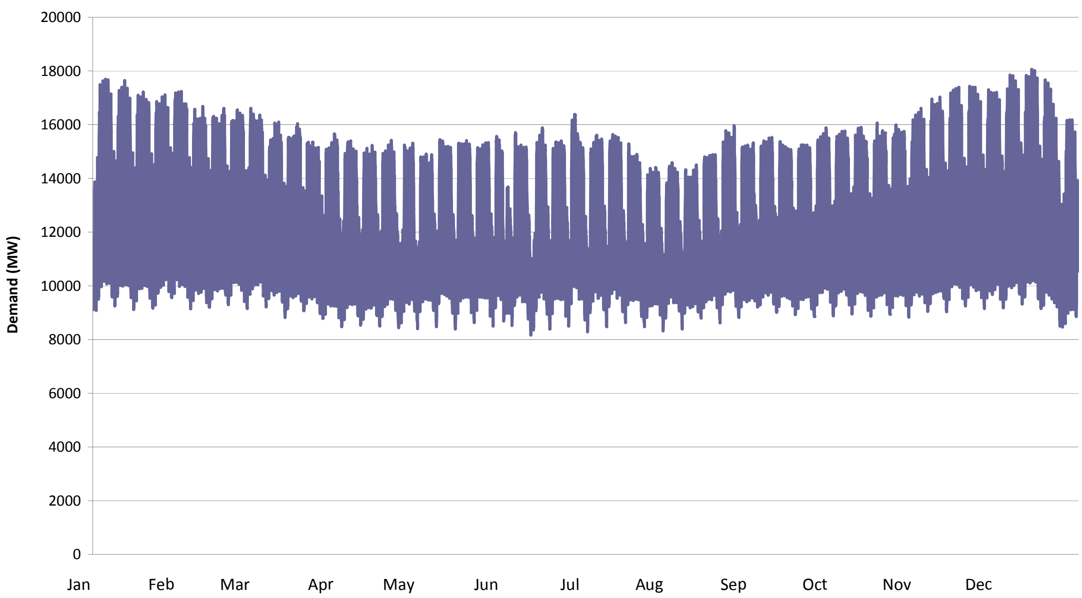
Source: Eurostat (nrg_105a).

4.1.2 Demand Shape

Figure 4.1 shows hourly power demand in the Netherlands over the course of a year. As evident in the figure, peak load is higher in the winter than in the summer, typically exceeding 17GW in winter months. Off-peak demand is relatively steady at around 9-10GW. There is significant intra-daily variation in power demand.

For our modelling, we assume the 2011 shape of demand is repeated up to the end of the modelling horizon.

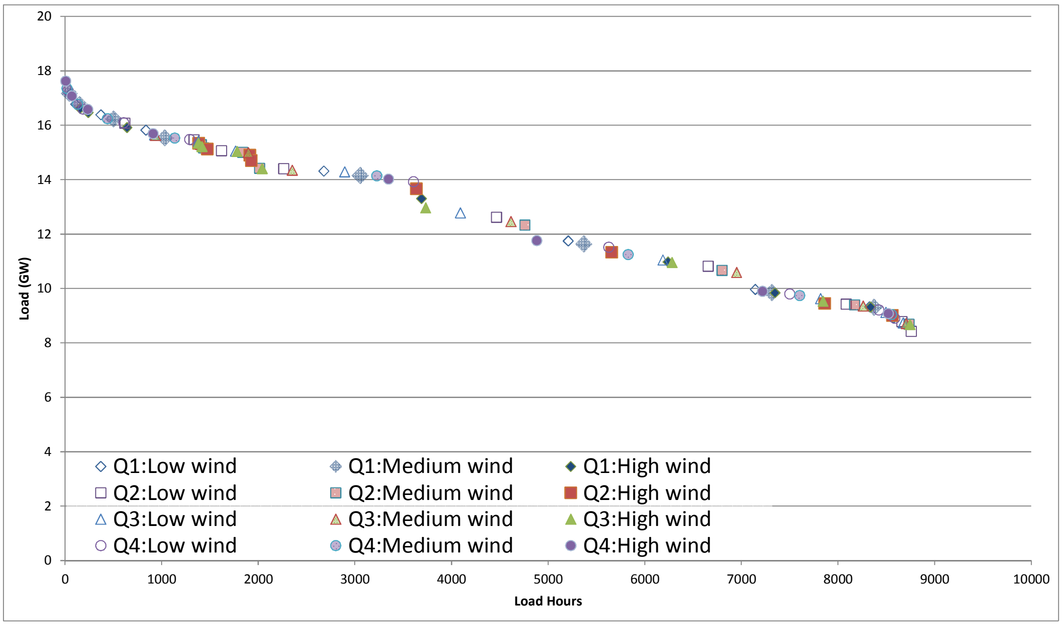
Figure 4.1
Dutch Power Demand Shape 2011 (Chronological)



Source: ENTSO-E, Country Package 2011

As describe in 3.2, rather than modeling every hour, we sample load and intermittent renewables data, using a statistical technique which allows for representation of situations with high, medium and low wind output. The sampled points from this analysis, which is further outlined in Appendix B, are shown in Figure 4.2 below.

Figure 4.2
Sampled Load Points and Wind Output States

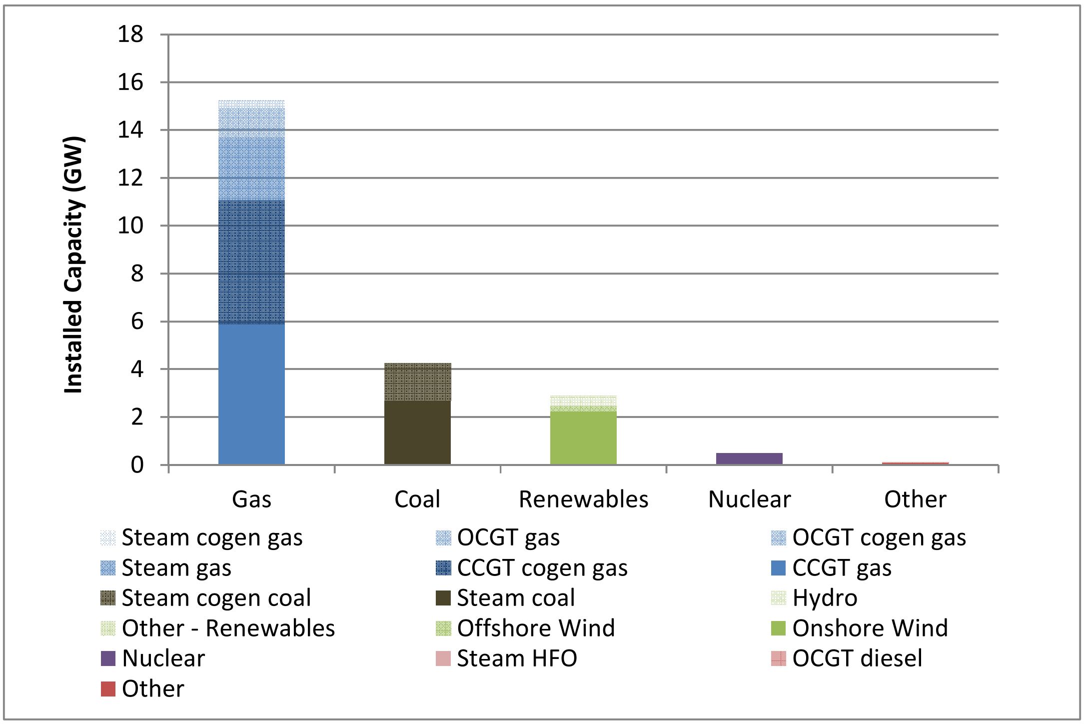


4.2 Existing Generation Capacity

In total, we have assumed that the Netherlands had around 23GW of installed capacity at the end of 2011, as illustrated in Figure 4.3. The Dutch capacity mix is dominated by gas-fired capacity. In 2011 the biggest share of generation capacity was gas (15.2GW), followed by coal (4.2GW), renewables (2.9GW) and a small amount of nuclear (0.5GW). Most of the gas capacity is either CCGT or cogen CCGT, with the remainder being OCGT cogen or steam gas.

We assume that capacity which is already under construction comes as scheduled, and assume that some of the existing capacity retires according to schedule, or once it reaches its useful economic life. Details of these changes applied are set out in Appendix C. We allow the model to endogenously construct new capacity as required, according to the new entrant costs set out in 4.5.

Figure 4.3
Installed Capacity (End of 2011)



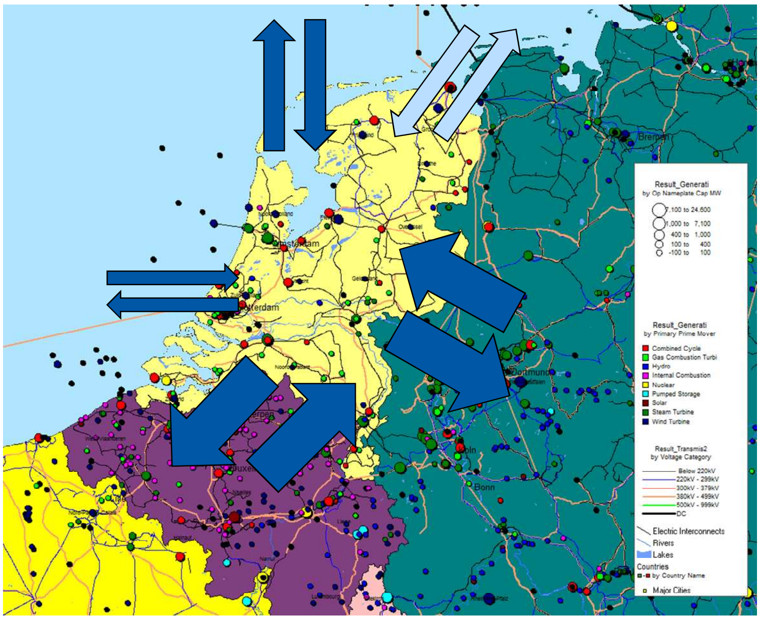
Source: Platts Powervision; Rijs

4.3 Interconnection with Other Regions

The Netherlands is highly interconnected with neighbouring systems, notably the German and Belgian markets, but also the UK, Norway and the planned interconnector to Denmark in 2016 as set out in Figure 4.4. We assume these capacities change according to Table 4.3 and have de-rated capacity uniformly by average availability.

The interconnection capacity is likely to reduce impact of Dutch renewables on the Dutch power market, compared to what they would have been without interconnections. We have therefore modelled the most important interconnectors to Germany, Belgium and the Nordpool area (Norway/Denmark). However, these markets are also undergoing significant structural changes. Most importantly the recent significant expansion of wind and solar capacity in the German market is set to continue up to 2020, in light of the recent decision to phase out German nuclear plants following the Fukishima incident in Japan.

Figure 4.4
Interconnections from The Dutch Power Market



Source: Platts Powervision

Table 4.3
Interconnection Capacity from Netherlands (De-rated)

		2012	2013	2014	2015	2020	2025	2030
Export	Belgium	2465	2649	2832	3016	3934	3934	3934
	Germany	2797	2885	2972	3060	3497	3497	3497
	UK	874	874	874	874	874	874	874
	Norway	612	612	612	612	612	612	612
	Denmark	0	0	0	0	612	612	612
Total		6749	7020	7291	7562	9529	9529	9529
Import	Belgium	2378	2518	2658	2797	3497	3497	3497
	Germany	3541	3628	3715	3803	4240	4240	4240
	UK	874	874	874	874	874	874	874
	Norway	612	612	612	612	612	612	612
	Denmark	0	0	0	0	612	612	612
Total		7404	7632	7859	8086	9835	9835	9835

Source: Tennet, ELIA (data BE) and EU report priorities for 2020 and beyond – A Blueprint for an integrated European energy network. The quoted capacity is de rated by 13% to take into account non-availability (7%) and flow overhauls (6%). Note that in the current analysis we have not modelled flows between the UK and the Netherlands.

4.3.1 Key Policy Developments in Other Countries

The most significant developments outside the Netherlands include the likely increase in renewable energy supply in interconnected regions, and the potential implications this could have for flows across the relevant interconnectors. The most influential neighbouring country in this respect is Germany, where the decision to phase out nuclear power and the country's substantial commitment to solar power implies a very significant transformation of the country's power sector.

We assume that renewable generation capacity in Germany expands to deliver the country's 2020 targets, with the country reaching its maximum installed solar PV capacity of 52 GW by 2020 (although actual peak output may not ever reach this level).

Table 4.4
German intermittent RES Assumptions for 2020 (GW)

	2012	2020
Onshore wind	29	43
Solar Photovoltaics	25	52

Source: EWEA (2011)[32], EWI[33], Bundesnetzagentur[34]

[32] Current installed wind capacity from: http://www.ewea.org/fileadmin/ewea_documents/documents/publications/statistics/Stats_2011.pdf

[33] Wind projection: EWI, GWS & Prognos, "Studie Energieszenarien fuer ein Energiekonzept der Bundesregierung", project number 12/10, 27 August 2010, Tables A1-11. (Average Scenarios IIA and IIB)
Solar Projection**:** 52 GW is the upper limit for solar support. Some sources suggest this target may be reached already by 2014. http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/8499167

[34] Installed solar capacity increased by 7.5GW in 2011, on top of 17.3GW installed at end of 2010: http://www.bundesnetzagentur.de/cln_1911/SharedDocs/Pressemitteilungen/EN/2012/120109IncreaseNumberPhotovoltaicSystems.html; http://www.solarwirtschaft.de/fileadmin/content_files/BSW_Solar_Fakten_PV_1110.pdf

4.4 Commodity Price Assumptions

Our price assumptions about delivered fuel costs are based on third-party projections of international benchmark indices, to which we have added regional taxes and transportation costs. Our general approach is to rely on current market prices, including spot and forward prices, as far into the future as these commodity and derivative markets are liquid. We then rely on projections from the International Energy Agency's most recent World Energy Outlook (WEO 2011) for prices beyond the forward curve horizon. To allow for a relatively smooth transition between forward prices and the IEA projections, we interpolate between the two sources over 3-6 years.

In summary, our approach is as follows:

- **Short run:** Current prices (from Bloomberg);
- **Medium term:** Forward curves (from Bloomberg);
- **Long run:** Interpolation to long run IEA WEO 2011 projections.

A summary of our fuel price assumptions is provided in Table 4.5. Details for each fuel price, and how we convert them into local prices as applicable to the Netherlands are set out in Appendix A.

Table 4.5
Commodity Price Assumptions for Benchmark Indices

	Units	2010	2011	2012	2013	2014	2015	2020	2025	2030
ARA Coal Price	$/t	91.5	121.8	92.7	95.3	100.0	105.8	129.0	151.7	177.2
Brent Oil Price	$/bbl	78.8	109.6	108.4	100.8	97.4	93.9	113.8	182.1	218.7
TTF Gas Price	€/MWh	17.42	22.69	24.66	25.78	26.05	27.85	37.24	45.80	55.12
EU ETS Carbon Price	€/t	14.24	13.14	7.42	7.56	8.02	11.66	29.84	39.58	51.42

Current and forward carbon prices are significantly below the long-run prices projected by the IEA.

In the sensitivity analysis in section 5.5 we model a scenario that tests the sensitivity of the results – and the robustness of different policies – to one of the most important price assumptions, the gas price. This is done by assessing the impact of a more volatile gas price on the modelling results.

4.5 New Entrant Capacity

4.5.1 Costs of new conventional generation capacity

Table 4.6 shows the assumed construction costs for CCGT, coal and OCGT units. The overnight construction cost and operating life are sourced from a PB Power study (2011), converted into Euros using 2011 exchange rates and inflated using a Euro CPI index.

The capacity of the plant, annualised Fixed O&M, variable O&M and net efficiencies are all read into the power market model which optimises new build (if required).

The implied levelised costs are included for illustration only and show total cost resulting from an illustrative capacity factor. The levelised cost is endogenous and depends on fuel price fluctuations and the relative position in the merit order of the plant, which is determined by the model.

Table 4.6
Construction cost of Conventional Generation

2012€	Units	CCGT	Coal	OCGT
Construction Costs				
Upfront Construction Cost	€/kW	786	1,933	486
Lead time	Years	2	3	2
Capital Cost incl. IDC	€/kW	846	2,159	521
Capacity	MW	450	600	310
Financing		-	-	-
Operating Life	Years	30	40	30
Real Discount Rate (pre-tax)	%	7.5%	7.5%	7.5%
O&M		-	-	-
Fixed O&M	€/kW/Yr	32	50	26
Variable O&M	€/MWh	0.1	1.2	-
Efficiency		-	-	-
Efficiency, HHV Net	%	53.7%	41.8%	38.0%
Implied Levelised Cost				
Expected Capacity Factor	%	88.5%	88.5%	25.0%
Levelised Fixed Cost	€/MWh	13.4	28.6	32.1
Approximate Fuel Cost (Current Level)	€/MWh	45.6	32.6	64.6
Carbon Costs	€/MWh	2.6	5.6	3.6
Variable O&M	€/MWh	0.1	1.2	-
Total Levelised Cost	€/MWh	61.7	67.9	100.3

Source: CCGT and Coal plant construction costs from PB Power (2011)[35], converted into Euros at 2011 FX rate and inflated to current values using historic Euro CPI. Capital cost for OCGT is calculated based on the ratio of CCGT to OCGT costs set out in Mott MacDonald (2011) as PB Power does not contain Gas OCGT. The applied WACC is a NERA generic real estimate. Levelised costs are included for illustrative purposes using contemporary fuel costs.

35 *Electricity Generation Cost model 2011 update, PB Power, prepared by Parsons Brickerhoff for DECC*

4.6 Cost and Potential of Renewable Generation Capacity

For most of the renewable energy technologies considered, including power, heat and green gas technologies, our cost estimates are based on the latest available data estimated by ECN/KEMA and published for use in calculating base levels under the 2013 SDE+.[36]

The exceptions to this are for technologies that are not supported (or no longer supported) by the SDE+, such as biomass co-firing. For these technologies, we have indicated below the source of our cost estimates.

In addition, we test the sensitivity of our results to alternative assumptions about renewable energy costs, which we discuss below.

Before presenting our base assumptions, it is important to note that various data sources, including those on which we have relied here, suggest relatively high levels of technical and realisable potential for renewable energy in the Netherlands, especially for renewable heat, offshore wind, green gas and dedicated biomass. When basing projections on these estimates, however, it is important to treat them with caution. As anywhere, when there is limited experience with certain technologies, initial estimates of potential may ignore various barriers that ultimately restrict the available supply potential. Our modelling of RES supply is able to reflect such barriers by introducing growth constraints and by including risk perceptions in the level of the WACC. In the modelling results that we present below, we consider different sensitivity scenarios where we assume that the potential is lower than assumed in the studies from which our data are drawn. This representation of barriers is a simplification, however, and may miss certain market risks and market dynamics that influence actual investment decision making.

4.6.1 Wind

4.6.1.1 Costs

For onshore wind costs, ECN data suggests construction costs to range between 1,350 and 1,950 €/kW (€ 2012) for conventional onshore wind, depending on the size of the turbines. Costs are €2,450/kW (€ 2012) for in-lake onshore wind. ECN data suggests fixed O&M costs between €15.3 and 25.8/kW/year (2012 €). Variable costs for these categories, including O&M and other variable costs, range between 10 and 25 €/MWh.

In line with the current SDE+ scheme, we have considered 4 categories for onshore wind, in particular, 3 categories of in-land onshore wind and 1 category for wind in-lake. Together with a 15 years lifetime and 8 percent WACC assumption, levelised costs for this technology range between 85 and 123 €/MWh. Assumed load hours range from 2,200 to 3,100.

For offshore wind, the current SDE+ 2013 suggests just one offshore wind category. Hence, following ECN's estimates, we assume construction cost for offshore wind to be 4000 €/kW, with €150/kW/year fixed O&M costs. With 4,000 load hours, a 15 years lifetime and an 8 percent WACC, levelised costs are around 160 €/MW.

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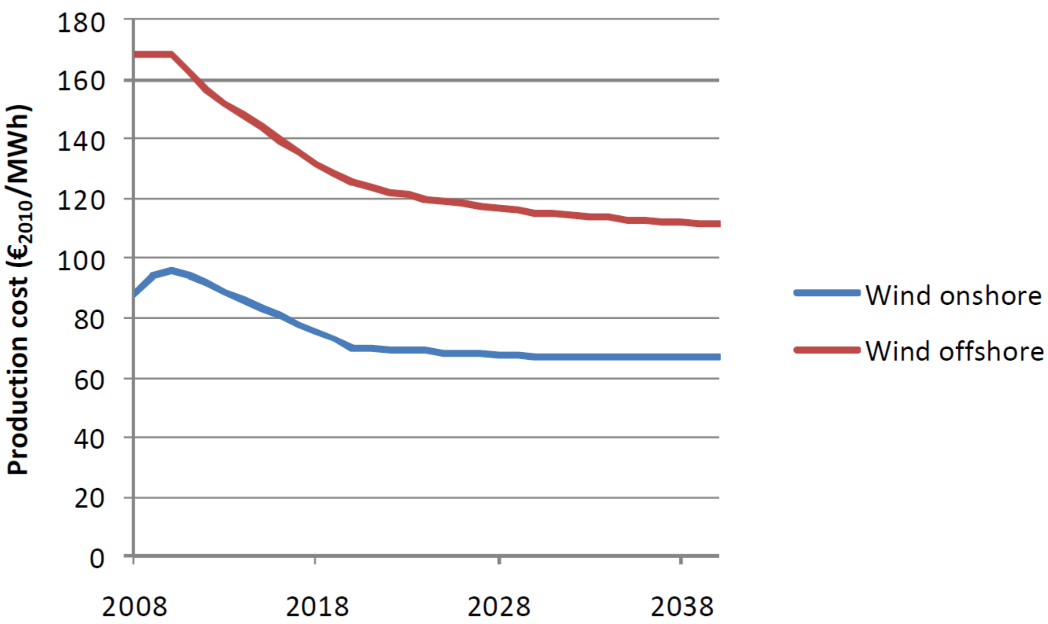
[36] http://www.ecn.nl/units/ps/themes/renewable-energy/projects/sde/sde-2013/. In selected cases we have supplemented this with additional [unpublished] information.

We assume that the costs of wind decline faster than those of other technologies, in line with various other analyses.

For example, one estimate of the reduction in the costs of onshore and offshore wind is illustrated in Figure 4.5, which is reproduced from a 2011 ECN report. The figure suggests reductions in offshore wind costs close to 4 percent in the early years falling to around 1 percent in the years approaching 2020. The rates of reduction are similar for onshore wind. Hence, according to ECN data, the 3 percent decrease per year up to 2020, followed by a lower decrease, of 1 percent, after 2020, seems reasonable for both onshore and offshore wind.

Figure 4.5
Onshore and Offshore Wind Production Cost Trajectories (ECN, 2011)



Source: Reproduced from ECN (2011)[37]

Other sources corroborate these projections of changes in wind costs over time.[38] For example, Figure 4.6 presents a meta-analysis undertaken in 2012 by the International Energy Agency ("IEA") of a collection of different projections of the levelised costs of onshore wind over time.[39] The IEA suggests that onshore wind levelised costs are expected to decrease by 1-3 percent annually between now and 2030. Although the IEA analysis does not consider the costs of offshore wind, it does note that because offshore wind is a "newer" and less

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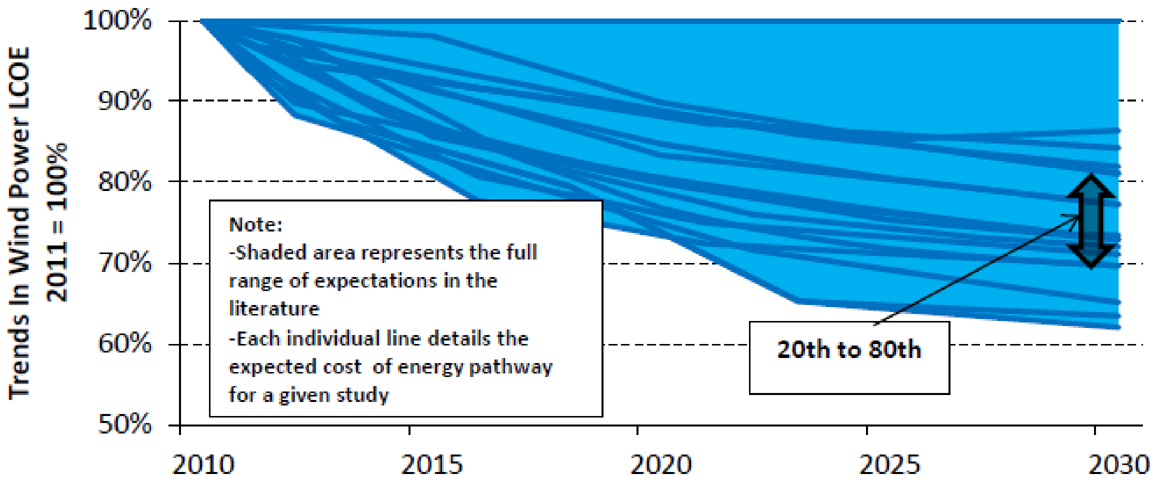
[37] ECN. "Cost-benefit analysis of alternative support schemes for renewable electricity in the Netherlands." (2011).

[38] IEA Wind Task 26 "The Past and Future Cost of Wind Technologies", May 2012, NREL "Recent Developments in the Levelised Cost of Energy from US Wind Power Projects", February 2012 and the Crown Report "Offshore Wind Cost Reduction Pathways Study ", May 2012.

[39] Among others, EREC/GPI 2010, Tidball et al. 2010, U.S. DOE 2008, EIA 2011, Lemming et al. 2009, EWEA 2011, EPRI 2010, Peter and Lehmann 2008, GWEC/GPI 2010, IEA 2009 and European Commission 2007.

developed technology, it is reasonable to assume that its costs will decline more quickly than those of offshore wind.

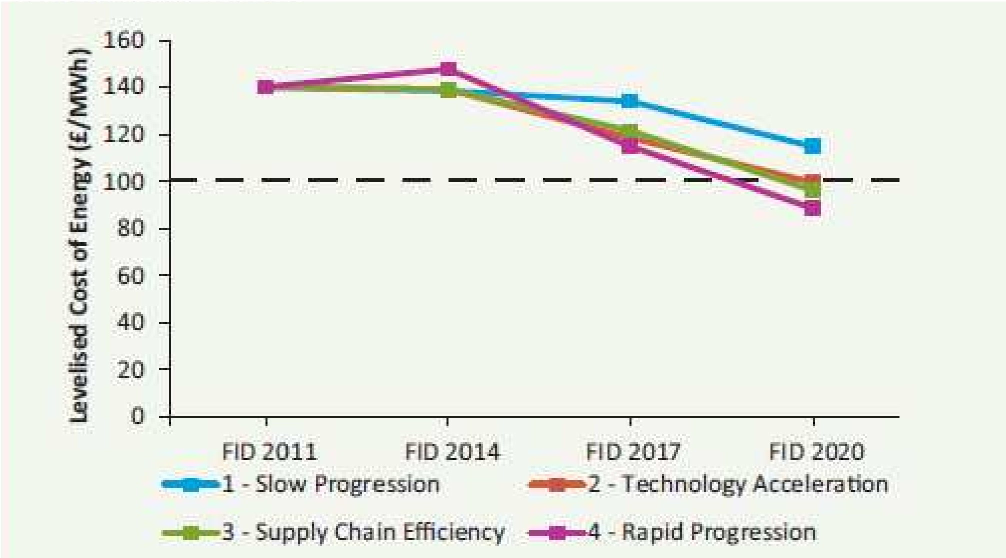
Figure 4.6
Onshore Wind Production Cost Trajectories (IEA, 2012)



Source: Reproduced from IEA (2012)

Finally, Figure 4.7 shows the decrease in offshore wind costs over time (up to 2020), as estimated by the UK's Crown Estate in a study of potential future developments in offshore wind costs, published in May 2012. The Crown Estate estimates a decrease ranging from 1.9 percent per year up to 2020 under a "slow progression" scenario that assumes only incremental advances in technology and supply chain development, to as high as 4.4 percent on a yearly basis for a "rapid progression" scenario. This assumes progress in both technology and supply chains, as well as a larger market for offshore wind.

Figure 4.7
Offshore Wind Production Cost Trajectories (Crown Estate, 2012)



Source: Reproduced from Crown Estate (2012).

For our modelling, we assume that the capex and opex of offshore and onshore wind falls by 3 percent in real terms annually up to 2020. By 2020, the levelised cost of onshore wind is between 67 and 98 €/MWh, and the cost of offshore wind is around 125 €/MWh.[40]

4.6.1.2 Capacity Potential

We have drawn on various data sources, detailed below, to estimate the supply potential of onshore and offshore wind in the Netherlands. We apply two supply-side constraints to wind power capacity:

- First, there is likely to be an overall resource constraint, that is, a constraint on actual sites (both onshore and offshore) where wind parks can be installed.
- Second, industry supply chain constraints are likely to exist. The overall wind potential depends on the development of the supply chain, so that a shortage of skilled workers or infrastructure may significantly reduce supply potential. Technologies starting from a very small base may not be able to grow very quickly. In addition, the rate of new build may also be affected by planning and permitting rules, including requirements for public consultation. We represent these constraints by applying a limit to the new capacity that can be added in any given year.

Figure 4.8 shows historical annual capacity growth rates for the Dutch onshore wind capacity, as well as the growth in capacity that will result from developments that are expected based

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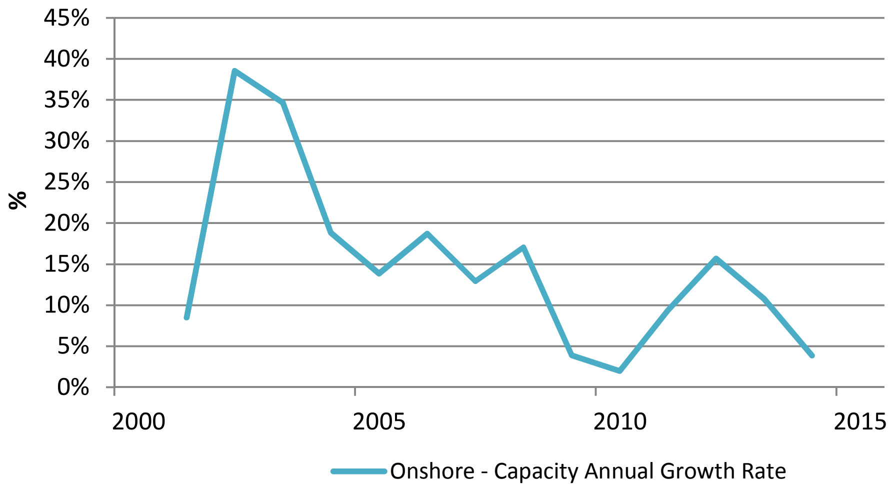
40 After 2020 we assume that costs decline annually by only 1 percent per year, although this does not typically affect the modelling results up to 2020.

on the latest SDE and SDE+ results as well as planning applications. These expectations are derived from IEA (2011), NWEA and Bosch & Van Rijn (2011) projections.

Figure 4.8
Annual Capacity Growth Rates – Onshore Wind



Source: IEA (2011) – Country report for Netherlands, NWEA and Bosch & van Rijn.

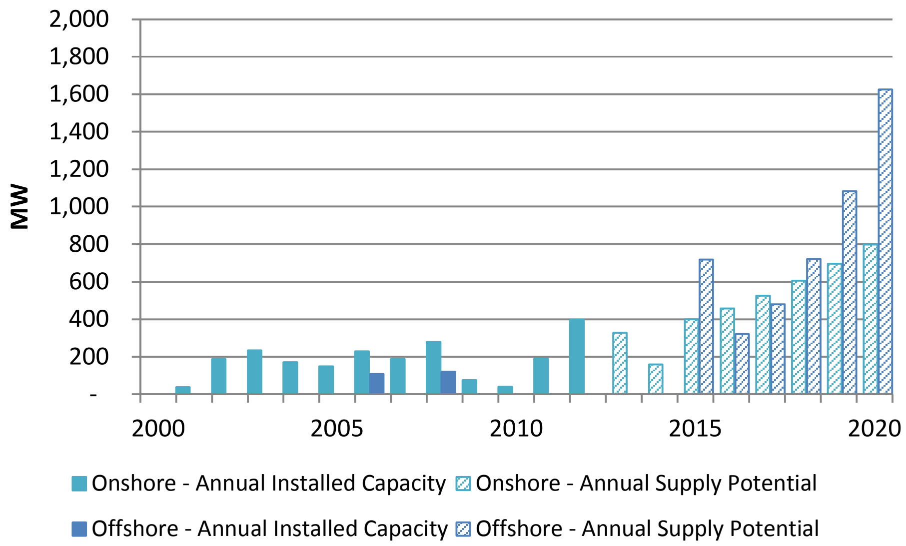
As shown in Figure 4.8, the annual growth rate for onshore wind capacity, in relative terms, was higher in earlier years. The amount of annual capacity added has not increased much in *absolute* terms since 2003, and in recent years has been very low. This is in part due to a "backlog" that has accumulated as a result of previous subsidy schemes in the country. In particular, between 1 and 1.3 GW of new onshore wind capacity is expected to come forward between 2012 and 2016. (Bosch & van Rijn's estimates are based on surveys of regional authorities and developers about existing permit applications and the likelihood that the associated projects will be developed successfully.)

Several sources, including ECN and IEA, suggest that the maximum onshore wind potential / uptake by 2020 ranges between 4 GW and 6 GW. We assume the maximum onshore wind potential to be 6 GW by 2020.

The same sources indicate a maximum offshore wind potential / uptake ranging from 5 GW to 6 GW in total. As previous development of this technology has been limited, we assume the maximum potential by 2020 to be 5.2 GW.

As mentioned above, wind capacity has not increased much in absolute terms in recent years. While significant potential is available for both onshore and offshore wind by 2020, we constrain the potential for capacity additions in the near future and relax this constraint later to allow for the possibility that the supply chain develops, particularly for offshore wind. Specifically, we assume annual onshore wind potential can add approximately 400 MW per year in 2015, with this maximum increasing by 15 percent each year. For offshore wind, after the addition of expected capacity under the SDE of somewhat over 700 MW in 2015, we assume that capacity can increase by around 300 MW in 2016 and by up to 50 percent more than the previous year in each subsequent year thereafter. Figure 4.9 shows historical installed capacity up to 2011, our assumptions about the amount built in 2012-2014, and our assumptions about subsequent future potential capacity up to 2020, for onshore and offshore wind.

Figure 4.9
Annual Installed Capacity and Supply Potential, Wind



Source: NERA analysis based on IEA (2011) and Bosch & van Rijn data.

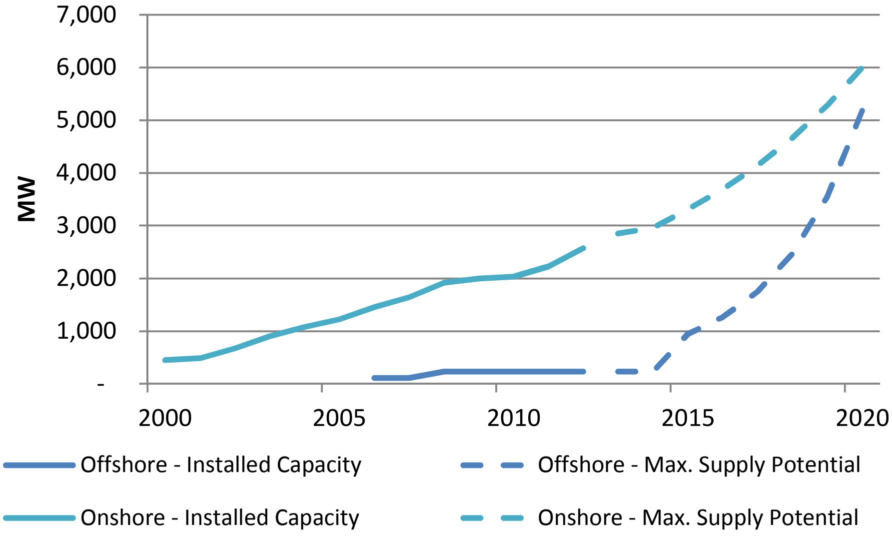
Note: Capacity for 2011-2014 is derived from Bosch & van Rijn (2011) projections, as well as expected capacity estimates as given by projects that were awarded subsidies under the SDE and SDE+ schemes.[41]

Note that the figures presented above from 2015 and beyond are *not* a projection of future wind capacity to be installed in the Netherlands, but rather, an estimate of the maximum achievable capacity that could theoretically be installed each year, given a conducive level of policy support. Actual uptake will depend on a variety of other factors, including the policy in place.

Figure 4.10 shows the historical installed capacity and the cumulative maximum capacity that could be installed given these supply constraints for onshore and offshore wind, from 2000 to 2020. As above, the capacity assumed for 2012-2014 for onshore, and 2012-2105 for offshore, is based on the expected construction of capacity currently in the pipeline.

[41] We assume that out of all the onshore wind projects that were awarded subsidies under the SDE and SDE+ subsidy schemes between 2008 and 2011 and that were not already in operation, 90 percent would come forward. For the case of offshore wind, only 719 MW secured subsidies in 2009. We have assumed these projects are completed by 2015.

Figure 4.10
Historical Installed Wind Capacity and Future Capacity Constraints



Source: NERA analysis based on IEA (2011), Bosch & van Rijn and Agentschap.nl data.

4.6.2 Biomass

To estimate the levelised cost of biomass technologies in the Netherlands we have drawn on ECN/KEMA cost estimates for the case of dedicated biomass plants, and on older ECN estimates for biomass co-firing,.[42]

4.6.2.1 Retrofit co-firing

Dutch energy companies began co-firing biomass with coal in the early 1990s, as a result of a temporary surplus in demolition wood and sewage sludge. More recently, the focus has shifted towards using higher amounts of biomass, and permanent co-firing, as a result of subsidy incentive schemes for co-firing biomass put in place by the Dutch government. The amount of co-firing has increased over time, as plants with the capability to co-fire biomass have increased their use of biomass material in response to government incentives.

Currently, co-firing is occurring at four coal plants in the Netherlands, representing 2.25 GW of capacity. By 2020, additional plants may also co-fire biomass, and some of the existing plants may expand the share of biomass that they co-fire beyond current levels. Existing plants may be limited for technical reasons in the amount of biomass that they can co-fire – for example, fuel handling and storage facilities may be limited. Table 4.7 shows current and expected future co-firing maximum potential in the Netherlands. We have segmented the existing capacity into three bands to reflect the constraints on the ability to co-fire biomass without substantial additional investment, or on the ability to co-fire without violating equipment guarantees.

[42] Sources include ECN (2005) and IEA (2005).

Table 4.7
Maximum Co-Firing Potential by Percentage Band

Band	Capacity	2012	2015	2020
Units	*MW*	*%*	*%*	*%*
Low	1685	<20%	20%	20%
Mid	1005	20% - 30%	35%	35%
High	600	>30%	50%	50%

Source: SQ Consult information based on discussions with generators and technology experts.

New co-firing capacity can be introduced by expanding capacity at plants that already co-fire, or by investing in equipment at plants that do not yet co-fire to allow them to do so. We also allow new coal plants to co-fire biomass, although this may be restricted by the terms of supplier guarantees.[43]

We have assumed that capital expenditures to convert a conventional coal plant for co-firing are around €254 /kW in 2012 €.[44] We assume the heat conversion efficiency and the availability of existing coal-fired power stations are not affected by biomass co-firing. We also assume fixed O&M costs to be the same as for a new coal plant.

Finally, we assume a lifetime of 10 years for retrofit co-firing, and a WACC of 8 percent.

4.6.2.2 Dedicated biomass

Dedicated biomass currently accounts for only a small proportion of the Dutch market total installed capacity. By the end of 2009, only 546 MW of installed capacity were available, accounted for in a significant part by waste incineration plants. Other types of plants, like landfill gas or sewage / wastewater gas plants, were also available.

Additional dedicated biomass capacity is possible in the future. One recent report has estimated total supply potential for dedicated biomass at around 885 MW by 2020, with around 260 MW in large-scale dedicated biomass plants (at least 50 MW installed capacity), and the remaining 625 MW in small scale dedicated biomass plants (less than 50 MW installed capacity).[45]

For modelling purposes, we have considered two different types of dedicated biomass plants, following the distinction in available supply potential by 2020 for this technology. In particular, we have distinguished between small scale plants, of less than 50 MW, and large scale plants of at least 50 MW installed capacity. In addition, we have assumed that the maximum amount of capacity that can be added annual is around 50 MW for small scale plants and 500 MW for larger plants. Whereas we assume the smaller scale plants are

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[43] Supplier guarantees on boilers often prevent new coal plants from co-firing within the first two years of their life. This would only be waived by generators should the RES support be sufficiently high to incentivise them to take the risk of foregoing insurance cover.

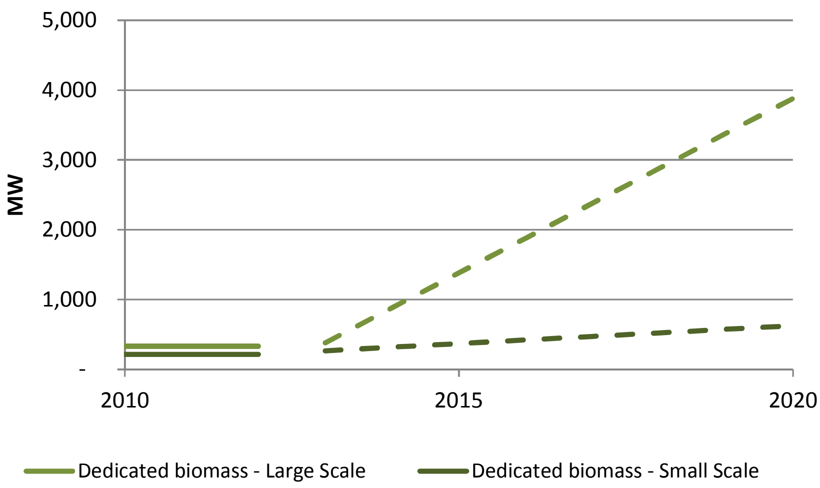
[44] ECN (2005)

[45] Frontier Economics (2011).

relatively restricted by suitable sites, we allow the large-scale plants to expand much more quickly, and in principle do not restrict the total capacity that could be built. We note, however, that if these plants are cogeneration (or CHP) plants, it would be necessary for them to find heat customers, which is likely to significantly restrict the amount of capacity that could be supported. We assume that power-only dedicated biomass plants do not face such demand-side constraints.[46]

Figure 4.11 shows the maximum total supply potential that are implied by our constraints for these two technology bands, from 2010 to 2020.

Figure 4.11
Historical Capacity and Maximum Trajectory, Dedicated Biomass



Source: NERA analysis based on various sources.

Note that, as is the case for wind, these numbers do *not* represent a *projection* of future installed capacity for dedicated biomass, but are instead an estimate of the maximum capacity that could theoretically be installed each year and by 2020. Again, actual uptake will depend on a variety of other factors, include levels of policy support.

As discussed above, even if the current SDE+ does not provide support to co-firing at existing plants, it does provide it to dedicated bio-energy plants. However, the level of support provided to dedicated biomass is insufficient to support investment in power-only plants, so under the current policy, these investments must operate as combined heat and power plants (CHP, or cogeneration). Because renewable CHP receives subsidy for both its heat and its power output, it is possible to profitably run a biomass CHP plant with the subsidies available from the current SDE+, provided a customer for the associated heat can be found. This poses a significant challenge, however. Although there is substantial

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46 As discussed below, however, the support available for biomass plants under the SDE+ is currently set at a level that appears to be insufficient to incentivise the development of power-only plants. Dedicated biomass only becomes attractive if it is able to get SDE+ support for useful heat output as well as useful power output. As we discuss below, if the level of SDE+ support were increased, this could make power-only dedicated biomass profitable, which would expand the potential of biomass to help meet the RES target.

conventionally-fired CHP capacity already in place in the Netherlands, and potential for expansion, the estimated potential for renewable CHP is quite limited (estimates are for around 1.5 PJ of heat – or less than 1 PJ of electricity – from plants larger than 10 MWe, and 12 PJ of heat – or around 4 PJ of electricity – from plants smaller than 10 MWe. [47] Significant expansion of the use of biomass therefore appears to require extension of support to biomass co-firing and/or increasing the level of subsidy available to allow dedicated power-only biomass plants to become profitable.

ECN/KEMA data for the SDE+ 2013 suggest construction costs of around €1,400 /kW (2012 €.) for small-scale dedicated biomass plants, and €1,930 /kW (2012 €.) for large-scale plants, while fixed O&M costs are €80/kW/year for the smaller plants, and €110/kW/year for the larger ones. While data suggest large-scale dedicated biomass plants to be more expensive, on a per kW basis, than small-scale plants, for both construction and fixed O&M costs, it also indicates that large-scale plants are almost twice as efficient as small-scale ones, making the larger plants cheaper on a levelised cost basis. In particular, efficiency for electricity-only production is 33 percent for large-scale plants, and 19 percent for small scale ones.

Finally, we assume a 12 year lifetime and 8 percent WACC for both dedicated biomass technologies.

4.6.2.3 Biomass Price

Due to limited information available in the market on biomass prices, we have adopted a different approach for projecting these prices than for other fuels. We assume that the price of biomass remains fixed in real terms at the current price level for internationally traded wood pellets. For 2012, we assume a biomass price of €27.2/MWh consistent with current prices for wood pellets. Table 4.8 presents some recent market data about biomass prices. Most of the prices quoted are for pellets, but at least one is likely to be less processed forestry residues.

Table 4.8
Delivered Biomass Price

Source	**Price**	
Units	*€ / GJ*	*€ / MWh*
Argus	7.8	28.1
CE Delft	7.5	25.2
ECN	7.5	25.2
APX (Wood Pellets)	7.6	27.2
FOEX Pellets	8.2	29.61
FOEX Finland biomass	4.8	17.42

Source: NERA analysis based on information from ECN, CE Delft, Argus Media, APX-ENDEX, and FOEX Indexes Ltd.

[47] Source : ECN (2010) Actualisation Option Document 2010. http://www.ecn.nl/nl/units/ps/themas/nationaal-energie-en-klimaatbeleid/optiedocument/

Notes: APX value is for the Industrial Wood Pellets index, based on an average monthly price for 2012 (quoted on July 27th, 2012) of €128.4/tonne and a calorific value of 17 GJ/tonne. See http://www.apxendex.com/.

