27, November 2017

Integration costs and market value of variable renewables: A study for the Dutch power market

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Abstract— Increasing shares of wind and solar power in the electricity system have a considerable impact on electricity markets. The variable and uncertain generation from these renewables is a source of additional costs. These costs include the costs of back-up needed for periods with low wind and solar production, the cost of transmission to reach demand centers, and the costs of balancing the electricity system to adjust for wind and solar power forecast errors. Furthermore, electricity generation from wind and solar with very low marginal costs depresses electricity prices on the wholesale market, an effect that is even more pronounced for the price that wind and solar earn on the market. While these cost increases and price effects are common to all electricity markets, the magnitude of the effects will to a large extent depend on the local characteristics of an electricity market, such as the incumbent generation mix and the interconnections with other markets. In this study, we introduce a modelling framework utilizing a detailed European electricity market model to quantify integration costs and price effects of variable renewables in the Netherlands. Our methodology allows calculation of various components of the integration costs based on a single consistent dataset and modelling tool. Our results for the Netherlands underline the importance of interconnections in reducing the integration costs of renewables in the electricity system.

"Keywords: variable renewable generation; integration costs; wind; electricity markets; market value; market integration"

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1. Introduction

The European Union (EU) aims to cut its emissions substantially by more than 40% in 2030 and 80% in 2050. This has led many EU member states to set ambitious targets for the deployment of renewable sources (EC, 2011). The target set for 2030 is to increase the share of renewables to at least 27% of EU energy consumption (EC, 2015). Achieving both emissions and renewable targets has a significant impact on the EU power sector that has been transforming over the past decades from an electricity system with dispatchable conventional generation to a system with non-dispatchable generation as a result of increasing shares of variable renewables, such as wind and photovoltaics (PV). This increase will be even more substantial over the years to come. However, electricity generation from variable renewables has some specific characteristics, i.e., variability, unpredictability, low short-run marginal costs, that are different from conventional generation, leading to a variety of impacts on the electricity markets.

An important impact of increasing penetration of wind and solar power in electricity markets is the integration cost. Integration costs are defined as "the increase in power system operating costs" (Milligan and Kirby, 2009) or as "the marginal cost increases in the residual system" (Ueckerdt et al., 2013) caused by renewables. Technical characteristics of variable renewable energy may incur significant integration costs at the system level, which is neglected by the widely used method of Levelised Cost of Electricity[1] (LCOE) (Ueckerdt et al., 2013, Roy, 2015). The integration costs of renewables are in general classified in three components: profile costs, balancing costs, and grid costs.

Profile costs, the first component of integration costs, result from more variability in electricity production, meaning large changes in electricity production from one hour to the other. This variability will have to be accommodated by the new flexibility options such as electricity storage that are costly or by the dispatchable conventional generation with short and long-term effects. In the short-term, the conventional generators should cycle with more frequent start-ups and ramp up and down quickly. In the long-term, there is need for sufficient backup capacity for those periods in which renewable production is low in order to secure the system adequacy. However, the full load hours of the required backup capacity also decrease with increasing renewable generation. Hence, in an energy-only market with high shares of renewables, capital intensive conventional generators must cover the cost of their capacity with reduced load factors, which results in higher residual system[2] cost. Thereby, profile costs are the sum of increased operational- and capital costs for conventional generation in the residual system as a result of flexibility and utilization effects. Profile costs also include wind curtailment costs. The second component of integration costs is the balancing costs that result from unpredictability of variable renewable generation. Non-dispatchable generation from wind and solar depends on inherent uncertain wind and solar predictions (forecast error). Balancing deviations of variable renewable generation in real time will result in redispatch costs and additional need for reserves, increasing the cost of the system. The third component of integration costs is the grid costs. Increasing variable renewable generation requires reinforcement of the transmission grid (high voltage) and distribution grid (medium and low voltage). Centralized renewables are in general located far from demand, hence additional transmission capacity is needed to transfer renewable generation to demand centers. For decentralized renewables, the distribution network needs to be adjusted to accommodate the intermittency.