4.6.3 Heat and "Green Gas" (Biomethane)

We have modelled levelised costs for heat and green gas using ECN / KEMA cost estimates for the SDE+ 2013, together with other sources,[48] in a way that is similar to our approach to power generation technologies, except that we do not model a separate "heat" market. Instead, we calculate the resource costs of heat and green gas technologies costs as the incremental costs relative to conventional gas or heating technology costs. (We refer to the conventional alternative as the "counterfactual".) We have considered the appropriate counterfactual costs to be natural gas costs for green gas technologies, conventional CHP for all renewable CHP technologies, and gas boilers for the rest of the heat technologies.[49]

Based on these assumptions and ECN's cost estimates, we calculate the incremental levelised costs of renewable heat, renewable CHP and green gas technologies to range from as low as *negative* €5.4 /MWh (–€1.8 /GJ) for heat produced from certain biomass boilers (that is, the renewable technology is more attractive than the conventional counterfactual, even without any policy support) to as high as €113.4 /MWh (€31.5/PJ) in 2012 €, for technologies such as solar thermal heat.

We also assume certain restrictions on the total amount of renewable heat and green gas capacity supported by the SDE+ that could be developed by 2020, again, drawing on previously published estimates of this potential.[50] These estimates suggest that only a few technologies actually have the potential to contribute significantly to the RES target by 2020. These include manure co-fermentation green gas plants, biomass fermentation, geothermal, solid biomass boiler and solar thermal heat plants, and biomass CHP plants. Altogether, these could account for up to 125 PJ of RES supply in 2020. We note that ECN suggests no additional potential for landfill gas or gas from sewage treatment, although in 2010 these technologies accounted for on the order of 5 PJ of RES output.[51]

4.7 Summary of Key Data Inputs

Table 4.9 shows the supply potential, total production costs and resource costs of the range of RES technologies included in our analysis. Resource costs have been calculated as the difference between the total production costs of each technology, and the corresponding "conventional energy" counterfactual. Hence, resource costs may be interpreted as the additional cost of producing 1 MWh (or 1 GJ) of energy with renewable sources, as opposed to producing it in a conventional way (for example, a CCGT plant for the power market, or a conventional gas boiler for the case of heat technologies).

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[48] Source: ECN, "Herijking DE-beleid 2010-2020", November 2012.

[49] CHP cost estimates are based on estimates provided by EL&I, indexed to gas prices.

[50] Source: ECN (2010) Actualisation Option Document 2010. ECN/PBL http://www.ecn.nl/nl/units/ps/themas/nationaal-energie-en-klimaatbeleid/optiedocument/

[51] Based on CBS statistics: www.cbs.nl/NR/rdonlyres/3047C025-FC03-4457-B7D2-BC0783F52EF1/0/2012c89pub.pdf.

Table 4.9
Current Supply Potential and Production Costs in 2012 of RES Technologies

Technology	Supply Potential	Total Production Cost	Resource Cost	Total Production Cost	Resource Cost
	PJ	*€/GJ*	*€/GJ*	*€/MWh*	*€/MWh*
Onshore Wind - Low	20	23.1	5.9	83.0	21.3
Onshore Wind - Mid	22	26.0	8.9	93.8	32.1
Onshore Wind - High	11	26.1	9.0	94.0	32.3
Onshore Wind - In-Lake	1	33.6	16.4	120.9	59.2
Offshore Wind	73	43.8	26.6	157.6	95.9
Existing Biomass Cofire	23	18.7	7.8	67.4	28.0
Biomass Cofire	11	21.9	10.9	78.8	39.4
Dedicated Biomass - Large	112	35.2	18.1	126.8	65.0
Dedicated Biomass - Small	19	50.8	33.7	182.9	121.2
Green Gas Manure Cofermentation	40	28.8	20.0	103.8	72.1
Heat Biomass Fermentation	7	15.7	3.0	56.4	10.8
Green Gas Biomass Gasification	8	22.5	13.7	80.8	49.2
Heat Geothermal	30	9.0	0.9	32.5	3.3
Heat Biomass Boiler Solid	23	10.9	(1.8)	39.1	(6.5)
CHP Biomass Small	12	26.0	21.1	93.5	76.1
CHP Biomass Large	1	22.2	17.4	80.1	62.7
Heat Solar Thermal	2	31.5	23.4	113.6	84.4

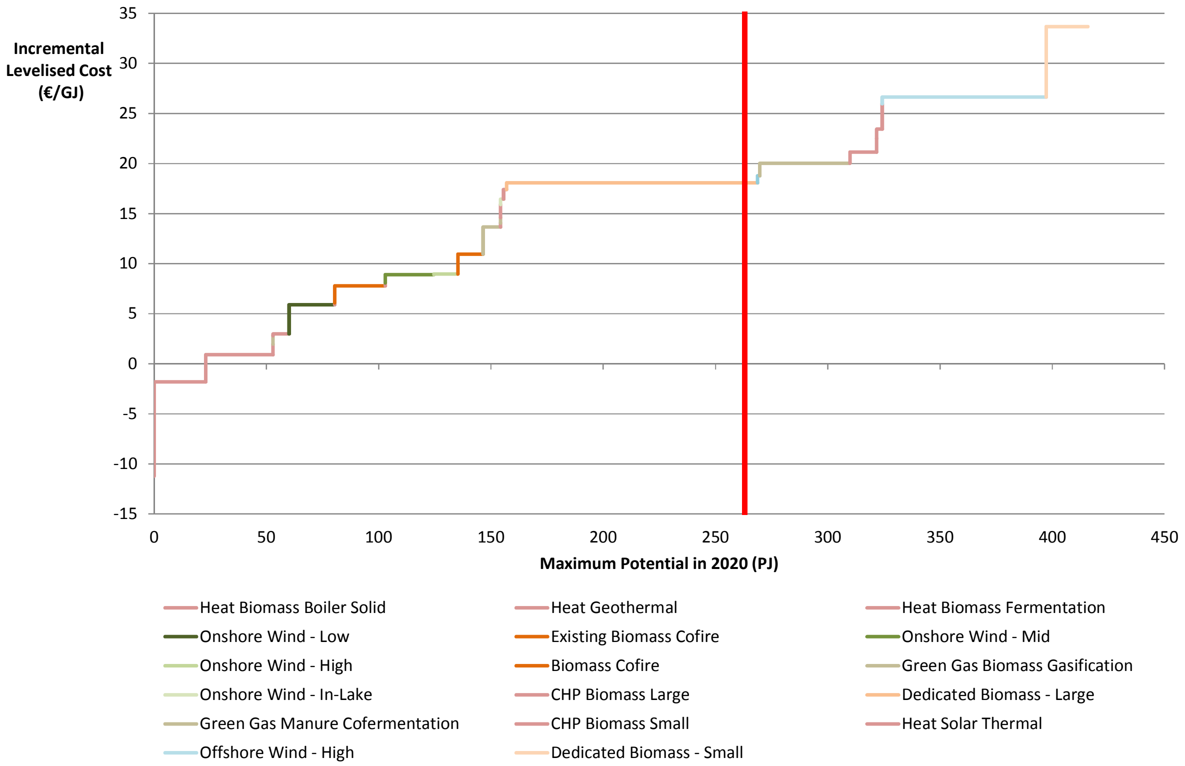
Source: NERA analysis based on information from various sources as specified in the previous sections.

Note: Actual total supply potential for green gas technologies is multiplied by 78.5 percent, as for every Nm3 of green gas produced in the Netherlands, only 0.785 Nm3 contributes to the European RES target. In addition, costs for green gas technologies have been divided by 0.785 to reflect this adjustment. (This factor is calculated for each country and reflects the average conversion efficiency and non-energetic end-use of green gas.)

Figure 4.12 shows these resource costs and potential output of the RES technologies included in our analysis, presented as a “supply curve” for renewable energy to meet the Netherlands’s 2020 target. The figure shows the approximate resource (or incremental) costs and maximum potential in 2020, including existing renewable energy capacity. Based on this analysis, the maximum potential is around 430 PJ. For reference, the figure also shows the overall RES target that would need to be met in 2020 by renewable heat, power, and green gas, in order to achieve the Netherlands’s overall 2020 target. This target has been derived based on numbers suggested by the National Renewable Energy Action Plan (“NREAP”). The NREAP suggests an overall RE target of around 300 PJ. However, out of the total 300 PJ, the transport sector is expected to deliver around 40 PJ, leaving a total target of 260 PJ to be provided by power, heating and cooling and green gas technologies.

The figure suggests that assuming all of the potential sources in each technology category were incentivised to be developed by 2020, the most expensive RES technology needed to hit the 260 PJ target would be large dedicated biomass, at a *resource* cost (compared to the relevant counterfactual source of energy[52]) of around €18/GJ (or €65/MWh). However, because the figure shows only a snapshot of *current* costs, and because it assumes that the maximum assumed available potential from each technology can be effectively developed in time to meet the 2020 deadline, the implied output from each RES technology should be treated with considerable caution as a tool for understanding how the Netherlands might meet its 2020 target.

Figure 4.12
2020 Incremental RES Supply Curve (2012 Costs)



Source: NERA analysis based on information from ECN and other sources.

Note: The supply curve cost for power technologies has been calculated relative to the 2012 levelised cost of a new entrant CCGT plant based on an estimated gas price in 2012 of €25/MWh. The cost for heat, CHP and green gas technologies has been calculated as the incremental cost over the levelised cost of the corresponding conventional counterfactual technology, in particular, natural gas for green gas technologies, conventional CHP for renewable CHP technologies and gas boilers for heat technologies.

Note that Figure 4.12 shows current costs for new RES technologies. That is, it does not consider any decrease in levelised costs of the RES technologies through time. However, as discussed in section 4.6, we assume costs for onshore and offshore wind decrease by 3 percent each year. This implies that even if these technologies appear relatively expensive

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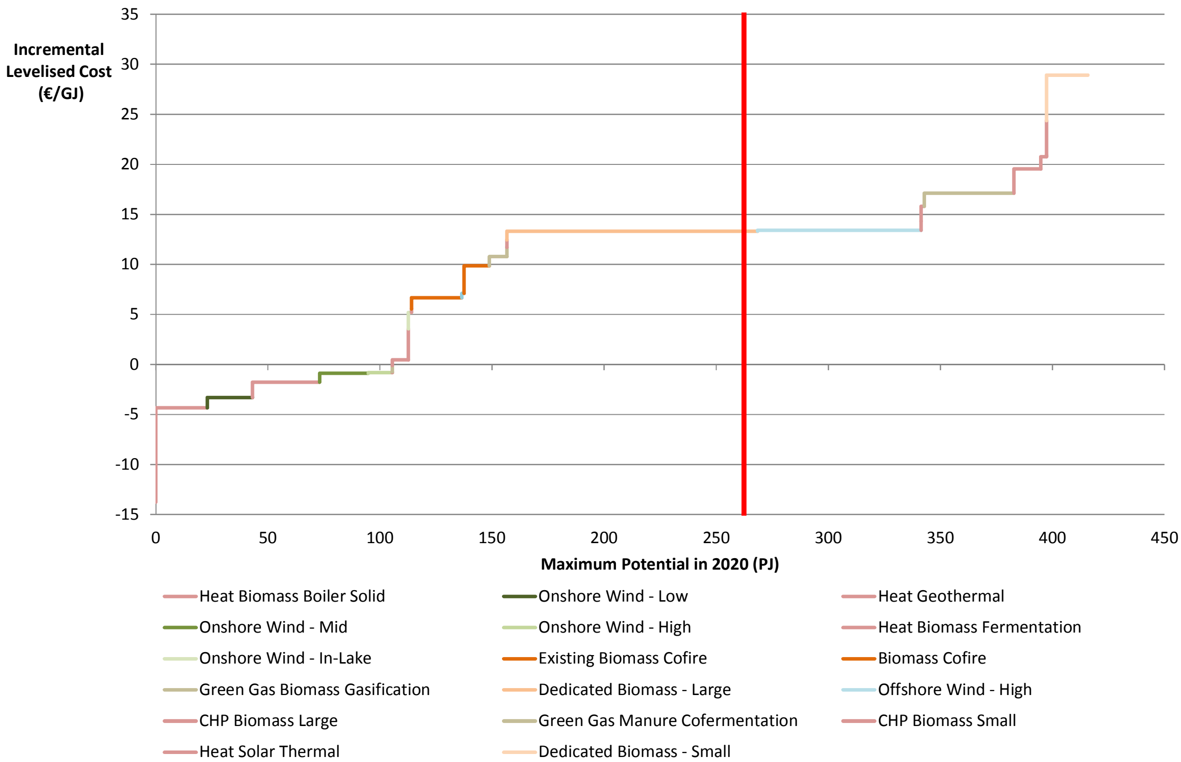
52 The relevant counterfactual is determined in our model by the market electricity price; however, we have simplified this in the supply curve presented here by assuming that the counterfactual cost is equal to an estimate of the long-run marginal cost of a new entrant gas-fired CCGT, which is higher than current market power prices in the Netherlands.

compared to other heat and green gas technologies, this relationship may shift through time, and onshore and offshore wind may become cheaper. In addition, different changes in counterfactual costs for power, heat and green gas technologies may lead to additional shifting between the costs of these technologies.

This is shown in Figure 4.13. In particular, when considering 2012 costs, offshore wind appeared to be one of the most expensive technologies, and was much more expensive than some heat and green gas technologies such as manure co-fermentation green gas. By 2020, however, offshore wind becomes cheaper than the green gas technology, and comes very close to the resource cost of large dedicated biomass plants.

Figure 4.13
2020 Incremental RES Supply Curve (2020 Costs)



Source: NERA analysis based on information from ECN and other sources.

Note: The supply curve cost for power technologies has been calculated relative to the 2020 levelised cost of a new entrant CCGT plant based on an estimated gas price in 2020 of €33/MWh. The cost for heat, CHP and green gas technologies has been calculated as the incremental cost over the levelised cost of the corresponding conventional counterfactual technology, in particular, natural gas for green gas technologies, conventional CHP for renewable CHP technologies and gas boilers for heat technologies.

4.8 Renewables uptake experience in the Netherlands

As noted above, the large majority of experience with the development of renewable energy in the Netherlands is with larger scale renewable electricity projects. There is much less experience with the development of green gas or renewable heat projects. To a large extent this is due to the fact that policy instruments such as the SDE and its predecessor, the MEP, primarily targeted renewable electricity projects. Since 2008 green gas production has been supported through the SDE and in the last round of the SDE+ renewable heat was added, resulting in a large amount of renewable heat projects being offered. Despite this surge in interest, it seems unlikely that the total potential estimated in the data sources upon which we have relied can and will actually be realised before 2020, given the current state of market development. For example:

- A significant share of the first renewable heat projects that were granted SDE+ funding have been to expand heat production at existing sites or life-time extension of existing plants.[53] These projects offer significant potential at relatively low costs. However, once these projects are completed, further growth in renewable heat would mainly need to be derived from new project developments.
- Implementation of large-scale renewable heating projects is furthermore hampered by the current crisis in the housing and office market. Plans for building new homes and offices have been either put on hold or reduced in size, providing fewer opportunities to develop a sound business case for renewable heat.
- The potential for deep geothermal heat has been estimated at approximately 30 PJ, with the largest share of projects in the horticulture sector. The 2012 SDE+ applications included 32 projects for geothermal heat with a total estimated annual production of approximately 10 PJ. This relatively large amount can be explained by the fact that various parties have reached the stage that they aim to develop their first project development in the next years as well as by the notion that the tariff set for geothermal heat was reasonably attractive. Experience to date with deep geothermal project is, however, relatively limited: in 2010 total energy production amounted to 0.3 PJ according to CBS. Under the current SDE+ 2012 so far 6 geothermal projects (total expected production approximately 1.6 PJ/year) were granted SDE+ funding. The first smaller projects are currently being realized; these are stand-alone and smaller-scale projects. For the large-scale projects project developers currently focus on well drilling and well testing (e.g. to tackle the problem of "by-production" of oil and gas). A real growth in large-scale geothermal heat development is only expected after a couple of years of testing and gaining experience.
- The maximum potential for green gas production is estimated at ~60 PJ in 2020 in the studies used for this project. Although green gas production has been subsidized under the SDE since 2008, total production in 2010 amounted to just 0.4 PJ (which included only projects at landfill sites). Over the past 4 subsidy rounds under the SDE (2008-2011) a total of 51 projects were awarded funding. Of these, only 9 projects had actually been implemented as of 1 July 2012.
- The same reasoning holds for dedicated large-scale biomass electricity projects. GDF-Suez and Delta, for instance, have announced that they are exploring the options to turn a coal-fired plant into a dedicated biomass plant. Eneco and Nuon/Vattenfall had announced plans to develop several larger-scale biomass plants. But parties have stated that further investment certainty is required to assure actual project development and so

[53] Agentschap NL, Tabellen stand van zaken SDE+ 2012, status October 1, 2012. This is 46 percent of the total renewable heat production that requested SDE+ support.

far Eneco's 49 MW biomass plant in Delfzijl is the only project that has actually been realized.[54]

To reflect this uncertainty about the extent to which hypothetical renewable energy potential will actually be available at the costs suggested, we consider sensitivity scenarios in which we significantly reduce the RES potential in different technology categories, and assess the cost and subsidy implications for meeting the RES target.

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[54] In other countries, including the UK, plans to re-power coal plants as biomass plants, and to develop new dedicated biomass capacity have confronted similar uncertainty, both from economic conditions and from policy uncertainty, including concerns about the relationship between subsidy levels and the price of biomass fuel, which may fluctuate.

5 Modelling Results

In this section, we present our main modelling results, and compare the outcome of both quota-based policies and subsidy-based policies in terms of the key indicators of policy success – including total resource costs (i.e. the incremental costs relative to the world without the policy), total "excess profits" from subsidy payments, total subsidy payments and total renewable output, or distance from the renewable energy target.

As discussed above, according to standard economic theory, in a world where there is perfect information there should be no significant difference between a quota-based policy and a subsidy based-policy. In particular, the two types of policies can be designed to achieve the same outcome. However, neither policy-makers nor investors have perfect information and foresight. Hence, the choice between policies comes down to evaluating the outcomes of these policies under circumstances of imperfect information and unexpected future developments.

Our approach is therefore to start from a baseline set of assumptions about future costs, prices, RES potentials, etc., and to design the potential policy options (for example, the required support levels, etc.) with these expectations in mind. Then, we model the outcomes of the policies when our assumptions are correct and compare the policies. Finally, we consider what happens under the different policy designs when the future differs from the assumptions that were used to inform the policy design.

We have considered four policies based on the current SDE+, and five REC-based policies:

- **Current SDE**+ (**SDE+**): We have modelled expected RES uptake under the current SDE support scheme. (See section 5.2.1.)
- **SDE+ plus co-firing** (**SDE+_cf**): This policy offers a premium payment of €35 per MWh on top of the cost of a new entrant CCGT plant in 2012 for biomass co-firing in addition to the SDE+. (See section 5.2.2.)
- **SDE+ plus co-firing and high budget (SDE+_cf+_hb)**: as above, but also the total budget that can be committed to RES technologies each year is multiplied by 2.7, to around €5.7 billion.[55] (See section 5.2.3.)
- **"Target-Achieving" SDE+** (**SDE+_ta+_lr**): in addition to supporting co-firing and increasing the yearly budget to €5.7 billion, we increase the support levels available to

[55] Note that it is important to distinguish this annual budget from the amount of subsidy that is actually paid out by the government in each year. The annual budget represents a hypothetical "pot" of money that is committed to the projects that are built during a given year (each "vintage") for their lifetime. Only a fraction of this "pot" for each vintage will actually be spent in any given calendar year – in the worst case, for support that will last 15 years, one-fifteenth of each vintage pot will be spent each year to support the projects in that vintage. In fact, under most circumstances, the amount of money will be significantly less than this amount, because the worst-case scenario is based on a realised power price that is 33 percent below the expected power price. Thus the sum of the subsidies paid to a given vintage of projects over their lifetime is likely to be less than the budget or "pot" that is committed, in theory, to projects in that vintage.

The amount of subsidy that is actually paid out *each year*, is therefore very different from a given vintage year's total budget. The amount paid out in a given calendar year is the sum of each fraction of the vintage pots that is required for each vintage that operates in that calendar year. This amount may be more or less than the total budget amount for a given vintage year.

certain technologies that are necessary to meet the target, so that they receive enough support to be profitable. (See section 5.2.4.)

- **Uniform RECs** (**REC_uniform**): a REC-based policy that offers one certificate per MWh of renewable energy produced, irrespective of RES technology. (See section 5.2.5.)
- **Uniform RECs plus bonus/malus (REC_b/m)**: All RES technologies receive one certificate per renewable MWh produced, but expensive technologies receive an additional subsidy payment, whereas inexpensive technologies must pay a charge to receive their certificates. (See section 5.2.6.)
- **Banded RECs (REC_banded**): a REC-based approach that offers a different number of RECs to each RES technology, depending on their relative costs. More expensive technologies receive a greater number of RECs to compensate for their higher costs. (See section 5.2.7.)
- **Uniform RECs plus banking (REC_banking)**: All RES technologies receive one certificate per renewable MWh produced each year, and RECs may be banked for compliance in future years. (See section 5.2.8.)
- **Uniform RECs plus banking, and target post-2020 growth (REC_bank2030)**: All RES technologies receive one certificate per renewable MWh produced each year, and RECs may be banked for compliance in future years. In addition, in contrast to the other uniform RECs cases described above, the target does not remain constant at 260 PJ after 2020, but increases (gradually tapering off), reaching 334 PJ in 2030. (See section 5.2.9.)

As noted above, we consider a range of scenarios designed to shed light on the costs and effectiveness of the policies when there is uncertainty about RES costs and potential. We start with a "Perfect Information" scenario, which assumes that RES costs are known with certainty now and in the future, so policies can be finely adjusted to ensure that overpayment does not occur. Next we present the results of a scenario in which costs are consistently overestimated, leading to overpayment and excess profits (and in some cases overachievement of the target).[56] We next consider a scenario in which the RES potential of selected technologies – in this case, heat and green gas – are significantly more limited than had been assumed when the policies are initially developed, which results in target underachievement and higher costs. And we consider a scenario with similar high level effects, in which the costs of selected RES technologies are higher than expected. These latter two scenarios provide some indication of the inefficiency associated with differentiated support (capped support for some technologies at a maximum level, for example) when there is heterogeneity of technology costs, as discussed below. They also give a sense of the ranges of costs of meeting the target if average costs are higher than expected.

Like the Perfect Information scenario, the Low RES Cost scenario represents a significant simplification of reality, because we assume that no adjustments are made to cost assumptions and associated policy support levels, even though they overestimate RES costs. The Low RES Cost and other scenarios can be thought of as simplified representations of how the policies perform under different types of uncertainty, but they also provide insight

[56] We could also have considered a "High RES Cost" scenario, which would have resulted in missing the target under some policies, and significantly higher costs to meet the target in others.

into how costs compare and how RES output is affected under a range of alternative assumptions.

Results for all these policy options, under our baseline set of assumptions, are shown below in section 5.1. In addition to these policy options, we also consider a REC policy that under-achieves the target output level. Various different certificate buy-out prices are modelled that, at certain levels, have the effect of reducing renewable energy output below 260 PJ in 2020. Such a policy would require additional support for more expensive technologies in order to meet the legislated target. Following the presentation and discussion of the Perfect Information case results, we therefore discuss the relative performance of a hybrid scheme drawing in part from a REC policy and in part from an SDE+ support scheme.

5.1 Overview of Results

Figure 5.1 shows total RES output in 2020, under our "Perfect Information" assumption, in each of the nine different policy scenarios outlined above. The figure shows that the current SDE+ policy provides only enough support to deliver 164 PJ of renewable energy – considerably less than the 260 PJ target. Adding support for biomass co-firing increases the RES output to 190 PJ, still significantly below the target. Under the third SDE+ variant, we increase the annual available budget to around €5.7 billion, without changing the level of support that can be provided to individual technologies. This leaves output still below the target, at 230 PJ. Under the final SDE+ variant, we also increase subsidy levels for dedicated biomass and offshore wind, yielding 267 PJ of RES output.

Under the uniform REC and REC with bonus/malus policies, precisely 260 PJ of RES output is delivered in 2020, because this is what the policies are designed to do.[57] In contrast, under the banded REC policy, output is well above target, at 281 PJ, for reasons we discuss below. Finally, under the two REC banking policies, output is below the target, at 222 PJ for the "pure" banking case, and 250 PJ under the banking scenario that also includes a growing target after 2020. This reflects the finding that in these two cases, the 260 PJ target for 2020 is met in part via the use of RECs awarded during the period 2015-2019. Adding the higher target in future years makes it more profitable to save banked RECs for even later use, resulting in higher RES output in 2020.

As the figure below illustrates, the mix of output under the different policies does vary, although in broad terms the output is similar across most technology categories. The amount of green gas and offshore wind varies the most, largely due to the way that the SDE+ favours technologies with low "total costs". This also affects other technologies.

[57] The output is precisely 260 PJ under the assumption that there is no buy-out price. If there is a buy-out price, suppliers can pay it instead of surrendering certificates, and output may not achieve the target level. We explore buy-out price options below.

Figure 5.1
2020 Output under Various Policies, Perfect Information Scenario

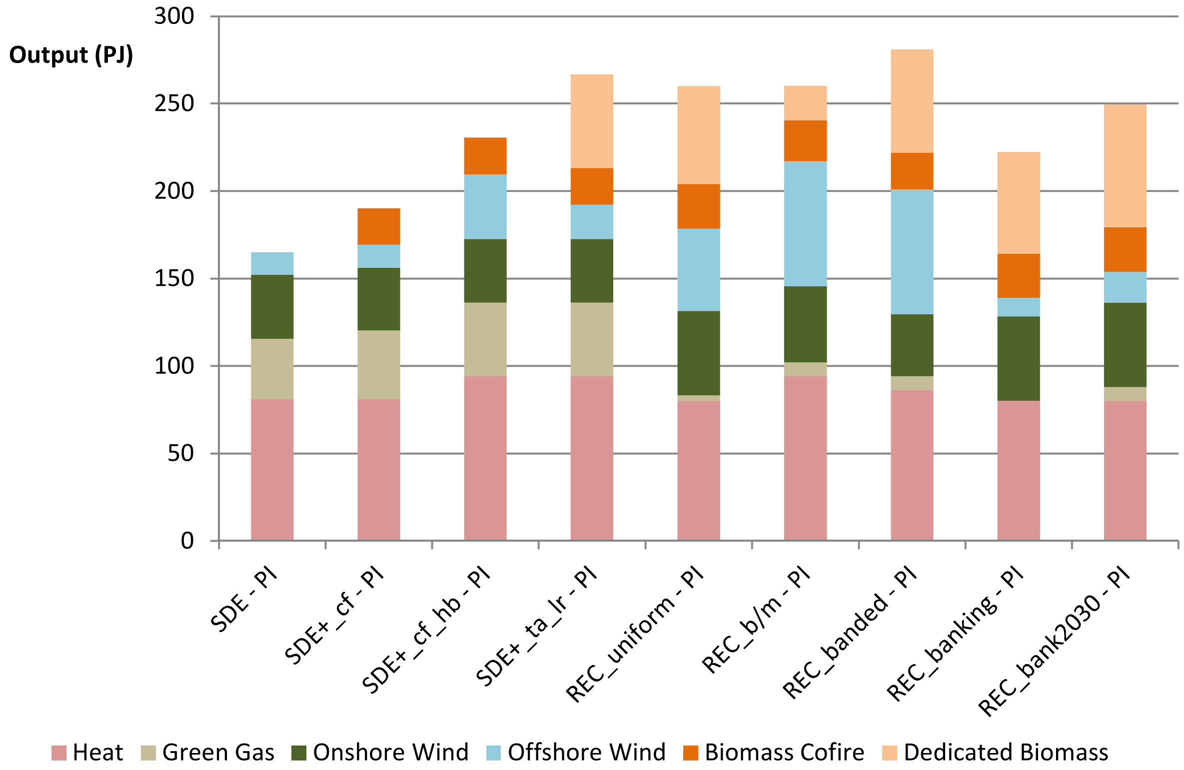

Figure 5.2 and Figure 5.3 show total resource costs in 2020 for each type of RES technology, and the present value of resource costs for each type of RES technology, calculated until 2030. (Note that the resource costs are not the same as the costs borne by consumers – the latter are closer to the "subsidy" or "policy support cost", discussed below. As discussed in previous sections, resource costs may be understood as the additional costs required in order to produce an additional PJ of energy with renewable sources, rather than with conventional energy sources such as CCGT or coal plants, gas boilers, etc.) These figures show the sum of the resource costs associated with any capacity supported by the policy being analysed for capacity built from 2015 (the year that we assume the new policy will start to support new capacity). These figures show that, of the policies that achieve (or more than achieve) the 260 PJ target, the uniform REC policy has the lowest resource cost. Note that it is important to compare the costs of the policies on a lifetime basis, as there are differences associated with the mix of technologies.[58]

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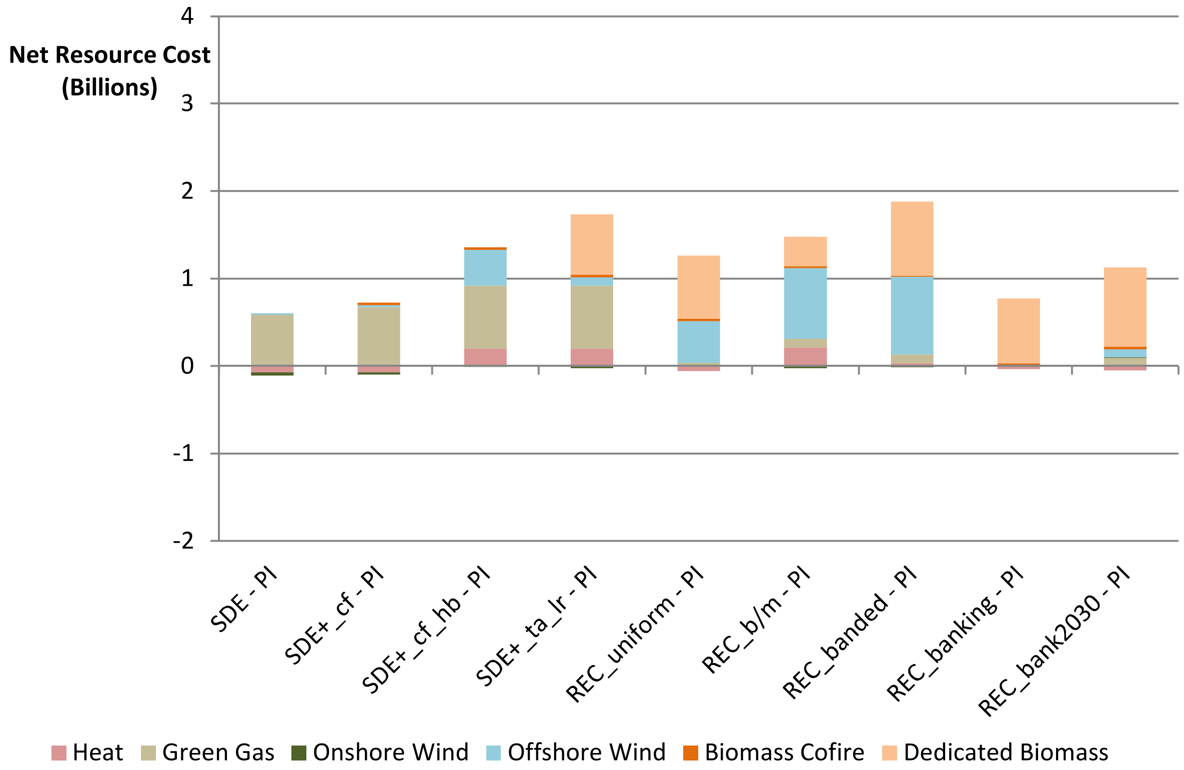
[58] To calculate the Net Present Value included in the results below, we apply a 3.5 percent discount rate to future costs for renewable energy capacity that is installed between 2015 and 2020, over its lifetime.

Figure 5.2
2020 Resource Costs, Perfect Information Scenario



An important finding of our analysis is that the SDE+ tends to support more green gas (and certain other heat technologies) instead of less costly power generating technologies, which results in higher incremental or resource costs for the SDE+ than for the REC-based options. This is most evident when comparing green gas to offshore wind, but also affects onshore wind. Some of the onshore wind potential has negative resource costs by the end of the period, and therefore is adopted under all policies even without support. However, some higher-cost onshore wind still requires support, and has lower *incremental* (i.e. resource) costs than green gas. However, because green gas technologies have *total* costs that are lower than wind, they are able to access subsidies earlier. The SDE+ budget is exhausted before the less expensive wind technologies have an opportunity to apply for support.

Under the REC banking policies, there is a smoother REC price trajectory, which results in a somewhat different mix of technologies being taken up (although to some extent this is also due to the fact that the 260 PJ target is not quite achieved, because some technologies find it attractive to build in earlier years, under the possibility of banking and submitting their certificates for the 2020 target).

Figure 5.3
Net Present Value of Resource Costs, Perfect Information Scenario

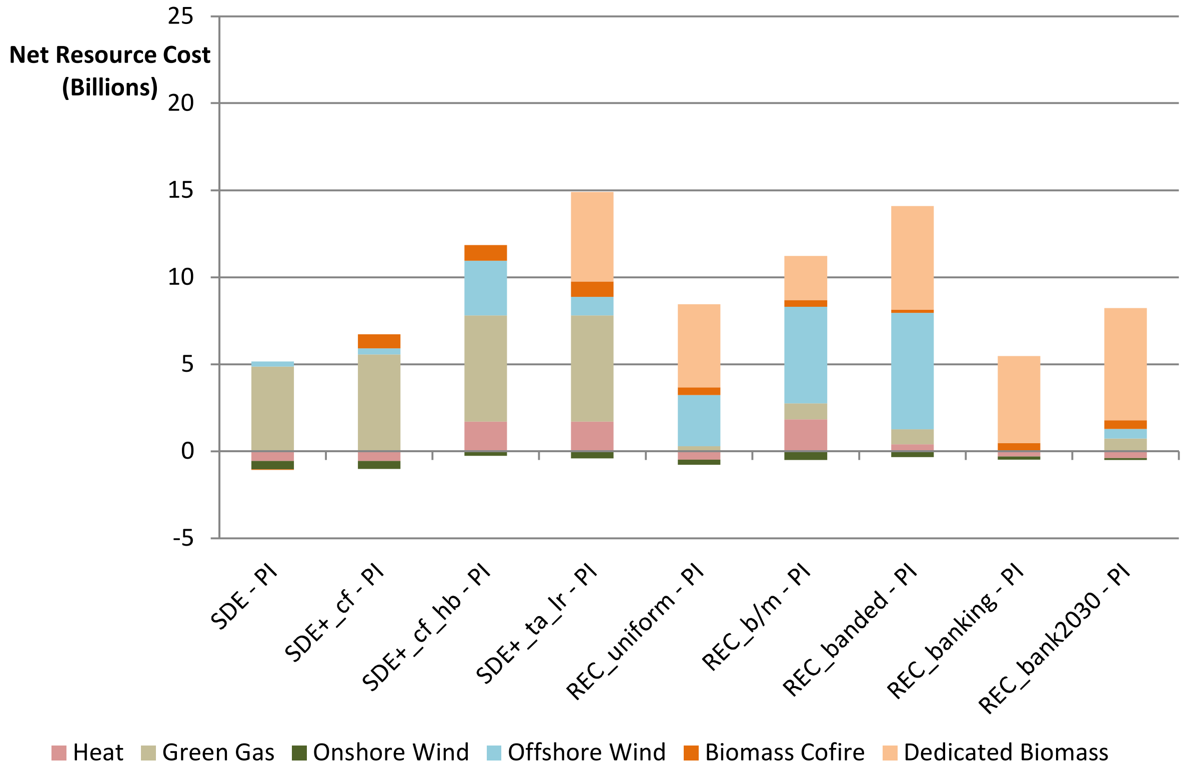


Figure 5.4 shows the net present value of the total rents provided for each type of RES technology to 2030. As expected, rents are minimised under the SDE+ – *effectively because we have assumed this to be the case* in this first scenario. That is, we assume in the Perfect Information scenario that all RES technologies receive more or less exactly the support that they need to "break-even".[59] Even so, under the SDE+, rents are not equal to zero, because some technologies with negative resource costs still earn rents that are independent of the policy.

This highlights an important distinction between rents, or excess profits, and excess *support* provided through the RES policy. In particular, a technology with negative resource costs would receive no support under a price-based scheme, hence making it impossible to talk about "excess support" under these circumstances. However, this technology would still perceive "economic profits" as a result of its investment. For cases where the resource costs are zero or positive over the full lifetime of the technology (for example, solid biomass heat), the excess support is equal to the total amount of subsidies received by this technology. For cases where resource cost is always negative, total rents will be an overestimate of the excess *support*. Similarly, where there is a mix of types within a given technology category, some with positive and some with negative resource costs, the total rents will be larger than the excess support offered.

[59] Note that in this scenario, the "free category" or *vrije categorie* of the SDE+ is not really used, because all costs are known and base prices are set at the correct level.

Rents are considerably higher under the certificate-based policies, because low-cost technologies can benefit from the fact that higher-cost technologies must be given sufficient incentives to build. This is mitigated somewhat in the Banded REC and Bonus/Malus policies, but the risk of providing rents remains. (As we discuss below, for example, in these latter two policies, the specific policy designs shown do not attempt to adjust the differentiated support that is offered to offshore wind over time. As the price of offshore wind declines, this results in excess support to the technology in later years. This is particularly noticeable for the bonus/malus RECs scenario, where rents for offshore wind are much higher than rents under the banded RECs. The reason for the difference is that under the bonus/malus scenario, offshore wind receives a bonus in absolute terms. As costs go down, the bonus becomes larger relative to resource costs. However, for the banded RECs scenario, additional support through multiple RECs depends on the REC price, which is not fixed, so there is less over-compensation as the cost of new offshore wind declines.)

Figure 5.4
Net Present Value of Rents, Perfect Information Scenario

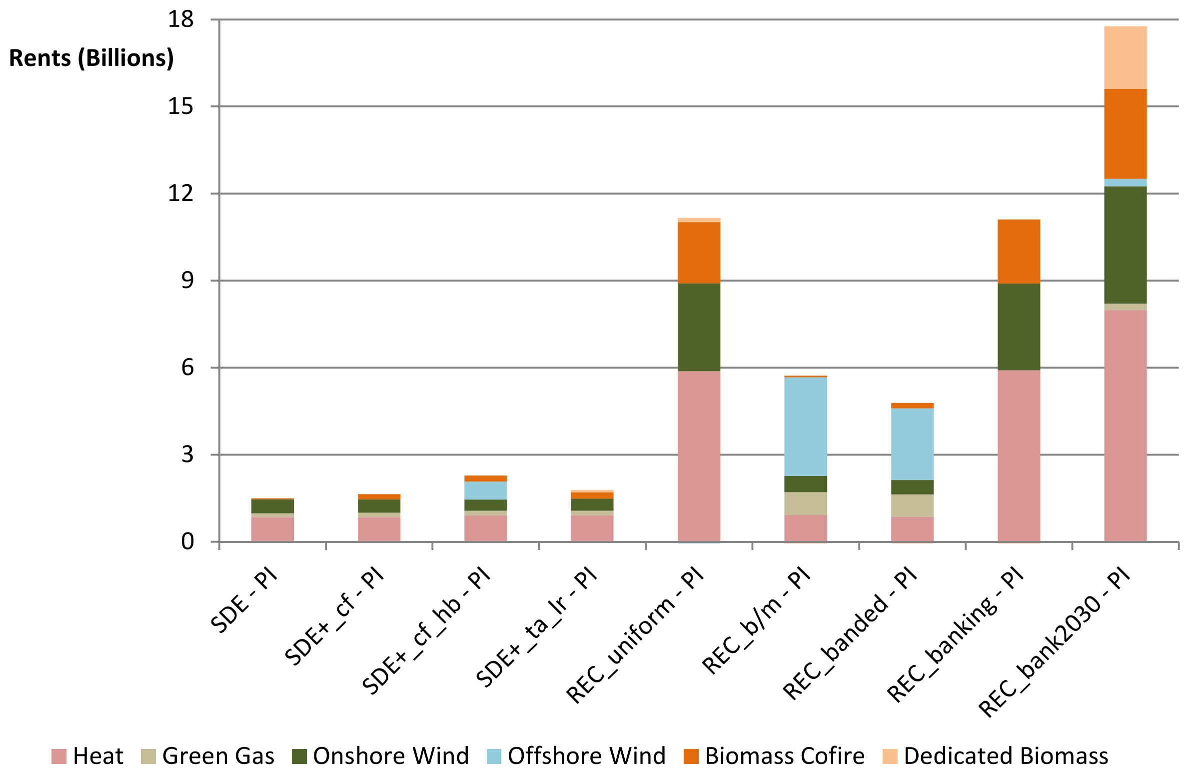
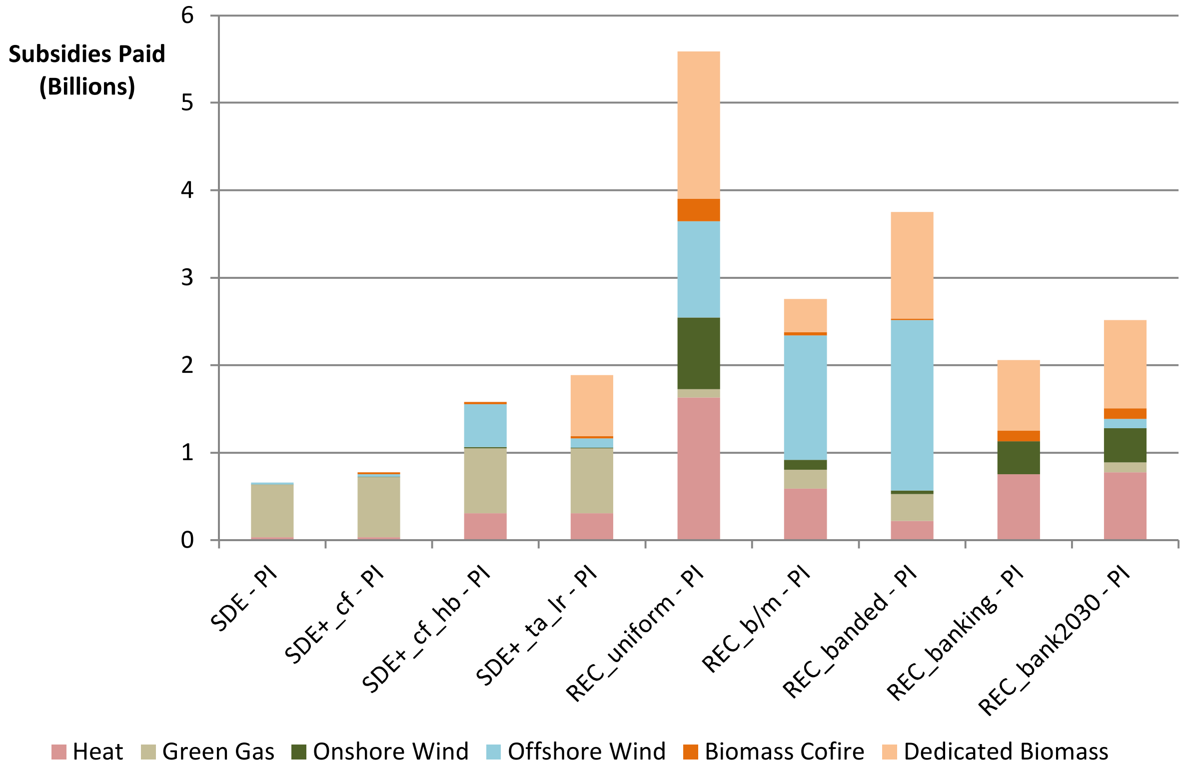


Figure 5.5 and Figure 5.6, below, show total subsidies paid in 2020 for each type of RES technology, and the present value of subsidies paid for each type of RES technology, calculated until 2030, respectively. Under the uniform REC policy without banking (or an increasing target), 2020 subsidies are highest, because the REC price hits a peak in this year.[60] The *net present value* of subsidies paid is more similar across different policy types

[60] This is in part a function of the approach to modelling, but also is likely to reflect actual market behaviour, and points to a potential difficulty in the design of a certificate policy. If the target does not increase beyond 2020 – and therefore does not need to incentivise new offshore wind or biomass capacity – then the REC price may be expected to fall to the

(whether SDE+ or certificate-based), especially amongst those that achieve the target output, at around €16-18 billion. The REC with banking and an increasing post-2020 target option shows the highest subsidies, because of the need for increasing REC prices over time to meet the future (2030) RES target.

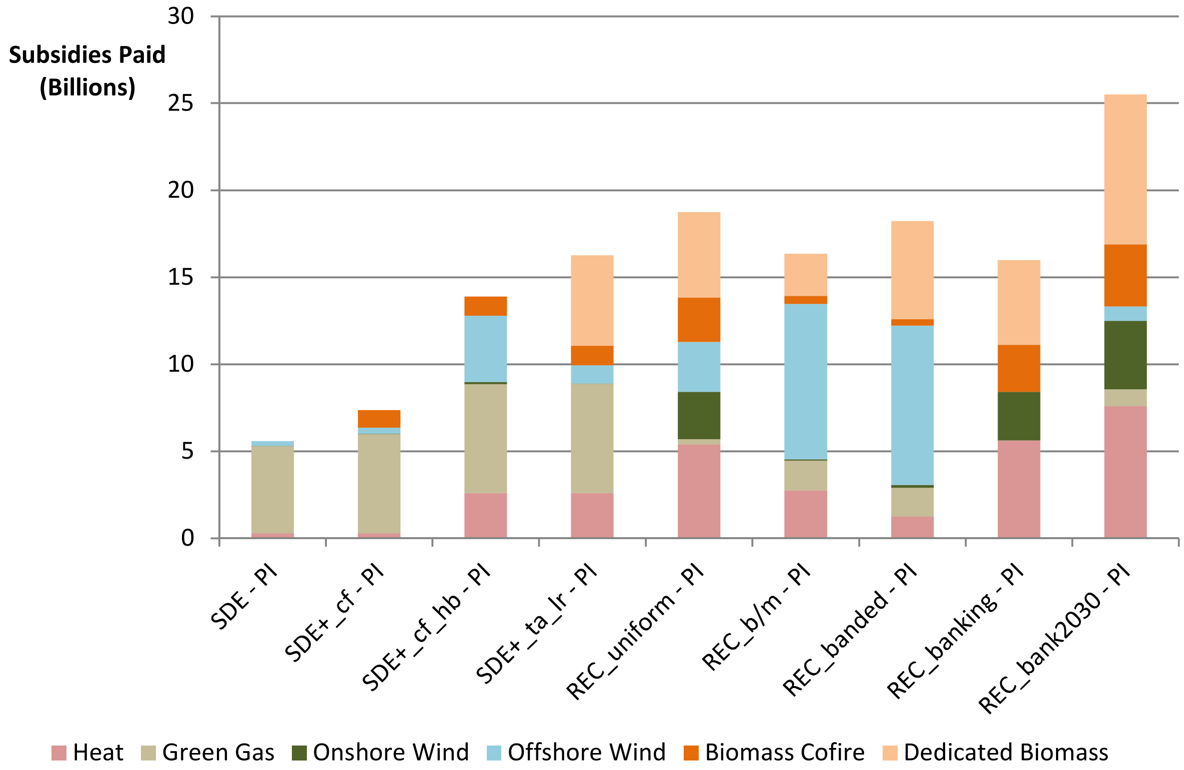
Figure 5.5
2020 Subsidies Paid, Perfect Information Scenario



Note: *In the first three of the REC-based policy designs shown, because the REC target does not increase after 2020, and because we have assumed no banking and no buy-out price, the market price of RECs spikes in 2020, because this is the last year that new renewable capacity is built. After this year, renewables can earn RECs, but they will generate as long as they cover their variable costs, which are much lower than their full (i.e. their long-run marginal) costs. This explains the significant difference between total subsidies paid in 2020 under (especially) the Uniform REC case, and the two banking cases. Banking eliminates the price spike that the model predicts in 2020, and therefore 2020 support costs are much lower.*

level of the incremental variable cost of the marginal REC producer. At this level, however, REC prices will not be high enough to pay back the capacity built in 2020, so the price must be extremely high in 2020 to fully cover the capital costs of the capacity installed in that year. In reality, investors would not assume that the prices would spike – or would be allowed to spike – and this would deter them from investing. This should, in turn, push REC prices up in advance of 2020, but would not resolve the "cliff-edge" issue if there were no post-2020 increase in the target.