Integration costs of variable renewables have been estimated by many studies (e.g., Milligan and Kirby, 2009, Milligan et al., 2011, Ueckerdt et al., 2013, Hirth, 2012, IEA, 2014, NEA, 2012). Based on the review of these studies by Sijm, 2014, the integration costs can widely range from 10-30 €/MWh for wind and 25-50 €/MWh for solar at 10%-30% penetration levels. These studies in general use a simple approach by considering only the historic pattern of residual demand or a theoretical model for an isolated country. Therefore, they are unable to capture the interactions between generation and demand on the day-ahead market and the intraday and balancing market as well as the interdependencies between neighboring electricity markets. This paper introduces a more sophisticated modelling framework to quantify the integration costs of renewable generators in the Netherlands for the year 2030 and provides the following improvements to the existing literature on the methodology for calculation of integration costs.

The magnitude and the decomposition of the integration costs depend on a complex interaction of factors such as renewable penetration levels, the incumbent generation mix, correlation between load and renewable profiles, the fuel and CO2 prices, and the interdependencies between interconnected markets. Thus, it is important to quantify these costs by electricity market models that represent real world systems, which take

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[1] The LCOE is the ratio of the costs incurred to build and operate a power-generating unit on the amount of electricity expected to be generated on the lifetime of this unit. It is used to compare different electricity sources, despite their different cost structures

[2] The term "residual system" is used for the part of the power system supplied by dispatchable generation. It is analogous to the term "residual load" that is often formulated as total load minus generation from variable renewables.

into account these factors. In this study, we utilize a transmission-constrained European power market model, COMPETES, which is formulated as a unit commitment problem to simulate the day ahead and intraday/balancing markets in 33 countries in Europe and the electricity trade between them. The model takes into account the interconnection capacities within these countries as well as the detailed characteristics of electricity supply such as start-up costs, the ramping capabilities of different technologies, the lumpiness in generators' start-up decisions, and the adaptation of the electricity system by optimal capacity expansion of more flexible new conventional generators. These are important factors in an electricity system affecting integration costs, which have not been taken into account at the same time by other integration cost studies.

Furthermore, existing studies quantifying integration costs calculate only profile costs endogenously by using their methodology whereas they take the balancing and grid costs from other studies, which may constitute inconsistency due to the differences between underlying system assumptions of these studies, e.g., generation-mix, fuel prices, demand and/or renewable profiles, and the location of variable renewables may be assumed differently under different studies. Another contribution of this paper is that we take into account the interactions between the day-ahead and intraday/balancing markets and we calculate the profile and balancing costs endogenously by utilizing the COMPETES model based on a single consistent dataset and assumptions. Similar to the other studies, we do not calculate grid reinforcement costs within the Netherlands endogenously. A proper estimation of these costs requires a detailed network representation of the Netherlands where the availability of data is limited. Moreover, the grid cost estimations depend on the exact location of the renewable projects within the Netherlands, which is uncertain for the year 2030. The grid cost estimations could be added exogenously, e.g. based on other integration cost studies, but then the underlying assumptions for these estimations would be different, resulting in inconsistency between the grid costs and the profile and balancing costs.

The Netherlands does not exist in isolation, and therefore electricity trade between the Netherlands and its neighbors is important for quantification of the integration costs. The benefits of interconnection and market integration on reducing the integration costs of renewables are well known but they have not been quantified by existing integration cost studies which in general assume an isolated country. In this study, we model the allocation of the cross-border transmission network between EU countries and quantify the potential benefits of the interconnection capacity expansion between the Netherlands and the neighboring countries on the profile and balancing costs. Our results show that the benefit of interconnection capacity expansions in reducing the integration costs of variable renewables is higher in comparison to the cost of these capacity expansions. Thus, the interconnection capacity investments in the Netherlands considered in this study result in net benefits for the integration of variable renewables.

Finally, we quantify the price impact of an increase in variable renewable penetration in the Dutch power market and the benefits of interconnection capacity on their market value. Non-dispatchable power generation from wind and solar, having very low marginal costs, depresses the electricity prices on the wholesale market, especially during windy and sunny hours. This results in reduction of their market value. Market value is defined as the marginal revenue that generators can earn in markets, without income from subsidies (Joskow, 2011, Hirth, 2013). It is an indication of the profitability of generators and the investors' perceptions of its business prospects. In our analysis, we observe that the market value of variable renewables decreases further with higher penetration, diminishing their business case. However, the renewables benefit more in an integrated electricity system since their market value increases with investments in the cross-border capacity.

The paper is organized as follows; Section 2 presents the definition of integration costs given by Ueckerdt et al., 2013 and our methodology to calculate profile and balancing costs by using a three-step approach. In Section 3, the assumptions and the quantitative results are provided under various scenarios reflecting the cost and market value impact of increased renewable penetration and the additional cross-border transmission capacity in the Netherlands. Section 4 concludes and discusses policy implications of integrating variable renewables. A short description of COMPETES input data is provided in Appendix A.

2. Background

The concept of integration costs for variable generation is defined as the additional costs in the residual system when introducing renewables. Although the definition is simple, the calculation of integration costs is not straightforward and varies between studies. In order to calculate integration costs, a comparison of two cases is required: an electricity system with and without variable renewables. One of the main difficulties of this comparison originates from the design of the base case without variable renewables. The base case without variable renewables is in general defined by introducing a benchmark technology as a proxy. Such a proxy is assumed either to supply a flat block of electricity over a certain period – which is equal to the total renewable energy without its variability and uncertainty – or to be a perfect generator that reduces the load proportionally (Ueckerdt et al., 2013). However, the choice for fuel cost of such proxy is crucial and affects the calculation of integration costs (Milligan et al., 2011). We do not consider a benchmark technology supplying a flat block of electricity or reducing the load proportionally for the base case. Instead, we endogenize the investments of the conventional generation capacity in both cases by running an investment planning model. As a result, the optimal generation mix will be different for the two cases. We hypothesize that the optimal generation mix without renewables will include a higher share of base-load generation (e.g., nuclear, coal) with relatively low generation cost, whereas an optimal generation mix with renewables will include higher share of flexible generation with relatively low capital cost (e.g., combined cycle plants (CCGTs) and gas turbines).

Another difficulty is choosing a good indicator for the integration cost such that it distinguishes the additional costs of renewable generation from its benefits to the system. For instance, if the absolute residual costs are compared for the cases with and without renewables, increasing renewable generation will always result in lower absolute residual costs since total fuel-based generation in the residual system decreases with increasing renewable generation. A common indicator in the literature to calculate the integration cost is the average residual system cost (per MWh), which typically increase with increasing variable generation. Ueckerdt et al., 2013 provide a rigorous method for calculating integration costs as the marginal impact of additional wind or solar power on the costs of the residual system. They introduce System LCOE as the sum of marginal generation cost and the marginal integration cost of variable renewable generation. The marginal integration cost is defined as the marginal increase in profile costs, balancing costs, and grid costs as illustrated in Fig. 1. In this study, we use the average residual system cost as an indicator of integration cost of renewables based on the definition of Ueckerdt et al., 2013.

a. We first calculate the absolute integration costs of the variable generation. The absolute integration costs C_{int} are derived by calculating the difference between the residual system cost of the case with variable renewable energy (VRE) and the residual system cost of the base case with low or no renewables (Base case).

$$C_{int}\,(€) = \left(\frac{C_{Resid}\,(VRE)}{E_{Resid}\,(VRE)}\left(\frac{€}{Mwh}\right) - \frac{C_{Resid}\,(Base)}{E_{Resid}\,(Base)}\left(\frac{€}{Mwh}\right)\right) * E_{Resid}\,(VRE)(Mwh) \qquad (1)$$