Figure 5.6
Net Present Value of Subsidies Paid, Perfect Information Scenario



The following sections provide greater detail and discussion of the results for individual policy options, along with observations about comparisons across the policies.

5.2 Perfect Information Scenario Results

This section shows our results for these nine policy options, under our Perfect Information scenario assumptions.

5.2.1 Current SDE+

Under the SDE+ no support is offered to biomass co-firing technology. Additionally, the budget and the subsidies for all the included technologies are offered at the levels proposed under the SDE+ 2012. The budget level is set around €1.7 billion. This total budget is too small to achieve the target output level. Additionally, some of the SDE+ base level subsidies are set at too low a level to provide sufficient support for all technologies.

The following Table 5.1 shows the base level subsidy levels as well as resource costs for all of the technologies considered (including co-firing, which is only actually supported under subsequent policies):

Table 5.1
Technology Subsidies and Resource Costs (2012 Prices)

Technology	Original Units	SDE+ Base Level	Resource Cost	Resource Cost	Resource Cost
		Original Units	*Original Units*	*€/GJ*	*€/MWh*
Low cost onshore wind	*€/MWh*	85.0	21.3	5.9	21.3
Mid cost onshore wind	*€/MWh*	96.0	32.1	8.9	32.1
High cost onshore wind	*€/MWh*	96.0	32.3	9.0	32.3
Existing biomass cofire	*€/MWh*	n.a.	28.0	7.8	28.0
Biomass cofire	*€/MWh*	n.a.	39.4	10.9	39.4
In-lake onshore wind	*€/MWh*	122.9	59.2	16.4	59.2
Offshore wind	*€/MWh*	150.0	95.9	26.6	95.9
Green Gas Biomass Gasification	*€/Nm3*	0.56	0.34	10.7	38.6
Green Gas Manure Cofermentation	*€/Nm3*	0.72	0.50	15.7	56.6
Heat Geothermal	*€/GJ*	9.0	0.9	0.9	3.3
Heat Biomass Boiler Solid	*€/GJ*	10.9	(1.8)	(1.8)	(6.5)
Heat Biomass Fermentation	*€/GJ*	15.7	2.3	2.3	8.4
Large scale power-only biomass	*€/GJ*	22.2	18.1	18.1	65.0
CHP Biomass Large	*€/GJ*	22.2	17.4	17.4	62.7
Small scale power-only biomass	*€/GJ*	26.0	33.7	33.7	121.2
CHP Biomass Small	*€/GJ*	26.0	21.1	21.1	76.1
Heat Solar Thermal	*€/GJ*	31.5	23.4	23.4	84.4

Notes:

1. *For power market technologies, resource costs have been calculated as the difference between levelised costs for each RES technology and the expected production cost of new entrant CCGT. For heat, cogeneration and green gas technologies, resource costs have been calculated as the difference between levelised costs and the corresponding counterfactual cost, where this counterfactual has been assumed to be natural gas for green gas technologies, a gas boiler for renewable heat technologies and gas CHP for renewable cogeneration technologies.*
2. *The base subsidy level for existing biomass co-firing and new biomass co-firing technology is modelled to be the same, despite existing plants having a lower resource cost.*
3. *Large- and small-scale biomass receive an SDE+ subsidy based on their useful energy output, whether this is electricity or heat. The level appears to be calculated such that capacity is only profitable if it makes use of heat – that is, if it is CHP. It would also be possible to operate a dedicated biomass plant in power-only mode. Under the current SDE+, however, such a plant would still receive the same subsidy, and therefore would not be profitable.*
4. *For green gas from gasification, we have derived the SDE+ base level shown in the table by combining our counterfactual gas cost estimates with updated incremental cost estimates developed by ECN and provided to us by the Ministry.*
5. *Not every unit of green gas that is produced actually counts towards the renewables target. In the Netherlands, only 78.5 percent of each unit of green gas output is eligible. The price that is required to support an additional unit of green gas to count toward the target is therefore higher than the SDE+ base levels shown in the table, and the resource cost is also higher. When modelling the resource costs of achieving the target with green gas, we therefore reflect a factor of 0.785 in the analysis.*

As per the SDE+ 2012, the different technologies are generally willing to apply for support in order according to their levelised costs, to allow the cheapest technologies priority access to support. In the first Tranche, geothermal heat, biomass fermentation heat and solid biomass boiler heat technologies are assumed to be willing to access subsidies. Subsequently, the priority is allocated to low cost onshore wind, large scale biomass CHP, inexpensive green gas and large scale dedicated biomass in the second Tranche; mid and high cost onshore wind, green gas manure co-fermentation and small scale biomass CHP in the third Tranche; then on-lake onshore wind and large solar thermal heat technologies in the fourth Tranche; and finally offshore wind and small scale dedicated biomass plants in the fifth Tranche.

Table 5.2 shows selected detailed modelling results for the Current SDE+ policy. Several of the technologies have been grouped together to simplify the presentation. Looking down the table, first the existing generation plants are covered, followed by new uptake.

Table 5.2
SDE+ Results

	2020					NPV		
Technology	**Electrical Capacity**	**Output**	**Resource Cost**	**Subsidy**	**Rents**	**Resource Cost**	**Subsidy**	**Rents**
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	0	0	-	(0)	(38)	-	38
New Heat	n.a.	55	(71)	34	104	(549)	294	843
New Green Gas	n.a.	34	585	602	16	4,871	5,008	137
New Onshore Wind	1.8	16	(38)	3	41	(478)	11	489
New Offshore Wind	0.3	2	18	23	5	284	284	(0)
New Biomass Cofire	-	0	0	-	(0)	0	-	(0)
New Dedicated Biomass	-	-	-	-	-	-	-	-
Total	**6.3**	**165**	**495**	**661**	**166**	**4,090**	**5,596**	**1,507**

Note: *We do not include the resource or subsidy costs associated with "existing" capacity. We define "existing" capacity as capacity that is now in place or that is expected to be in place by 2015. (We assume that the policies being modelled here will first begin supporting new investments in 2015.) Existing capacity, and its output, is assumed to be attributable to other policies, rather than the policies that we model. We assumed that MEP support is discontinued by 2015. In policies modelled below, we assume that existing co-firing units can apply for new subsidy.*

The results indicate that the current SDE+ will not achieve the desired RES target, falling short by 95 PJ.

Based on the cost assumptions and bidding order assumptions set out above, renewable heat technologies account for the largest share of output, (55 PJ), followed by new green gas (34 PJ), existing heat and green gas (26 PJ), new onshore wind (16 PJ) and existing onshore wind (21 PJ), and new (2 PJ) and existing offshore wind (10 PJ). There is almost no biomass co-firing, because the existing plants are assumed to receive no further support under the current SDE+ once existing support policies expire.

Total installed renewable capacity from power plants in 2020 is 6.3 GW. Existing onshore wind has the largest share, accounting for 2.7 GW. "Existing" refers to capacity in place now (in 2012) as well as the capacity that is in the pipeline and expected to be completed before 2015, whose costs therefore are not directly relevant for our analysis. From 2015 we assume that the policies that we model begin supporting new capacity. New onshore wind provides the second largest capacity at 1.8 GW.

Under the SDE+, new onshore wind is built as well as heat and green gas technologies. No power-only dedicated biomass is built, even though it has access to subsidies relatively early in the application process, as it is not profitable at current subsidy levels.

In 2020, total resource costs are €495 million and subsidies paid are €661 million. This implies excess support of €166 million. As expected, excess profits are relatively low under this policy as subsidies are low and directed at the cheaper technologies.

The net present value of total resource costs for the policy (as noted above, calculated until 2030, and using a 3.5 percent discount rate) is €4.1 billion. The value of the subsidies is €5.6 billion, implying rents in the order of €1.5 billion. Excess support is significantly lower, however, because certain renewable heat technologies enjoy rents even without policy support (as does onshore wind).

5.2.2 SDE+ plus co-firing

This policy adds to the previous one by providing support to biomass cofiring with a payment of €35/MWh of electricity output on top of the electricity price in 2012. In subsequent years, co-firing is treated as any other SDE+-eligible technology, with its cost assumed to be at the level implied by the support required in 2012, and actual SDE+ support determined by the electricity price. Biomass cofiring is one of the inexpensive technologies, being willing to apply for subsidies in Tranche 2. We have assumed the budget to be added to accommodate biomass co-firing to be €400 million, so the total available SDE+ budget is €2.1 billion. The base price levels for the rest of technologies remain the same. Table 5.3 presents the results for the SDE+ plus subsidies for co-firing. We assume that existing units, currently supported under the MEP, can apply for new SDE+ support without incurring costs of retrofitting, while new plants can apply but incur a cost of retrofitting co-firing capability.

Table 5.3
Summary Results for SDE+ with Co-Firing

Technology	2020 Electrical Capacity	2020 Output	2020 Resource Cost	2020 Subsidy	2020 Rents	NPV Resource Cost	NPV Subsidy	NPV Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	12	26	46	20	598	844	246
New Heat	n.a.	55	(71)	34	104	(550)	293	843
New Green Gas	n.a.	39	671	690	19	5,554	5,710	155
New Onshore Wind	1.7	15	(28)	4	32	(449)	9	458
New Offshore Wind	0.4	3	24	29	5	351	350	(2)
New Biomass Cofire	0.3	8	28	23	(5)	209	160	(49)
New Dedicated Biomass	-	-	-	-	-	-	-	-
Total	**6.5**	**190**	**651**	**825**	**175**	**5,713**	**7,364**	**1,651**

Both installed capacity and output increase slightly relative to the existing SDE+. However, the new policy still does not achieve the target output level, only reaching 190 PJ. Capacity levels remain the same for all technologies with the exception of existing and new biomass co-firing, which represent approximately 600 MW and 300 MW, respectively. The increase in output can be attributed to these technologies.

Total NPV lifetime resource costs increases to €5.7 billion, given an increase in RES output. Total lifetime subsidies increase to €7.3 billion, providing lifetime rents of €1.7 billion. Again, excess support is smaller than rents, because certain heat technologies do not receive any support.

5.2.3 SDE+ plus co-firing and high budget

Under the previous two policies the targeted 260 PJ of RES output is not reached. Therefore, this policy looks to model the impact of increasing the total budget on the uptake of the different technologies. The budget is increased by 176 percent as compared to the previous scenario, from €2.1 billion to €5.7 billion and all other parameter assumptions remain as per the previous policy (so that biomass co-firing is again supported).

Table 5.4
Summary Results for SDE+ with Co-Firing and High Budget

Technology	2020					NPV		
	Electrical Capacity	Output	Resource Cost	Subsidy	Rents	Resource Cost	Subsidy	Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	12	26	47	20	680	935	255
New Heat	n.a.	68	197	308	110	1,714	2,609	896
New Green Gas	n.a.	42	724	744	20	6,085	6,254	169
New Onshore Wind	1.7	16	(11)	15	26	(254)	129	383
New Offshore Wind	1.8	26	408	489	81	3,152	3,784	632
New Biomass Cofire	0.3	8	29	23	(5)	218	171	(47)
New Dedicated Biomass	-	-	-	-	-	-	-	-
Total	**8.1**	**230**	**1,373**	**1,626**	**253**	**11,595**	**13,882**	**2,287**

The higher SDE+ budget drives the output up to 230 PJ, still short of the required target. Total RES power generation capacity increases to 8.1 GW relative to the lower-budget option presented above, driven by a minor increases in new onshore wind, and especially a significant increase in offshore wind, up to 1.8 GW. The increase in output, however, is due to a significant increase in new heat and new green gas technologies, whose total output increases from 94 PJ to 110 PJ, and in offshore wind output, from 3 to 26 PJ. Note that dedicated (power-only) biomass still is not built, because the subsidy level is not high enough to make investment profitable.

Total lifetime resource costs (€11.6 billion), subsidies (€13.9 billion) and rents (€2.3 billion) all increase in proportion to the increase in output under this high budget scenario. Resource costs, as before, are driven principally by new green gas, which has a 2020 resource cost of €724 million.

5.2.4 "Target-Achieving" SDE+

Under the previous scenario, in spite of increasing the available annual budget for each year's new capacity to €5.7 billion, the target was still not quite achieved. Our modelling suggests that increasing the budget further does not actually result in additional investment – instead, it is necessary to increase the subsidies available to selected technologies in order to make them profitable. For example, dedicated (power-only) biomass, or offshore wind have no uptake at all.[61]

If we combine the increase in the annual budget to €5.7 billion, with an increased subsidy for selected technologies – in particular, dedicated biomass and offshore wind – the target can be achieved. Because the subsidies are assumed to be set at a level that is just slightly above the true costs of all RES technologies, the policy achieves the target at low social and subsidy cost.

In order to estimate the yearly budget required to reach the target under the target-achieving SDE+, we have started by calculating the required subsidy payment for each technology in each year, given the assumed initial base price (*basisbedrag*) support levels for each technology and an estimated long-run energy price.[62] (or corresponding counterfactual costs, for heat and green gas technologies). In particular, the required subsidy payment for each technology has been calculated as the difference between the corresponding base price and the floor price (assumed to be two-thirds of the long-run baseload market price). Each year technologies will access subsidies in a "merit order" determined by their total production costs. As long as base prices are sufficiently high to cover costs, in any particular year all the technologies will be willing to build as long as there is budget still available. This allows us to obtain an estimate of the annual build under any level of yearly budget, hence leading to an estimate of the total renewable output produced in 2020 as a consequence of setting a particular budget level.

Figure 5.7 shows the estimated output achieved in 2020 under different annual budget levels, as compared to the current SDE+ budget level (plus additional biomass co-firing support), of around €2.1 billion. In particular, we have considered budget levels ranging from 0.5 times the current budget level, up to as high as 3 times the current budget level. These budget levels yield 2020 output levels ranging from 131 PJ in the lowest budget case, to 280 PJ for the case where we increase the current SDE+ budget by 3 times. The figure shows that multiplying the current budget by a factor of 2.7, i.e., up to €5.7 billion, will yield the desired target of 260 PJ in 2020.

[61] This is partly due to the fact that their basis price is not set high enough. For offshore wind, however, its cost does fall, so that by 2020, developers would find it profitable to apply for subsidies under the free category. However, as noted above, because other technologies – notably green gas – are able to apply for support earlier, because they have lower total costs, offshore wind is not able to compete effectively for the support.

[62] As the calculation of the required budget for reaching the target is required before obtaining results, and hence, obtaining a long-run baseload power market price as reported by the model, we have assumed this price to be equal to the cost of a new entrant CCGT in each year, in line with our assumptions for the calculation of the supply curves in 2012 and 2020.

Figure 5.7
2020 RES Output Under Different Budget Levels

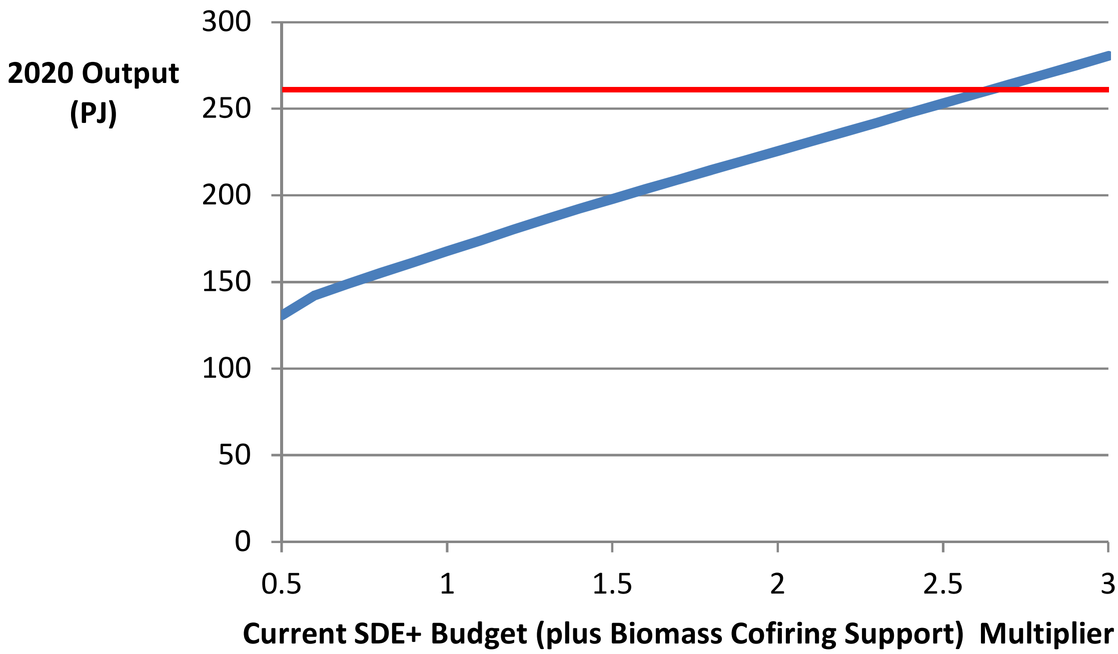


Table 5.5 shows the base level subsidy levels for all of the technologies considered, including the revised base level subsidy levels for dedicated biomass and offshore wind.

Table 5.5
Revised SDE+ Base Levels (2012 prices)

Technology	Original Units	SDE+ Base Level
Low cost onshore wind	€/MWh	85.3
Mid cost onshore wind	€/MWh	96.3
High cost onshore wind	€/MWh	96.3
Existing biomass cofire	€/MWh	96.6
Biomass cofire	€/MWh	96.6
In-lake onshore wind	€/MWh	123.3
Offshore wind	€/MWh	160.1
Green Gas Biomass Gasification	€/Nm3	0.56
Green Gas Manure Cofermentation	€/Nm3	0.72
Heat Geothermal	€/GJ	9.0
Heat Biomass Boiler Solid	€/GJ	10.9
Heat Biomass Fermentation	€/GJ	15.7
Large scale power-only biomass	€/GJ	35.9
CHP Biomass Large	€/GJ	22.2
Small scale power-only biomass	€/GJ	51.5
CHP Biomass Small	€/GJ	26.0
Heat Solar Thermal	€/GJ	31.5

Note: *The shaded areas indicate technologies for which the subsidies have been increased in order to ensure that investments in these technologies at least "break-even". The base level for offshore wind declines over time with the cost of the technology.*

Table 5.6 shows summary results under this SDE+ variant. The RES output results are similar to the scenario where only budget was increased, but not subsidy levels. The additional support for dedicated biomass and offshore wind leads to an increase in output, and the target actually being achieved. A total of 267 PJ is produced in 2020. Installed RES capacity in the power sector reaches slightly more than 9 GW by the end of 2020.

As compared to the scenario where only the budget was increased, the mix changes slightly. Under the high-budget scenario, the mix included mostly heat, green gas and onshore and (existing) offshore wind. Because much of the heat that is taken up appears to have a negative resource cost compared to its conventional counterfactual, this uptake remains mostly unchanged: its profitability is not affected by the available budget or the quarter in which it is allowed to access subsidies. The same applies to green gas uptake: as this technology is willing to access subsidies in an earlier Tranche than dedicated biomass, the increased incentives for dedicated biomass do not affect its uptake or total output. However, technologies such as offshore wind and part of the onshore wind are only willing to access subsidies starting in the fifth and fourth Tranche, while dedicated biomass would access subsidies in the fourth Tranche. Output from new onshore wind is partially displaced, decreasing from 17 PJ to 16 PJ. Starting in 2017, offshore wind moves to Tranche 4 and competes directly with dedicated biomass. This explains why we now see 9 PJ of new offshore wind contributing to 2020 output.

Total lifetime resource costs increase significantly under this scenario from €8.1 billion to €14.5 billion relative to the scenario where only the annual budget was increased – as a result of RES output increasing by 61 PJ from significantly more expensive technologies. The higher costs are largely due to the increase in output and the high uptake from (quite) expensive dedicated biomass. In spite of the higher uptake, lifetime rents actually fall slightly, relative to the "High Budget" case.

Table 5.6
Summary Results for Target-Achieving SDE+

Technology	2020 Electrical Capacity	2020 Output	2020 Resource Cost	2020 Subsidy	2020 Rents	NPV Resource Cost	NPV Subsidy	NPV Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	12	26	46	20	683	941	258
New Heat	n.a.	68	197	308	110	1,717	2,613	896
New Green Gas	n.a.	42	724	744	20	6,087	6,256	169
New Onshore Wind	1.7	16	(25)	7	32	(403)	29	432
New Offshore Wind	1.0	9	93	107	14	1,063	1,044	(19)
New Biomass Cofire	0.3	8	29	23	(5)	216	171	(45)
New Dedicated Biomass	2.0	54	692	700	9	5,143	5,221	78
Total	**9.2**	**267**	**1,736**	**1,936**	**199**	**14,507**	**16,275**	**1,768**

5.2.5 Uniform RECs

This section presents results for the first of the modelled certificate-based policies. Under this option, RES technologies are offered one renewable energy certificate (REC) for each MWh (or GJ) of renewable energy produced. The only exception to this rule is for green gas. Only 78.5 percent of the total physical green gas output can be used to qualify as RES output to meet the 2020 EU target, so a factor is applied to account for this reduced ability of green gas to contribute to the target.[63]

Table 5.7 shows summary results under this uniform REC scenario. Because the supplier obligation requires that the target be met, total output under this scenario is exactly 260 PJ. However, the output mix is different from the way the target is achieved under the SDE "target-achieving" scenario presented in the previous section.

[63] We model this by reducing the potential and proportionally increasing the resource cost, as explained above. This means that the reported output in the tables presented is indeed the eligible output used to meet the RES target, however it is lower than the amount of green gas that might actually physically be produced.

Table 5.7
Summary Results for Uniform RECs

Technology	Electrical Capacity	Output	2020 Resource Cost	Subsidy	Rents	NPV Resource Cost	Subsidy	Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	17	37	513	476	235	1,818	1,583
New Heat	n.a.	54	(57)	1,631	1,688	(465)	5,406	5,872
New Green Gas	n.a.	3	36	95	59	288	285	(3)
New Onshore Wind	3.0	27	2	819	817	(308)	2,730	3,038
New Offshore Wind	2.5	37	475	1,101	626	2,941	2,863	(78)
New Biomass Cofire	0.3	8	29	256	226	212	731	519
New Dedicated Biomass	2.0	56	724	1,689	965	4,758	4,906	148
Total	**12.1**	**260**	**1,246**	**6,103**	**4,857**	**7,661**	**18,740**	**11,079**

One striking difference between the simple REC policy and the others discussed above is that there is only minimal output from green gas under the REC policy. Apart from a small potential of cheap green gas, the technology generally has fairly high *resource* costs (again, also taking into account the adjustment related to target eligibility described above), although its total cost tends to be quite low. Hence, unless it is necessary in order to reach the target (i.e. unless the maximum potential from all less expensive technologies, in terms of resource costs, is not enough), it will not be taken up under a quota-based policy scenario, which allows the lowest-cost technologies to be taken up. Under the SDE+, green gas is willing to access subsidies in Tranche 3, before offshore wind for example, which in later years has lower lifetime resource costs. Green gas is given priority because its *total cost* is lower, even though based on standard economic cost benefit analysis, it is the *resource (incremental) cost* that should be relevant to the selection of technologies.[64]

Under the uniform REC scenario both dedicated biomass and offshore wind are taken up to a greater extent than under the previous “target-achieving” SDE policy, although neither reaches its maximum potential. This is because the two technologies switch position in the RES supply curve, with the levelised cost of new offshore wind capacity assumed to drop below the levelised cost of biomass in later years. Under the REC system, investors are assumed to observe that offshore wind investments become attractive relative to the other technologies (on a lifetime basis), and therefore start to build them when the costs have declined sufficiently. Under the SDE+, policy-makers and analysts need to observe the decline and adjust the phasing of applications (and subsidies) accordingly to ensure that the least expensive technologies are given priority over more expensive ones. Even under perfect adjustment of the phasing of applications (and subsidies), it still may be that some (slightly) more expensive technologies, (for example, dedicated biomass in years just preceding 2020), apply for and receive support in advance of other, less expensive technologies that apply in the same Tranche.

64 We have accounted for the fact that technologies whose total production costs are lower than what is assumed and reflected in their base price (*basisbedrag*) may choose to access lower SDE+ subsidies before the Tranche in which their assumed base price is available. However because offshore wind’s *total* cost remains higher than the total cost of co-fermentation green gas (even though its resource cost is lower) it does not apply for SDE+ support before green gas.

As expected, resource costs are lower under this policy relative to the “target-achieving” SDE policy, because of the automatic preference for the lowest incremental cost technologies. (The slightly lower output under the Uniform REC – 260 PJ compared to the target-achieving SDE+’s 267 PJ – also contributes slightly to the difference in resource costs.)

While this policy is optimal from a resource cost point of view, the least-cost technologies end up receiving very large levels of excess profits due to high levels of support and the absence of differentiation. Note, for example, that a significant amount of heat uptake is given by technologies that have negative resource costs. These technologies would be willing to build even without policy support, but they still receive the full benefit of the REC value for their output.

The total subsidy cost is higher than under the “target-achieving SDE” scenario modelled above, rising to €18.7 billion.

As noted previously in section 5.1, we observe a REC price spike in the target year of 2020. A very high certificate price is required in the final year in order to remunerate the capacity that is added in 2020, because after 2020 there is no further requirement for *new* investment, and the REC price falls. If the design of the policy could be adjusted to smooth the REC price trajectory while maintaining the same NPV of support (to incentivize the same investment), much lower subsidies would be paid out in 2020. We consider a policy design that does attempt to smooth the REC price trajectory in section 5.2.9, below.

5.2.6 Uniform RECs plus Bonus/Malus

This section presents results for the uniform RECs plus bonus/malus policy. Under this policy, RES technologies receive one REC for each MWh of renewable energy produced, in a similar way to the uniform RECs scenario. However, as the results presented above suggest, although a pure uniform REC policy is “efficient” in the sense that it minimises resource costs, it also leads to substantial overpayment to inexpensive technologies, which will result in higher end-user energy prices. As set out in the preceding discussion, the bonus/malus approach modifies the basic REC policy by providing a supplemental payment to more expensive technologies, to make them viable and able to contribute to meeting the RES target, by simultaneously *charging* the lowest cost technology for the right to receive their RECs. This has the effect of reducing the excess profits to the lowest cost technologies. The bonus/malus adjustments for each technology are presented as adjustments to variable cost adjustment in Table 5.8

Table 5.8
Bonus/Malus values

Technology	Variable Cost Adjustment	
	Bonus	Malus
	€/GJ	
Low cost onshore wind		(2.0)
Solid biomass boiler heat		(2.0)
Geothermal heat		(1.1)
Mid cost onshore wind		-
High cost onshore wind		-
Biomass cofire	0.1	
Biomass fermentation heat	1.0	
In-lake onshore wind	7.5	
Biomass gasification green gas	11.6	
Large biomass (CHP)	15.4	
Offshore wind	17.7	
Manure cofermentation green gas	18.0	
Small biomass (CHP)	19.1	
Large solar thermal heat	21.4	

We have calculated the bonus/malus for each technology by comparing the resource costs of each technology with reference to their respective counterfactual. We choose a "reference RES" technology as the one that will receive one REC and no bonus or malus – here set as mid-cost onshore wind. The bonus or malus for each other technologies is then calculated as the difference between the resource cost of the mid-cost offshore wind and that RES technology.[65]

Table 5.9 presents summary results under the bonus/malus REC policy. Again, as expected the 260 PJ target is met exactly. However, compared to the uniform RECs scenario, the output mix shifts away from new dedicated biomass towards new offshore wind and new heat. The reason for this is that, while under the uniform REC scenario, the resource cost minimising option was being chosen, providing a bonus/malus leads to heat and dedicated biomass technologies to have the same "perceived" cost, so both become profitable at the same certificate price. This explains why, while before more of the (cheaper) dedicated biomass was being taken up, under the bonus/malus scenario more heat technology relative to dedicated biomass is willing to build. Additionally, output shifts from dedicated biomass to offshore wind because we assume that the bonus/malus for all technologies is fixed over time. Offshore wind costs decrease relative to dedicated biomass costs, hence providing an

65 Note that the particular choice of this "reference" technology does not matter, as choosing one or another technology will result in the same relative differences between each of the RES incremental levelised costs, and the REC value will make up the difference. For ease of administration, if there is a desire to balance the amount of bonus paid out with the malus payments coming in, then there would be a need to set the reference technology somewhere in the middle of the supply curve. It is likely that some "true up" would be required that would either charge energy suppliers (if bonuses exceeded malus payments) or refund them (if the reverse were true) in some way proportionate to their total energy supply or RES commitments.

advantage to offshore wind through the bonus received. This illustrates one of the potential difficulties with the bonus/malus approach – and indeed with any approach that seeks to differentiate the support level assigned to different technologies. Ideally, the bonus/malus would need to be re-calculated each year, taking into account the expected REC price, to determine the appropriate level of support for each technology. In practice, getting such adjustments right may be challenging – perhaps more so than adjusting the SDE.

Table 5.9 shows that the policy, as a result of discriminating between cheap/expensive technologies through the bonus/malus, achieves lower total excess profits relative to the uniform RECs case. Most of the rents under this scenario are driven by new offshore wind – again, because the bonus for the technology is fixed, despite the fact that the costs are expected to fall. Total lifetime rents decrease from €11.1 billion to €5.6 billion.

Moreover, subsidies paid are lower than in the uniform RECs case. On the one hand they increase due to the excessive uptake in technologies that do not actually minimise total resource costs. However, the side payment system significantly reduces subsidies for new heat, despite these technologies' higher uptake, reflecting the fact that much of it has negative resource costs and would build anyway. The side payment only to truly expensive heat technologies acts to correct for this. Additionally, subsidies are much lower for dedicated biomass due to much lower output as compared to the Uniform REC case. Lifetime subsidies decrease from €18.7 billion to €16.4 billion.

Table 5.9
Summary Results for Uniform RECs plus a Bonus/Malus

	2020					NPV		
Technology	**Electrical Capacity**	**Output**	**Resource Cost**	**Subsidy**	**Rents**	**Resource Cost**	**Subsidy**	**Rents**
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	17	35	97	61	244	348	104
New Heat	n.a.	68	211	590	379	1,840	2,758	918
New Green Gas	n.a.	8	101	217	115	916	1,708	792
New Onshore Wind	2.5	23	(25)	113	138	(491)	72	563
New Offshore Wind	4.2	61	811	1,422	611	5,537	8,925	3,388
New Biomass Cofire	0.2	6	22	37	15	148	103	(45)
New Dedicated Biomass	0.7	20	335	377	42	2,543	2,451	(92)
Total	**11.9**	**260**	**1,490**	**2,851**	**1,361**	**10,736**	**16,364**	**5,628**

As noted above, some of the differences in the modelling results under the bonus/malus case arise because we have not attempted to modify the bonus or malus payments in each year so that they continually match the requirements of each technology in that year. This means that the bonus/malus policy diverges from the SDE+ case, which in theory it ought to be possible to make it identical to. In practice, the fluctuating REC price and changing reference "counterfactual" or index prices will make it difficult to set the bonus and malus accurately in advance. The differences we observe in the modelling results are likely to exaggerate the real-world differences between an annually adjusted SDE+ policy and an annually-adjusted REC plus Bonus/Malus policy, but we believe they give an indication of actual differences between the policies.

5.2.7 Banded RECs

An alternative approach to mitigate the issues encountered under a uniform REC policy is to discriminate between technologies by awarding different quantities of certificates per MWh. As per the bonus/malus approach the technologies are categorised by their relative resource cost, those with a higher resource cost receiving more certificates per unit of output. Table 5.10 shows the REC allowances awarded to each technology type for reference:

Table 5.10
REC Allowances

Technology	**REC Eligibility** *REC/MWh*
Solid biomass boiler heat	(0.2)
Low cost onshore wind	0.0
Geothermal heat	0.1
Mid cost onshore wind	0.2
High cost onshore wind	0.2
Biomass cofire	0.2
Biomass fermentation heat	0.3
In-lake onshore wind	0.8
Biomass gasification green gas	1.2
Large biomass (CHP)	1.5
Manure cofermentation green gas	1.7
Offshore wind	1.7
Small biomass (CHP)	1.8
Large solar thermal heat	2.0

In implementing this type of policy it is important to accurately estimate the resource costs of the different technologies. Errors in this process will inefficiently allocate certificates. It is also important to identify how many certificates are allocated to each technology band. If they are not properly distributed then it may mean the target output is not reached; sacrificing one of the key advantages of a quota-based policy tool.

Table 5.11 presents the results obtained for the banded REC policy. Note that, as with the bonus/malus policy, we have not attempted to model changes in the banding levels over time. Because the resource costs of each technology change relative to each other, it is likely that policy-makers will adjust the banding levels to avoid over-compensating individual technologies, as it becomes clear that over-compensation is occurring. Thus these results are likely to overstate the excess support offered. Moreover, another consequence of keeping the banding support fixed is that offshore wind becomes more attractive than onshore wind. Although both wind technologies become cheaper, because offshore wind is more expensive, its cost reduction is greater in absolute terms. The incremental support that it receives (indeed, the excess support) therefore becomes larger, in absolute terms, than the support provided to onshore wind. Some offshore wind therefore displaces the more expenses onshore wind under this policy relative to the to the Uniform REC case.

Table 5.11
Summary Results for Banded RECs

Technology	Electrical Capacity	Output	2020 Resource Cost	Subsidy	Rents	Resource Cost	NPV Subsidy	Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	17	35	63	28	119	308	189
New Heat	n.a.	60	34	218	184	408	1,265	857
New Green Gas	n.a.	8	99	311	212	870	1,652	781
New Onshore Wind	1.6	15	(12)	39	52	(334)	161	495
New Offshore Wind	4.2	61	888	1,948	1,060	6,672	9,137	2,465
New Biomass Cofire	0.1	4	14	15	1	54	53	(1)
New Dedicated Biomass	2.1	59	847	1,220	373	5,978	5,653	(325)
Total	**12.3**	**281**	**1,905**	**3,815**	**1,910**	**13,768**	**18,228**	**4,460**

In this case total output is higher than the target level for 2020, unlike the alternative REC policies covered above. This is because once there are differences in the number of RECs allocated to each technology, it is much more difficult to ensure that the total output is equal to the desired level by setting a target for RECs. It is difficult to know, in advance, how many RECs will be produced, given the banding parameters. The technology mix changes somewhat relative to that under the uniform REC case. Onshore wind output is reduced, whilst there are small increases in heat, green gas and dedicated biomass. However, the most significant change is the large uptake of offshore wind to 61 PJ, making it the largest contributor to 2020 output. This is because the offshore wind cost falls over time, making it relatively more attractive given its banding (which we do not adjust over time, although this represents a significant simplification of the most likely implementation of a banded REC policy). The REC target in this case leads to total output of 281 PJ, 21 PJ higher than the required target.

The net present value of lifetime resource costs are higher than under the uniform REC scenario at €13.8 billion. This is to be expected, given that the banding mechanism allows more expensive technologies to become competitive than would be the case under a "pure" cost minimising system. The total lifetime support received is lower than under the uniform REC policy, despite high subsidies to offshore wind and the overachievement of the target. This is due to the reduction in support for new heat and onshore wind. As a result of the differentiation of support, rents are substantially lower.

5.2.8 Uniform REC plus banking

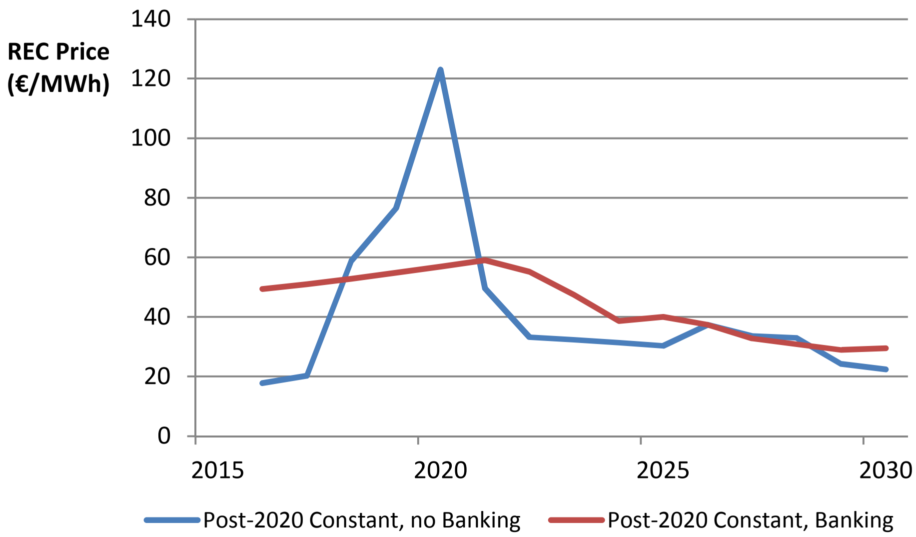
As noted above, under the Uniform REC policy option the policy support provided in the year 2020 is very high, because we model a large price spike in 2020. The spike is driven by the requirement to meet the target and the need to remunerate any (high capex) new capacity (such as offshore wind) that is built in 2020 before REC prices fall back to the short-run incremental cost of RES technologies.

Allowing banking of RECs serves to smooth the spike somewhat, although as we will see below, simply allowing banking is not enough to prevent a significant reduction in REC prices after 2020.

In anticipation of a high certificate price in 2020, RES producers are incentivised to generate certificates in advance, hold on to them and then release them into the market or use for compliance when the price rises. This arbitrage between compliance years increases the price prior to 2020 and reduces it in 2020

The resulting REC price is presented in Figure 5.10 (in red), which is significantly smoother than the price observed under the Uniform REC policy with constant post 2020 output target and no banking (shown in blue). Instead of observing a steep peak in the certificate price above €120/MWh in 2020, we observe a much shallower price trajectory, rising from around €50/MWh in 2016 to close to €60/MWh in 2020, and decreasing afterwards, below €30/MWh in 2030. The decrease in certificate prices shortly after 2020 is reasonable, as future demand for certificates decreases when approaching the end of the period.

Figure 5.8
Comparison of REC Price Trajectories in Uniform and Banking Cases



The results obtained for this policy option are presented in Table 5.13. First, looking at output, we observe that only 222 PJ is produced in 2020. The remaining 38 PJ of the target are made up via certificates that have been banked in previous years. (Additional capacity still needs to be added after 2021 to reach the then constant 260 PJ target, and this explains why the REC price continues to rise for a year after 2020.) Compared to the Uniform REC policy, there is no output from new offshore wind or green gas, as a significant part of the target is met through certificates banked in previous years from other technologies such as dedicated biomass. Moreover, once this capacity is built, it continues to generate in future years, apparently eliminating the need for offshore wind to meet the target.[66]

As expected, the direct support received by RES technologies in the year 2020 is significantly lower than in the Uniform REC case, due to REC price smoothing. The subsidy level drops by more than 60 percent, from €6.1 billion to €2.3 billion.

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[66] Recall that we assume that dedicated biomass can be built without any limit to total capacity.

Table 5.12
Summary Results for Uniform RECs plus Banking

Technology	2020 Electrical Capacity	Output	Resource Cost	Subsidy	Rents	NPV Resource Cost	Subsidy	Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	17	36	237	201	273	1,948	1,675
New Heat	n.a.	54	(35)	754	790	(291)	5,618	5,909
New Green Gas	n.a.	-	-	-	-	-	-	-
New Onshore Wind	3.0	27	3	379	376	(187)	2,805	2,992
New Offshore Wind	-	-	-	-	-	-	-	-
New Biomass Cofire	0.3	8	29	118	89	212	734	523
New Dedicated Biomass	2.1	58	739	808	68	4,980	4,886	(94)
Total	**9.6**	**222**	**771**	**2,296**	**1,524**	**4,986**	**15,991**	**11,005**

Total lifetime resource costs (€5.0 billion), subsidies paid (€16.0 billion) and rents (€11.0 billion) are also lower than in the Uniform REC case. However, because the output target is not actually achieved in 2020, it may not be appropriate to compare the two.

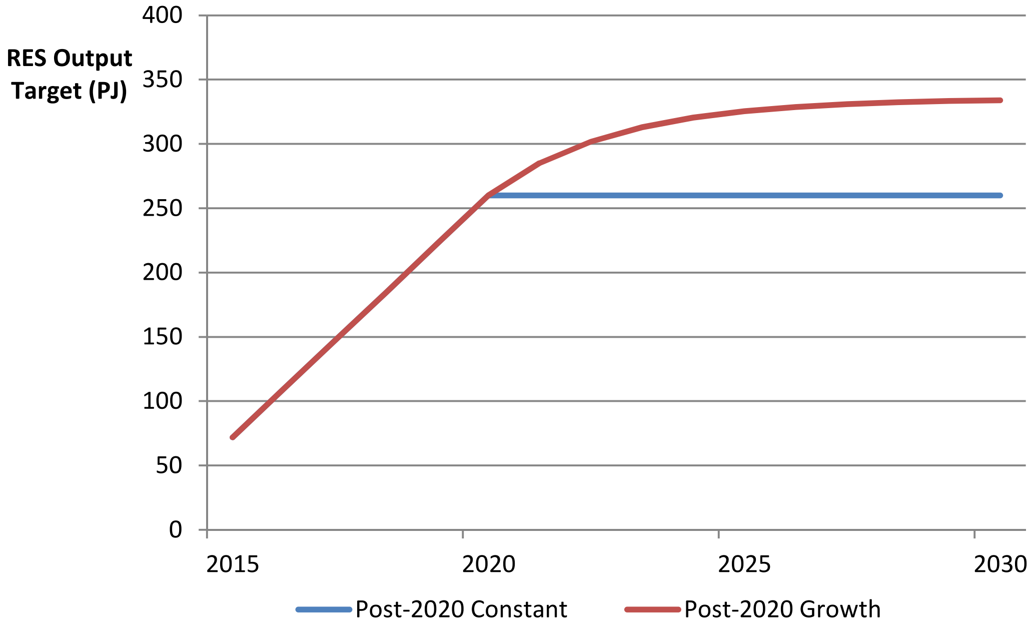
5.2.9 Uniform REC plus banking, and target post-2020 growth

In addition to the simple banking option presented above, we also model a banking policy that increases the RES target in the years after 2020, in an attempt to come closer to the 260 PJ 2020 target.

In the previous policy analyses, we assumed that the targeted 260 PJ remained as a target in subsequent years up until the policy horizon in 2030. By increasing this target following 2020, incentives to invest in new RES technologies beyond 2020 are improved, and more output is achieved in 2020.

In Figure 5.9 the blue line shows the target as modelled for the previous REC policies, remaining unchanged after 2020. Here, the increased target levels are introduced, as shown by the red line, rising to around 330 PJ by 2030.

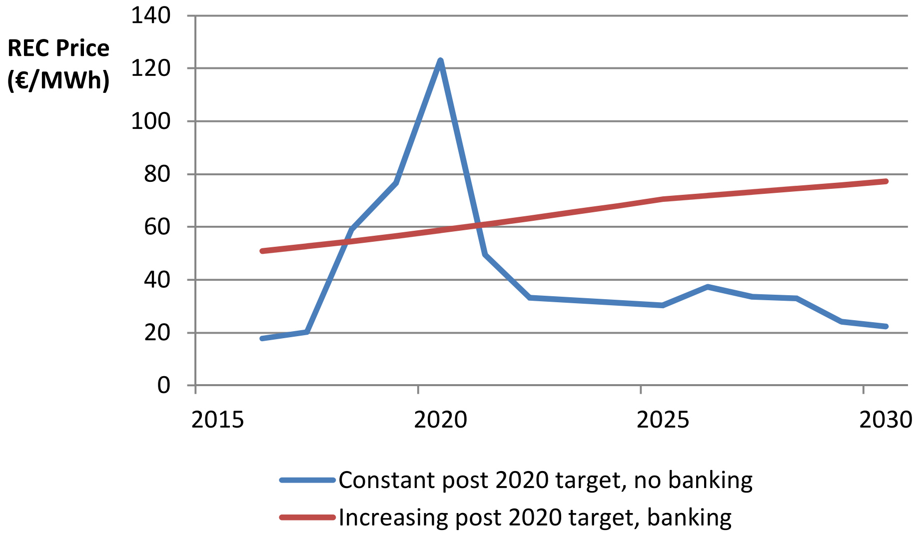
Figure 5.9
RES Output Target beyond 2020



As mentioned in the previous scenario, allowing "banking" of certificates between years provides an additional means to smooth the REC price over time. In anticipation of a high certificate price in 2020, RES producers will be incentivised to generate certificates in advance, hold on to them and then release them into the market or use for compliance when the price rises.

The resulting REC price is presented in Figure 5.10 (in red), which is, again, significantly smoother than the price observed under the Uniform REC policy with constant post 2020 output target and no banking (in blue). Instead of observing a steep peak in the certificate price up to €123/MWh in 2020, we model a much shallower price trajectory, similar to the one shown for the previous scenario. However, under this scenario, the price trajectory continues to increase throughout the next decade, rising from around €50/MWh in 2016 to €77/MWh in 2030.

Figure 5.10
Comparison of REC Price Trajectories in Uniform and 2030 Banking Policies



The results obtained for this policy option are presented in Table 5.13. First, looking at output, we observe that only 250 PJ is produced in 2020. The remaining 10 PJ of the target are made up via certificates that have been banked in previous years. Compared to the Uniform REC policy, output from new offshore wind is reduced to 7 PJ, in part displaced by new green gas and dedicated biomass. In the banking scenario, it becomes profitable to build more dedicated biomass earlier, because its output can be banked for use in later years when it is even more valuable. This reduces the need for offshore wind capacity and output in 2020.

As intended by this policy, the direct support received in the year 2020 is significantly lower than in the Uniform REC case, due to the price smoothing. The subsidy level drops by more than half in that year, from €6.1 billion to €2.8 billion. The increased post-2020 target means that RES generators require less support in 2020, because they can expect increased certificate revenues in the following years. On top of this, banking means that slightly less output is required in 2020 because it is compensated for by surplus supply in previous years.

Table 5.13
Summary Results for Uniform RECs plus Banking and 2030 RES Target

Technology	2020					NPV		
	Electrical Capacity	Output	Resource Cost	Subsidy	Rents	Resource Cost	Subsidy	Rents
	GW	*PJ*	*€m*	*€m*	*€m*	*€m*	*€m*	*€m*
Existing Heat & Green Gas	n.a.	26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Onshore Wind	2.7	21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Offshore Wind	0.9	10	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Existing Biomass Cofire	0.6	17	37	245	208	279	2,701	2,422
New Heat	n.a.	54	(50)	778	828	(380)	7,595	7,974
New Green Gas	n.a.	8	92	113	21	741	963	223
New Onshore Wind	3.0	27	8	391	383	(109)	3,939	4,048
New Offshore Wind	0.5	7	91	104	12	553	815	262
New Biomass Cofire	0.3	8	29	122	93	213	887	674
New Dedicated Biomass	2.5	70	908	1,007	99	6,431	8,591	2,160
Total	**10.6**	**250**	**1,115**	**2,759**	**1,644**	**7,727**	**25,491**	**17,763**

Total lifetime resource costs (€7.7 billion), subsidies paid (€25.5 billion) and rents (€17.8 billion) are all higher than in the Uniform REC case, however. The increase is due to the rising RES targets in later years, which impose increasingly costly renewables on consumers in later years. In order to incentivise RES output above 260 PJ in the ten years following 2020, the REC price increases (as shown in Figure 5.10) meaning greater lifetime support is provided to RES generators built up to 2020. Rents are increased because the high REC price leads to more profits awarded to infra-marginal plants.

5.2.10 Uniform REC with Buy-out price

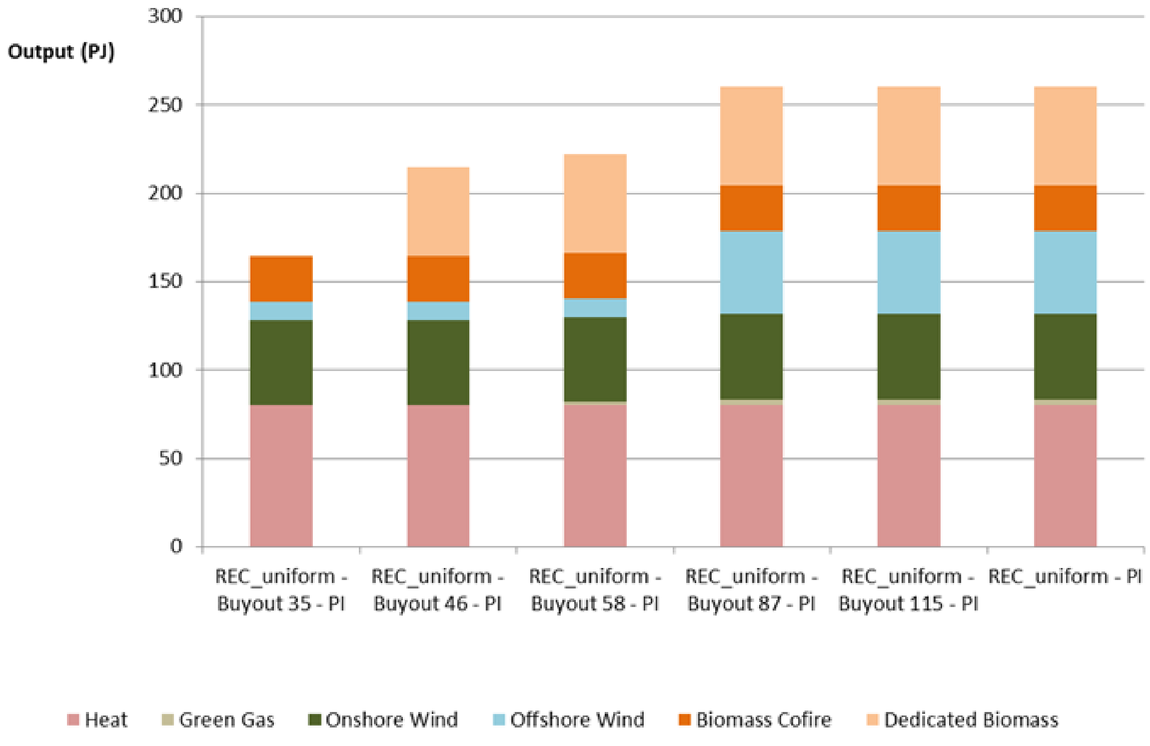
As we have discussed above, the main limitation of a uniform quota-based policy such as the Uniform RECs case is that it implies a high level of total support paid, due to the necessity of equally compensating all the technologies, including the more expensive ones. That is, even the cheapest technology will receive a level of support equal to the cost of the most expensive technology needed to meet the target. In addition to the nine policies that are presented above, here we consider the impact of including a *buy-out* price within the Supplier Obligation scheme. In order to achieve the RES target output, this is likely to require topping-up with complementary support for more expensive technologies.

The buy-out price allows obligated suppliers to pay a charge, rather than buying certificates that they need for compliance. This has the effect of capping the REC market price at the level of the buy-out. It therefore limits the total cost burden of the policy that is ultimately passed through to consumers. However, the disadvantage of introducing a buy-out price is that it places the achievement of the target RES output at risk. If suppliers elect to pay the buy-out price instead of purchasing certificates from RES generators (or the market place) then output will be below the required level, including only the less expensive technologies. Under such a policy design, the REC system would need to be complemented by additional measures (such as a revised SDE+).

In the following charts we present a comparison across different buy-out prices[67]. We analyse the impact of setting the buy-out price in 2020 at the following levels and compare against the Uniform REC policy option with no buy-out: €35/MWh, €46/MWh, €58/MWh, €87/MWh and €115/MWh. Aside from the introduction of a buy-out price, the other policy parameters are assumed to be the same as under the Uniform REC case.

Figure 5.11 shows the different output levels across the range of buy-out prices considered with the Uniform REC comparison included on the right hand side of the chart. The lower buy-out prices reduce output below the target level as only the cheapest technologies are incentivised to build. Under the €35 scenario no dedicated biomass, green gas or new offshore wind contributes to the output. Raising the buy-out price then provides sufficient incentive for dedicated biomass at €46, increasing total output to 215 PJ. At €58 the only difference is slightly more dedicated biomass and a very limited introduction of inexpensive green gas.

Figure 5.11
REC_Buy-Out Output (2020)



Raising the buy-out price further to €87 provides sufficient incentive for very slightly more green gas and, crucially, new offshore wind to boost output.[68] This allows the target of 260 PJ

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[67] As noted in the Supplier Obligation policy discussion in section 2.3.2 of this report, a variable buy-out price could also be specified ex ante that increases the further the Netherlands falls below its RES target trajectory. The design of this variable cap could be used to reflect the government's preference regarding the trade-off between meeting the target and limiting the cost exposure passed through to consumers.

[68] The REC price trajectory under this scenario cannot peak at €120 in 2020, but can rise nearly as high in 2019 *and* 2020.

in 2020 to be reached. Modelling the buy-out price at €87, €115 or removing it altogether results in the same level of output and the mix of technologies contributing to it.[69]

5.2.11 Combining a 'below target' REC policy with SDE+ support

The lower the REC buy-out price, the lower the subsidies paid out. This tool is therefore useful in protecting consumers against escalating costs. However, RES output is also insufficient to meet the target in 2020. Hence, more expensive technologies such as offshore wind and dedicated biomass would still be needed to achieve the desired 260 PJ. One option would be for these technologies to be separately supported through a subsidy-based scheme, thus avoiding the provision of rents to the less expensive technologies. Moreover, providing a certain level of output under a REC-based system limits some of the disadvantages of a subsidy-based scheme targeting all technologies, among them the risk that costs are not estimated correctly.

To illustrate this with an example we take the policy case where the buy-out price is set to €46/MWh. This yields an output of 215 PJ in 2020. Under this policy there is no uptake in 2020 from new green gas, nor from new onshore wind. Support for these technologies could therefore be introduced to complement the Uniform REC with Buy-Out approach. Under the Target Achieving SDE policy, for example, new green gas and new onshore wind contribute 42 PJ and 9 PJ respectively. Total lifetime subsidies are paid out to these technologies of the order of €2.6 billion for heat and €0.03 billion for onshore wind.

This approximation of a policy hybrid would therefore result in an output in 2020 of 266 PJ, just above the target and akin to the "target achieving" SDE policy. The net present value of subsidies would be €2.6 billion from the complementary SDE type support on top of approximately €13.9 billion in support provided by the REC with Buy-Out policy. This would give a total lifetime subsidy for the hybrid policy of approximately €16.5 billion. This is fractionally more expensive than the under the target-achieving SDE (€16.3 billion) and the Uniform REC plus Bonus/Malus (€16.4 billion) policies. However, it is below the subsidies paid out under the standalone Uniform REC (€18.7 billion) and Banded REC (€18.2 billion) options.

The main differences would be in the implications for technologies with costs below the buy-out level (which might receive higher rents under the hybrid policy than under the SDE+ – again, assuming the SDE+ successfully discriminated its support offerings). Moreover, if the buy-out price were set *above* certain technology-specific basis price caps that apply under the SDE+, then the hybrid approach would improve overall efficiency by permitting more expensive *instances* of a particular technology (that are still inexpensive, relative to other technologies) to receive support that they would not be eligible for under the SDE+. In other respects, the hybrid policy is likely to be very similar to the SDE+. Technologies whose costs exceeded the buyout would either be eligible for the SDE+ (in which case we can assume that they would be treated exactly as they currently are under the SDE+), or they would not be eligible to receive SDE+ support at that level (in which case they probably

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69 Investors and developers are still willing to build the same quantity of RES capacity because the REC price is able to rise sufficiently high that, over all years, revenues compensate the initial capital outlay for all investments.

would be limited in their current eligibility to access SDE+ support above a corresponding basis price – so that again, their treatment would be largely the same as under the SDE+).

Lastly, it is worth noting that the hybrid system would introduce additional complexity that could deter investors, at least until familiarity with the new system increased. In particular, investors would need to understand how the interaction of REC prices with SDE+ support would work in practice, and would be more likely to delay investment while they observed and gained confidence in the new system. In principle this is no different from the kind of hesitation that would be observed as a result of any significant change in policy, but because this form of hybrid policy has not been used elsewhere, it may result in more reluctance to proceed until investors were convinced that they understood the likely dynamics of the interactions.

5.3 "Low RES Cost" Sensitivity Results

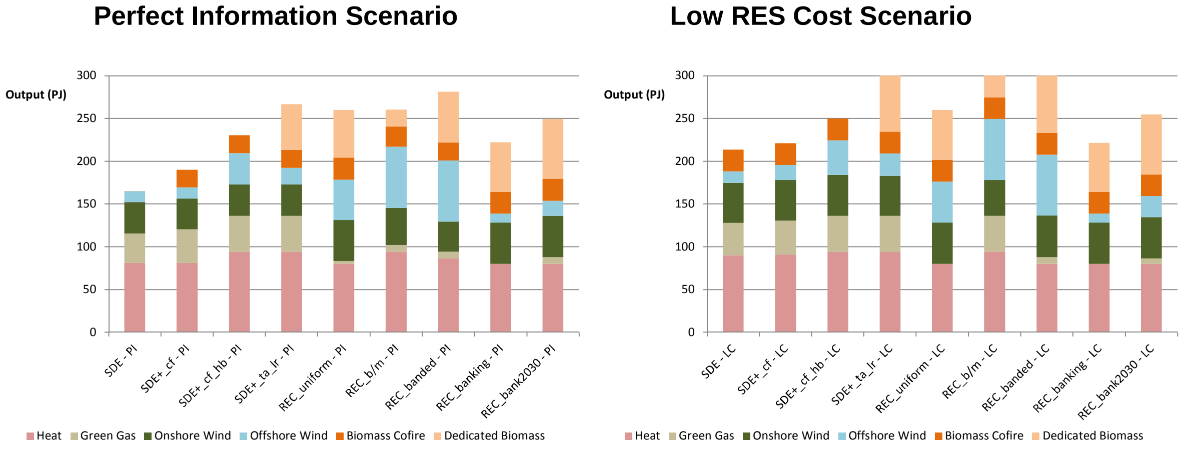
We now turn to various "sensitivity analyses" that are designed to explore how the different policies fare when expected policy design inputs, such as costs, potential, and the like, do not actually turn out as expected. The "Low Cost" sensitivity analysis considers the possibility that all costs for RES technologies are actually 20 percent lower than the Perfect Information scenario from 2012 onwards. This allows us to investigate the impact that incorrect cost information would have on the results. All other policy design parameters remain fixed – thus the SDE+ baseline support levels are the same, budget limits are the same, and banding and bonus/malus settings are the same as in the Perfect Information scenario policies.

We use this scenario, and the next one, to provide insight into the impacts of errors in estimating the average costs of technologies. We also use these sensitivity scenarios to help understand the implications of a failure to account for heterogeneity within a technology group. Of necessity, the modelled results reflect simplifications of how we might expect such uncertainty to play out in the real world – in particular, we do not attempt to modify the policies dynamically, and we do not explicitly attempt to model the cost heterogeneity. Nonetheless, as we discuss, the results provide helpful illustrations of expected impacts that shed light on how policies would work when exposed to the uncertainties that exist in the real world.

In each of the following analyses the results from the Perfect Information scenario are presented in the left hand panel and the Sensitivity results are presented in the right hand panel for ease of comparison.

Figure 5.12 compares the Perfect Information scenario RES output in 2020 with the Low Cost sensitivity analysis for 2020 output.

Figure 5.12
Low RES Cost Scenario – Output (2020)



For the price-based RES policies (variants of the SDE+), we expect higher output as a result of this amendment. Lower costs may allow both inexpensive and expensive technologies to access subsidies in earlier Tranches than expected, under the free category. Given that there has been no change in budget, lower per-unit subsidy requirements imply that greater output should be achievable under the Perfect Information scenario, at least for the technologies whose total supply potential was not already reached under the Perfect Information scenario.

This is indeed the case for the target-achieving SDE+ scenario, for example. Total output under this scenario is now 310 PJ, as opposed to the previous 267 PJ under the Perfect Information scenario. While technologies such as inexpensive heat and green gas were already built up to their maximum potential under the Perfect Information scenario, these consume a lower proportion of the budget, allowing for more dedicated biomass and offshore wind to be build.

Under the Uniform RECs policy, output remains unchanged, but offshore wind and dedicated biomass displace the 3.1 PJ of output from green gas in the Perfect Information scenario. This is because green gas is less expensive (in terms of total production cost) than onshore wind and dedicated biomass, so when costs are reduced by 20 percent, this has a greater impact on the resource costs of the latter two technologies. As a result, the relative ordering of the resource costs for the three technologies (which are already very close in 2020) shifts. For the Banded REC policy output increases as a result of the lower costs, principally due to increased dedicated biomass output. The same happens for the Bonus/Malus policy, output rises to above the required 2020 target, even though there is also a reduction in heat, as green gas more than compensates for this lost output. In the last place, output is also slightly higher under the banking RECs case, with an increase particularly in offshore wind. This is due to the fact that the even higher decrease in costs through time for this technology makes it attractive for offshore wind to build later in time, as compared to the Perfect Information scenario, preferring to bank less certificates.

Figure 5.13
Low RES Cost Scenario – Net Resource Cost (NPV)

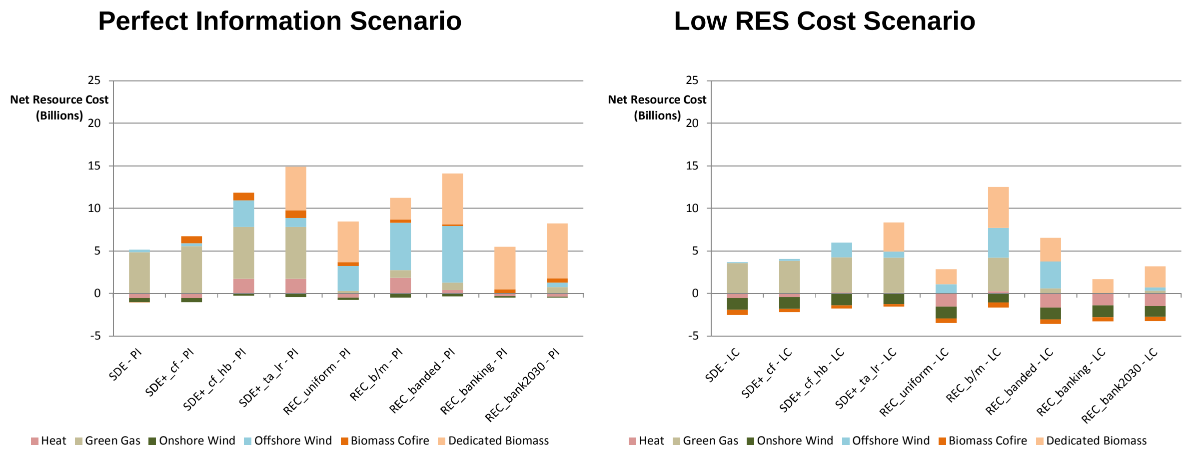
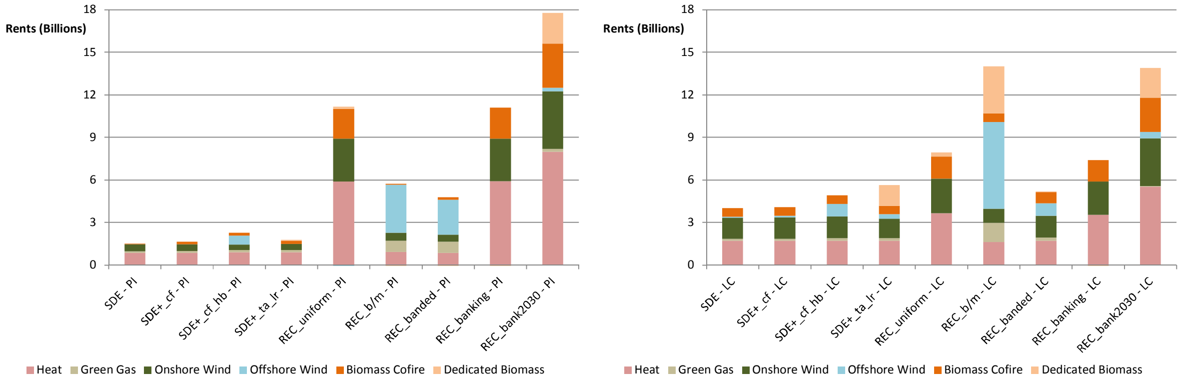


Figure 5.13 shows that – as expected – the low cost sensitivity results in lower total lifetime resource costs across all policies, apart from the Bonus/Malus REC case. The counter-intuitive result for the Bonus/Malus example is because green gas displaces some heat even though it has a higher resource cost. Moreover, the 20 percent reduction in costs for all technologies, combined with constant levels for the bonus/malus (i.e. we assume that these are not adjusted to reflected the unexpected reduction in costs) lead to a switch between technologies on their "perceived" merit order. This means that more expensive technologies, such as offshore wind, experience a higher decrease in absolute terms as a result of the 20 percent decrease in costs, as compared to a cheaper (in absolute terms) technology such as onshore wind. In spite of this, the bonus/malus, received in absolute terms as well, remains the same – and is now too high – for something expensive such as offshore wind. This creates an *advantage* for more expensive technologies as compared to cheaper ones, leading to the first ones being willing to build for a lower REC price. This explains the switch in the output mix from cheap to (more) expensive technologies, hence the increase in resource costs under this scenario.

As noted above, the results shown here assume that there is no recognition of the banding levels, SDE+ limits, or side-payments being set inappropriately, given the lower-than-expected costs. It is likely that such adjustments would take place, although they may not occur immediately – perhaps after 1-2 years of over-subsidisation. This implies that perhaps one-third of the increased rents (relative to the Perfect Information scenario) that are suggested here might be observed in practice.

Figure 5.14
Low RES Cost Scenario – Rents (NPV)

Perfect Information Scenario **Low RES Cost Scenario**



As would be expected, when costs are reduced by 20 percent, rents are higher in most policy scenarios. The increase is proportionately greatest for the price-based support schemes: although the per-unit support under the SDE+ declines because technologies apply in the "free category", they still have costs that are well below the level of support for which they apply in the relevant Tranches.[70] Even so, rents under the target-achieving SDE+ remain lower than under the Uniform REC regime – but not lower than under the banded REC case.

Uniform RECs (both with a constant post-2020 target, as with an increasing post-2020 target and banking) provide the only example where rents are reduced under the low cost scenario. In these two cases, the overall cost reduction across all technologies has the effect of reducing the cost differentials between technologies. In the Banded REC case we see that offshore wind rents are reduced, offset to some extent by increased rents for heat, co-firing, and onshore wind. Finally, under the Bonus/Malus REC policy rents are significantly higher under the Low Cost sensitivity. The majority of these rents are provided to offshore wind because the side payments are not adjusted to reflect the reduced costs. Dedicated biomass also earns significant rents.

In general, rents increase for the differentiated support policies – whether certificate-based or subsidy-base – *unless we assume that the parameters are adjusted* to reduce the overpayment.

Under the SDE+, for example, it is likely that base support levels would be revised downward within a year or two, as better information about technology costs / performance became available, and perhaps as development proceeded faster than anticipated. However, the potential negative effects of not adjusting the base levels immediately are likely to be mitigated under the SDE+ by the fact that developers would apply in earlier Tranches for their subsidy, under the "free category". (This effect is already modelled in the results above, and explains, in part, the lower rents under the SDE+ policies.)

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[70] Note also that the reduction in costs reduces the downside risk that developers face under the SDE+ (because of the floor price).

Similar adjustments would be likely to occur under the differentiated REC policies – although with these policies, there is the added complication of what happens to the REC market. Regulatory review and intervention is likely to be more difficult when certificates earned by previous vintage developments affect the support received by new investments.

Figure 5.15
Low RES Cost Scenario – Subsidies Paid (NPV)

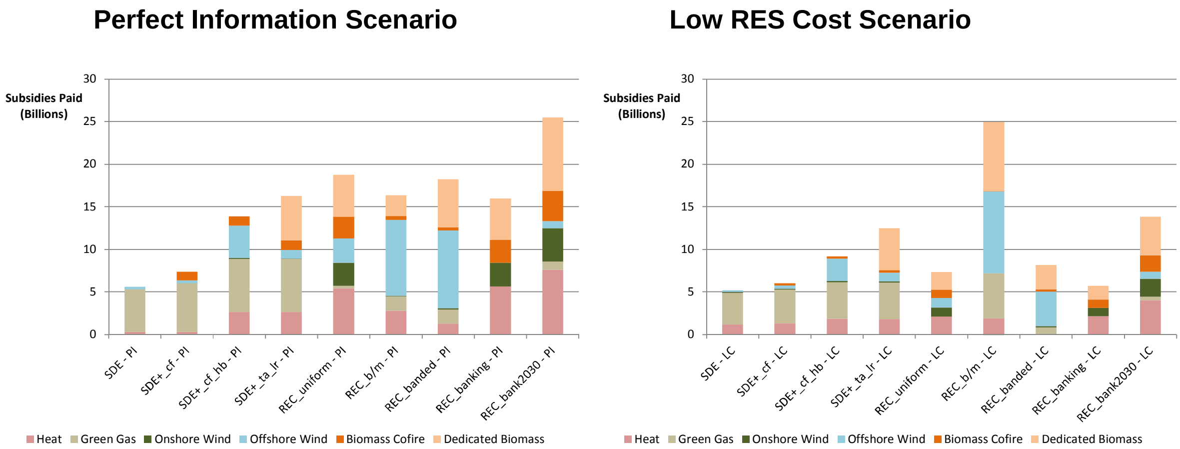


Figure 5.15 suggests that the lower RES costs have a greater impact on support paid under the REC policies than under the SDE+, although support falls in nearly all cases. Under the SDE+ support costs are somewhat lower because some technologies access lower subsidies in earlier tranches, reducing the total draw on the SDE+ budget. Because the REC price is set at the resource cost of the most expensive technology required to meet the target, which is now 20 percent "cheaper", the REC price will be much lower, because 20 percent of the total cost is a much larger share of the *resource* cost of each technology. The decrease in subsidies is smaller under the SDE+ because even though costs decrease by the same amount, subsidies only decrease by the difference between the pre-determined technology base-price and the next-lower "free category" price. As a result, subsidies go down by only between 5-10 percent.

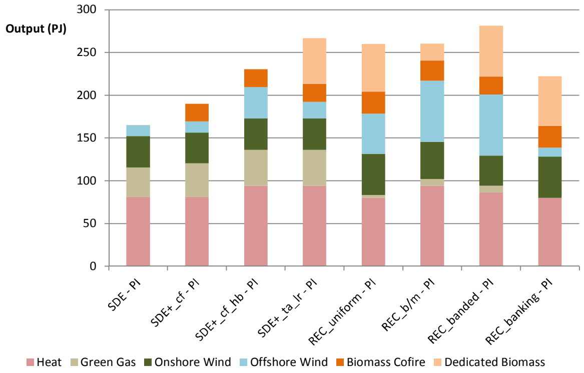
5.4 "Reduced Heat Potential" Sensitivity Results

In the Reduced Heat Potential ("RHP") sensitivity the availability of all heat and green gas potential is reduced by 50 percent as compared to the Perfect Information policy scenarios presented in section 5.2 above. All other policy design parameters remain fixed.

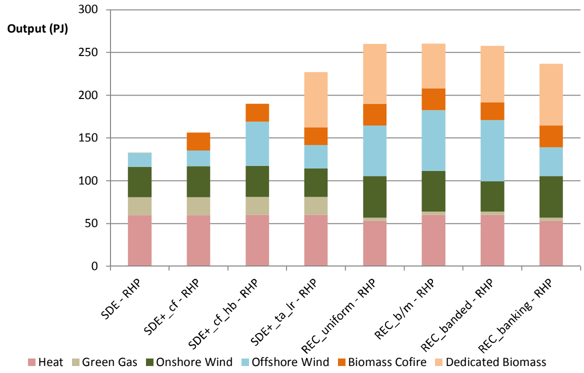
This sensitivity allows us to test the implications of reduced RES potential directly. It also provides some insight into what might happen under the SDE+ if there were significant cost heterogeneity which meant that some proportion (in this case, half) of the potential renewable heat or green gas projects were prevented from accessing subsidies above a certain level, due to a cap on subsidy levels.

Figure 5.16
Reduced Heat Potential – Output (2020)

Perfect Information Scenario



Reduced Heat Potential Sensitivity

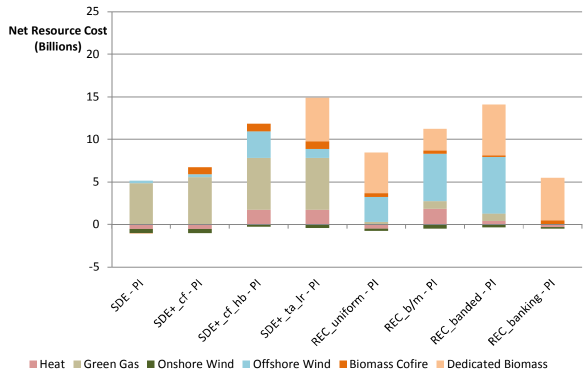


As we would expect, reducing the available RES potential from heat technologies tends to reduce the amount of output from renewable energy, all else being equal. Only under the REC policies does output reach the targeted level. In the Uniform REC case, both offshore wind and dedicated biomass output increase, to compensate for the reduction in heat and green gas potential. Under the target-achieving SDE+, the loss of heat potential leads to an increase in dedicated biomass and offshore wind – but there is insufficient budget left to support the required additional output to meet the target. If the SDE+ were to be adjusted to meet the target, we calculate that it would require an increase in the annual budget of around 15 percent, or €0.8 billion, to €6.3 billion.

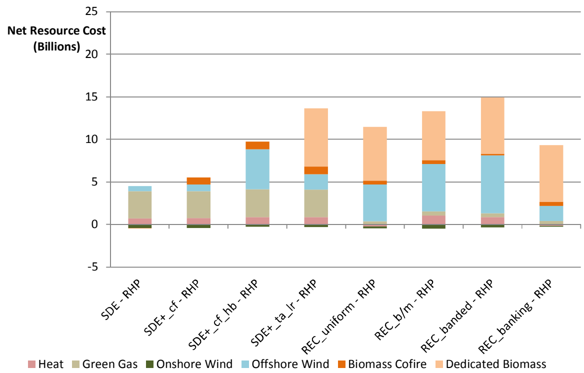
The removal of the heat potential is also significant for costs, because under the Perfect Information scenario, most of the heat output was provided by heat technologies with negative resource costs. This potential is substantially reduced under this sensitivity. Because heat provides a relatively inexpensive source of renewable energy supply, its removal increases the cost of achieving the target.

Figure 5.17
Reduced Heat Potential – Net Resource Costs (NPV)

Perfect Information Scenario



Reduced Heat Potential Sensitivity



Because much of the renewable heat and biomethane potential that is assumed to be available under the Perfect Information scenario is assumed to have "negative" cost, eliminating its uptake does not always reduce the *positive* resource costs of the policy by the corresponding amount. Under the Uniform, Banded and Bonus/Malus REC policies, cutting the assumed renewable heat potential leads to higher resource costs, because more expensive offshore wind and dedicated biomass are required to meet the target.

Figure 5.18
Reduced Heat Potential – Subsidies Paid (NPV)

Perfect Information Scenario **Reduced Heat Potential Sensitivity**

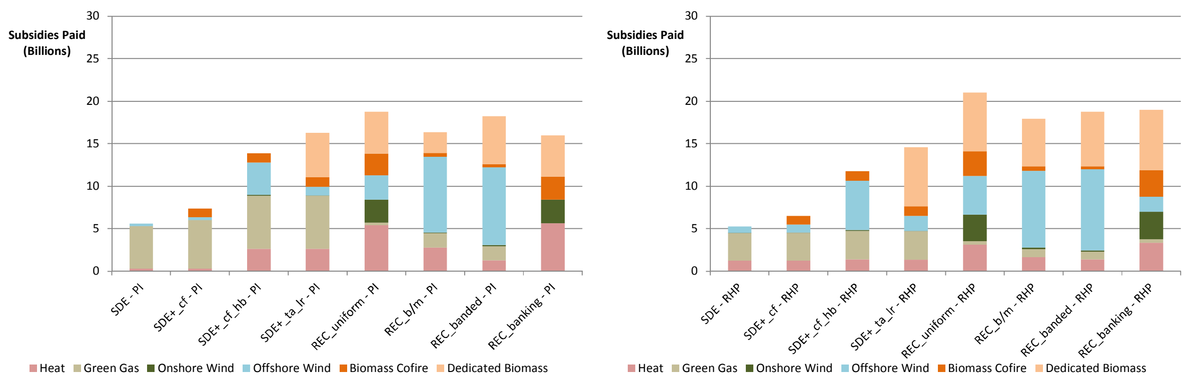
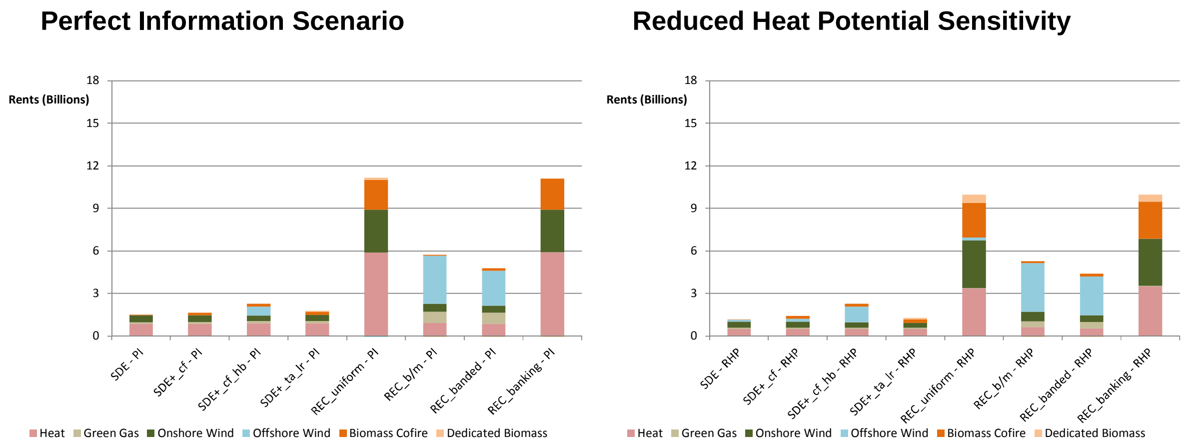


Figure 5.18 shows how the total discounted lifetime value of the policy support changes under the reduced heat potential scenario. The total support costs are lower under the reduced heat scenario across the SDE+ variants due to lower output. However, the difference is mitigated in part because heat potential did not receive much subsidy, as it was assumed to have negative resource costs. A difference in the subsidies paid by technology can be seen for the target-achieving SDE+ scenario, where previous (inexpensive) heat uptake has been replaced by more expensive dedicated biomass as well as slightly more offshore wind. Of course, under these policy variants, the target is no longer achieved. Subsidies to green gas (and to a less extent, for heat) drop under all the SDE+ type scenarios, because there is less of it. Under the Uniform, Banded and Bonus/Malus REC policies lifetime subsidies increase, as the policy automatically adjusts to ensure that the target is met by pushing the REC price higher to incentivise greater levels of investment, earlier, in more expensive technologies, such as dedicated biomass.

Finally, Figure 5.19 shows the total lifetime rents paid under the different policies. The rents remain similarly low under the SDE+ variants when the heat potential is restricted – this is because we assume that SDE+ is precisely calibrated to offer the correct subsidy, and no more, to each technology. Under the REC scenarios, the limited heat potential actually decreases rents, even if it provides some additional rents to both offshore wind and dedicated biomass technologies. This is because heat output was driving the greater part of the rents, given that most of this output was for technologies with negative resource costs, which would have been willing to build anyway.

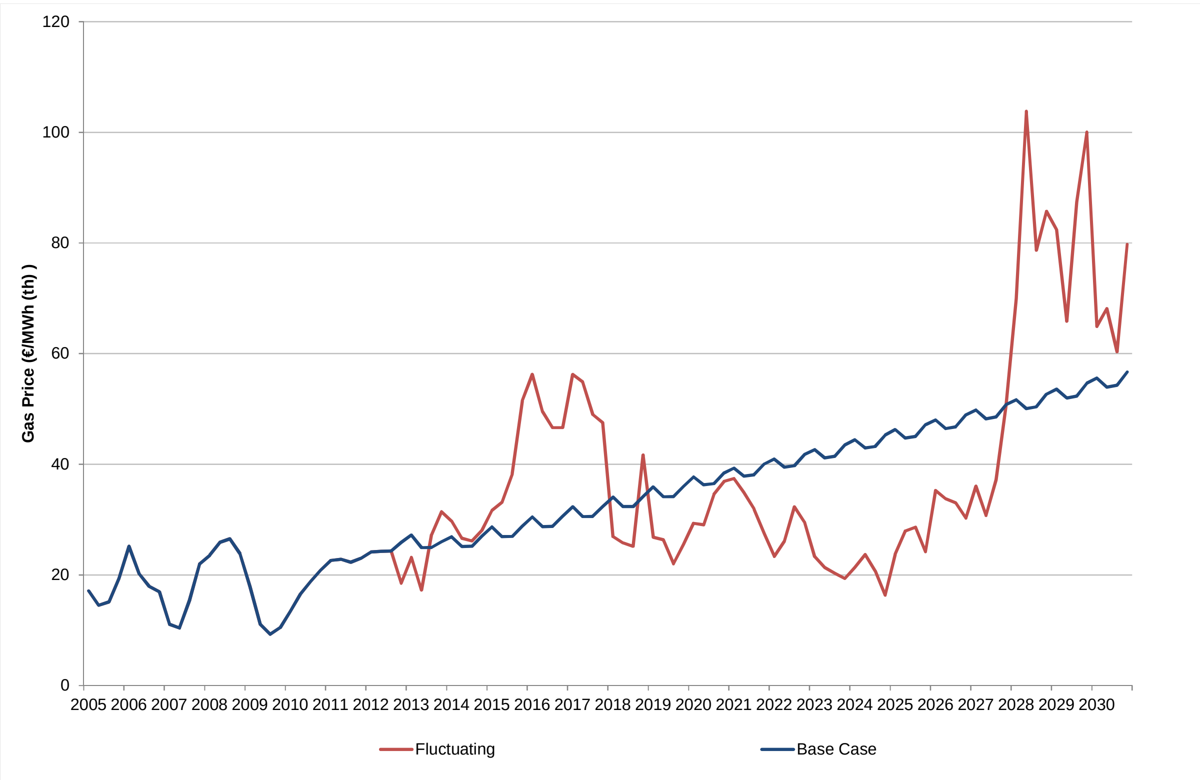
Figure 5.19
Reduced Heat Potential – Rents (NPV)



5.5 "Volatile Gas Price" Sensitivity Results

This sensitivity analysis considers the impact of increased volatility in the wholesale market gas price whilst holding all other assumptions equal. In Figure 5.20 the gas price for the Perfect Information scenario is shown along with the significantly more volatile gas price (red series) under consideration here.

Figure 5.20
Gas Price Scenarios



The risk, under the volatile gas price scenario, is that when the gas price falls, this also brings electricity prices down with it. Under the SDE+, this may cross the threshold price floor level, below which RES technologies no longer receive additional support. Under the REC policies, in contrast, the REC price is expected to rise in response to reductions in the power price, to ensure that RES technologies remain profitable. In fact, we observe just this relationship in our modelling. However, even with the dramatically fluctuating gas prices above, the lowest annual baseload electricity price only rarely approaches the SDE+ price floor. The downside risk to SDE+ investors only poses a significant threat if the gas price falls well below current levels – as it did, we note, in 2007 and 2009. We have not been able to test more potential gas price trajectories within the scope of this work.

As for the previous sensitivities, in each of the following analyses the results from the Perfect Information case are presented in the left hand panel and the Volatile Gas Price sensitivity results are presented in the right hand panel for ease of comparison. All policy design parameters remain fixed – thus the SDE+ support levels are the same, budget limits are the same, and banding and bonus/malus settings are the same as in the Perfect Information policies.

Figure 5.21 shows RES output in 2020 for the nine policy scenarios under the Volatile Gas Price sensitivity, relative to output for these scenarios under the Perfect Information assumptions. Output increases very slightly for the SDE+ type scenarios with no change to the mix of technologies. Under the Uniform and Bonus/Malus RECs scenarios, total output is, by construction, the same as under the Perfect Information scenario, as these are target-based policies. The output mix varies across all of the REC scenarios, where green gas displaces output from some expensive power market technologies such as offshore wind (in the Uniform REC policy) and dedicated biomass. This is partly a function of the way that the heat and power markets are modelled, because the increased investment risk that comes as a result of the fluctuating gas price is captured more completely in the electricity market modelling than in our modelling of heat technologies.

Figure 5.21
Volatile Gas Price – Output (2020)

Perfect Information Scenario **Volatile Gas Price Sensitivity**

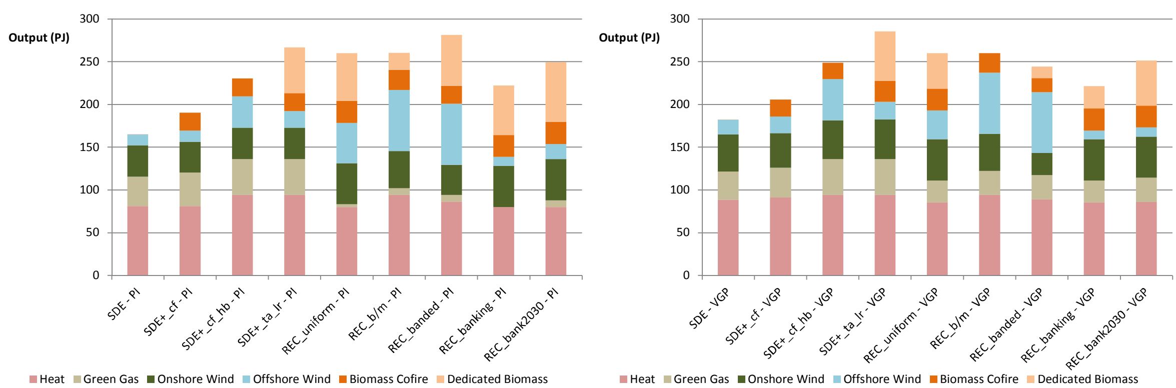


Figure 5.22 compares lifetime resource costs under the Perfect Information case and the Volatile Gas Price sensitivity for the nine considered policy scenarios.[71] Specifically with respect to the REC policies, the contribution of dedicated biomass to the lifetime resource cost is reduced due to lower output. This is related to the fact that investors cannot be certain of enjoying the benefits of high prices (or of avoiding the risks associated with low prices).

Figure 5.22
Volatile Gas Price – Net Resource Cost (NPV)

Perfect Information Scenario **Volatile Gas Price Sensitivity**

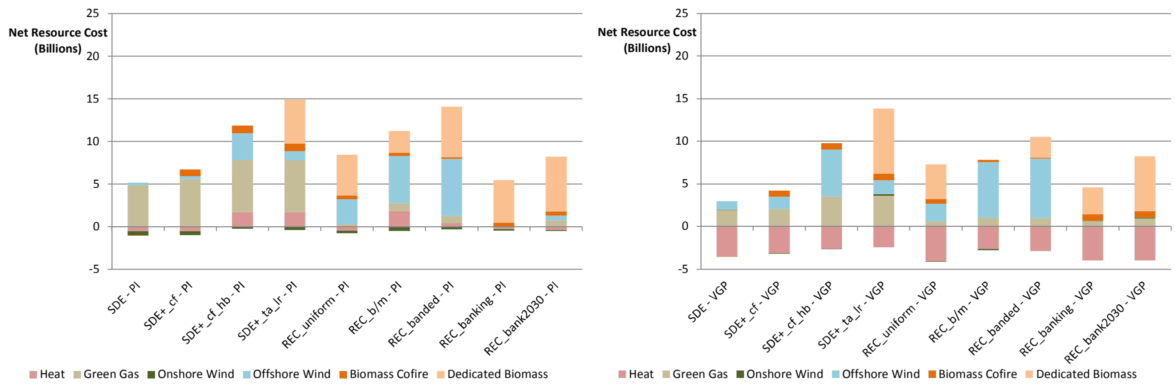


Figure 5.23 compares rents under the Perfect Information scenario and Volatile Gas Price sensitivity. The negative resource costs for heat and green gas result in significantly higher rents under all policies. Under the SDE+ scenarios we observe an increase in lifetime rents – although this does not reflect excess support from the policy, but rather the fact that the technologies would be built anyway. Under the REC policies, substantial rents are received by green gas and especially heat technologies. This is because they receive support even though they have negative resource costs.

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71 Under the volatile gas price sensitivity heat and green gas resource costs appear significantly lower when compared to the Perfect Information case across all of the different policy options. One reason for this is that we calculate the resource cost for heat and green gas technologies relative to the cost of gas at the time of investment.

Figure 5.23
Volatile Gas Price – Rents (NPV)

Perfect Information Scenario **Volatile Gas Price Sensitivity**

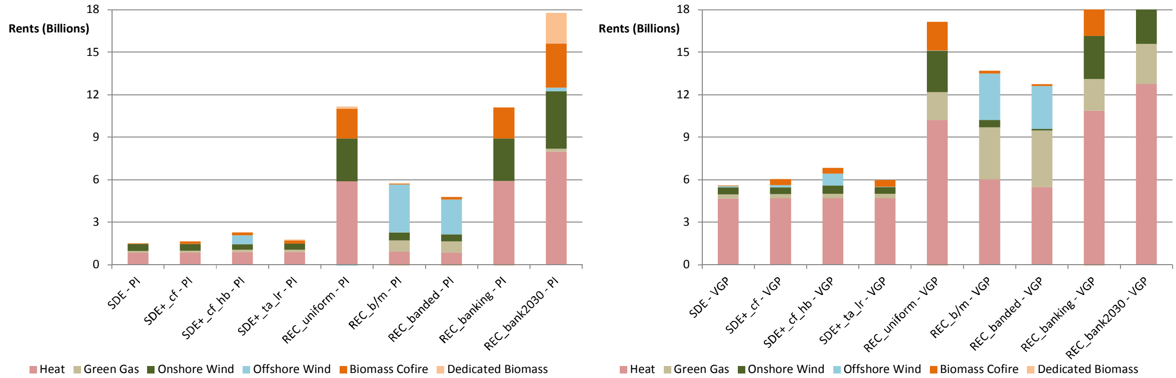
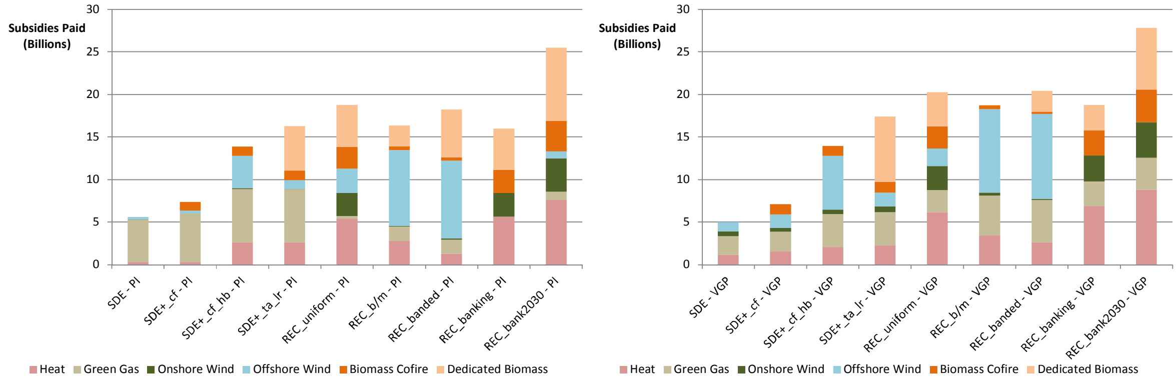


Figure 5.24 compares lifetime subsidies paid under the Perfect Information scenario and the Volatile Gas Price sensitivity. Across the SDE+ policies, subsidies are higher under the Perfect Information scenario than the volatile gas price simulation. This is because the resource cost is higher and the policy adjusts to this, minimising any excess support. This is driven almost entirely by green gas. Conversely, for the REC based policies, the green gas subsidies are higher under the volatile gas price sensitivity as a result of higher uptake. Overall total lifetime subsidies are higher for REC policies under the volatile gas price scenario when compared to the Perfect Information. In particular, technologies require a higher "premium", or REC price, in order to be willing to build towards the target, hence increasing total subsidies paid.