$C_{Resid}(VRE)$ and $C_{Resid}(Base)$ indicate the total costs of the residual system whereas $E_{Resid}(VRE)$ and $E_{Resid}(Base)$ indicate the residual demand for the case with renewables and the base case, respectively.

b. Second, we calculate the marginal integration costs with respect to the increase in variable renewable generation (i.e., $E_{VRE}(VRE) - E_{VRE}(Base)$) compared to base case:

$$\frac{\partial C_{int}}{\partial E_{VRE}}\left(\frac{€}{Mwh}\right) = \frac{C_{int}}{E_{VRE}(VRE) - E_{VRE}(Base)}\left(\frac{€}{Mwh}\right) \tag{2}$$

E_{VRE} indicates the total variable renewable generation for the corresponding cases.

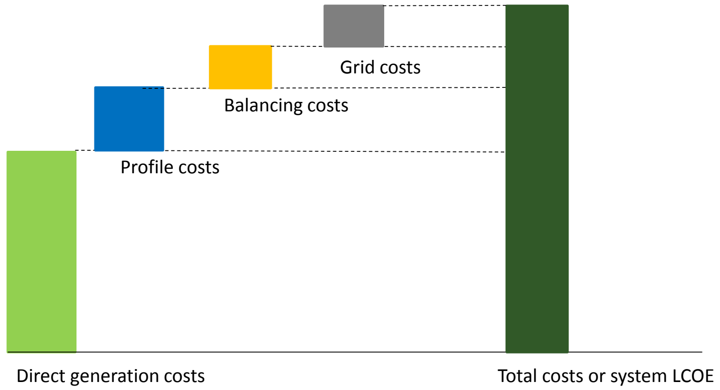

Fig. 1. Levelised costs of electricity (Ueckerdt et al. 2013): costs/$MWh_{renewable}$

C_{Resid}, E_{Resid}, and E_{VRE} depend on the variable renewable penetration and the electricity market outcomes. These values are calculated in a case study by using the methodology described in Section 3. In the case study, we quantify endogenously the profile and balancing costs for the Netherlands. Thus, $C_{Resid}(VRE)$ represents the profile costs and balancing costs. Profile costs consist of the long-term adequacy costs as a result of back-up capacity cost and the decreased utilization of back-up capacity incurred to the residual system. Curtailment costs of variable renewables are implicitly included in the operational costs. Balancing costs are the redispatch costs and short-term adequacy costs as a result of the increased need for reserves to balance renewable generation deviations in real time. Intra-country grid costs are not calculated since these costs require a detailed representation of the network within the Netherlands.

While we do not take into account possible grid costs within the Netherlands, we quantify the benefits of additional cross-border transmission capacity on the reduction of integration costs of wind. This is done by simulating wind penetration scenarios with current and increased cross-border transmission capacities of the Netherlands and calculating the decrease in profile and balancing costs.

3. Methodology

In European electricity markets, trade takes place on several time scales from long term markets (i.e. forward markets) to medium and short term markets (i.e. day-ahead markets, intraday markets, and balancing markets). The day-ahead and intraday markets are organized by power exchange where buyers and sellers of electricity provide their bids and offers and the market is cleared at a price (e.g. EPEX). The day-ahead market closes one day prior to the actual delivery of electricity and the market is cleared at the market price for each hour of the next day. The intraday market takes place during the day of operation and closes one hour to 5 minutes prior to the actual delivery. After the closing of the intraday market, TSOs are responsible for real time balancing by activating earlier contracted reserves in case of contingency to secure system stability. In order to calculate the profile and balancing costs of variable generation in the Netherlands, we will make a distinction between balancing the variability from wind and solar energy on the day-ahead market and balancing the deviations in wind power generation because of the forecast errors on the intraday and balancing markets. In our approach, we will not distinguish between the intraday market and the single-buyer market for regulating and reserve power; instead we will consider balancing deviations in wind power generation because of forecast errors as one market, and refer to it as "*intraday market*".