Figure 5.24
Volatile Gas Price – Subsidies Paid (NPV)

Perfect Information Scenario **Volatile Gas Price Sensitivity**



Overall, these results suggest that the precise trajectory of a volatile gas price will have a significant influence on resource costs. With a price above trend in the years leading up to 2020 and then below thereafter until approaching 2030, resource costs for heat and green gas technologies are highly negative. This drives very high rents, particularly under the REC type policy schemes. Output, on the other hand, is only marginally impacted by the volatility modelled.

5.6 "High Wind Costs" Sensitivity Results

The final sensitivity scenario that we model is a High Wind Costs ("HWC") sensitivity. We assume that instead of falling at the rates outlined above in section 4.6.1.1, the total production costs of wind technologies are maintained constant through time. All other policy design parameters remain fixed.

Figure 5.25 shows RES output in 2020 for the nine policy scenarios under the High Wind Costs sensitivity, relative to output for these scenarios under the Perfect Information case. Output decreases for all the SDE+ type scenarios with no change to the mix of technologies. The reason for this decrease is that the higher wind costs make the previous budget insufficient to achieve the target RES uptake. The target-achieving SDE+ now achieves output slightly below the target at 255 PJ. The REC-based policies all achieve the target, with the exception of the uniform RECs plus banking scenario

The output mix changes across all policies, with less contribution from offshore wind in all policies, and most also witnessing reductions in onshore wind. Dedicated biomass and green gas displace the lost wind output.

Figure 5.25
High Wind Costs – Output (2020)

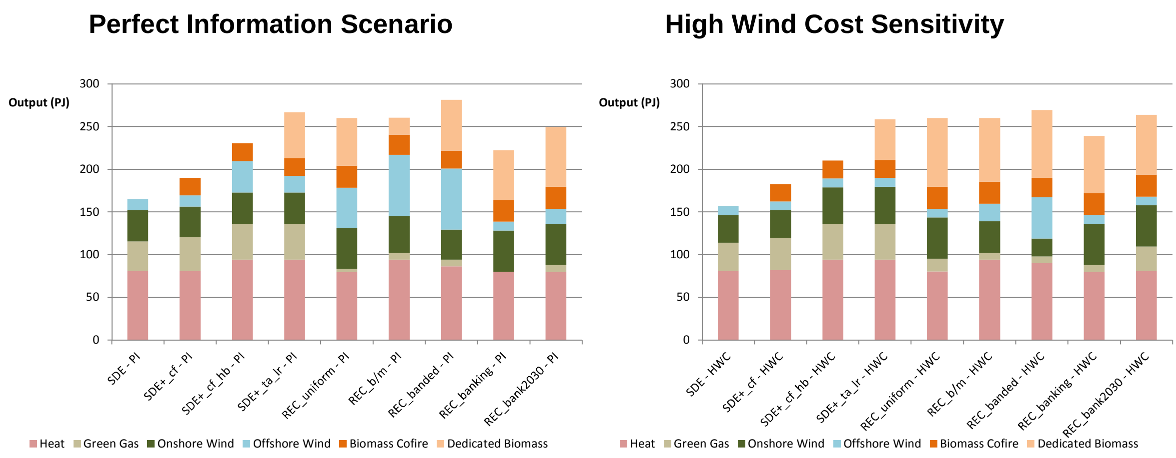


Figure 5.26 compares lifetime resource costs under the Perfect Information scenario and the High Wind Costs sensitivity for the nine modelled policies. Resource costs are very slightly higher under the SDE+ (with the reduced output noted above). Resource costs rise more under the REC-based policies, which still meet the 260 PJ target.

Figure 5.26
High Wind Costs – Net Resource Cost (NPV)

Perfect Information Scenario **High Wind Cost Sensitivity**

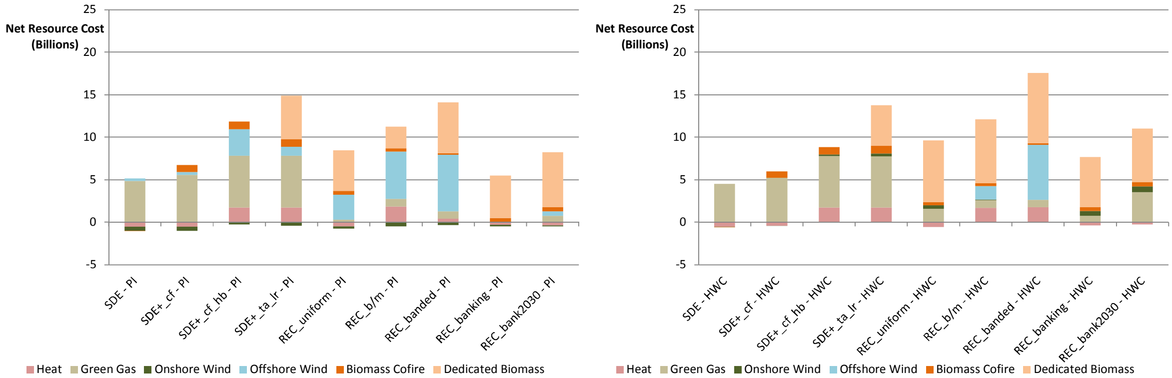
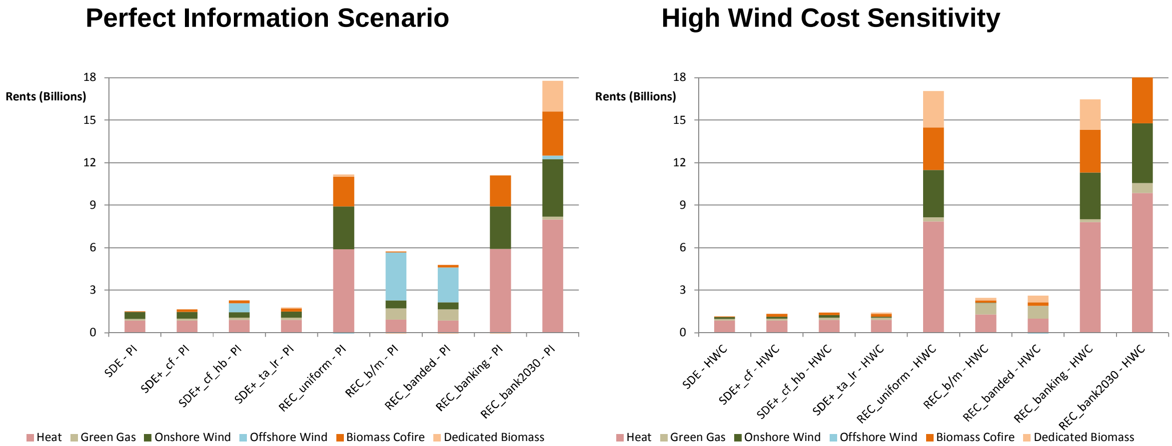


Figure 5.27 compares rents under the Perfect Information scenario and High Wind Costs sensitivity. As both production costs and subsidies for wind technologies remain constant and set just above the level required for these technologies to break even (without having to adjust the subsidies through time to account for the decrease in wind costs), rents are now slightly lower for the SDE+ type scenarios as compared to the Perfect Information case. The same applies to the banded and bonus/malus RECs scenarios. In particular, lifetime rents for both onshore and offshore wind disappear in the High Wind Costs sensitivity, as compared to the Perfect Information case, where these rents, especially for offshore wind, were significant. (Recall that we did not revise the banding or bonus/malus levels over time, so that when we eliminate the change in wind costs, the original levels do not yield rents to nearly the same degree. The actual differences in outcome under these two alternative sensitivities therefore are likely to be less than what is implied here, as the policies would almost certainly be adjusted in the real world.)

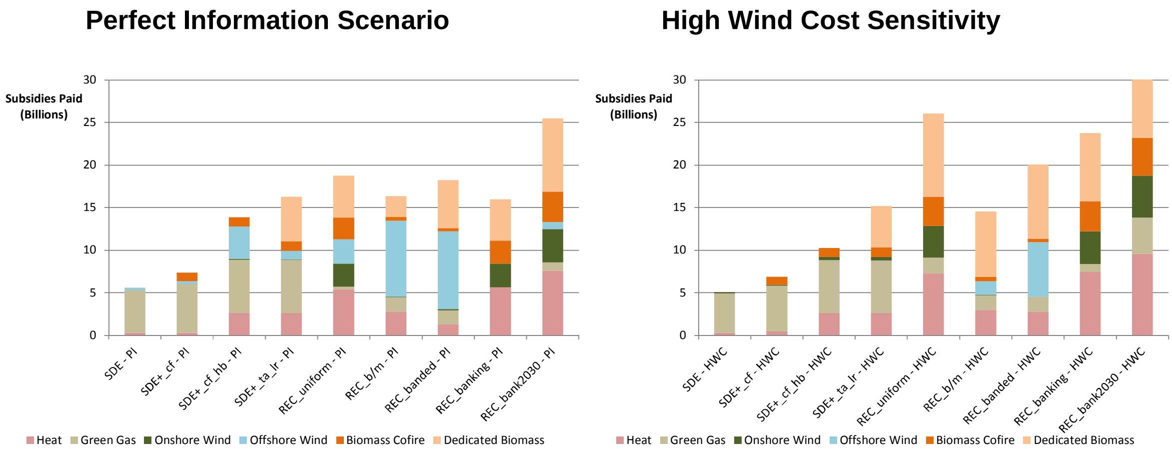
Despite the reductions in rents for some policies, rents increase under the two uniform REC scenarios (with constant and growing post-2020 target plus banking). The reason for this is simply given by the fact that the marginal technology required for reaching the target is now more expensive, hence leading to higher rents for all the other technologies.

Figure 5.27
High Wind Costs – Rents (NPV)



Finally, Figure 5.28 compares lifetime subsidies paid under the Perfect Information scenario, and High Wind Costs sensitivity. For the RECs scenarios, having a more expensive marginal technology necessitates paying higher subsidies to all technologies required to meet the target, even if these technologies would have been willing to built at the previously lower REC price.

Figure 5.28
High Wind Costs – Subsidies Paid (NPV)



5.7 WACC Sensitivity Results

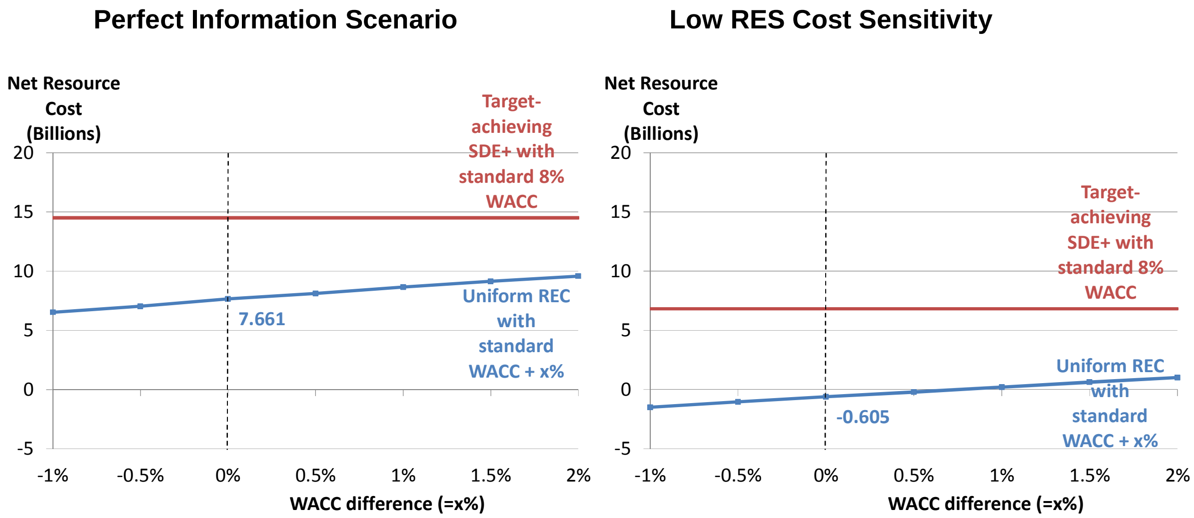
This sensitivity analysis considers the impact of applying different levels of WACC to the new entrant RES technologies under the uniform RECs scenario, whilst holding all other assumptions equal. As discussed in section 2.5, a quota-based policy such as the uniform RECs scenario offers both advantages and disadvantages in terms of risk exposure that may result in a different premium being demanded by investors, compared to the SDE+.

For our standard modelling we assume a WACC of 8 percent. For the sensitivity analyses presented here, we have modelled the uniform RECs scenario (for both the Perfect Information scenario and Low RES Cost scenario) using WACC levels as low as 100 basis points below the standard level, and as high as 200 basis points above it – that is, we have tested the impacts on our results at WACCs ranging from 7-10 percent.

Figure 5.29 shows lifetime net resource costs under the Perfect Information scenario (left panel) and Low RES Cost sensitivity (right panel), for the uniform RECs scenario. The figure shows the results when we assume our standard WACC (indicated in the Figures by the dotted vertical line), as well as the impacts of using alternative WACC assumptions. These costs are shown alongside the cost that we estimated for the corresponding Target-Achieving SDE+.

For both the Perfect Information scenario and the Low RES Cost sensitivity, lifetime net resource costs increase as the assumed WACC levels increase. However, even when we assume that investors faced with a REC demand as much as a 200 basis point premium, overall resource costs under the Uniform REC policy remain significantly lower than the costs under the Target-Achieving SDE+.

Figure 5.29
Net Resource Costs (NPV)



Note: *The dotted line indicates lifetime net resource costs under both the Uniform RECs and Target-Achieving SDE+ policies under the standard 8 percent WACC assumption. For the Perfect Information case, resource costs correspond to the values presented in sections 5.2.4 and 5.2.5, in Table 5.6 and Table 5.7, respectively. As expected, lifetime resource costs are lower for WACC levels below the standard 8 percent assumption, and higher for higher than 8 percent WACC levels.*

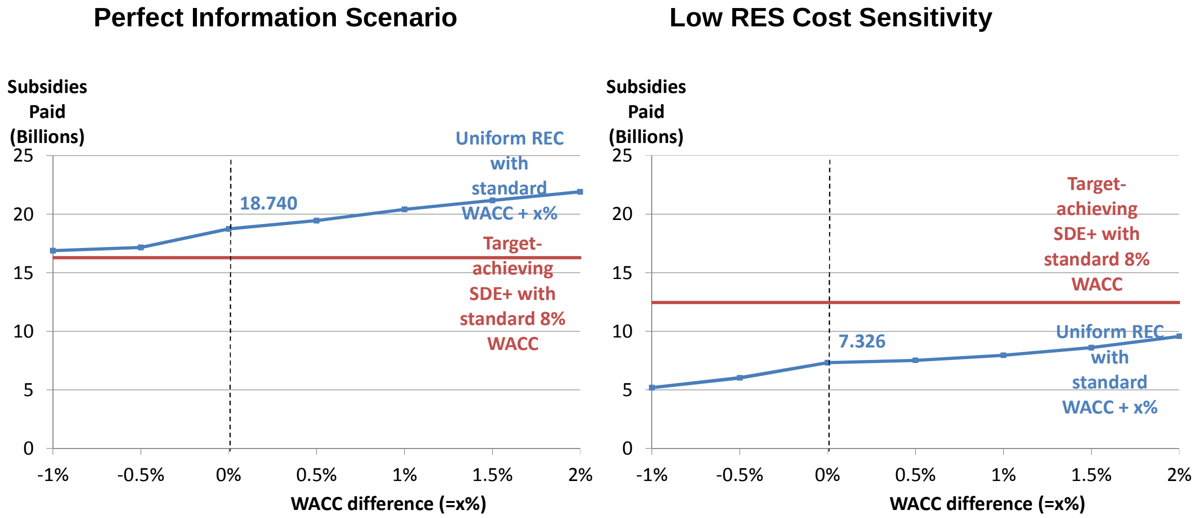
For the Perfect Information scenario, if we assume that the trend suggested by the results presented above hold for higher WACC levels, the analysis suggests that a WACC as high as 15 percent would be needed in order for resource costs to become higher under the REC scenario than under the SDE+ scenario.[72] The WACC required to even out the resource costs between the two policies is even higher under the Low RES Cost sensitivity, at 17 percent.

[72] Note that we have not modelled any WACC level below 7 percent, or above 10 percent. Values for WACC levels outside this range have been by extrapolating the results shown.

Figure 5.30 shows lifetime *subsidies* paid under the Perfect Information scenario (left panel) and Low RES Cost sensitivity (right panel) over the same range of WACC levels. Again, the figure compares our modelling results for the uniform REC policy to the results for the Target-Achieving SDE+. As discussed above, in the Perfect Information scenario, the subsidy costs under the Uniform REC regime are higher than under the SDE+, despite lower resource costs, because of the profits earned by low-cost producers. Under the Low RES Cost sensitivity, the Uniform REC policy actually appears to have lower subsidy costs as well as lower resource costs.

Under the Perfect Information scenario, decreasing the WACC applied in the Uniform REC case by 100 basis points (1 percentage point) brings the support costs of the policy very close to the costs of the Target-Achieving SDE+. (We estimate that the WACC would need to fall to around 6.5 percent for the support costs of the Uniform REC to drop below the costs of the SDE+.) Under the Low RES Cost sensitivity, even increasing the WACC to 10 percent is not sufficient to increase lifetime support costs of the Uniform REC policy above the costs of the Target-Achieving SDE+. Again, extrapolating from the trend (we have not modelled WACCs any higher) suggests that a WACC as high as 12.5 percent under the REC system would be needed for the certificate policy to have a higher support cost than the SDE+ policy.

Figure 5.30
Subsidies Paid (NPV)



Note: *The dotted line indicates lifetime subsidies paid under the uniform RECs and target-achieving SDE+ scenario under the standard 8 percent WACC assumption. For the Perfect Information case, resource costs correspond to the values presented in sections 5.2.4 and 5.2.5, in Table 5.6 and Table 5.7, respectively. As expected, lifetime subsidies paid are lower for WACC levels below the standard 8 percent assumption, and higher for higher than 8 percent WACC levels.*

6 Consumer Impacts

6.1 Policy Impacts on Energy End-Users

This section provides a high-level indication of who might pay the cost in 2020 of the various renewable energy support policies presented above. The results focus on the Perfect Information sensitivity scenario. Under the other scenarios we would expect the impacts in 2020 to be proportional to the support costs in 2020 – thus under the Low RES Cost scenario, the impacts of the Uniform REC policy would actually be lower than the impacts of the target-achieving SDE+.

At the request of the Ministry of Economic Affairs, Agriculture, and Innovation we consider four approaches to recovering the annual support costs of the policy from different end-user groups, spreading the costs across either:

1. all electricity and gas consumers,
2. only electricity consumers,
3. only non-industrial electricity and gas consumers, or
4. only non-industrial electricity consumers.

(This would be done under the supplier obligation options, for example, by obliging only gas suppliers, or both gas and electricity suppliers, to meet the RES quotas, and by calculating the affected suppliers' quotas based either on their total sales, or on their sales to non-industrial consumers only.)

Table 6.1 presents the relevant energy consumption information, for the year 2010.

Table 6.1
Electricity and Gas Consumption by End-User Group (2010)

	Industrial	Non-industrial	Total
Fuel		*PJ*	
Electricity	141	244	385
Gas	240	697	937
Total	380	941	1,322

Source: Data for total final power and gas consumption and the split of industry use relative to other sectors is taken from Eurostat.

The different options, and their associated price impacts, are presented in Table 6.2:

Table 6.2
Impacts of Policy on End-User Energy Prices (2020)

Policy	Total Subsidy in 2020	Electricity		Electricity & Gas	
		All users	All non-industrial users	All users	All non-industrial users
	€m	*€cent/KWh*			
Current SDE+	661	0.6	1.0	0.2	0.3
SDE+ plus co-firing	825	0.8	1.2	0.2	0.3
SDE+ plus co-firing and high budget	1,626	1.5	2.4	0.4	0.6
Target-Achieving SDE+, Low Rents	1,936	1.8	2.9	0.5	0.7
Uniform RECs	6,103	5.7	9.0	1.7	2.3
Banded RECs	*3,815*	*3.6*	*5.6*	*1.0*	*1.5*
Uniform RECs plus Bonus/Malus	*2,851*	*2.7*	*4.2*	*0.8*	*1.1*
Uniform REC, Banking	2,296	2.1	3.4	0.6	0.9
Uniform REC, Post 2020 growth, Banking	2,759	2.6	4.1	0.8	1.1

Source: NERA analysis drawing on Eurostat consumption data.[73]

Notes: 1. The 2020 cost impact under the Uniform REC policy (and, to a lesser extent, the Banded and Bonus/Malus REC policies) is significantly affected by a price spike in the REC market in that year, which we discuss in section 5.2.5. The three policies have been shaded in the table to highlight this difference.

2. Under the first three policies, subsidies are lower because the target output is not met.

The results show that the price impacts of the subsidies will be substantially higher if applied only to electricity users rather than across both electricity and gas users. The subsidy burden on just electricity users would represent a significant increase in the total consumer cost per unit of energy. Spreading the cost increase to gas consumption as well significantly reduces the impact per kWh consumed, because total gas consumption is more than twice that of electricity consumption. It is important to note, of course, that the retail price of gas is also much lower than the price of electricity per kWh, so an approach that spreads the costs equally in Eurocents per unit of final energy consumption would represent a much larger *relative* impact on the retail gas price than it would on the electricity price.

As noted above, the much higher apparent impacts in 2020 due to the uniform REC policy is a direct consequence of the price spike in the REC market that we have already discussed. If measures are taken to design the policy in a way that smoothes the price (for example, following the banking policy), the impacts in 2020 are significantly reduced – although they are still higher, in 2020, than the impacts of the SDE+.

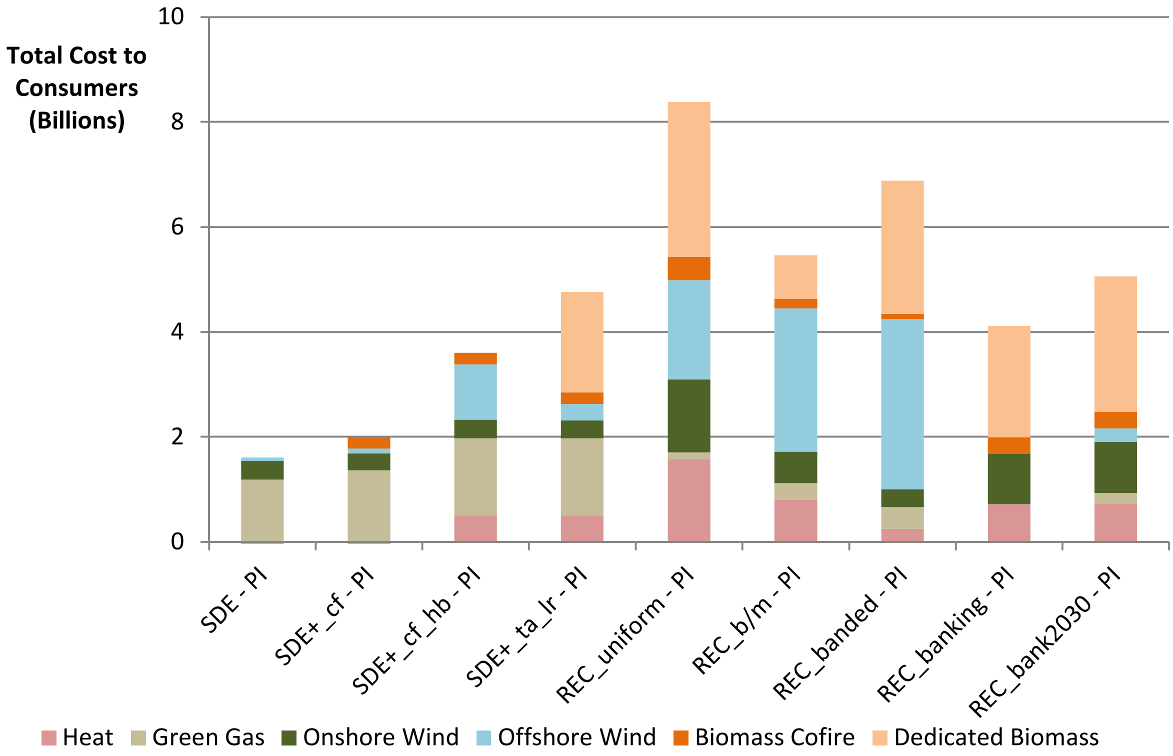
Under the Target-Achieving SDE+, the per kWh end-user price impacts range between 0.5 €cents, if shared across all users, and 2.9 €cents, if shared among only non-industrial

[73] This data is based on 2010 figures. Any shift in total consumption, the power to gas ratio or sectoral mix by 2020 will therefore impact these results. However, they serve as a useful reference for how the subsidy cost might be applied in 2020. Note that under the Current SDE+, costs are split equally between household and industrial customers. For ease of policy comparison, we have not applied this division to the SDE+ costs shown above.

electricity users.[74] The large differences between the costs across different end-user groups emphasises the importance of the policy decision in this regard.

The Ministry of Economic Affairs, Innovation and Agriculture has also asked us to report the "total cost" of the RES technologies – as distinct from the more standard incremental or resource costs that would typically be used for cost-benefit assessment – that would be supported by each of the policies, to allow them to assess the contribution of energy expenditure on RES to consumers' overall consumption. A comparison of the total costs in 2020 is shown below in Figure 6.1. The pattern of total costs largely parallels the underlying subsidy costs presented in Figure 5.6, above.

Figure 6.1
Total Cost of RES to Consumers (Energy Expenditure + Support Costs), 2020



Note: As above, the 2020 cost impact under the Uniform REC policy (and, to a lesser extent, the Banded and Bonus/Malus REC policies) is significantly affected by a price spike in the REC market in that year.

[74] Industrial electricity use accounts for 37 percent of total consumption, whereas industrial use accounts for a smaller share (29 percent) of electricity plus gas use – in part because industrial users also may use other, cheaper fuels.

7 Linking to Other REC Markets

7.1 Motivation for linkage

The EU Renewables Directive of 2009 mandates that 14 percent of Dutch final use energy must be derived from renewable energy sources. However, the Directive does not require all renewable energy to be sourced domestically – instead, it allows countries to meet their targets either via domestic production or through production in other countries that also have a target under the Directive, but that are able to achieve a surplus of renewable energy relative to their target.[75] The target also can be achieved via a combination of the two options.

In theory the attractiveness of linking country certificate schemes derives from the ability to more cost effectively achieve renewable energy output targets across the wider region. This depends upon the relative price of certificates in the unlinked regions and upon a trade-off between consumer welfare and that of RES generators. For example, if the price of certificates were cheaper in Sweden than the Netherlands, linking REC systems in the two countries could enable Dutch suppliers to meet their obligations at a lower cost, provided there was sufficient additional RES supply potential in Sweden. Reducing the costs of meeting the RES target in the Netherlands would be expected to reduce the costs borne by final energy customers, thus benefitting Dutch consumers. Dutch RES producers, however, would lose out, due to the international competition, receiving less revenue for each certificate awarded.

From the perspective of the linked country (Sweden, in this example) such a link is likely to increase the price of RECs relative to what it would be without a link. This will mean that RES producers in Sweden would receive more revenue for their certificates. As a consequence, Swedish consumers would have to pay more for their final energy consumption. Overall there will be a net flow of funds from the high REC price area to the low price area and a net flow of certificates in the opposite direction.[76]

The intention of this section is to provide some background to potential schemes with which the Netherlands may wish to link. The focus is on the Swedish certificate system, which was recently joined by Norway at the beginning of 2012. We focus on the Scandinavian system for two reasons. First, the system has a relatively large and well-established certificate market where the two countries, Norway and Sweden, have expressed their openness to further expansion. Second, whilst not direct neighbours, the countries lie in reasonable proximity and, to a certain extent, have interconnected physical power markets. Such physical interconnection is not a prerequisite for the linking of certificate markets, but it may facilitate such linking.

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[75] This extends beyond EU Member States to EFTA countries, such as Norway, that are also bound to the agreement. The joining of schemes between Member States is permitted under Article 11 of the EU Renewable Directive. A possible third option might be to meet the target by reducing overall consumption and hence the absolute contribution required of RES technologies. This, however, shifts the focus towards implementing energy efficiency savings and is beyond the scope of this analysis.

[76] In addition to benefiting RES producers through higher revenues in the low REC price area, there may be a wider positive impact there through greater employment opportunities as well as improved energy self-sufficiency derived from the investments in long term renewable capacity.

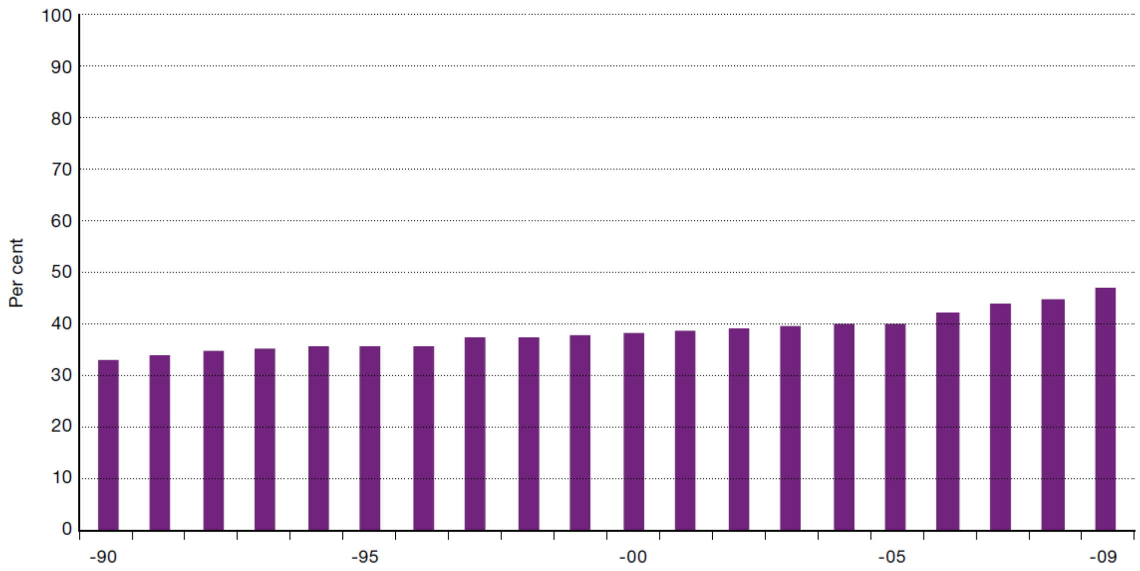
7.2 Background on schemes outside of Netherlands

The following sections present information on the Swedish, Norwegian and Belgian certificate schemes As noted above, the Swedish scheme was recently joined by Norway, and both countries have relatively abundant supplies of renewable energy (a circumstance that has been taken into account within the EU Renewables Directive, which obliges the two countries to achieve a high share of renewables, relative to the Netherlands). The Belgian supplier obligation scheme is significantly smaller and fragmented in its coordination across the country's three official regions.

7.2.1 Sweden overview

Total Renewable Energy production in Sweden in 2009 was 187 TWh (673 PJ). Sweden has the largest proportion of renewable energy in relation to final energy use in the EU thanks largely to an abundance of hydropower sources.[77] Consequently the country's share of the EU 2020 Renewable Energy targets is particularly high. Under the EU Renewable Energy Directive Sweden has engaged in a binding agreement to source 49 percent of total final energy use from renewable sources by 2020. On top of this the government has chosen to raise this to (at least) 50 percent.[78] The following Figure 7.1 shows progress towards this goal with the share or renewable energy production out of total energy production between 1990 and 2009. Having reached a 47 percent share in 2009, Sweden appears well-placed to achieve its 2020 objective.

Figure 7.1
Share of renewable energy in Sweden 1990-2009



Source: Reproduced from Energy in Sweden 2011 (data from Swedish Energy Agency and Eurostat).

77 Swedish Energy Publication, *Energy in Sweden 2011*.

78 This is a self-imposed objective and therefore only the 49 percent target is binding at the EU level.

7.2.1.1 The Swedish REC scheme

One of the main policy measures designed to support domestic renewable energy production is the 'electricity certificate system' which went live on 1 May 2003. As the name suggests, the policy focuses exclusively on renewable electricity production. Alternative policies are in place to increase the share of renewable energy outside the power sector. The scheme obliges electricity suppliers as well as certain large industrial customers[79] to source a proportion of the final consumption they supply from renewable sources, or via tradable green certificates. The proportional requirements translate into a headline objective to increase the production of electricity from renewable energy sources by 25 TWh by the year 2020 relative to 2002 levels. The scheme is intended to run until at least 2035.

It is important to note that not all renewable electricity generation in Sweden qualifies for certificates. This will be elaborated below, but essentially the scheme does not reward older plants that were already operating competitively prior to the launch of the electricity certificate system in 2003. In 2010, only 18 TWh of electricity production qualified to receive support under the Swedish electricity certificate system.[80] Figure 7.2 shows the evolution of renewable- and peat-sourced electricity production that qualifies to receive certificates from 2004 to 2010. Biofuels are consistently the principal recipient of certificates. They made up 62 percent of the total share in 2010.

It is expected that the contribution of wind power will increase over the coming years. The Swedish Energy Agency's 2012 review of the certificate system noted that the government intends to expand wind output from 6.1 TWh in 2011 up to 30 TWh by 2020. This is envisaged to be delivered by both onshore wind farms (20 TWh) as well as offshore wind farms (10 TWh).[81]

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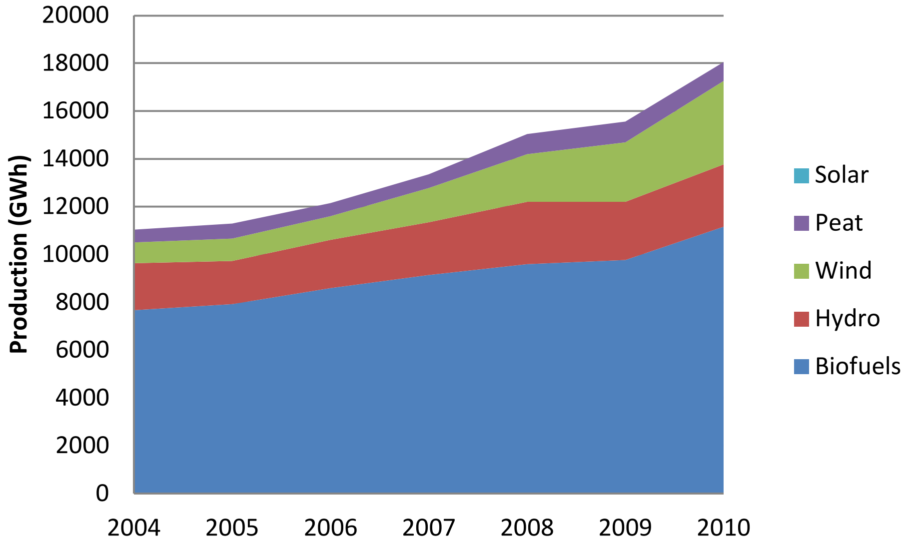
79 In addition to electricity supply companies, the quota obligation applies also to a few of the most electricity-intensive companies and to electricity users who have used electricity that they have themselves produced, imported or purchased on the Nordic power exchange.

80 Total renewably sourced electricity generation in 2009 was 81 TWh (IEA statistics: http://www.iea.org/stats/index.asp)

The Swedish certificate system recognises Peat (0.8TWh production in 2010) as a renewable source of energy. However, this does not match the EU Renewable Energy Directive definition and so must be discounted when specifically considering the 2020 targets. Data from Swedish Energy Publication, *Energy in Sweden 2011*.

81 Swedish Energy Publication, *Energy in Sweden 2012.*

Figure 7.2
Total Renewable and Peat production qualifying for certificates, 2004 - 2010



Source: Swedish National Grid and Swedish Energy Agency (Energy in Sweden 2011)

Certificates are awarded and allocated to generators of renewable energy in direct proportion to their output. Each MWh of output is awarded one certificate. This is therefore a 'technology-neutral' or Uniform REC system because it does not distinguish between different *types* of generation, only those that are classed as eligible and those that are not. As we have discussed in this report, this approach may confer rents or excess profits to generation technologies that are already competitive or that simply are much less costly than the marginal renewable source. To counteract this, Sweden narrowed the group of plants that are eligible to receive certificates, and limited the period over which existing plants can receive them: installations that had been commissioned prior to the introduction of the system (May 2003) are only able to receive certificates up until the end of 2012. [82]

Certificates can be 'banked' between years, and there is no limit on banking. This means that once a certificate has been awarded, under current rules it can be used to comply with a quota in any year up until 2035, when the existing scheme is scheduled to end.[83]

At its introduction, the scheme included a fixed buy-out price at which obligated suppliers could pay for any certificate deficits they held. However, this was removed from 2005 because the target was not being met. The cap was replaced with an ex-post penalty for non-compliance with the required obligation. Currently this penalty is set at 150 percent of the average certificate price over the compliance year.

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82 11.5 TWh of RES production in 2011 was from plants commissioned prior to 2003, which will no longer be awarded RECs from the beginning of 2013. In certain instances certificates could be awarded up until 2014 if plants had previously received a public investment grant for their construction after 15 February 1998.

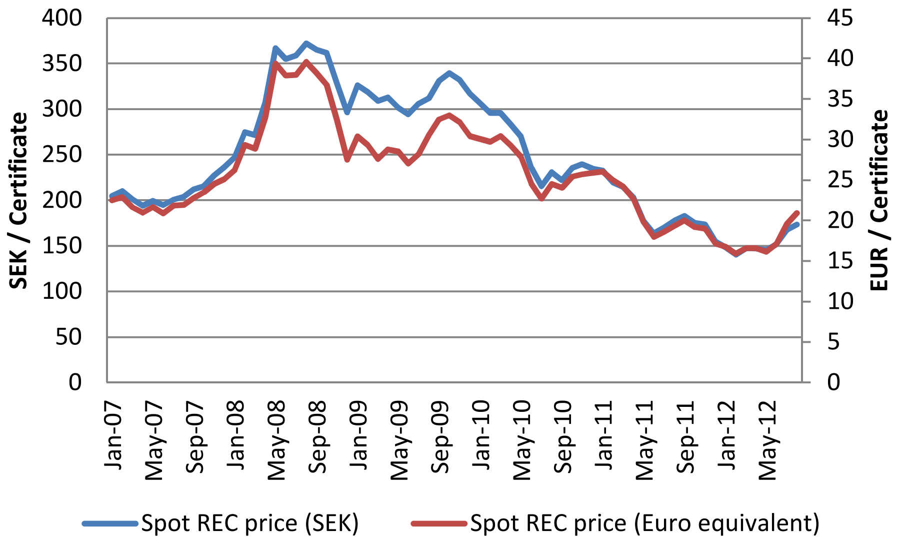
83 As noted above, such banking provisions mean that it would be possible for the country to miss its 2020 targets if a large pool of banked certificates were used instead of relying on renewable energy produced in 2020. For compliance with the EU target, it is not clear whether EU law would permit the use of certificates banked from previous years.

7.2.1.2 Certificate market trends

In order to understand the impact for the Netherlands of linking with the Swedish scheme, it is important to understand some of its key parameters. Here, we present a brief overview of the evolution of the certificate price, market liquidity and the certificate surplus.

Figure 7.3 shows the monthly average spot market certificate price between 2007 and 2012 in both Swedish Krona (SEK) and Euros (EUR). This uses the price published by the SKM exchange, which is currently the largest exchange for Swedish RECs and the only one to publish price information. Whilst many transactions are made outside of the exchange, such over-the-counter or bilateral trade prices will often refer to published exchange prices, so the data provide a reasonable representation of the evolution of the market price. The Swedish Energy Agency attributes the price rise in the first half of 2008 to expectations of lower renewable capacity causing pressure on the supply of permits. The economic crisis from late 2008 then revised down projections of total energy demand and therefore the amount of certificates required to meet a proportional quota. This was coupled with unexpectedly high renewable electricity production in the autumn of 2008, increasing the availability of certificates.[84] There has been a slight increase in the spot price since January 2012, when Norway joined into the scheme. However, this appears to be neither triggered by the news of confirmation that Norway would join the scheme in 2011, nor was there a pronounced effect on the date of their accession. Therefore, it is not clear what, if any, impact this event had on the certificate price.

Figure 7.3
Spot market certificate price 2007 - 2012 (monthly averages)



Source: *SKM monthly average REC spot price*
OANDA monthly average interbank exchange rate (mid price)

Note: *Between January 2007 - August 2012, the value of one Euro fluctuated between 8.27 and 11.20 SEK.*

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[84] Swedish Energy Agency publication, *The Electricity Certificate System 2011*

Liquidity in the market for certificates has improved over time. The bulk of trading still occurs in March, when clear spikes in traded volume are observed, coinciding with the compliance deadline to match certificates to the quota. In March 2005 approximately 5 million certificates were traded. This rose to a March peak in 2011 of over 20 million certificates.[85] Norway's accession to the scheme is expected to boost liquidity still further, allowing the certificate market to perform more efficiently.

In 2011 there was a surplus of certificates of the order of 8.8 million units (each unit represents one MWh of renewable electricity output).[86] This was an addition of 3.3 million in 2011 on a previously accumulated surplus of 5m. The surplus is expected to increase slightly further through 2012 due to an expansion in RES output. A 'Checkpoint' review is scheduled approximately every four years with the next one due no later than 2015. One of its functions will be to review the total surplus of certificates held. A surplus is useful to the extent that it facilitates liquidity and can smooth price fluctuations. Additionally, as discussed in the following section on market power, if the surplus is not concentrated amongst a few RES generators, it can serve to mitigate the exploitation of market power. However, where the quota projection is out of line with actual electricity use (i.e. the forecast used to set the annual quotas does not match actual consumption) a readjustment of the future quota is likely to be made at the checkpoint review.

7.2.1.3 Summary of Swedish system

The Swedish government, via the Swedish Energy Agency, has cited its openness to an expansion of the REC system to other countries.[87] Given that Sweden is well-positioned to satisfy its 2020 renewable energy target, they should be able to export surplus certificates to countries where renewable energy generation costs are higher.

From the beginning of 2013, all plants[88] that were commissioned prior to 2003 will no longer be eligible to receive certificates. This will significantly reduce the supply of RECs produced in Sweden and require over half of the existing output to be replaced through new investment. However, this rule has been in place since the implementation of the scheme. Given that banking is possible, the market price should therefore already have accommodated the expected impact of the eligibility change, and may help to explain the reserve of certificates that has been accumulated to date. It is expected that wind capacity expansion in the coming years will provide the largest new contribution to the RES target.

Current REC prices in Sweden are less than the resource costs of RES supply in the Netherlands used in this report. Assuming REC prices in the Scandinavian system remain at this level, linking supplier obligation schemes may therefore allow the Netherlands to meet its renewable energy targets at a lower cost than under a purely domestic market. However, this will mean that there are lower incentives for the Netherlands to expand the renewable share within the domestic generation mix.

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[85] Data from *The Electricity Certificate System 2011*

[86] Data from *The Electricity Certificate System 2012*

[87] One example is referenced in Platts Renewable Energy Report, 'Sweden-Norway trading scheme could boost investors interest', issue 214, October 4, 2010.

[88] With certain minor exceptions as noted in the scheme description.

7.2.2 Norwegian overview

In 2011 total electricity consumption in Norway was 122 TWh, the second largest consumption level, behind Sweden, of the Nordic countries. High levels of consumption relative to the rest of Europe are driven by a large proportion of electric heating, cold winters and a sizeable share of energy intensive industry in the region. However, Norway is well placed to deliver renewably sourced power, due to its natural geographical features. Over 95 percent of installed electricity generation capacity is hydro power based.

Although not part of the EU, EFTA[89] members, such as Norway, are encompassed by the objectives of the EU Renewable Directive. The Norwegian target for 2020 is a 67.5 percent share of renewable energy sourced consumption. This represents an increase of approximately 9.5 percent compared to 2005 levels.[90] This is the highest share of the 2020 targets of any participating country, reflecting the already large share of electricity renewable generation in Norway.

7.2.2.1 Joining the Swedish scheme

Prior to 2012 Norway did not have a specific market-based mechanism to support and incentivize investment in renewable energy capacity. In order to assist them in achieving their targets for renewable electricity, the Norwegian and Swedish governments agreed to operate a linked REC market from 1 January 2012[91]. The high level operating structure and features of the Swedish policy, as described above, remain in place and have been adopted by Norway. By 2020 the linked scheme intends to expand renewable energy production by 26.4 TWh relative to 2012, splitting this burden equally between the two countries.[92]

Norway has imposed slightly different rules to Sweden regarding which generation plants are eligible to receive certificates. However, for those that satisfy the requirement the same technology-neutral principle of one certificate for each 1MWh produced applies. The following plants are entitled to renewable certificates:[93]

- Power plants based on renewable energy sources with a construction start date after 7 September 2009.
- Existing power plants expanding their production on a permanent basis, with a construction start date after 7 September 2009.
- Hydroelectric power stations with installed capacity up to 1 MW that had a construction start date after 1 January 2004.

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89 The European Free Trade Association comprises of Liechtenstein, Iceland, Norway and Switzerland and is linked to the European Union.

90 Ministry of Petroleum and Energy press release, *Target of 67.5 percent for Norway's renewable energy share by 2020*. 21 July 2011.

91 The binding agreement between the two countries for a common certificates market was signed on 29 June 2011.

92 Norwegian Water Resource and Energy Directorate article, *Energy* certificates, 24.02.2012. The reference case for the measurement of the expansion of renewable energy production is the beginning of 2012.

93 Extract from NVE website is caveated that in some cases only part of the plant production may be eligible to receive certificates.

These eligibility restrictions therefore exclude the vast majority of Norway's existing hydro electricity generation and focus on promoting investment in additional capacity.

The Norwegian and Dutch energy markets are already, in part, integrated. On 12 January 2011 the Norwegian and Dutch power markets were physically connected. As noted in section 4.3 above, the interconnection capacity between the Netherlands and Norway is 612 MW in both directions. Following this, in a wider plan of European integration, on 14 March 2012 intra-day trading was launched on the NorNed power exchange. This may facilitate the transition to linking of certificate schemes if considered desirable.

7.2.3 Belgium overview

The Belgian political landscape is characterised by a federalist approach, each of the three official regions largely determining their own policy. This holds true for energy regulation. Whilst there is a national department responsible for high level policy and delivering the 2020 targets, the specific means by which these targets are achieved is largely left to the regions of Walloon, Flanders and Brussels Capital to manage.

Belgium has an EU 2020 target to produce 13 percent of total energy consumption from renewable resources, compared to a current share of only 4.6 percent in 2009.[94] Currently, the vast majority of renewable energy in Belgium is produced from biomass and waste. In 2009 this made up 91 percent of total renewable energy production. Wind power represented 5 percent and solar power 1.5 percent.[95]

Total electricity production in Belgium in 2009 was 91 TWh. Just under 5 TWh of this was produced from renewable sources.[96] A green certificate system has been in place in Belgium since 2002 with a guaranteed minimum price to promote renewable electricity production. The trade of certificates is subject to federal legislation, but the quota obligations, minimum price and fines are defined within the regions. In effect, this therefore means that three separate schemes are in operation as the regulatory rules differ by region. The only element managed at the federal level is the support for offshore wind (which is not located within the land area of any of the regions). Certificates are allocated by the state and can be surrendered against the obligation in any of the three markets.

Since implementation of the schemes, and across them all, certificates are only provided for new installations. Support is provided for 10 years, apart from for PV and off-shore wind which receives support for 20 years from the installation date.[97]

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94 Eurostat news release. The contribution of renewable energy up to 12.4% of energy consumption in the EU 27 in 2010. 18 June 2012

95 Eurostat data

96 IEA Electricity Statistics, http://www.iea.org/stats/index.asp

97 RE-Shaping project (Fraunhofer ISI, Energy Economics Group), Renewable Energy Policy Country Profiles. 2011 version.

7.3 Assessing the merits of linking for the Netherlands

It is an advantage that there is already a degree of integration within the European electricity market. The physical interconnections between Germany, BeNeLux and Nordic markets facilitate a more homogeneous price between the national markets.

Provided REC market conditions and rules are similar across the 'linked' regions, economic theory suggests that efficiency gains can be realised from a larger market, akin to the gains from trade through specialisation. Widening the market for renewable energy support should allow greater access for a larger population to the cheapest technologies from within the linked system. However, overall welfare gains will come at a cost to certain sectors. A linked system is also likely to increase dependency between countries.

As mentioned earlier, the linked Scandinavian system intends to increase renewably sourced electricity capacity by 26.4 TWh (95 PJ) between 2012 and 2020. Given that a further 12 TWh of Swedish RES generation is due to be phased out in 2013, this will also need to be replaced, stretching the target somewhat. In comparison, under the Uniform REC policy scenario modelling for the Netherlands within this report, RES output from the power sector must increase from approximately 50 PJ in 2015 to 175 PJ in 2020[98]. This therefore implies a more demanding target for the Netherlands than within the Scandinavian system.

In theory, without a linked system, the region or country with the least stringent target will have a lower REC price, assuming equal risks and costs for building and operating plants. Upon linking the systems there will then be a flow of investment from the more stringent country to where lower uptake is required. Linking should therefore stimulate further investment in RES technologies in the Scandinavian system that can then export RECs to the Netherlands.

The Dutch domestic RES output requirement could be reduced, provided there is spare capacity to expand renewable electricity production beyond the Scandinavian target at a lower cost than in the Netherlands. The planned expansion of almost 25 TWh of wind in Sweden by 2020 indicates that this may be feasible. However, significant investment will still be required within the Netherlands. For example, to eliminate the need for offshore wind in the Netherlands in delivering the Dutch 2020 output target, the Scandinavian target would have to be increased by a further 40 percent to just over 130 PJ.

Any increase in renewable electricity output within Scandinavian would also need to be matched to corresponding electricity demand. This is likely to require greater interconnections between Scandinavia and the rest of Europe. However, awaiting investment in interconnection capacity could further delay investment in generation capacity. For example, Norway announced in 2012 that it planned to build two 1.4 GW interconnections,

98 This just takes figures from the power sector's contribution to total RES output for ease of comparison. Given that the Scandinavian system just subsidises renewable electricity it is likely that, in linking, the Netherlands would also only be able to incorporate electricity output within the scheme, rewarding other energy technologies through a different policy approach.

one to Germany and another to the UK. These are not expected to be completed until 2018 and 2020 respectively.[99]

In the following paragraphs certain opportunities and issues are highlighted to qualitatively inform a discussion on the merits of linkage to the Netherlands.

7.4 Opportunities for the Netherlands

- Linking to an existing system can significantly reduce the 'design and build' costs of implementing a stand-alone domestic certificate scheme. This might be referred to as a form of transaction cost. Administrative tools as well as a developed marketplace for exchanging certificates already exist in Sweden (and now Norway) that could be transferred and adopted at relatively low cost.
- Efficiency 'gains from trade' are another key argument to favour linkage. Renewable energy projects will be chosen from across the linked area, rather than just from within individual countries. This increased competition should therefore have a downward effect on the (average) support price of renewable energy generation required to meet the EU targets in 2020. As this price is eventually passed through to consumers, the linked system therefore has the potential to lower the consumer impact.
- The price of certificates exchanged within the Norwegian and Swedish scheme indicates that there is at least some available RES potential in the Scandinavian countries that can compete in the electricity market with a lower subsidy than would be required in the Netherlands to stimulate sufficient investment to meet the 2020 target. As shown in Figure 7.3 the spot market price of certificates in Sweden has ranged from a high of just over €40/MWh in Summer 2008 to a low of approximately €15/MWh in early 2012.
- A larger market that spans multiple countries is likely to promote a more liquid market for certificates. This can drive efficiency gains by providing greater confidence to investors and obligated suppliers that they will be able to buy and sell certificates in line with their evolving strategies and risk-management positions. Greater liquidity should also reduce price fluctuations that may otherwise be observed where insufficient players are in the market to adequately match buyers and sellers of certificates. A further argument in support of liquidity is that it can better enable small producers to regularly participate in the market. This may be particularly appropriate for them if they have greater need to maintain a cash flow to sustain their production costs by regularly selling certificates that they have been awarded.

7.5 Potential concerns for the Netherlands

- If investors are aware of the potential for linking with another scheme at a future date, this will affect their investment decisions. The possibility of linking will influence expectations of REC prices, given the expansion of competition across a wider market place. If investors in Dutch generation capacity believe that the REC price would fall in a

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[99] Reuters, US edition, *Nordic power bills to jump on new export links*, 11.10.2012.

linked market, relative to a domestic market, this would reduce domestic investment.[100] Reduced domestic investment would not necessarily be a problem if a linking arrangement and timeframe were agreed ex-ante and proceeded as planned. However, where there is uncertainty, and should the link not go ahead, this may mean that domestic RES investors would be left unprepared to achieve the national RES target.

- Linking to another scheme requires agreement on the rules that govern the scheme and the key parameters that define it. Should the Netherlands look to join an existing scheme then they will likely be pressured to adopt its existing features, unless sufficient incentive can be provided for the scheme to be adapted. It is possible to link schemes with slightly different design parameters. However, anything implemented in one scheme will have a knock-on effect across the whole of the linked system. Where countries or regions disagree on the key parameters, it may be difficult to achieve agreement to link. There are various features that the Dutch government must consider here.
  - The Swedish and Norwegian system currently does not have a buy-out price. Therefore, the REC price will vary as required to deliver the required amount of output. This, however, exposes consumers to the risk of high energy prices driven by the REC support. Adopting a buy-out price in only one of the linked countries (e.g. the Netherlands) would be possible, but would create challenges and could raise concerns in the other countries. Where the price binds, it would place an upper limit on the REC support and risk the attainment of target output in the Netherlands, as well as collectively across the linked regions.[101] Convincing the other countries that it is in their interest to accept the Netherlands within their scheme, even with a buy-out price, may hinder negotiations.
  - Joining the Swedish and Norwegian scheme would require that the Netherlands also permits unlimited banking of certificates between periods up until 2035. It is not feasible that, within a linked scheme, some certificates are bankable and others not. Otherwise, certificates would not be homogenous and would take on different values depending upon whether they were eligible to be submitted in subsequent years or not. As discussed above, banking can help smooth the REC price over time, by allowing certificate holders to save them when the price is perceived to be low and sell them to the market (or surrender them) when the price is perceived to be high. It is unclear whether banked certificates might be used to comply with the 2020 target.
  - The Netherlands intends to use one scheme to promote all RES generation. This is in contrast to Sweden and Norway, whose supplier obligations only apply to the power market. It may be possible to persuade the Scandinavian countries to accept certificates from other technologies, provided the RES target is set at an appropriate level. An alternative would be to use a linked REC scheme to support power and then

[100] This is true whether the linking of the Netherlands's REC system is (expected to be) from its inception or is (expected to be) delayed until sometime after inception. As long as RES investors are aware that the target may be achieved more cheaply at some point in the future by foreign suppliers, they will have more limited incentives to commit capital.

[101] However, if the buy-out price were set below the "unlinked" Scandinavian price, then it would be expected to "bind", and could threaten the attainment of targets. If the buy-out price were set *above* the price that would be realised in Norway and Sweden in the absence of a link to the Netherlands, then the link would have limited effect on the achievement of targets or in the Scandinavian countries.

develop a separate incentive scheme to provide support for non-power energy sources. This could be done via an SDE type approach.

  – Finally, the Swedish and Norwegian scheme is technology neutral. It therefore selects the cheapest technologies from the pool of options that are able to deliver the required output. The banding or bonus/malus approaches would therefore not be consistent with the Scandinavian market. Maintaining them would imply awarding technology-specific cost advantages to one country over another, which is unlikely to be acceptable to countries not adopting technology differentiation. As discussed in the previous section on market power, whilst linking can have the effect of mitigating market power, opportunities for high rents are likely to persist under this uniform REC type scheme.

- Should a linked system mean that the Netherlands is a net importer of certificates from other countries to satisfy its obligation, there could be longer term detrimental effects to the development of renewable energy expertise in The Netherlands. It would also expose The Netherlands to additional risks if the countries from which the Netherlands imports certificates decided to break from the scheme, leaving The Netherlands with insufficient ability to meet target obligations on its own in the short term. However, this is less likely to be a specific threat with regard to the 2020 targets, given the relatively short timeframe.

In summary, there are various potential advantages that the Netherlands may be able to derive from linking with other existing certificate based support schemes. The most notable of which are the opportunity to meet the EU target at a lower overall cost and to mitigate market power by opening up the market and improving liquidity in the transaction of certificates. However, linking is likely to entail various concessions with regards to the design of the support scheme and the technologies that are included. It also may increase dependency on the other linked countries. Giving credible long-term signals with regards to Government intentions about plans to link to other schemes is therefore important in reducing investor uncertainty.

8 Issues Related to Market Power

This section sets out potential market power issues related to the introduction of a supplier obligation in the Netherlands. Market power is most likely to be a potential issue under a certificate-based scheme, so the discussion focuses on a REC system. However, a brief consideration of means to exploit market power under an SDE type mechanism is also provided at the end of the section.

In the context of renewable certificate markets, market power might be exercised by market participants withholding certificates from the market to inflate the price above a competitive price, either by banking them (if banking is allowed), or by withholding generation from renewable energy sources in order to reduce supply and thus inflate the certificate prices.

Withholding renewable capacity would potentially have three implications that should be of concern to policymakers – one related to economic efficiency, the other to the distribution of impacts, and the third concerning the achievement of the overall RES target:

1. First, the exercise of market power may result in inefficient outcome may not be "economically efficient", i.e. some green resources may not be dispatched, and green generation may fall short of the target, or substituted by more expensive resources; and
2. Second, it may mean that consumers pay too much for green certificates, in that a reallocation of resources takes place from the consumer to private companies, which may be seen as unsatisfactory.
3. Third, if generation is withheld in 2020, it could mean that the RES target is not achieved.

In the discussion of market power, we will distinguish between (i) the short run, where installed capacity is fixed, and (ii) the long run, where new capacity can be built (but possibly subject to some remaining physical constraints).

In the short run, REC prices will be governed by the equilibrium between supply (existing capacity, wind output), and demand (REC requirement). Because of the completely inelastic nature of certificate demand – represented by the fixed annual target – under certain conditions there may be significant incentives for a RES generator to withhold capacity or certificates from the market, in order to increase the price. Although in some cases such behaviour may be harmful to consumers, in other cases, it may actually represent an efficient way to ensure adequate investment incentives in the long run.

The short run supply curve for REC certificates is very steep because many renewable energy technologies have negative variable costs of producing RECs, whilst some have very high variable costs. For some renewable energy technologies nearly all of the life-time costs are sunk at the time of investment. For example, a wind turbine, once built, would probably be willing to generate at zero or *negative* REC prices, because of its very low variable costs and the revenue it can earn from electricity sales on the power market.[102]

[102] In practice, of course, the REC price would not be able to go negative unless generators were forced to surrender their REC certificates, or power revenues were tied to the submission of REC certificates.

In the long run, however, the significant fixed costs of renewable electricity and heat generation must be considered. Investors will only invest if they expect to recoup the fixed costs associated with construction of assets. Hence, in order for average long run REC prices to be sufficiently high to incentivise investments, the short term REC price has to be significantly above short run marginal costs of most generators in the market.[103]

It is therefore likely that either allowing for a certain degree of market power in the short run, or embedding a shortfall of REC supply in the market (for example, by keeping interim targets somewhat in excess of output) will be necessary in order to provide adequate investment incentives. In the long run, if entry of new capacity is possible such entry should mitigate market power. However, if the scope for new entry is limited or is controlled by incumbent operators, this "threat of new entry" may be weakened. It is therefore important to consider the potential to exercise market power in both the short run and the long run to understand its possible impact in the Netherlands.

Throughout this section we will use the term "marginal cost" of REC certificates to refer to the incremental cost of supplying certificates *net* of revenues in other energy markets (electricity, heat, or gas).[104] The *marginal cost* does not account for any fixed costs associated with the construction of the asset, which are treated by asset owners as sunk in the short term.

In the discussion below, we provide illustrative figures using stylised cost estimates for different RES technologies. We show one block for "Biomass," which represents biomass co-firing and any dedicated biomass, and one block for "Other RES," representing cheaper heat and green gas technologies as well as wind. We select these technologies to represent key features of RES supply potential in the Netherlands, but the illustrations below represent a significant simplification of the actual current and potential future situation with respect to RES supply. For example, there is likely to be considerable dispersion within the category "biomass." Importantly, biomass co-firing plants may have higher incremental marginal costs than dedicated biomass due to the opportunity cost of coal generation.[105]

8.1 Market Equilibrium in the Short Run

In this section, we analyse the short run equilibrium of the REC market. By "short run", we mean that capacity is fixed (so entry/exit decisions have already been made and have been acted upon) and fixed costs are sunk.

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103 Biomass co-firing units do not share this feature of high capital cost and low fixed cost. Instead, they tend to have low fixed costs (which, again, may already be sunk) and high marginal costs. In the absence of a buy-out price, co-firing may, due to its high marginal cost, set the short term REC price.

104 We define the minimum value of this quantity as zero when the RES source is cheaper than the counterfactual electricity, heat, or gas energy source.

105 To the extent biomass co-firing plants have an option of changing the biomass/coal mix in their plant, an increase of the biomass proportion effectively displaces generation from coal. For every extra unit of biomass generation, the plant loses profits it would have made on coal. At times when coal generation would otherwise be generating, the marginal incremental cost of co-firing biomass is therefore significantly higher than the cost of running a dedicated biomass plant with similar efficiency.

8.1.1 The Competitive Outcome

In the short run, the RES Supply curve in the Netherlands is expected to be steep: Wind capacity has a very low marginal cost, so will usually always be dispatched, even on a power-market only basis. The marginal cost of wind generation is therefore close to zero (or even negative – that is, it is profitable to run even without policy support). However, other resources, such as biomass have a significant variable cost component, and hence also high marginal costs. Biomass *co-firing* plants have an even higher marginal cost than dedicated biomass, because (assuming these plants would otherwise be burning coal instead of biomass[106]) the cost of co-firing includes an *opportunity cost* equal to the lost profit from generating power from inexpensive coal.

A short-run perfectly competitive equilibrium is illustrated in Figure 8.1. In the figure, REC demand intersects the supply curve at biomass, which sets the REC price.

Figure 8.1
Short Run - Perfectly Competitive Market

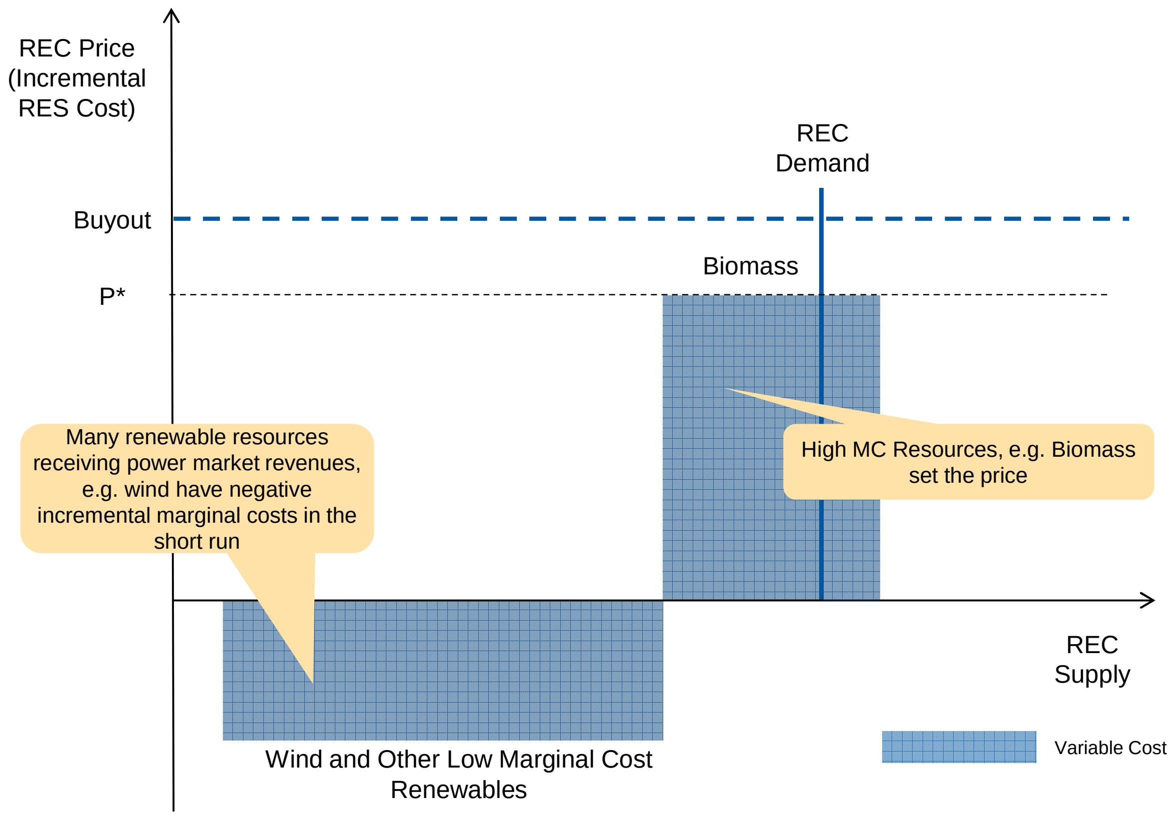

Figure 8.2 shows the gross margin earned by each resource type in this equilibrium (shown in green). Note that the figure does not include fixed costs, because these are *sunk* and do not figure in short-run decision making. As illustrated in the figure, resources with low marginal

[106] As suggested in the preceding footnote, the case is different if plants that are set up for co-firing actually are unable to burn coal in the portion of the unit fitted for co-firing. In this case, there will be no opportunity cost of generating from coal in the biomass portion of the plant, and the costs will be similar to the costs of a dedicated biomass plant.

costs earn a significant amount of profit on the margin (which we would expect to be required to offset the capital costs that they have incurred as a result of their investment). These resources will nearly always generate, regardless of the REC price. However, the resource which sets the price, i.e. *dedicated* biomass, earns no profit on the margin in the competitive outcome. Note that the figure is a very stylised version of the RES supply curve. In practice, there is significant distribution of costs within the group due to different fuel sources and efficiency levels.

This stylised short run outcome is an incomplete representation of the market, however, because it ignores long-run incentives. In particular, we note that the most expensive units on the margin would earn no, or very little margin, and therefore would have little prospect of recouping any sunk/fixed cost associated with the construction of their asset. For example, if dedicated biomass units could only ever expect to receive their variable costs (net of power revenues), investors would not choose to invest in them in the first place, because they could never expect to recover their initial capital outlay[107].

More realistically, one of the following is likely to occur: either (i) the market price of RECs will rise above the short run marginal cost as suppliers seek, at some points in time, to exercise (short-run) market power or (ii) there will be a shortfall of supply, such that the REC price will rise to a buyout price.

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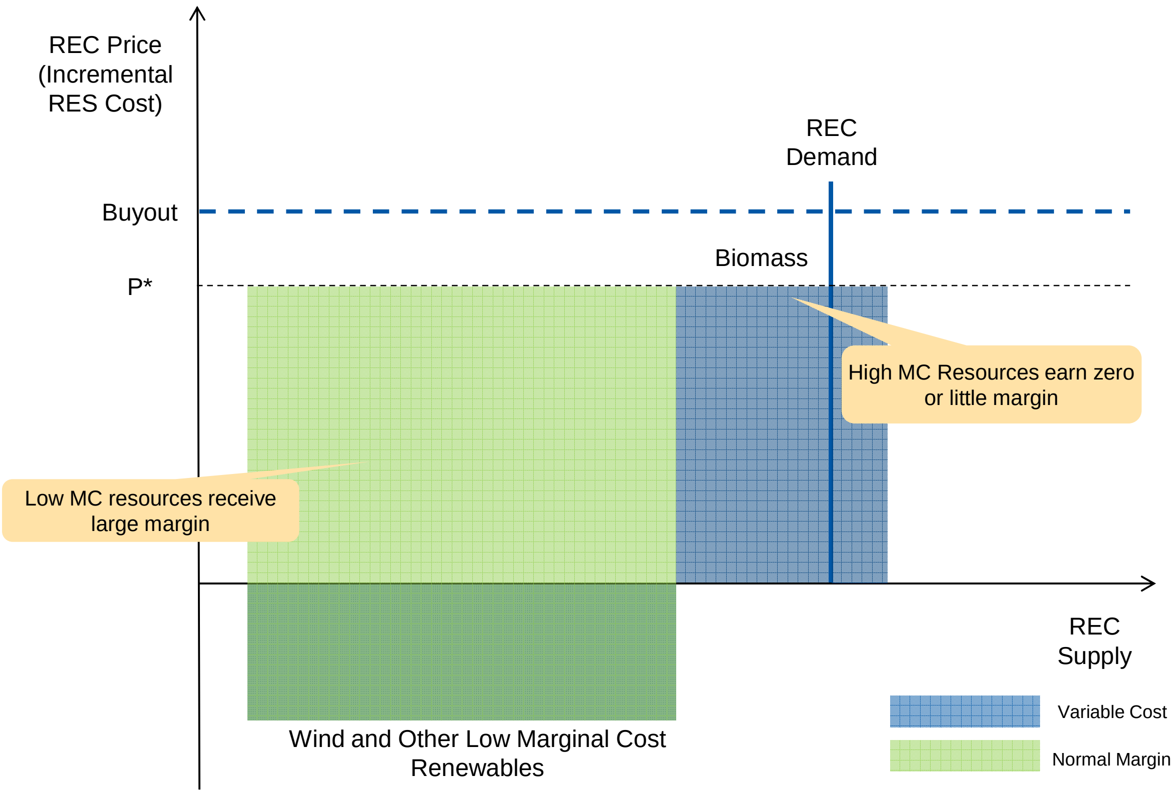
[107] Some coal plants invest in biomass co-firing for other reasons than the REC price, such as compliance with environmental rules, or to reduce CO_2 emissions.

Figure 8.2
Short Run Gross Margins in a Competitive Outcome



8.1.2 Concentration of ownership or coordination between "Marginal Plants"

If the plants on the margin are controlled by a few operators, and/or the operators of these plants are able to coordinate the withholding of capacity, explicitly or tacitly, they may have the ability to raise the REC price, either by withholding supply or by simply offering certificates to the REC market above their marginal cost.

Figure 8.3 illustrates the incentives. If a given plant is the marginal, or REC price-setting, technology it has an incentive to offer REC certificates into the market at a price higher than its marginal cost, because it will still be dispatched, even if it raises the price.[108] On the dispatched capacity, it earns a gross margin equal to the red square (illustrated as "monopoly margin"). This higher margin also benefits other lower-cost renewable energy producers (as shown in Figure 8.3). The potential to exercise market power is exacerbated by the fact that REC demand is perfectly inelastic – that is, it does not depend on the REC price at all, because the target is fixed, regardless of the price – subject to the buyout. This means that in principle, biomass plants can increase prices up to the cost of biomass co-firing and still sell all of their units on the market.

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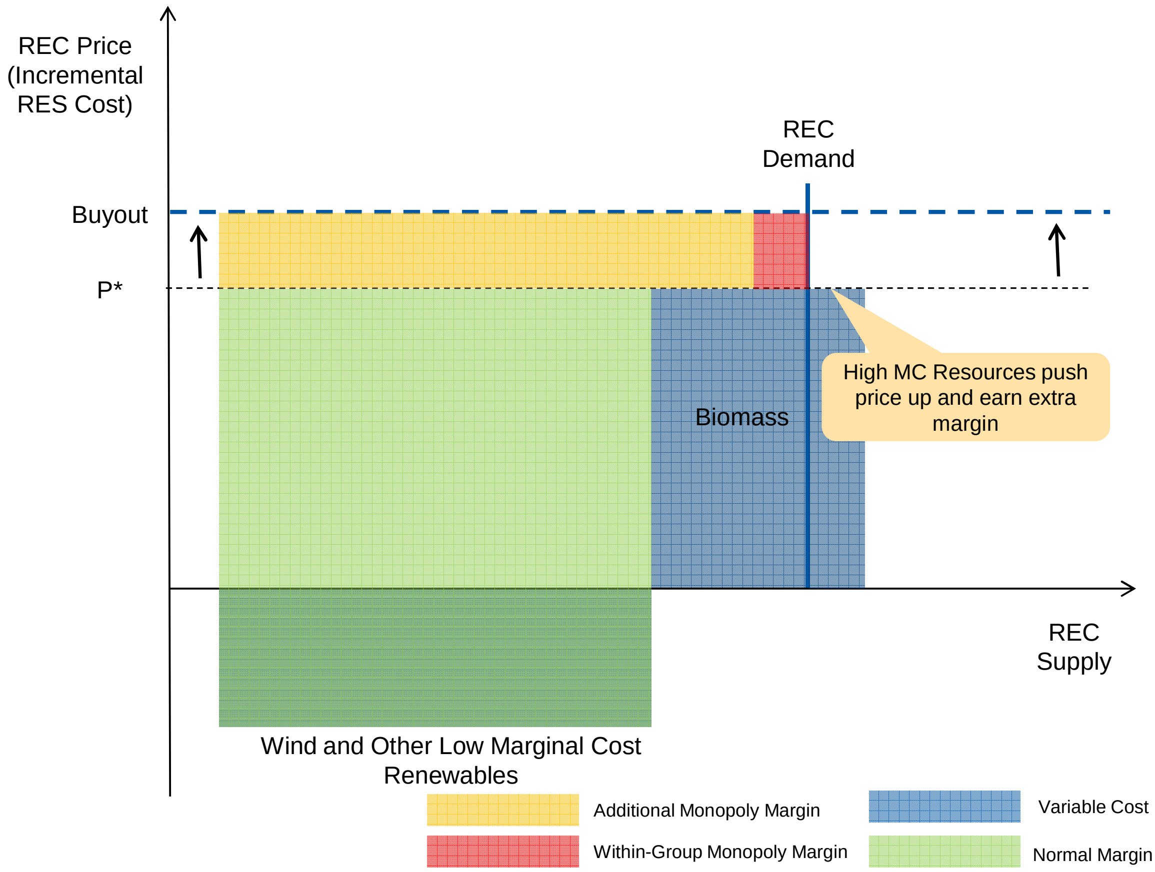
108 In this illustrative example they do not lose any output by increasing the price but we note that in reality, some of the output by an individual player may be displaced by other units.

Figure 8.3
Biomass Plants Exercise Market Power: Short Run Margins



In order for this to be profitable for the operator, he would, however, have to avoid raising the price of certificates so much that he were priced out of the market entirely.[109] The larger the concentration of ownership, the easier coordination will be (whether explicit or tacit). Table 8.1 shows a rough estimate of the distribution of ownership of coal capacity in The Netherlands by 2020, and hence represents approximately the potential ownership of the biomass co-firing capacity.[110] As evident in the table, the data suggests that RWE (Essent) controls nearly half the coal capacity, and that the three largest players control 86 percent of capacity, giving rise to a very concentrated market for potential biomass co-firing. In addition to the effects on the REC market, this level of concentration is also likely to give incumbent operators significant advantages in the form of buying power for biomass (which may be used in waste-based electricity- or heat-generating technologies).

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109 In this illustrative example, although there is not much effect on “allocative efficiency” – i.e. which units are generating – there is a cost increase to the consumer because the REC price is higher. In general, if there is cost dispersion among generators, there is a risk of loss of “economic efficiency” as soon as generators bid above marginal cost..

110 The estimate is based on the ownership of current plants, adjusted to reflect committed new entry and retirements.

Table 8.1
Estimated 2020 Ownership of Coal Plants in The Netherlands, %

Holding Company	Coal Ownership (%)
RWE AG (Essent)	47%
GDF SUEZ (Ectrabel)	22%
E.ON AG	17%
Vattenfall AB (Nuon)	10%
DELTA NV	4%
ENECO	0%
Total	100%

Source: Platts Powervision, reflecting committed new entry and expected retirement by 2020.

8.1.3 Concentration of ownership between marginal and infra-marginal plants

There may be even greater incentives for a renewable energy producer to exercise market power if the price-setting capacity is controlled by a firm that also owns low-cost, or "infra-marginal" plants – in this case, existing wind capacity, as shown in Figure 8.4. In this example, by reducing output of the biomass plant the REC price increases, which is to the benefit of wind generators, including the one owned by the same company. Note that this may be a profitable strategy for the company even if it requires cutting the output from the biomass plant away entirely, because the forgone margins on the biomass plant are very small compared to the significant impact on revenues to the wind farm.

Figure 8.4
Market Power and Incentives to Withhold Supply

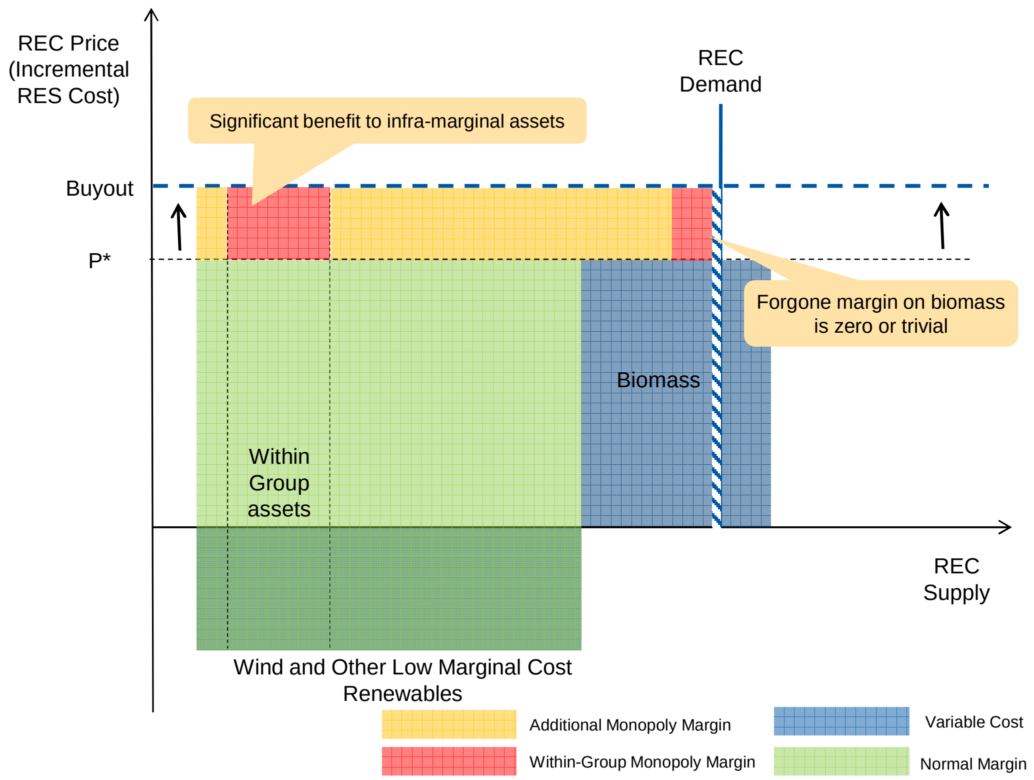


Table 8.2 contains an estimate of the current market shares of renewable generation capacity together with the coal ownership share. This suggests that, although no single player is likely to be characterised as dominant in the renewables field, RWE does have some cross ownership which could eventually affect incentives in the biomass co-firing market. We understand that Essent is indeed planning further expansions into renewables, although of course this is to be expected given the existence of renewables targets and the firm's position within The Netherlands.

Table 8.2
Estimated Current Renewable Electricity Cross-Ownership

Holding Company	Coal Ownership (%)	Current Wind Market Share (%)
RWE AG (Essent)	47%	9%
GDF SUEZ (Ectrabel)	22%	1%
E.ON AG	17%	0%
Vattenfall AB (Nuon)	10%	19%
DELTA NV	4%	3%
ENECO	0%	20%
Other	0%	47%
Total	100%	47%

Source: NERA and SQ estimates based on data form Platts Powervision and data on company websites.

8.1.4 Summary – short run market power

In this section we have shown how market players can affect REC prices in the short run. In particular, owners of marginal plants may be able to affect the market price by withholding REC supply and thereby increase the price. Even if this makes the REC supply from this company less competitive, and the owner may have to reduce output from some plants, the additional revenue may often exceed the forgone profits on marginal plants. These incentives are much stronger if the company also owns infra-marginal units, such as wind.

However, as noted above, allowing for some degree of market power also provides the necessary incentives for investment, as we discussed in more detail in the next section.

8.2 Long Run Equilibrium and the Threat of New Entry

8.2.1 Relationship of long-run and short-run equilibria

In the long term, the average price is constrained by the cost of new entry. This is only true, if the threat of new entry is real. In this section, we assess factors which may reduce the scope for exercising market power.

If REC prices are consistently above the long run marginal cost ("LRMC") of potential new entrants, new entrants will find it profitable to enter the market.

An example of long run equilibrium is shown in Figure 8.5. The long term average REC price is equal to the LRMC of the marginal resource, and this will be at least as high as the *short run* marginal cost of renewables that determines the short run REC price.

- The relative costs of technologies when compared on a full cost basis (that is, the long run costs, including investment costs) is different from when their short-run costs are compared. Some assets have very large fixed costs and small variable costs, others vice versa.
- Over their lifetime, all investments must expect to recover their fixed costs.

If REC prices did not rise high enough to cover both variable and fixed costs, then targets would not be achieved, and this would create the circumstances necessary for the *short-run* marginal producer to exercise market power. This in turn would push prices up either to the level necessary to incentivise new investment, or to the buy-out price, whichever is lower.

8.2.2 Threat of new entry

Although the average REC price is likely to be above the short run marginal price, it should, in principle be constrained by the *average cost of new entry* (the "long run marginal cost", or "LRMC"). However, entry can of course only take place if there is *scope* for new entry, and if potential entrants have an interest in constructing new capacity.

The electricity and heat markets in the Netherlands are characterised by a number of physical constraints on new capacity, such as limits on the amount of additional onshore wind capacity (or of re-powering existing onshore sites) and suitable locations for renewable heat.

Furthermore, The Netherlands is expecting a large amount of fossil-fuelled capacity to come online in the period 2012-2015, which means there is a risk of significant oversupply in the power market. For incumbent operators that already have significant amounts of installed conventional capacity, the incentives for investing are dampened because new renewables will put downward pressure on the average power price received by these generators

Finally, there is significant concentration of ownership of fossil fuel power plants, notably for the coal plants that have potential for biomass co-firing. In an extreme case, where incumbent suppliers controlled all of the potential, low-cost new renewable capacity, this would allow them to force up the REC price by deliberately constructing less capacity than socially optimal. However it is likely that it would require a significant element of collusion to prevent all potential new entrants from investing in new capacity.

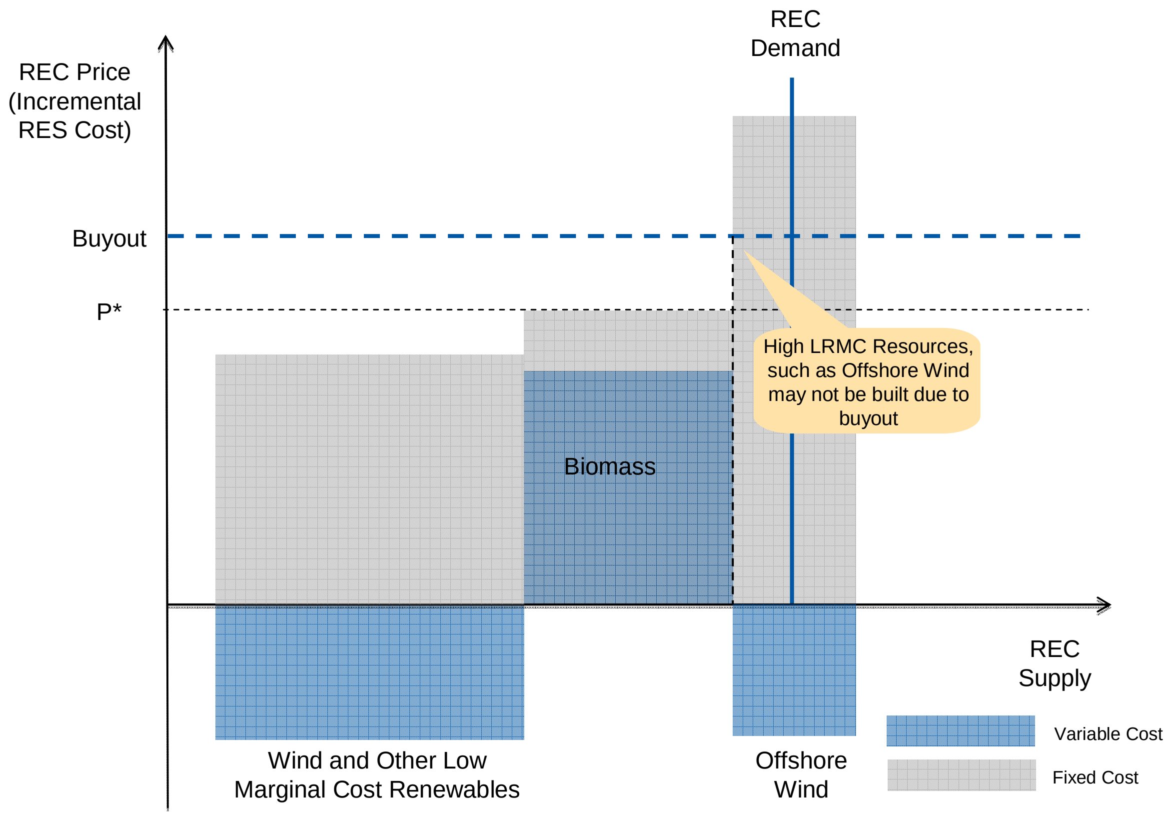
In a more likely scenario, incumbent operators simply have reduced incentives to pursue new investments, due to the effect of entry on infra-marginal revenues.

These circumstances mean there are likely to be some limitations to the threat of new entry. However, it is important to note that most of these issues are not much different in a REC system than they would be in the current SDE system, at least in the long term. For example, because of the fixed 2020 target to which the government is committed, projects that are essential to meeting the target may withhold new entrant capacity, to try to force up the SDE+ base level allowance.

Figure 6.8 shows the "long run equilibrium" with new entry. In this chart, wind and other low cost technologies still have negative (incremental) variable costs, but this is counterbalanced by significant fixed costs such that they have considerable "long run marginal costs". For example, the long run marginal cost of offshore wind is above the long run marginal cost of biomass. The ordering of biomass and other low cost technologies in the long run is kept the same for illustrative purposes but in practice some of the other low marginal cost renewables, such as more expensive onshore wind sites is higher than for biomass.

In an outcome with free new entry, as shown in the figure, on average, the REC price will be equal to either (i) the long run marginal cost of the most expensive resource required to meet the target (in the figure, biomass) or (ii) the most expensive resource below the buy-out price. In this figure, the REC demand is not met, because the buy-out price is set quite low, i.e. lower than the long run marginal cost of offshore wind.

Figure 8.5
Long Run Equilibrium



8.3 Market Power and Industry Structure

8.3.1 Position of energy supply companies (REC buyers)

Energy supply companies represent the ultimate source of REC demand. Under a supplier obligation they would be required to surrender a certain number of certificates per unit of energy they supply. In a perfectly competitive energy supply market the cost of acquiring these certificates would be passed on to consumers (with costs ultimately shared between consumers and suppliers), because suppliers would no way of affecting the REC price or end-user price of energy.

However, if suppliers are able to affect the extent to which REC acquisition costs are passed on to end-users, they may have incentives to try to reduce the REC price. Although energy suppliers cannot threaten not to buy certificates, they *can* theoretically threaten with the buy-out, which is credible only if the REC price is close to the buy-out price: By opting for more buy-outs, the supply of certificates would effectively increase. With a close supply/demand balance, that could drive down the REC prices very significantly. REC buyers may be able to use this threat to negotiate cheaper RECs from REC generators. However, when generators have the option of banking certificates for future years, the scope and incentives for exercising market power for REC buyers seems mostly theoretical.

8.3.2 Position of REC generators (REC sellers)

REC sellers (generators) have an interest in achieving as high a REC price as possible. In a perfectly competitive market, any attempt to offer RECs to the market at above marginal cost to try to push up the price, would be foiled by competitive bids. However, with sufficient concentration of generators, and a very steep REC supply curve, there may be only few competitors able and willing to enter even at quite high price increases. As discussed earlier in this chapter, generators could reduce output from marginal resources (which earn little profit anyway), and thereby push up the REC price achieved by more inframarginal units. In a thin market this behaviour could potentially affect REC prices significantly.

8.3.3 Position of "REC neutral" parties

A significant share of the Dutch power market is accounted for by integrated companies (including Essent, Nuon, and Eneco) that produce energy for a "wholesale" market while also simultaneously buying wholesale energy to act as suppliers to end-users. Some of these companies may end up in a "REC neutral" position, meaning they do not have to purchase RECs from the market to comply with legislation, because they themselves produce all RECs for their own use. If these firms were to force up REC prices they would be imposing higher costs on themselves. If they were unable to influence the wider REC market, then they would have no incentive to engage in what would essentially be an internal accounting exercise: if they tried to pass these prices on to their final customers, they would potentially risk losing customers to other suppliers who were willing to operate under different internal accounting principles to avoid passing through higher prices to consumers. However, if they could affect the wider market REC price then they would still have incentives to do so, at least if the energy supply business passes through a significant portion of the REC price to consumers (as is indeed very likely). For instance, if the energy generation business of these companies were to try to push up the REC price:

- The generation business would likely earn more money (from its sister supply business); and

- The supply business would likely be able to pass the REC price increase on to the consumer. Even if the retail energy supply market is perfectly competitive, a REC price that has been pushed up through the exercise of market power *in the REC market* will be the same for all other energy supply companies, who would also pass through the REC price increase.[111]

The effect of the "REC neutrality" may exacerbate problems with RES seller market power, because of the risk of a shallow and illiquid REC market, making it easier to affect the market price. In other trading systems with few obligated parties, it is not uncommon to find relatively limited trading, particularly when banking is allowed and there is uncertainty about the stringency of future requirements (or about future prices).[112]

In addition, if there is significant concentration of opportunity to develop new RES potential or limited ability to access RECs from other sources, and if this concentration of access to RECs resides within integrated companies, then this could create additional concerns about market power in the electricity retail market, as well as the REC market.[113] In an extreme case, if vertically integrated companies were the only ones able to develop RES capacity, or were otherwise able to restrict supply to RECs in some way, then they could use their control over RECs to restrict the ability of retail energy competitors to operate, because they would be unable to procure RECs. A less extreme case would simply be that integrated suppliers with some market power were able to raise costs to their retail supply competitors by withholding RECs from the market.

8.4 Mitigating Market Power

The extent to which market power is a serious concern in the Netherlands depends on how well the mitigating factors are designed.

A successful implementation of a supplier obligation may require a carefully designed buyout price and limitations to the duration of banking. A lower buyout price can reduce the potential for exercising market power. However, it creates a distortion in the market that, if set too low, may disincentivise sufficient investment in renewable energy generation. This can therefore jeopardise achieving the target, which quantity-based systems are often best able to deliver. Thus using a buy-out mechanism may sacrifice one of the important advantages of switching to a supplier-obligation approach. High levels of banking can also lead to similar outcomes.

8.4.1 Banking

In a competitive market, banking would mean that the REC price would no longer be set by the marginal resource in the individual year, but rather the marginal "energy" constraint over

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111 Note that even companies with "low cost REC generation capability" have no incentive to supply cheaper electricity to end-users because they face the same (inflated) opportunity cost of RECs, i.e. the market REC price.

112 The UK Renewables Obligation has seen limited "horizontal" trading between peers, with much more prevalence for "vertical" trading and long-term contracts that integrate the RES producer with the supplier. Other obligation regimes that have provisions for trading, but where there are a limited number of obligated parties – such as the UK's successive energy efficiency obligations (the EEC and the CERT), or the US CAFÉ standards for vehicle fuel economy – have also witnessed limited trading between competitors.

113 In effect, in a hypothetical extreme case, by instituting a REC regime in a context where (hypothetically) only a few firms were endowed with the ability to generate RECs, and then requiring RECs as a new "input" that all retail suppliers must purchase, the government would be harming consumers by putting previously viable competitors out of business.

the horizon of the certificate scheme (with some discounting). This gives rise to a much smoother, and more certain REC price path, as discussed above in sections 2.3.2 and 5.2.9.