We use a European electricity market model called COMPETES to simulate day-ahead and intraday markets in the short term in addition to the generation capacity investment decisions to satisfy resource adequacy in the long term. COMPETES is a power system optimization tool that seeks to minimize the total power system costs while accounting for the technical constraints of the generation units, transmission constraints between the countries and the generation capacity expansion for conventional technologies. The model covers 28 EU member states and some non-EU countries (i.e., Norway, Switzerland, and the Balkan countries), including a representation of the cross-border transmission network interconnecting these European countries (Fig. 2). There are 11 types of fossil-fuel fired power plants as well as nuclear, geothermal, biomass, waste, hydro, wind and solar technologies; unit by unit generation is detailed for the Netherlands, while all other countries are aggregated by fuel type and year. A description of COMPETES input data is provided in the appendix.

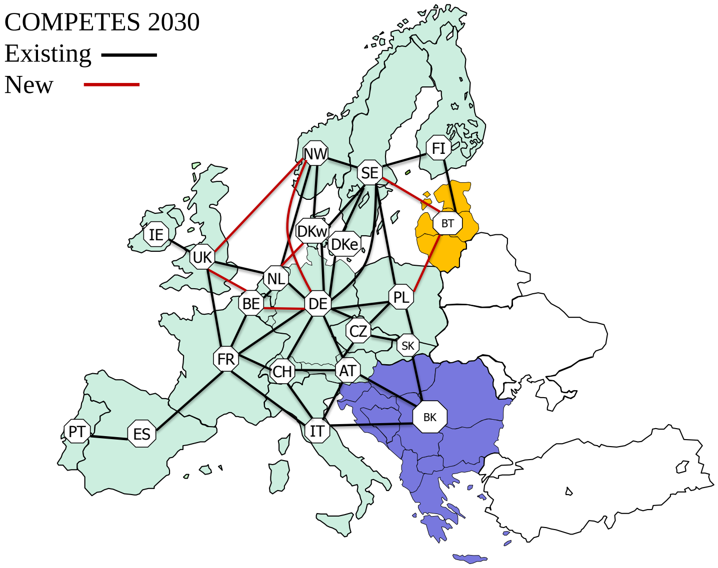

Fig. 2. Geographical scope of COMPETES

COMPETES can be used to perform hourly simulations for two types of purposes: a generation capacity expansion model formulated as a linear program to optimize capacity additions in the system and a unit-commitment (UC) model formulated as a mixed integer program taking into account flexibility, minimum load constraints, and start-up costs of generation technologies. The objective function of the model minimizes the sum of the generation and minimum load costs, start-up costs, load-shedding costs, and in case of generation capacity expansion, amortized costs of capacity expansions. Its solution gives the electricity market equilibrium in Europe under perfect competition assumption, i.e., it provides generation capacity, electricity dispatch, electricity prices, and flows as output. The generation capacity expansion and the unit commitment models are run sequentially to simulate long and short-term effects of renewables on the electricity market. Our methodology to calculate profile and balancing costs by using COMPETES consists of the following steps as illustrated in Fig. 3.