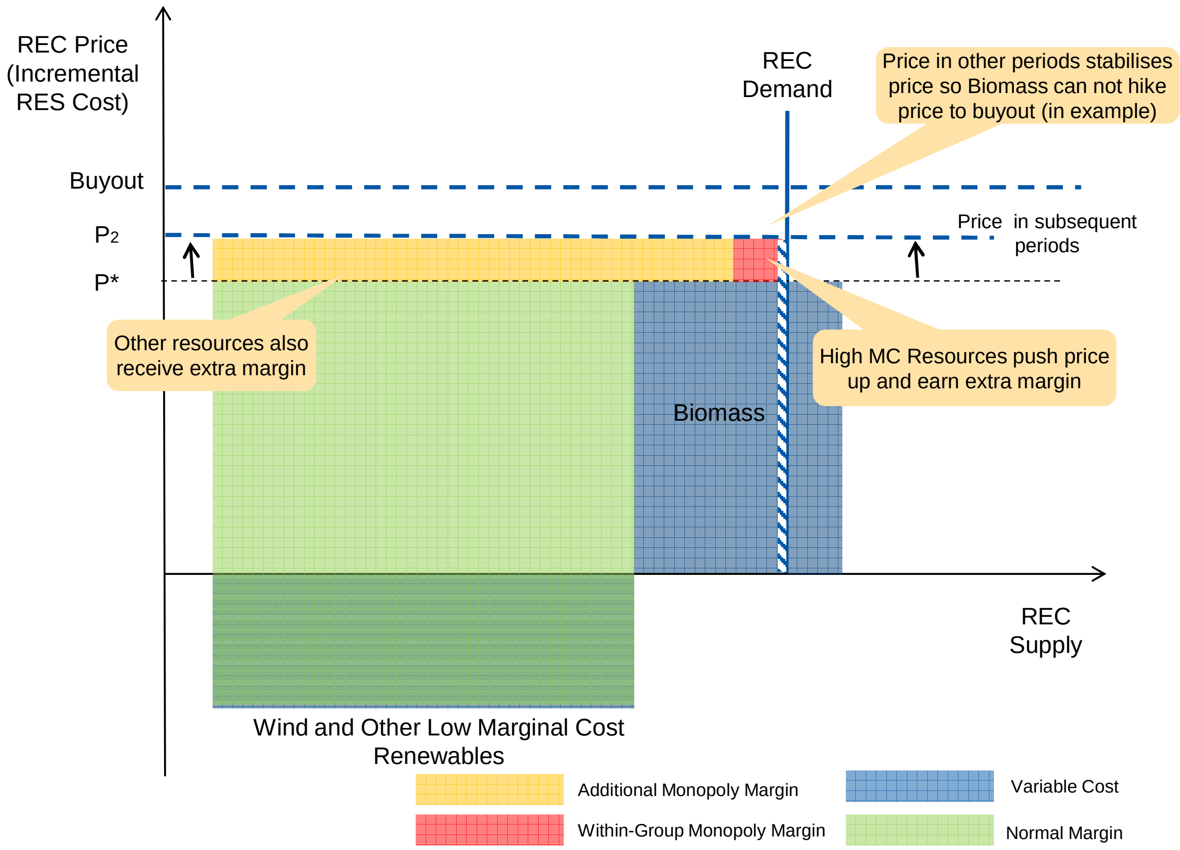
The ability to bank certificates affects market power in important ways:

- In any given year, it offers the opportunity for companies that already hold banked certificates to compete as alternative sources of supply, which can help ease supply shortages. This effectively means there is competition *between* periods. This is shown in Figure 8.6;
- Banking also means that market participants can, in principle, withhold output from the market to squeeze the price up in an individual year, without discarding of the certificates entirely. This means that in the initial years, existing RES sources would be able to deliberately withhold certificate supply to create a supply squeeze, forcing the REC price up to the buy-out price level.

This potential market power could be mitigated by prohibiting existing low marginal cost resources from receiving RECs (this has been the approach in the Swedish REC system, for example), but this would not be possible for existing co-firing capacity, which otherwise would not have an incentive to operate.

In summary, where reserves of certificates have built up, the supply of RECs in any given year is no longer constrained by the generation potential of installed assets, but augmented by the reserve pool. A surplus of “banked” certificates is therefore a useful protection against market power, where the surplus is held by a sufficient number of market participants. However, where the surplus is concentrated amongst a few, and these same holders of reserves also have a dominant position in renewable energy generation (i.e. controlling both current supply and banked supply) market power may be exercised at least in the short term.

Figure 8.6
Certificate Banking and Competition between Periods



Note that there may be limited scope for banked certificates to be applied to European 2020 RES targets, which would limit (but not eliminate) the flexibility that it would provide in the Dutch market.

8.4.2 Banding

Segmenting technologies according to their relative resource costs is another means to mitigate the effect of market power. As discussed above, however, this comes at the cost of economic efficiency because expensive technologies may be supported over cheaper ones. If low cost RES technologies are awarded proportionally fewer RECs per unit of output than their more expensive alternatives then the infra-marginal rents derived by cheaper generation, such as onshore wind and heat, will be reduced.

Under a Banded REC scheme, the short term REC price is no longer necessarily determined by the marginal cost of the most expensive technology required to meet the REC demand (or *target* output). Instead it will depend upon the way technologies are grouped and the number of RECs allocated to each band relative to their marginal cost. Banding is designed to flatten the effective long-run marginal cost curve, which should reduce the ability to exercise market power in the long run. However, in the short run, banding may not necessarily flatten the supply curve, and therefore its effects on the ability to exercise short-run market power are uncertain.

However, the extent to which banding is successful at mitigating market power depends upon the ability of regulators to accurately identify costs and thereby segment technologies. If cost estimates are incorrect, then banding may favour certain technologies at the expense of others. Additionally, as long as there remains heterogeneity of costs within a particular band, infra-marginal rents will still be present. Increasing the number of bands can reduce this, but is likely to lead to further administrative complexity and depends upon an even greater precision of cost estimates.

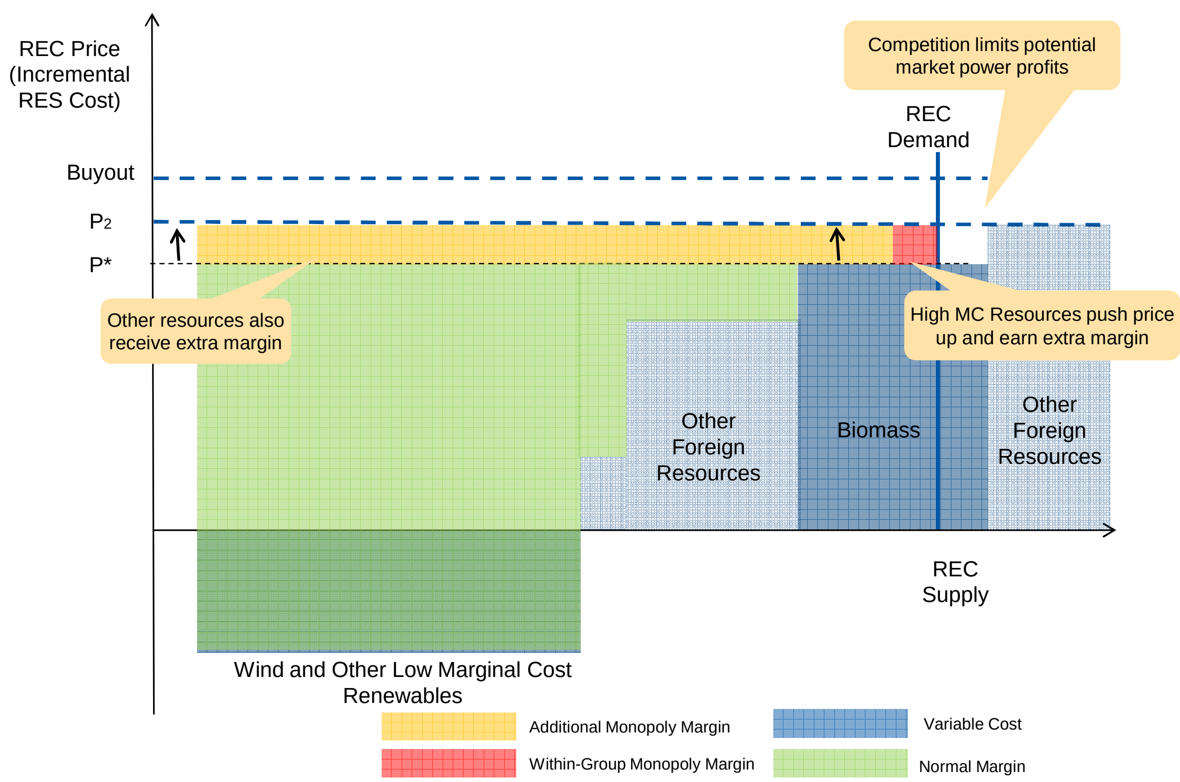
8.4.3 Link to other countries: Flatter supply curve

By linking the market to other regions, the market is larger and the scope for exercising market power is reduced. The residual demand curve is flatter and individual market players are much less likely to be able to affect the market price.

This finding is conditional upon:

- Linkage actually giving rise to a flatter residual demand, i.e. the linked market has plants which are marginal.
- That cross-ownership of assets is not too extreme. For example, if biomass in Netherlands tends to set the REC price and there were common ownership of cheap wind plants in Sweden and the Dutch biomass plants then the operator may have even stronger incentives to shade down generation from biomass than he would have had without the linkage.

Figure 8.7
Linked REC Market



The same effect would also be accomplished by widening the scope of renewable energy sources that are eligible to receive RECs. There are a number of renewable energy technologies that would contribute towards the Netherlands's RES target that are not currently supported by the SDE+, such as efficient heat pumps and solar thermal hot water heating. It may be worth considering expanding the set of eligible RES technologies to be as large as possible.

8.5 Market Power under SDE

Having considered the potential for market power under a REC system and certain means by which this can be mitigated, we turn briefly to look at the SDE+. There is considerably less scope for exploiting market power given the absence of a tradable certificate system. However, under some of the conditions discussed above that are conducive to the exercise of market power under a supplier obligation, there are certain parallel market power considerations that would apply under the SDE+. We discuss two of these here: Market power might be exerted if asset owners have the ability to influence technology cost estimates or by strategically withdrawing supply.

8.5.1 Influencing cost estimates

The per unit subsidy level for each technology and the ordering of access to support is determined by its absolute and relative resource cost, respectively. If cost estimates are derived by information provided to the regulator by a small number of potential developers from then there may be the potential for opportunistic developers to inflate their cost estimates and receive higher subsidies. This would be a particular concern if such companies owned a range of technologies and could therefore preserve the relative ordering of access at the same time.

Additionally, if there are few participants in the RES supply market there may be a disincentive to drive cost-reducing efficiency improvements. This is more likely to hold in the short term, where new entrant supply is constrained, and asset managers are aware that any reduction in cost would just lead to a corresponding cut in subsidy support.

In a similar sense to the Banded REC case discussed above, the accuracy of cost information is therefore essential to ensure the effectiveness of the scheme. However, given that there is now a large and growing market for developing renewable energy technologies, it is perhaps unreasonable to assume that domestic dominant market players are able to influence cost estimates. Regulators should be able to obtain reliable and comparable cost estimates for both the construction and operation of different technologies derived from international experiences. Only a small portion of the costs are likely to be specific to the Dutch market, such as the price of land.

8.5.2 Strategically withdrawing supply

Alternatively, under an SDE type scheme, dominant market participants in the supply of renewable energy may choose to withdraw part of their supply or delay investment in new capacity in one year in anticipation of an increased budget and subsidy levels in future years. This might be a particular strategy for operators of marginal co-firing plants where the subsidy is initially set in such a way that it is equally attractive to burn coal or biomass (with subsidy received on top of wholesale market price). In the absence of excess supply of RES, operators can choose to burn coal instead of biomass, prompting a below target RES output. Should RES support and budget then be set higher in the following year in order to make up for the deficit, operators can apply for biomass support and derive additional margin corresponding to the increase in subsidy.

In theory, this kind of exercise of market power by withholding capacity should only work in the short run, because the resulting excess demand would stimulate new entrants. But if there are barriers to entry – particularly if such barriers can be increased by incumbents – then such market power could persist for longer. For example, under the SDE+, dominant suppliers could exploit the application process by applying for support and, even if granted, not generating the corresponding output. This would crowd out alternative suppliers and potential new entrants, allowing the strategic withdrawal of supply to become a tool for longer term as well as short term profits.

The extent to which market power is a real threat under an SDE scheme largely depends, therefore, on the concentration of operators of marginal assets that might be put to alternative use such as co-firing plants and the concentration of potential investors in new capacity. In order to mitigate such threat, rules may be designed to ensure that RES generation closely matches the applications for support. Additionally, any barriers to entry, such as the control of land suitable for the development of generation assets, should be reduced.

9 Conclusions

9.1 Main Conclusions

- First, we note that any policy change whose effects are not easy to understand may result in delays to investments, because investors will wait to observe the operation and impacts of the new policy become before they begin new projects. Repeated changes may also make investors wary that policies are not stable, and result in further delays.
- The SDE+, in the form and with the annual budget in place during the Rutte 1 government, is unlikely to achieve an overall RES target of 14 percent renewable energy.[114]
- In our Perfect Information scenario, an expanded SDE+ would have the lowest impacts on consumers – but impacts are also relatively low for the Bonus/Malus REC policy, under which the REC market is combined with additional subsidies for expensive RES technologies and charges for inexpensive ones.[115] The Uniform REC policy, in which all RES sources receive one REC per MWh (or GJ) of output, has a larger impact on consumers.
- A Uniform REC policy has the lowest resource costs – that is, the incremental cost of the technologies used to meet the RES target is the lowest. However, because even inexpensive technologies receive the same support as the most expensive, the Uniform RECs policy leads to high excess profits, or “rents”. This amounts to a significant transfer from energy consumers to RES producers.
- When there is a mismatch between policy design assumptions and reality, the SDE+ does *not* always impose the lowest burden on consumers, because other policies may be better able to scale back impacts when costs are lower than expected. On balance, however, the SDE+ performs reasonably well in limiting consumer impact in most scenarios. The REC options have more variable impacts on consumers, unless combined with a buyout price.
- REC variants that differentiate the support received – including a Banded REC system, a Bonus/Malus system, or some other “hybrid” (such as a combination of the SDE+ with a REC system for lower-cost technologies) – tend to produce results that are similar to the SDE+. The Banded REC system may be more difficult to manage, however, because there is no longer a one-to-one relationship between the number of RECs in the system and the amount of energy actually produced to achieve the RES target.
- In general, of the policies with output above or equal to 260 PJ, the “target-achieving” SDE+ policy (or a hybrid REC buy-out plus SDE+ policy, which has very similar

[114] While the analysis presented here was finalized, the new Dutch government (Rutte 2) proposed a RES target of 16 percent in 2020 and increased the available budget. We have not assessed this new proposal. References in this report to the “Current SDE+” refer to the SDE+ as introduced in 2011 by the previous government (Rutte 1), which aimed to achieve a RES target of 14 percent.

At the time of our analysis the SDE+ annual budget ceiling was €1.7 billion. To make a meaningful comparison with REC policies, we assumed an additional €0.4-0.6 billion allocated under other policies to support biomass co-firing, amounting to a total budget ceiling around €2.1 billion.

[115] As noted, with perfect information it should be possible to design the Bonus/Malus and Banded REC policies to closely match the SDE+.

outcomes) usually results in the lowest impact to consumers. These are followed by REC policy variants, with the Uniform REC policy appearing most expensive. This ranking is reversed, however, in the “Low Cost” RES scenario, where we assume that policy-makers over-estimate the cost of RES supply. Under this scenario, the Uniform REC policy (with or without banking) imposes significantly lower costs on consumers than the target-achieving SDE+.

- The SDE+ could be made less expensive if it gave priority to technologies not on the basis of their *total* cost, but on the basis of *incremental* or resource cost.

- Under a REC system (including one with banking), if there is no increase in the RES target after 2020, the REC price will be prone to peaking in 2020 and then falling in 2021. This is because once new investment is no longer needed, the REC price is likely to fall back to the level of the short-run marginal cost of the marginal RES capacity. This short-run cost will not be sufficiently high to compensate capital investments in earlier years, implying the need for much higher prices before the sharp drop down to the short-run marginal cost.

- Concentrated ownership of assets that can be used to burn biomass could result in the exercise of short-run market power in a REC market, but it is less clear that this will have long-run detrimental impacts. Exercise of market power in the long-run would require limited competition and significant barriers to entry across other technologies as well, however. If these are features of RES supply in the Netherlands in the long-run they are also likely to make it possible to exert market power under the SDE+.

- Linking of REC markets tends to lower overall costs, but may not always result in lower impacts on consumers.

Additional conclusions are summarised below.

9.2 High Level Conclusions

- To achieve the 14 percent target, which we estimate to be approximately 260 PJ of renewable energy from electricity, heat, and (suitably adjusted) green gas output, the SDE+ will need to have its budget more than doubled, and the support that is available per unit output to certain technologies – notably offshore wind and dedicated biomass (operating in power-only mode) – is likely to have to be increased. In addition to increasing the budget for the SDE+, it will be cost-effective to ensure that support for biomass co-firing continues in some form – whether as part of the SDE+ or some other policy.
  - Using the SDE+ to support co-firing (as well as to support significant volumes of dedicated biomass capacity) is likely to require certain changes to accommodate the fact that biomass fuel has a variable cost, so that capacity installed in one year may require a “base price” (*basisbedrag*) that varies year by year.

- In our Perfect Information scenario, an expanded SDE+ would have the lowest impacts on consumers – but impacts are also relatively low for the Bonus/Malus REC policy.[116] The Uniform REC policy has a larger impact on consumers.
- When there is a mismatch between policy design assumptions and reality, the SDE+ does not always impose the lowest burden on consumers, because other policies may be better able to scale back impacts when costs are lower than expected. On balance, however, the SDE+ performs reasonably well in limiting consumer impact in most scenarios.
- A Uniform REC policy (in which every RES technology receives one REC per MWh output) has low resource costs, but very high rents, resulting in transfers from consumers to producers.
- If the SDE+ were modified so that cost Tranches were defined by *resource* (i.e. incremental) cost, rather than *total* cost, it would result in more cost-effective technology uptake and lower consumer impacts.
- The SDE+ may not achieve the RES target (and may over- or under-shoot) if information about costs and potential are not accurate. However, REC variants that seek to protect consumers (and energy suppliers) from high cost impacts through the use of a buy-out price also run the risk of missing the RES target.
- Any change to the existing system is likely to result in delays as project developers and investors seek to understand the implications of new rules and policies. The more unfamiliar the new policy, the greater the likely delay in new capacity.
- Policies that effectively eliminate rents (as the SDE+ or the differentiated REC regimes are intended to do) may, for a given fixed budget, enable the budgeted support amount to achieve a higher RES output target than a Uniform REC policy.
- A REC system of some kind could provide benefits if linked to other countries outside the Netherlands that were willing to offer their RES at prices below those in the Netherlands – but the future development of hypothetical pan-European REC prices is unknown. Although introducing a “hybrid” system that included RECs for inexpensive technologies and the SDE+ for more expensive ones (and as “insurance” against low REC prices) incorporates some of the attractive features of both policies, significant policy changes of any kind may make potential investors nervous, and delay investment.

9.3 Consumer Impacts

- Supporting renewable energy to meet the 2020 target will increase customer bills. Under the “Perfect Information” scenario, for policies meeting the target, we estimate that the impact on consumers ranges between 0.5 and 1.7 €cents/kWh in 2020, when the costs are distributed amongst all energy users (including industry) in proportion to their energy consumption.

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[116] As noted, with perfect information it should be possible to design the Bonus/Malus and Banded REC policies to closely match the SDE+.

  - Under the Perfect Information scenario, the target-achieving SDE+ (as modelled) results in the lowest impact on prices of the policies that achieve the target, at 0.4 €cent/kWh.
  - A Uniform REC policy with banking (but with a longer-term RES target in place to ensure that the 2020 target is more likely to be met) results in a relatively high impact of 0.8 €cent/kWh. Without banking and a long-term target, REC prices are much more volatile, with 2020 REC prices potentially much higher than 2019 or 2021. Other REC variants, such as the banded REC regime or a system with "Bonus/Malus" side payments, result in lower consumer price impacts than the corresponding Uniform REC design.[117]

- As described above, in addition to our "Perfect Information" policy scenarios, we also consider a range of other scenarios to shed more light on how the different policies are likely to operate in the real world, where assumptions about costs and resources may differ unexpectedly from what was assumed when the policies were designed.

  - The consumer impacts under other scenarios are similar, but in certain notable cases they differ in important ways. For example, under the Low RES Cost scenario, the consumer impacts of the Uniform REC case are *lower* than the impacts under the SDE+.[118]

- The impact on consumer energy prices rises to between 0.7 and 2.3 Eurocents/kWh in 2020 if industrial users are exempt from contributing to the scheme, again focusing on policies that achieve the target. If only non-industrial *electricity* consumers bore the burden the costs would range from around 3 Eurocents/kWh in 2020 for the target-achieving SDE+ to around 4 Eurocents/kWh in 2020 under the Uniform REC policy with banking and a longer-term target.

- Impacts on consumers can also be measured by the net present value of support paid to renewable energy sources. We estimate that the amount of this support required to achieve the 260 PJ target, on a lifetime net present value basis, is between €16-19 billion for the SDE+ and a Uniform REC, as well as REC policy variants. Under a Uniform REC system with banking *and* a higher 2030 target (to ensure that the 2020 target is respected despite the opportunity to bank) the value of the required support for capacity installed up to 2020 would be more than €25 billion.

  - As the REC price is subject to fluctuations, it is less easy to forecast the consumer impact of the policy with a degree of certainty. However, because REC prices tend to be negatively correlated with electricity prices across the different REC policy scenarios, a supplier obligation could serve to dampen overall fluctuations in the energy costs faced by consumers. The negative correlation between electricity prices

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117 In theory it should be possible, with Perfect Information, to design either of the REC variants to match the results of the SDE+, or to have even lower impacts (because of inefficiencies in the SDE+ design discussed below).

118 This is due to a combination of factors, including the SDE+'s focus on "total cost" (the inefficiency discussed below) and the assumption under the Low RES Cost scenario that no adjustment is made to support levels. Under this scenario, therefore, the expanded SDE+ over-achieves the 260 PJ RES target. However, even if the SDE+ budget is reduced so that the policy only just achieves the 260 PJ target, it still requires higher subsidies, under the Low RES Cost scenario, than the Uniform REC case.

and the REC price would be weakened by an ex-ante buy-out price. Therefore, a buy-out price would lessen the extent to which the REC price serves to smooth the energy costs passed on the consumer.

- – Across the Perfect Information policy scenarios considered the impact on consumers of reaching the RES target is estimated to range between 0.5 and 1.7 Eurocents/kWh in 2020 when distributed amongst all users in proportion to their energy consumption.
- – This rises to between 0.7 and 2.3 Eurocents/kWh in 2020 if industrial users are exempt from contributing to the scheme. If only non-industrial *electricity* consumers bore the burden the cost ranges from around 3 Eurocents/kWh in 2020 for the SDE+ to around 4 Eurocents/kWh in 2020 under the Uniform REC policy with banking.

9.4 Comparison of Target-Achieving SDE+ to REC Policies

- On a net present value basis, the Supplier Obligation with uniform RECs has low *resource* costs, but high “rents” (or excess support payments) – resulting in total subsidies that are similar to what occurs under the SDE+ in our Perfect Information scenario.
  - – Standard economic theory suggests that a supplier obligation should be able to achieve a given target in an “economically efficient” way – that is, at the lowest resource cost. This is borne out in the results, but it implies significant transfers from consumers to RES producers.
- In theory, the SDE+ could reproduce the low resource costs of the Uniform REC case, while also achieving low rents.
  - – However, as currently implemented, the design of the SDE+ gives priority to technologies based on their *total* cost, not their resource cost, and this results in a technology mix that is different from what is achieved under a Uniform REC case (with more heat and green gas, and less electricity).
  - – Based on standard economic cost-benefit analysis, this means the SDE+ does not result in the technologies being taken up that impose the lowest additional cost on the overall economy.
  - – To be able to reproduce the efficient RES technology mix, the SDE+ would need to be modified so that the ordering of applications was based not on estimated *total* production cost but on estimated *resource* costs.
- The (theoretical) ability of the SDE+ to reproduce the efficient technology mix (if access to support is based on *resource* cost) also depends, to some extent, on the accuracy of the cost estimates upon which the SDE+ is designed. In particular, the SDE+ must not cap the per-unit support offered to each technology at a level that is below the level of the “marginal” capacity installed in each technology category.
  - – Where cost heterogeneity is limited (or easily observed), this requirement for the SDE+ is easier to achieve than when there is substantial cost heterogeneity that cannot be observed by policy-makers or regulators.
- The ability of the SDE+ to limit rents relative to the cost-minimising technology mix of the Uniform REC policy also depends on the assumption that applicants for SDE+

funding are not able to "game" the application process by delaying their application and thereby securing support significantly in excess of their actual costs. The SDE+ would still have lower rents than a Uniform REC policy, because of the caps on support for specific technologies (reflected in the *basisbedrag*), but it may not be able to limit rents any further than this.

- The larger the overall budget, the more confidence developers of inexpensive technologies can have that they will be awarded support under the SDE+. This will give them more confidence that they can apply for support in higher Tranches, up to the maximum base price (*basisbedrag*) defined for their technology. When this occurs, the SDE+ becomes very much like a fixed FIT system for lower-cost technologies.
- Again, the greater the cost heterogeneity, the greater this risk. In addition, circumstances in which there is a concern that there could be market power exercised under a REC regime (for example, when renewables developers have a good idea about the costs of others and their own relative costs, and when they know that competitors will not be able to undercut them) are similar to those under which SDE+ applicants might seek to secure higher support levels by applying later in the process to attempt to secure greater subsidies.

▪ If the SDE+ is not based on accurate estimates of costs, two outcomes are possible: when costs are overestimated there are likely to be excess profits; when costs are *underestimated*, the SDE+ risks missing its target. Moreover, because the costs of projects vary *within* technology groups, certain projects that are more expensive than the maximum support level for a particular technology group (but that are still relatively inexpensive relative to other technologies) may be prevented under the SDE+ from receiving the support they need. Because such projects are still less expensive than projects in other technology groups, the resource costs of the policy will be higher than under a Uniform REC. These disadvantages of the SDE+ are shared by the Banded REC policy and the REC with Bonus/Malus payments. Under all of these policies, these disadvantages are the price for seeking to limit rents by offering different levels of support to different technologies.

- Rents under the SDE+ when RES costs are overestimated by 20 percent are approximately three-quarters the level under the Uniform REC case (around €6 billion on a lifetime basis, compared to €8 billion in the REC case), assuming no learning or adjustments to correct the over-subsidization. If SDE+ applicants delayed their applications to later tranches, however, this would push the subsidies higher. Against this, it seems likely that the overestimate of costs would in practice be noticed within one or two years, rather than persisting for the life of the policy. Taking both of these adjustments for "realism" into account, the actual rents expected in the real world would probably be significantly lower, but would still be substantial (perhaps to €3-4 billion).

▪ There is no way of knowing for certain to what extent estimates of the costs of different RES technologies used in setting differentiated policy support levels (whether under the SDE+, or a banded REC or bonus/malus regime) are inaccurate. Nevertheless, we have presented estimates of the implications of different under- and over-estimates on the overall costs and effectiveness of the different policy designs.

– It seems likely that inaccuracy of cost estimates and inability to represent cost heterogeneity results in excess support being paid even under the SDE+. Using our modelling results as a guide, it seems plausible that excess support could amount to €1-2 billion over the lifetime of the supported RES potential. This is still significantly less than the excess support under a REC system, but would bring the two policy types closer together in terms of total cost.

– The use of inaccurate cost estimates (whether because of cost heterogeneity or because the average is wrong) to determine the *maximum* support available to individual technologies under the SDE+ will also increase the *resource costs* of the SDE+, relative to the least cost way of achieving the target. Again, this could increase the subsidies required under the SDE+ by on the order of 10-15 percent, or around €2 billion on a lifetime basis.

– If the SDE+ in fact were to cost €2 billion more due to higher-cost technology choices, and on top of this to over-subsidise investments by an additional €2 billion relative to what we have modelled in our Perfect Information scenario, the total cost of the SDE+ could rise to approximately €20 billion, which would exceed the support costs under the Uniform REC policy. The costs of the REC Banding or Bonus/Malus REC system would be increased in similar ways.

– Some of the above differences due to imperfect information depend on the nature of the inaccurate information. Under the scenario in which we assume wind costs are higher than anticipated, the costs to consumers of the Uniform REC case increase more than they increase under the SDE+.

– Revising the SDE+ to allow applications for support in order of *resource* cost rather than *total* cost could reduce support costs under the SDE+ by more than €3 billion, however (because green gas and heat technologies would no longer receive what amounts to priority access) which would probably restore the SDE+ to its position as the policy with the lowest impact on consumers.

9.5 REC Market Variants

- As noted above, REC policies that differentiate the level of support offered to RES technologies could *in theory* achieve the cost-minimising RES mix expected from a Uniform instrument. Our modelling results confirm that it is possible to achieve a similar technology mix and reduce rents significantly under the two REC variants, at least under the Perfect Information scenario. However, for them to do this, costs and resource availability would need to be well-understood, *and* policy-makers would need to be able to adjust the policies precisely as costs and other circumstances change over time. In the real world these assumptions may be inappropriate. The sensitivity scenarios also highlight the fact that such differentiation imposes additional complexity and risk on the policy, however, because of the need to revise the levels of support as circumstances change.

- Our results suggest that in principle, the SDE+ does a somewhat better job than the differentiated REC approaches of *automatically* adjusting to reduce overpayment through its phased application process. However, this depends on the assumption that developers do not delay their SDE+ applications in an effort to secure higher support prices.

  - We have not tried to model deliberate adjustments to support levels to correct or update cost information, although it seems likely that these would take place under differentiated REC systems in the same way that they currently occur under the SDE+. This process is likely to reduce the levels of overpayment relative to what our modelling results suggest. Assuming that a significant over- or under-estimate of cost was corrected after 1-2 years, no more than one-third of the rents that we estimate in our "Low RES Cost" scenario might be observed in practice.

- A REC market may experience significant price volatility, and this may deter investors, driving up costs.
  - Certain supplier obligation design features can help to mitigate the volatility of the REC price. In particular, our modelling illustrates that allowing banking smoothes the REC price substantially. However, achieving the 260 PJ target in 2020 while also allowing banking appears to entail higher lifetime costs (and lifetime support requirements) than if no banking is permitted.
    - We do not model the quantitative implications of different time limits for banking. If banking of certificates to be surrendered in 2020 was only permitted for a limited number of years (e.g. for only one or two consecutive years) this could reduce the ability of banking to smooth REC prices.
  - Moreover, the REC price will be less prone to very high peaks if the RES target continues to increase after 2020. Otherwise, there is a risk that once new investment is no longer needed, the REC price will fall back to the level of the short-run marginal cost of the marginal RES capacity – which will not be sufficiently high to compensate capital investments in earlier years, implying the need for a price spike before the subsequent fall to the short-run marginal cost.
  - We consider an illustrative 2030 target of around 330 PJ, which supports a REC price sufficient to sustain investment, but does not seem particularly ambitious relative to the current 2020 target.

9.6 Hybrid Supplier Obligation / SDE+ System

- There is no "optimal" buy-out level for a REC system, as this depends on how far policy-makers are willing to stray from the overall RES target.
- We can, however, assess a hybrid policy that relies on a REC market, capped by a buy-out price, for less expensive technologies and the SDE+ for technologies that are more expensive.
  - A hybrid approach that overlaid a Supplier Obligation with buy-out on the existing SDE+ would introduce significant complexity, and uncertainty, to the existing policy.
  - Ignoring issues of uncertainty and lack of information, it would be expected to yield results very similar to the SDE+.
  - Taking into account the uncertainty that motivates the sensitivity analysis discussed above, we would expect differences to include somewhat greater excess support paid to low-cost technologies, but this would be counterbalanced by somewhat more efficient choices of low-cost projects.

- Under a hybrid policy, concern would remain about whether or not the target will be met, because there is no certainty about whether the SDE+ support will be sufficient to attract enough investment.
- Inefficiency would also remain, if certain technologies assumed to be "less expensive" were prohibited from applying for supplemental SDE+ support – so that a relatively expensive onshore wind site could not receive supplementary support from the SDE+, even though it would have been less costly than a dedicated biomass power plant.
- If all technologies were eligible to apply for SDE+ support, then it is not clear why any of them would forego the SDE+ in favour of the REC market.

- Potential future benefits of introducing a REC-based system could include linking with other countries' REC systems, but it is unlikely that this would have much impact on the achievement of the 2020 target, because the policy links would take time to develop. Linking could also impose various constraints on the flexibility to design the policy in a way best suited to the Netherlands. (It is not clear, for example, that a buy-out price would be accepted, in which case it would be necessary to limit eligibility only to technologies expected to be inexpensive, and to set the REC target lower than the overall 260 PJ RES target for heat + power.)

9.7 Linking to other REC Markets and Issues Related to Market Power

- Linking REC systems would lower the overall resource costs of meeting the combined RES targets of the participating countries, but would not necessarily benefit *consumers* in the Netherlands. For example, if other countries with even higher RES costs than the Netherlands linked to pan-European tradable certificates market, REC costs could rise under linking, rather than fall.
- Linking may also place certain restrictions on the flexibility of policy-makers to tailor their REC market to local conditions.
- A REC system could provide some scope for the exercise of market power, although as in some power markets, this could be a natural mechanism for ensuring that prices based on short run marginal cost rise to levels high enough to incentivise investment.
  - Opportunities to exert market power could be mitigated through the use of a buyout price or linking to other REC markets, and by expanding eligibility for RECs. Banding and banking could either reduce or exacerbate incentives to exert market power.
  - Some of the conditions that would lead to incentives to exercise market power may also affect the operation of the SDE+: for example, if there is limited opportunity to enter the RES / REC supply market, then producers with market power may choose not to produce (or to delay entry) in an effort to increase the size of the available SDE+ budget or the level of support available.
- Concerns about market power in a REC system may arise if a small number of (potential) RES producers are able to control the supply of RECs to the market, increasing prices and earning monopoly or oligopoly profits as a result.

  - It is necessary to consider both short-run and long-run exercise of market power. Exercise of market power in the short run may be less of a concern as long as the RES supply market is relatively open to new entrants. In fact, exercise of market power in the short run may be one mechanism by which prices rise high enough to incentivise new entry in the long run.
  - The Netherlands does have relatively concentrated ownership of coal-fired power plants. In the short run, operators of these plants may be able to influence the price of RECs through biomass co-firing in the short run. Because these generators also own RES assets with very low short run marginal costs, such as wind farms, they may have greater incentives to withhold co-firing output to drive up REC prices.
  - It is not clear, however, that such behaviour would lead to undue profits in the long term. A large proportion of the wind capacity in the Netherlands, for example, is held by smaller operators without links to the major generators. This suggests that the barriers to entry in the RES supply market may not have been very great in the past. If this continues to be the case, then the exercise of short run market power is likely to stimulate investment by a variety of new entrants, which would be expected ultimately to bring the REC price back down to competitive levels. Of course, if entry becomes more difficult in the future (for example, because it requires the development of dedicated biomass at existing coal sites, or because offshore wind requires greater access to capital and engineering expertise that is less widely available) then the market power could persist even in the long term.

- If there is the potential for market power to be exercised, and this market power is held by vertically integrated producers, then the exercise of market power by these vertically integrated companies could harm their competitors in the retail supply business by denying them access to a necessary “input” (which, prior to the introduction of the REC market, was not required for the business).

- A buy-out price and linking to other REC markets, as well as expanding the eligibility to earn RECs to a wider set of technologies, would help to mitigate market power. Banking and banding would have uncertain impacts on the potential to exercise market power.

- It is important to note that many of the circumstances that would make it possible to exercise market power within a REC market would also facilitate the exercise of market power to try to influence the operation and design of the SDE+. That is, a REC system is not the only one that could be susceptible to the exercise of market power.

9.8 Other Findings

- Volatile gas prices do pose a risk to investors under the SDE+ because of the floor price that limits available support, although this would have a negative impact on investors only if gas prices were to fall significantly below their current level. It is not clear how much this risk increases the premium demanded by investors, and the additional cost may be small. On the other hand, neither is it clear whether the floor price is really necessary to protect the government from the risk that its overall SDE+ budget will be breached – particularly as time goes by, and the budget has not already been used up.

- Although the electricity price may in individual years drop below the price floor, it is less likely to drop for a sustained period of time because other sources of generation capacity than gas would be likely to retire or be mothballed, counteracting the price drop. However, the significant drop in power prices observed in 2009 highlighted the potential risk of cash flow difficulties faced by renewable generators of drops in individual years.

- A REC market could be applied to all RES technologies, although care would need to be taken once the market was opened to technologies with different energy products. Green gas would need to be accounted for in a way that took into account its reduced contribution, per PJ of gas output, to the RES target, and there may be a need to consider how smaller, more decentralised end-users (such as small-scale residential heating systems) would participate in any REC market.
- Accommodating co-firing in the SDE+ would necessitate a revision to the existing policy to ensure that the level of support available remained consistent with variable biomass prices. It may be challenging to design a policy that offers sufficient levels of support to ensure operation under a range of prices while also preventing over-payment, given the multiple contractual arrangements available for users of biomass fuels (from spot purchasing to long-term contracts).

Appendix A. Commodity Price Assumptions

Our price assumptions about delivered fuel costs are based on third party projections of international benchmark indices, to which we have added regional taxes and transportation costs. Our general approach is to rely on current market prices, including spot and forward prices, as far into the future as these commodity and derivative markets are liquid. We then rely on projections from the International Energy Agency's most recent World Energy Outlook (WEO 2011) for prices beyond the forward curve horizon. To allow for a relatively smooth transition between forward prices and the IEA projections, we interpolate between the two sources over 3-6 years.

In summary, our approach is as follows:

- **Short run:** Current prices (from Bloomberg);
- **Medium term:** Forward curves (from Bloomberg);
- **Long run:** Interpolation to long run IEA WEO 2011 projections.

A summary of our fuel price assumptions is provided in Table 4.5. Details for each fuel price are set out in the following sections.

Table A.1
Commodity Price Assumptions for Benchmark Indices

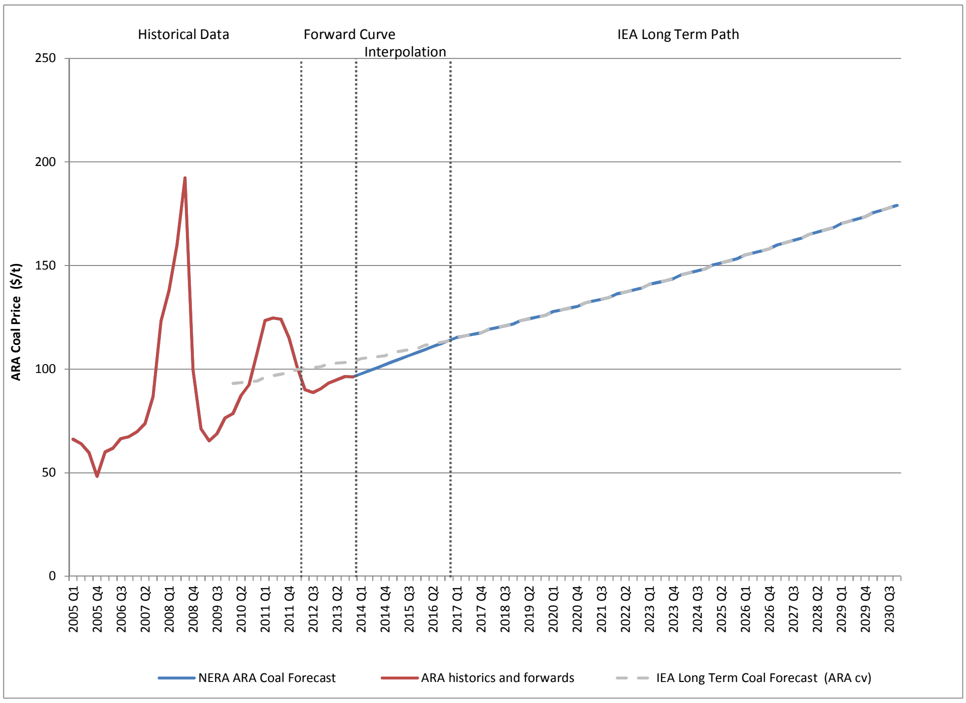
	Units	2010	2011	2012	2013	2014	2015	2020	2025	2030
ARA Coal Price	$/t	91.5	121.8	92.7	95.3	100.0	105.8	129.0	151.7	177.2
Brent Oil Price	$/bbl	78.8	109.6	108.4	100.8	97.4	93.9	113.8	182.1	218.7
TTF Gas Price	€/MWh	17.42	22.69	24.66	25.78	26.05	27.85	37.24	45.80	55.12
EU ETS Carbon Price	€/t	14.24	13.14	7.42	7.56	8.02	11.66	29.84	39.58	51.42

A.1. Coal Price

The delivered coal price consists of three components:

- **International Reference Price:** Amsterdam/Rotterdam/Antwerp (ARA) price (6000 kcal/kg)
- **Coal transportation cost:** We have assumed a small transportation cost amounting to about €6/t for coal in total. This is split between "International" and "National" transportation cost. This estimate is our standard assumption based on industry experience.
- **Taxes:** We have applied the current coal tax of €13.72/tonne,[119] which we have maintained constant in real terms thereafter.

Figure A.1
ARA Coal Price ($/t)



Source: Short term: Historical data from Bloomberg (ARA). Medium term: Forward curves up to December 2016. Long Run: World Energy Outlook 2011 "Current Policies" scenario. Inflated using implied US CPI from index-linked bonds as traded on information date. IEA projects real coal price of 115.9$/t by 2030, corresponding to a nominal price of just inside 180$/t. by 2030[120]

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[119] Deloitte, Energy taxes 2012, http://www.deloitte.com/assets/Dcom-Global/Local%20Assets/Documents/Tax/Alerts/dttl_CustomsFlash_EnergyEdition_number_1_2012.pdf

[120] IEA quotes prices using a calorific value of 6350 kcal/kg. Throughout this work we show coal prices using ARA notation. IEA prices are converted to ARA 6000 kcal/kg

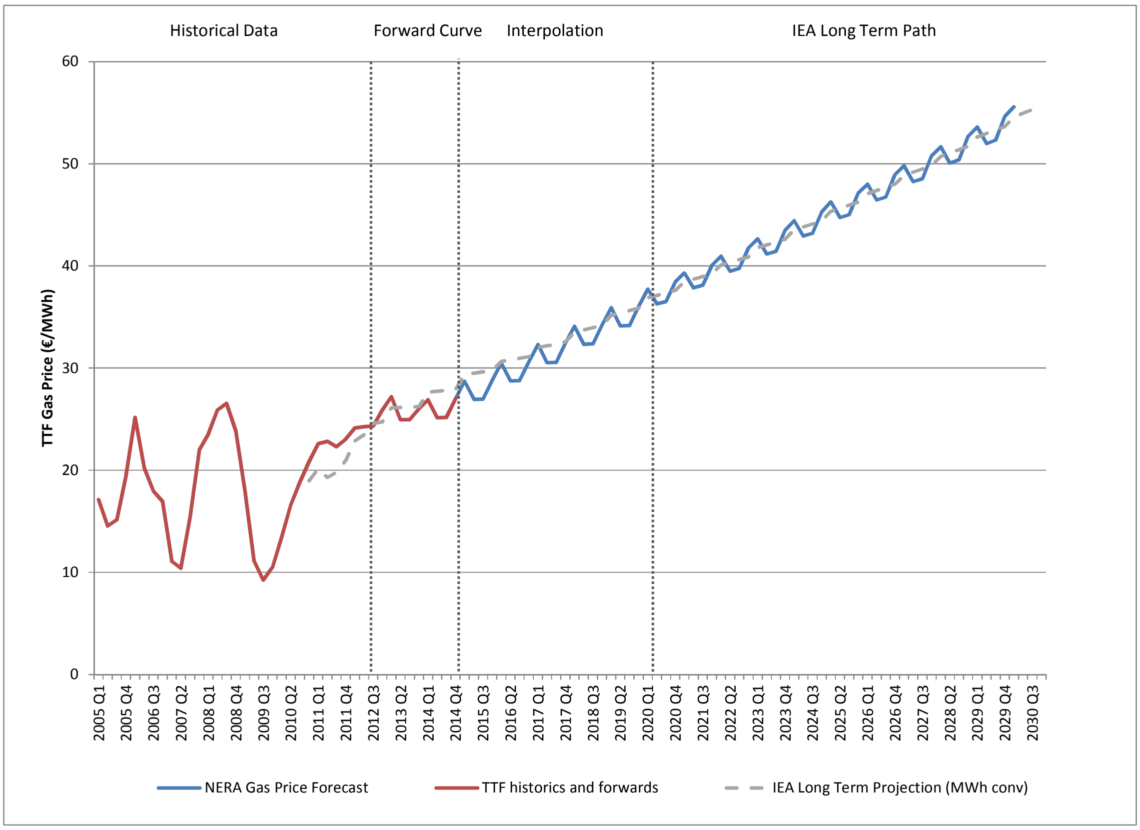
Table A.2
Delivered Coal Price

Coal	Units	2010	2011	2012	2013	2014	2015	2020	2025	2030
Reference Wholesale Price (ARA)	$/t	91.5	121.8	92.7	95.3	100.0	105.8	129.0	151.7	177.2
International Transport	$/t	3.3	3.3	3.4	3.5	3.5	3.6	4.1	4.6	5.3
National Wholesale Coal Price	$/t	94.8	125.2	96.1	98.7	103.5	109.4	133.1	156.4	182.5
National Wholesale Coal Price	€/t	71.5	89.9	76.0	80.0	83.3	87.6	105.3	123.8	144.5
Regional Transport	€/t	3.2	3.3	3.4	3.4	3.5	3.5	3.8	4.2	4.6
Coal Tax	€/t	13.4	13.5	13.7	13.9	14.1	14.3	15.5	17.0	18.7
Delivered Price to Power Plant	€/t	88.1	106.7	93.1	97.3	100.8	105.4	124.6	144.9	167.7

A.2. Gas Price

Due to the close proximity to the TTF gas hub we ignore gas transportation costs. Similarly, we assume no taxes specific to gas. Hence, we assume the delivered gas price is identical to the TTF hub price. We add seasonal "shape" to the gas price based on the observed spread between summer and winter prices in the current forward curve.

Figure A.2
TTF Gas Price Projection (€/MWh(t))



Source: Short term: Historical data from Bloomberg (TTF). Medium term: Forward curves up to December 2014. Long Run: World Energy Outlook 2011 "Current Policies" scenario. IEA projects a European gas price of $12.6/mmbtu by 2030 in real 2010 prices corresponding to a nominal price of $20.3/mmbtu in nominal terms (€16/mmbtu, or €55/MWh). Inflated using implied US CPI expectations and the forward FX rate at the information date of 0.8€/$. IEA forecast is provided in USD but is depicted here in EUR, using actual and forward FX rates which changes from 0.7 €/$ in 2010 to 0.8€/$ in 2012. The forward curve is shaped according to a historic gas price shape, scaled by the summer/winter spread observed in the forward curve in 2012/2013.

Table A.3
Delivered Gas Price

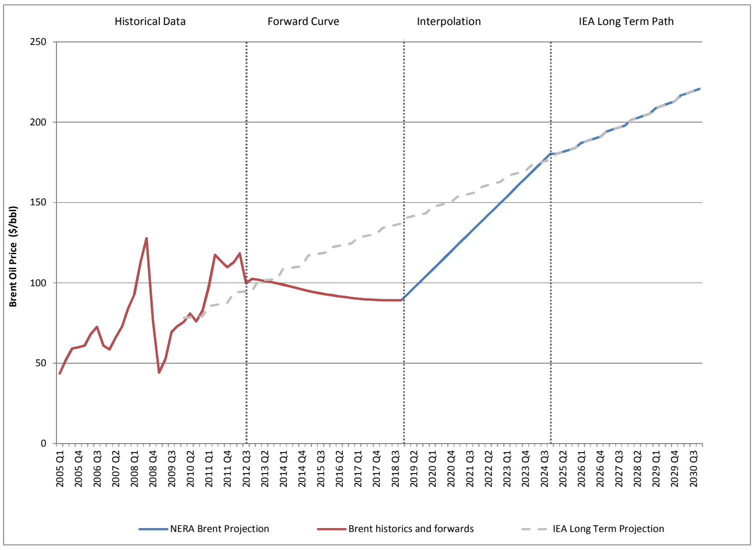
Gas	Units	2010	2011	2012	2013	2014	2015	2020	2025	2030
Wholesale Price (TTF)	€/MWh	17.42	22.69	24.66	25.78	26.05	27.85	37.24	45.80	55.12
Delivered Price to Power Plant	€/MWh	17.42	22.69	24.66	25.78	26.05	27.85	37.24	45.80	55.12

A.3. Price of Oil-Linked Fuels such as HFO and Gasoil

We have assumed that HFO and Gas-oil prices reflect three components:

- **Reference commodity price.** For gasoil and HFO we have identified representative series on which we have based historical information. Because of limited availability of forward curves for these fuels we use their historical relationship with the Brent oil price to project future prices.[121]
- **Transportation costs:** For HFO and Gasoil we have used generic assumptions based on confidential industry sources.
- **Taxes:** we have applied the government rates from 2012, with an HFO tax in 2012 of €34.47/tonne in 2012,[122] and the tax on gas oil to €258.86/tonne. Both are constant in real terms thereafter.

Figure A.3
Oil Price Projection ($/t)



Source: Short term: Historical data from Bloomberg. Medium term: Forward curves up to December 2018. Long Run: World Energy Outlook 2011, "Current Policies" scenario inflated using implied US CPI inflation. Projection of oil price of $135/bbl by 2030 corresponding to a nominal price of roughly $225/bbl in nominal terms.

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121 As the figure makes clear, there is currently a significant divergence between the long-run IEA projection and the forward curve.

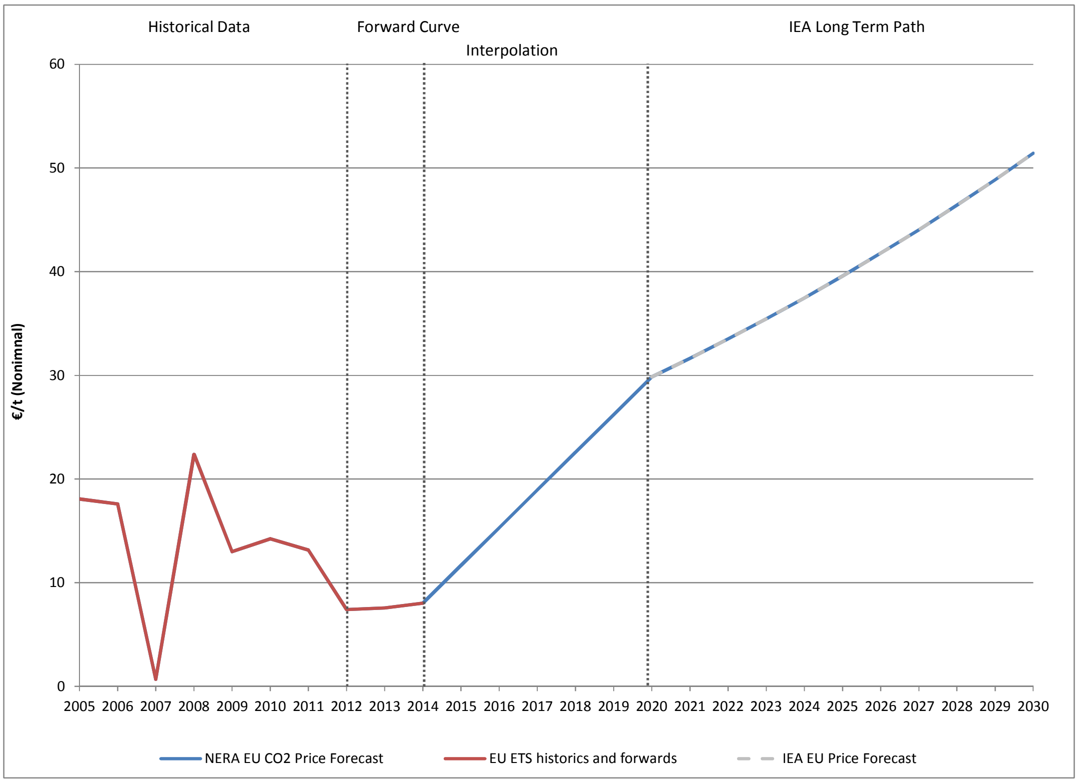
122 http://www.deloitte.com/assets/Dcom-Global/Local%20Assets/Documents/Tax/Alerts/dttl_CustomsFlash_EnergyEdition_number_1_2012.pdf

Table A.4
Delivered HFO and Gasoil Price

Oil	Units	2010	2011	2012	2013	2014	2015	2020	2025	2030
Brent Oil Price Projection	$/bbl	78.8	109.6	108.4	100.8	97.4	93.9	113.8	182.1	218.7
Gasoil										
Historic Gasoil	$/t	678.3	939.3							
Gasoil Regression with Oil				937.9	904.4	875.3	845.1	1015.5	1598.3	1910.4
Gasoil Projection	€/t	511.7	674.8	741.8	732.8	704.6	676.7	803.7	1265.0	1512.0
Tax	€/000 litres	207.2	207.2	258.9	261.2	265.0	268.7	291.8	320.3	351.6
Tax	€/t	243.2	243.2	303.8	306.6	311.0	315.4	342.5	376.0	412.7
Transportation	€/t	34.0	34.8	35.6	36.2	36.7	37.2	40.4	44.4	48.7
Delivered Price to Power Plant	€/t	788.9	952.7	1081.2	1075.6	1052.3	1029.3	1186.6	1685.3	1973.4
HFO										
Historic HFO	$/t	465.6	647.2							
HFO Projection	$/t			626.8	548.8	529.0	508.5	624.2	1019.8	1231.6
HFO	€/t	351.2	464.7	494.6	444.6	425.9	407.2	494.0	807.2	974.8
Taxes	€/t	32.5	32.5	34.5	34.8	35.3	35.8	38.9	42.7	46.8
Transportation	€/t	3.4	3.5	3.6	3.6	3.7	3.7	4.0	4.4	4.9
Delivered Price to Power Plant	€/t	387.1	500.7	532.6	483.1	464.9	446.7	536.9	854.3	1026.5

A.4. Carbon Price

Figure A.4
Carbon Price Projection (€/t)



Source: Short term: Historical data from Bloomberg. Medium term: Forward curves for 2013 and 2014. Long Run: World Energy Outlook 2011, "Current Policies" scenario. Projection of emissions price of $40/t by 2030 in real terms, corresponding to roughly $65/t in nominal terms, (€52/t nominal), when inflated using implied US CPI inflation and converted to € at the current forward exchange rate.

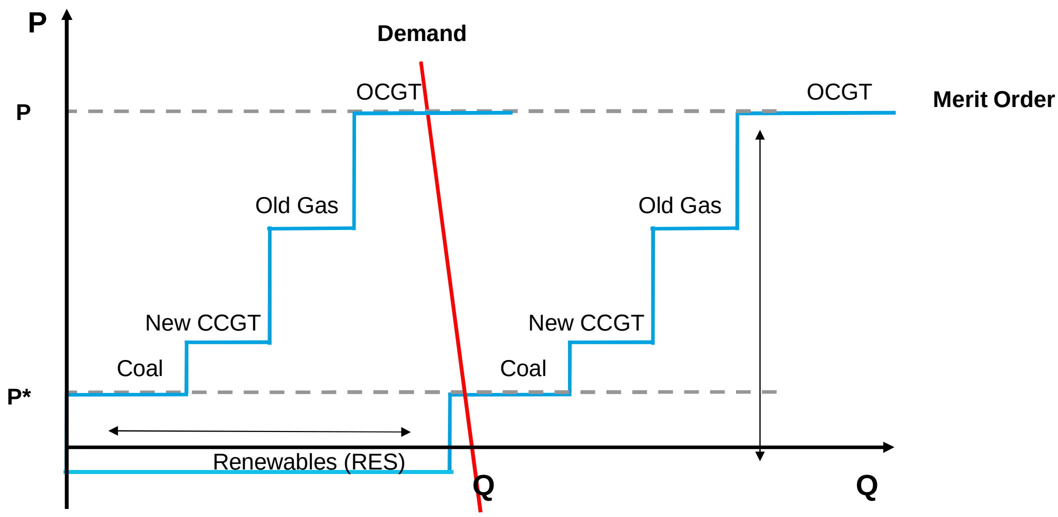
Appendix B. Intermittency and Load Duration Curves

B.1. Intermittent Output Shape and Relationship between Power Consumption and Renewables Output

Most of the potential renewable energy resources available to the Netherlands, notably wind power, are intermittent. In contrast to conventional generation capacity, the output from wind capacity depends on factors such as wind speed that are outside operator control. Netherlands is also connected to Germany, which has large amounts of both solar PV capacity (which depends on solar irradiation and hence is also intermittent) and wind capacity, both of which are expected to grow in the future.

Fluctuations in solar and wind output in the Netherlands and surrounding countries already affect the Dutch power market. In hours where there is a lot of wind output (or solar output in Germany), prices tend to be pushed down, and in periods with no renewables output, prices tend to be higher. This phenomenon is illustrated schematically in Figure B.1: for a given level of demand represented by the red curve, the addition of a substantial amount of renewable power capacity leads to a reduction in the electricity price from P to P*.

Figure B.1
The Effect of Intermittent Generation Capacity on Market Prices



In many regions where wind accounts for a substantial share of generating capacity and production,[123] the impact of wind on power markets has given rise to a negative correlation between output and price. A negative correlation between output of an individual generator and prices means wind generators typically sell power at a price that is lower than the baseload price, on average. This in turn affects the subsidy required for wind generators to break even. For example, before Western Denmark was connected to Eastern Denmark, the average price weighted by hourly wind output was up to 10 percent lower than the baseload

123 For example, Denmark, Spain, and Germany.

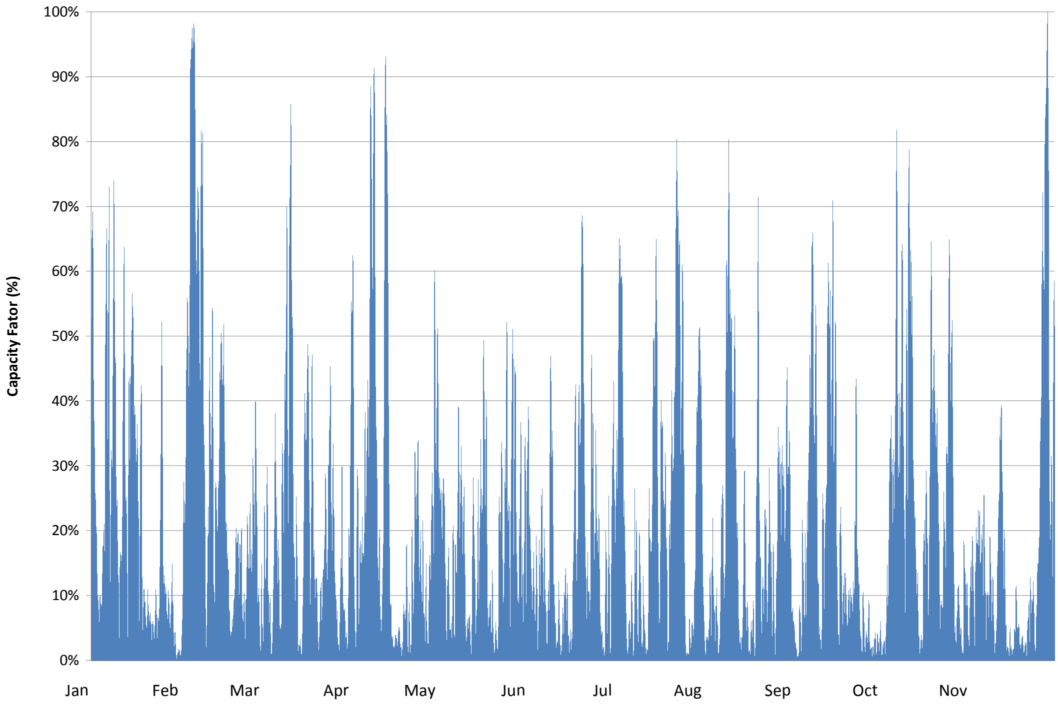
price for the region.[124] We model this price "haircut" endogenously by allowing for wind market impact.

Intermittent capacity also affects the profitability of other generators in the power market. With increased levels of renewable generation capacity there may be substantially less "residual demand", i.e. the demand which needs to be met by non-renewable capacity. This typically means there is less need for baseload capacity and greater need for peaking units when intermittent generation is low. This effect is more pronounced as wind and solar penetration increases and is likely to have a material effect on the profitability of existing plants – typically making plants that are able to operate in peaking mode more profitable (although this may depend on the nature of other existing capacity).

To take into account the intermittent generation and its impact on the power market in the modelling, we have utilised historical wind and solar generation patterns and estimated their relationship to Dutch power demand.

Figure B.2 shows a representative shape for aggregate on-shore wind generation.[125] There are frequent spikes with no discernible pattern, although there appears to be a slight tendency for higher output during the winter months.

Figure B.2
Onshore Wind Shape (Based on Capacity Factor of 21.5 percent)



Source: 50Hertz Transmission

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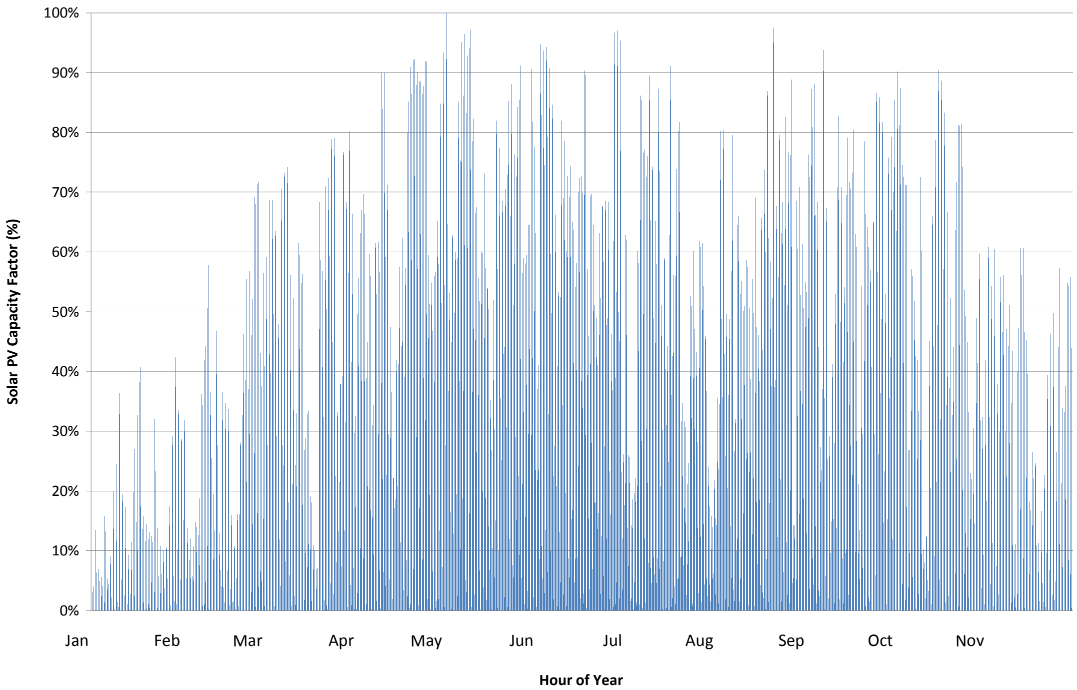
[124] Estimate based on data from Energinet.dk for the period 2009-2011

[125] We normalised the output/load to 1 (or 100%) by dividing with the maximum observation in the sample year. The wind shape shown is from Germany as we did not have these detailed shapes for Netherlands at the time of the analysis. In the final results we have utilised a Dutch wind shape.

Figure B.3 shows our assumed shape for solar PV. (In absolute terms the expected growth of solar generation capacity in the Netherlands is relatively small, but, high levels of capacity are expected in Germany, and developments in both countries will influence the Dutch power market.) The solar output share shows a clear seasonal trend of higher solar PV generation during summer months. There is, naturally, also a very strong diurnal pattern (that is, generation is high during the day and negligible during the evening/night). The figure below shows the actual realised output in 2011, and therefore reflects daily variation in weather, while also capturing seasonal variation. This provides a more realistic representation of the stochastic nature of solar output than assuming an idealised, "smoothed" daily and seasonal shape. We implement the solar shape in our modelling as an availability factor that co-varies with Dutch demand and wind output according to historic correlations, discussed below (see Table B.1).

Figure B.3
Solar PV Shape 2011 (Chronological) with capacity factor of 15 percent



Source: 50Hertz Transmission

Because wind and solar power are intermittent, it is important to understand how often the resources are available, and how the availability varies with demand, as this determines the prices the resources can achieve. The correlation between our reference solar and wind output and Dutch power demand in 2011 is shown in Table B.1. This shows that demand is correlated with solar output, but appears essentially uncorrelated with wind output. There does also appear to be a slight negative correlation between solar and wind output, suggesting that there may be some benefits of diversification among resources. Such diversification benefits are automatically captured in our modelling through the variation of availability by demand band.

Table B.1
Historical Correlations between Dutch Power Demand and RES Output (Shape)

	Demand	Wind	Solar
Demand	100%	5%	37%
Wind		100%	-16%
Solar			100%

Source: NERA analysis on data from ENTSO-E and 50 Hertz

B.2. Sampled Load Duration Curves

This section presents technical details concerning our modelling of wind output and demand. Our approach is designed to capture actual patterns of wind intermittency and their correlations with other variables and factors. We also have developed it to ensure that the decision to invest in wind takes into account these correlations and their implications for power prices.

The power market model that we are using is built around a load duration curve representation of electricity demand. A load duration curve model works by ordering demand periods (typically hours) by the level of demand, and then grouping periods with similar demand or load into representative "bands". The model then dispatches generation capacity against these levels of demand. When calculating the cost of generating electricity, the cost to supply demand within a given load band is weighted by the number of load hours in each band.

In its simplest form, a load curve model might simply sample "peak" (for example top 20 percent hours), "off peak" (for example bottom 20 percent load hours) and "shoulder" demand (everything else) over an entire year. Any variables that co-vary with demand can be represented within this framework as well. For example, given that solar output is generally higher during the day time than at night, it would be a reasonable assumption to assume higher solar availability in the "peak" band than "Off-peak" band. This can simply be estimated using average historic shapes.

There are very large computational benefits of using a load duration curve model because it vastly simplifies the computational complexity of the problem: Instead of calculating costs 8760 hours, the computer might only need to calculate 3 (and weight them accordingly). However, there are also disadvantages. In particular, variations in variables that are not correlated with demand are not easily represented. So, for example, it is not necessarily the case that wind output is higher during the day than during the night. Nor do gas prices follow intra-daily demand variations. Instead, gas prices often exhibit significant seasonal variation, which means they tend to be on average lower in the summer than in the winter where demand for gas is high, with the price differential reflecting the cost of storing gas. Because the load duration curve framework abstracts from these chronological and seasonal features, we need to make additional adjustments to ensure that they are appropriately represented in the model.

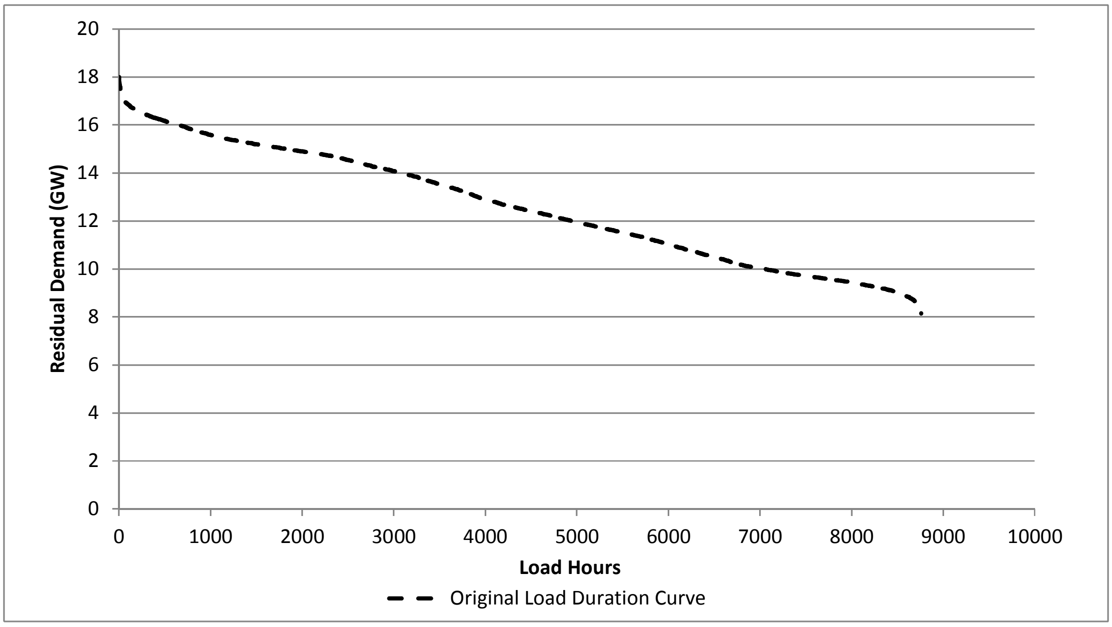
We have identified two important drivers of prices in the Dutch power market which do not necessarily co-vary with demand, and which therefore require some additional structure to be imposed on the model. These are:

- Seasonal variations in fuel prices over the year; and
- Variations in wind speeds over the day/year

For the purpose of this analysis, we have applied a sampling methodology for selecting bands, which takes these drivers into account. In particular, we sample a total of 100 bands per year, which we select to ensure a good representation of different situations. In the case of wind output, for example, it is important for us to represent situations where there is high (or low, or moderate, etc.) load and low wind output, as well as high (or low, etc.) load and high wind output. Solar is less important for the Dutch market so we include variations to the extent it covaries with demand and wind output, but do not use the solar output for choosing bands. (Also, because solar co-varies with demand, different levels of output are already reflected in the sampling approach).

Figure B.4 shows the original load duration curve, which contains 8760 hours.

Figure B.4
Original Load Duration Curve



Source: ENTSO-E, Country Package 2011

The objective of the sampling of bands is to ensure an accurate representation of the co-variation of demand with other variables. In particular, we want to ensure that the *residual* demand to be met by dispatchable generation capacity has an accurate shape that reflects the seasonality of wind and solar output, and that the relevant load hours are matched to fuel prices that accurately reflect seasonality. We have selected bands to represent this curve as follows:

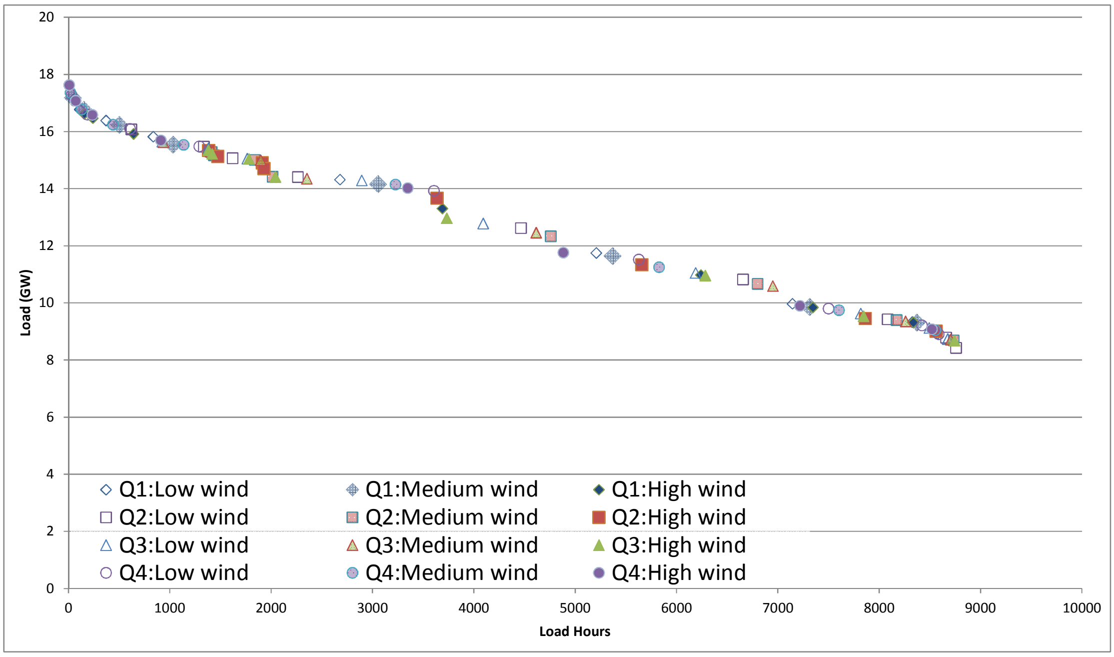
The bands are selected such that 25 bands are in each quarter of the year, to make it possible to capture seasonal variations in fuel prices and seasonal solar and wind output.

Of the 25 bands in each quarter, we further subdivide bands to represent different levels of wind output – labelled "low", "medium", and "high" output.[126] We select nine bands to represent periods when the wind load factor is below 20 percent of peak capacity, eight bands to represent load factors between 20 percent and 70 percent and the remaining eight bands to represent load factors above 70 percent. The relative share of time represented by these three wind output levels in each quarter is determined by the wind output shape (discussed above in section B.1).

Within each (quarterly) wind output level (consisting of eight or nine bands) we assign one band to the peak demand (the top 1 or 2 percent of hours) and one band to the demand trough (the bottom 1-5 percent, depending on band). The remaining six or seven bands are distributed such that the shape of the demand curve is captured as best as possible.

Figure B.5 shows the sampled bands together with the classification.

Figure B.5
Selected Bands in Load Duration Curve



For example, in the sample year, there were 1304 hours in Quarter 1 with *low wind conditions* (wind output <20 percent). In this subset of 1304 hours, we sampled 9 representative demand bands, which are indicated in the figure with an unfilled diamond. The top demand band within this group is selected to represent 1 percent of the 1304 hours,

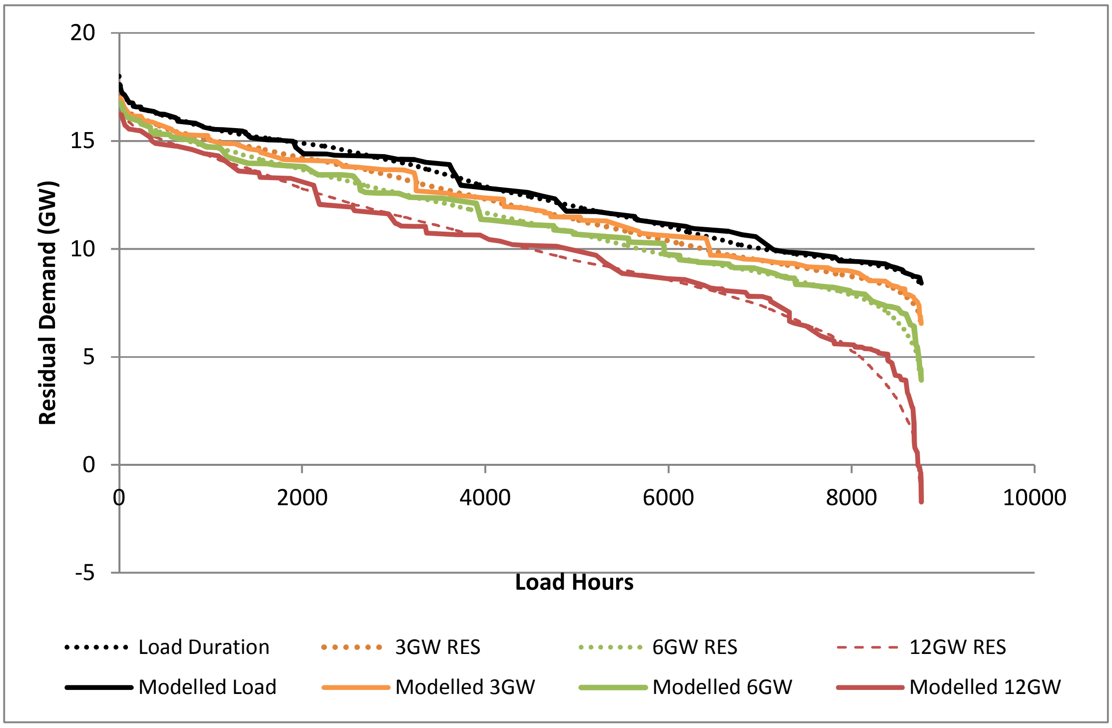
126 A common approach for incorporating intermittent renewables in a load duration curve framework is to net off output from renewables before it feeds into the power market model. However, this approach does not allow for the endogenous modelling of new capacity because the contribution in MWh/h for renewables is fixed exogenously before the modelling.

i.e. 13 hours. In these 13 hours, load was 95 percent of annual peak load on average, the wind load factor 8 percent and solar output 3 percent.

When calculating average generation costs, we weight output in each band according to the band's frequency. Hence, in the above examples, the illustrated band would carry a weight of only 13 hours of the 8760 hours in a year. Other bands have many more hours. In fact, we have deliberately designed the band selection such that bands representing frequently recurring shoulder demand conditions represent many more hours per band than extreme conditions.

As discussed above, as the level of wind capacity increases, the number of residual load hours to be served by dispatchable capacity falls, and because of the low level of correlation between wind output and demand, the residual load duration curve becomes steeper. In Figure B.6 we show how the residual load duration curve would be affected by increasing levels of onshore wind capacity. (Recall that we assume that additional wind capacity will have the same output shape as in the reference year.) The figure also shows how our load sampling methodology would compare to the hypothetical residual load duration curves under the different wind capacity levels (3GW, 6GW and 12GW respectively). The methodology captures the aggregate residual demand curve well for most combinations of demand and renewable output. In particular, it captures the fact that that residual "demand" may become negative when installed RES capacity reaches 12GW.

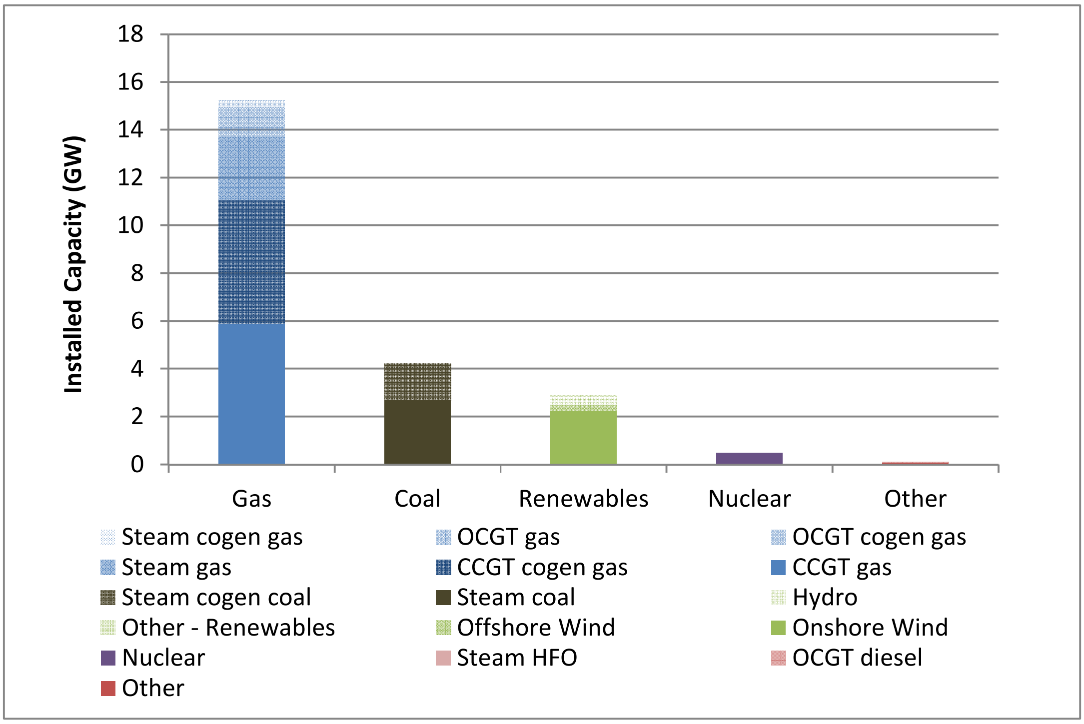
Figure B.6
Actual and Simplified Residual Demand with Increased RES penetration



Appendix C. Installed Capacity, Efficiencies and CHP/Must Run Constraints

In total, the Netherlands had around 23GW of installed capacity at the end of 2011, as illustrated in Figure C.1. The Dutch capacity mix is dominated by gas-fired capacity. In 2011 the biggest share of generation capacity was gas (15.2GW), followed by coal (4.2GW), renewables (2.9GW) and a small amount of nuclear (0.5GW). Most of the gas capacity is either CCGT or cogen CCGT, with the remainder being OCGT cogen or steam gas.

Figure C.1
Installed Capacity (End of 2011)



Source: Platts Powervision; Rijs

C.1. Planned Developments of Conventional Generation Capacity to 2014

A large number of new thermal units are either commissioned, or are under construction and are due to be commissioned in the period 2012-2014.[127] In our modelling, we assume these come online according to the schedule set out in Table C.1. The table also shows some capacity that is expected to be retired over the next few years.

There are additional plants at different stages of planning but for which construction is not yet underway. Rather than impose the construction of these plants in advance, we allow the model to decide how much capacity will be constructed in the future.

127 These developments are already underway, with, for example, the 870 MW Enecogen plant having been commissioned in late 2011.

Table C.1
Non-Renewable Committed Capacity Changes 2012-2014 (MW)

Plant	Type	2012	2013	2014
Clauscentrale B	Steam gas	- 640		
Clauscentrale C	CCGT gas	1,280		
Eemshaven Magnum	CCGT gas	1,312		
Enecogen	CCGT gas	870		
Hemweg 9	CCGT gas	435		
Moerdijk 1	CCGT cogen gas	- 358		
Moerdijk 2	CCGT gas	430		
Delfzijl I	Other - Renewables		50	
Hemweg 7	Steam gas		- 511	
Maasvlakte 4	Steam coal		800	
Maasvlakte 3	Steam cogen coal		1,070	
Diemen 34	CCGT cogen gas			435
Eemshaven RWE	Steam coal			1,600
Total		3,329	1,409	2,035

Source: Platts Powervision, cross-checked and corrected with data from industry sources.

C.1.1. Planned retirements of existing capacity beyond 2014

To make projections for the Dutch power market beyond 2014 we need to forecast the evolution of existing capacity on the system. We take the following approach:

- We assume units can retire no later than a maximum retirement date, which for coal plants we assume to be maximum 60 years[128], 40 years for existing nuclear plants, and 30 years for CCGTs. These lifetimes are assumptions on the useful life that each plant type can technically achieve, which we have derived from a range of industry data. They do not necessarily correspond to the duration of particular generators' licences;
- In addition, our wholesale market model endogenously selects retirement dates for units that do not earn sufficient margins in the energy market to cover their ongoing fixed operating costs. Hence, some units will retire earlier than the assumed maximum lifetimes set out above; and
- We assume that hydro and existing wind plants will remain online indefinitely.[129]
- Some units have announced retirement dates beyond 2015. However, we assume that these announcements do not necessarily reflect firm commitments and do therefore not make explicit assumptions about these retirements. Rather, we allow the model to endogenously select which plants to retire based on the profitability of the plants in the market. We will be able to vary this assumption – for example, to force the retirement of additional plants – in sensitivity analysis.

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128 In the model, existing plants are retired endogenously before then if it is economically beneficial to do so. We assume the fixed O&M includes any necessary improvement works to keep them online

129 Although parts of the technical installations at these sites are likely to change as they reach the end of their economic lives we assume that plants in these locations remain regardless of the subsidy scheme and economic environment. In practice, this assumption is unlikely to affect results of the mode much.

- In the case of coal plants, we assume that plants already comply with the new Industrial Emissions Directive, (2010/75/EU, hereafter "IED"), such that there is no further requirement to fit plants with any additional emissions abatement equipment to comply with the IED. Note, however, that this assumption can be changed based on additional information, and the model can be adapted to endogenise the decision whether to invest in abatement equipment and continue operation or to shut down instead.

We have obtained a detailed breakdown of plants on the system from Platts Powervision which we have checked against data from SQ Consult and also confirmed from other public sources. Our assumptions about units' thermal efficiencies (i.e. heat rates) are based on information collected from operators.

C.2. Evolution of Supply/Demand Balance before Modelling

Table C.2 shows the changes to capacity up to the period 2030 as a result of the above assumptions. The table includes the changes shown above in Table C.1. The aggregate capacity is shown in Figure C.2.

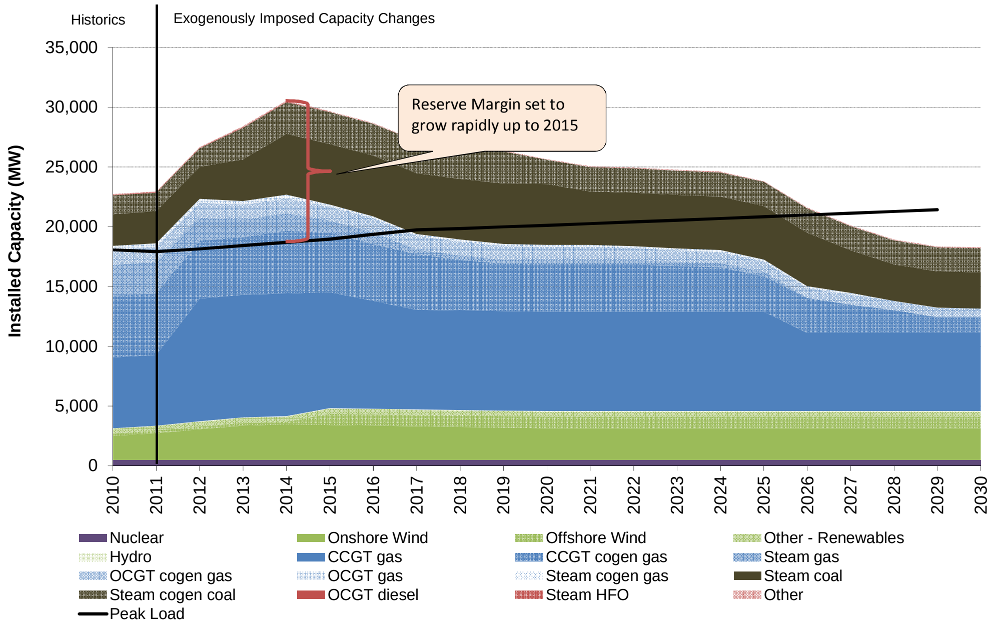
Rather than specifying exogenously which wind plants are due to come online, we model these endogenously. Hence, only projects due to come online during 2012 are included in the table. Any other projects under advanced development are not included in the table.

Table C.2
Exogenous Changes to Capacity 2012-2030 (New Build + Retirements)

		Initial	Change						
		2011	2012	2013	2014	2015	2016-2020	2021-2025	2026-2030
Gas	CCGT cogen gas	5,169	-358	0	435	-244	-1,048	-975	-1,658
Gas	CCGT gas	5,896	4,370	0	0	-579	-1,374	0	-1,775
Renewables	Hydro	49	0	0	0	0	0	0	0
Nuclear	Nuclear	480	0	0	0	0	0	0	0
Gas	OCGT cogen gas	1,245	0	0	0	-87	-38	-257	-147
Other	OCGT diesel	26	0	0	0	-26	0	0	0
Gas	OCGT gas	309	0	0	0	-141	0	-12	-149
Other	Other	74	0	0	0	0	0	0	-1
Renewables	Other - Renewables	376	0	50	0	0	0	0	0
Coal	Steam coal	2,675	0	800	1,600	0	0	-602	-1,443
Coal	Steam cogen coal	1,569	0	1,100	0	0	-645	0	0
Gas	Steam cogen gas	7	0	0	0	0	0	0	0
Gas	Steam gas	2,616	-640	-511	0	-467	-640	0	-358
Other	Steam HFO	13	0	0	0	-13	0	0	0
Renewables	Onshore Wind	2,226	399	328	160	0	0	0	0
Renewables	Onshore Wind MEP Retirement		-50	-50	-50	-50	-250	0	0
Renewables	Offshore Wind	228	0	0	0	719	0	0	0
	Total	22,956	3,721	1,717	2,145	-887	-3,995	-1,846	-5,531

Source: NERA analysis on data from Platts Powervision

Figure C.2
Exogenously Imposed Capacity Changes

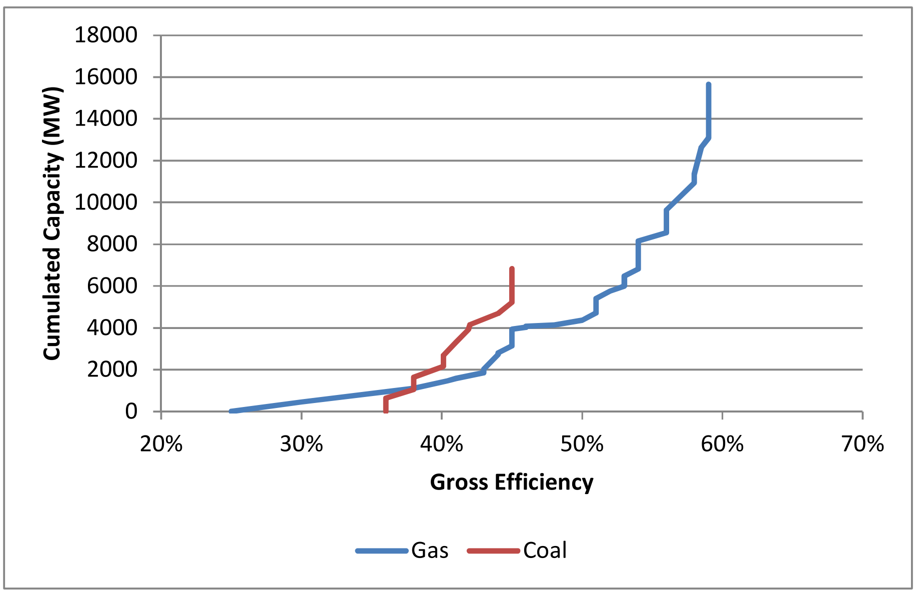


Source: NERA analysis on data from Platts Powervision

C.3. Efficiencies and CHP Constraints

Figure C.3 shows the distribution of gross efficiencies for gas and coal plants of currently installed capacity. We have applied this distribution of efficiencies to the capacity information in Powervision as set out in Table C.3.

Figure C.3
Distribution of Gross Efficiencies of Gas and Coal Plants



Source: Compiled on the basis of industry data from SQ Consult

Table C.3
Assumed Plant Efficiencies

	Capacity (MW)	Gross Efficiency (%)	Net Efficiency (%)
Coal			
Coal	2675	38.8%	33.9%
Cogen Coal	1569	44.1%	38.6%
Total/Average	4244	40.8%	35.6%
Gas			
OCGT	1245	35%	31%
OCGT Cogen	309	41%	36%
Other Gas	2616	44%	39%
Other Gas Cogen	7	46%	41%
CCGT Cogen	5169	53%	47%
CCGT	5896	58%	52%
Total/Average	15240	52%	46%

Source: NERA analysis based on an analysis of individual plants undertaken by SQ consult.

Table C.4 shows an estimate of "must-run" constraints for the different categories. The must run constraints reflect the requirement for plants to generate heat for industrial purposes during the course of the year, and for heating during the winter.[130] The "must-run" constraint means these plants are forced to run, rather than being dispatched as conventional capacity, which pushes them up the merit order and affects the cost of the generators meeting demand. The must run constraints are based on an analysis of heat requirements in summer and winter by individual plants undertaken by SQ Consult. For modelling purposes, we have assumed that must run units switch off at a power prices below zero.

Table C.4
Assumed Must Run Constraints

	Capacity (MW)	Winter Must Run (%)	Summer Must Run (%)	Winter Must Run (MW)	Summer Must Run (MW)
Cogen Coal	1569	42%	0%	657	0
OCGT Cogen	309	75%	75%	231	231
Other Gas Cogen	7	100%	80%	7	6
CCGT Cogen	5169	40%	31%	2,060	1,596
Total	5484	42%	26%	2,955	1,832

Source: NERA analysis based on an analysis of individual plants undertaken by SQ consult.

130 We understand that some of the CHP plants with heat delivery contracts are occasionally just run in boiler mode. We do not take this into account explicitly.

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