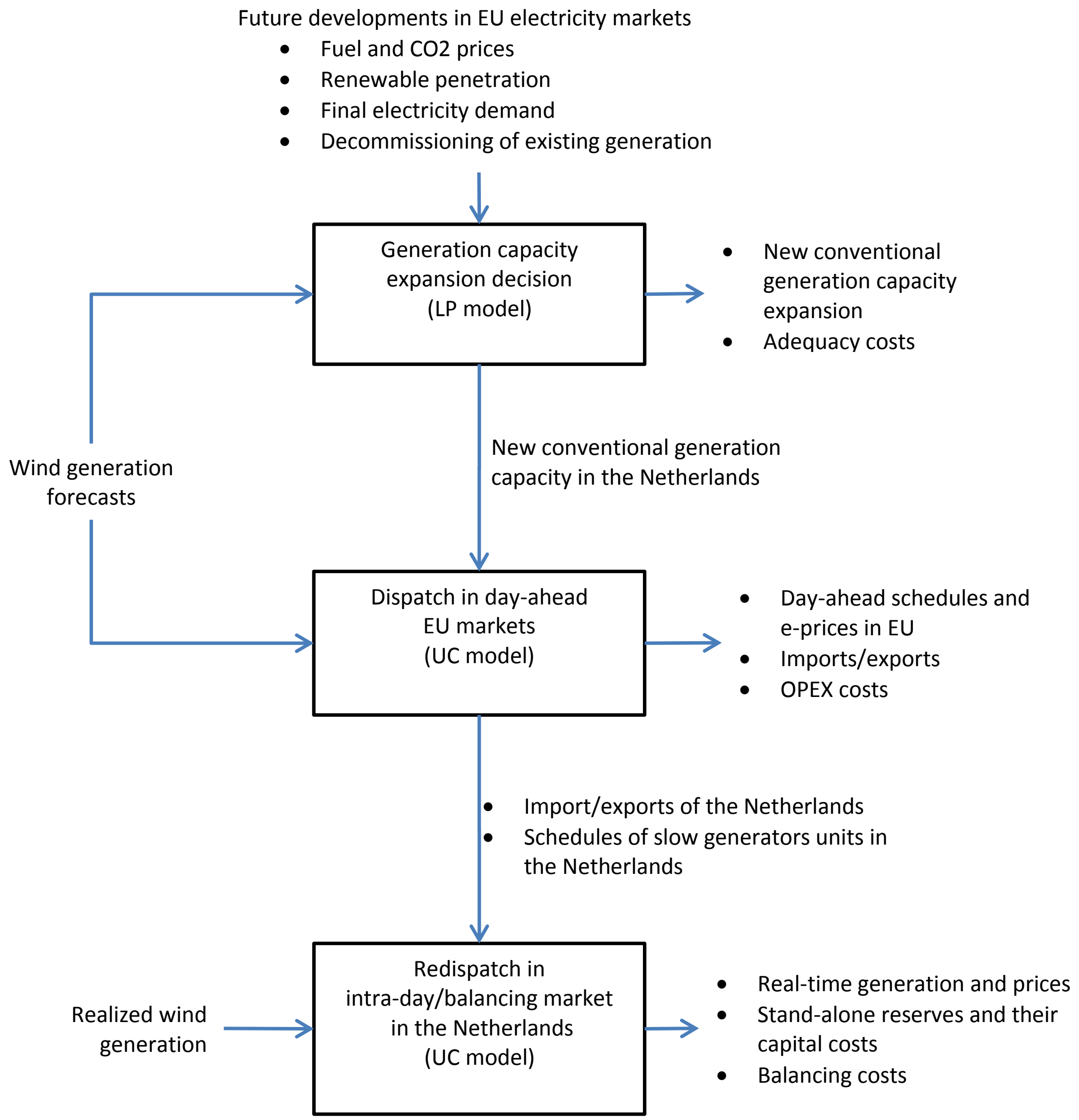

Fig. 3. Methodology to assess impact of variable renewables and their integration costs in the Netherlands

3.1. Long-term adequacy cost with increasing renewable generation

The long-term adequacy cost is one of the components of profile costs. It is the cost of generation capacity investments to satisfy resource adequacy for the day-ahead market with increasing share of renewables. In order to determine these costs, we use the generation expansion model of COMPETES that endogenously calculates the least cost conventional generation capacity additions[3]. The generation expansion model is formulated as a linear program, minimizing the overall annual investment and system operating costs, and the costs of load-shedding[4] in all the countries.

The main output from step 1 is the conventional generation capacity investments in the Netherlands given the generation, demand, and transmission developments in the other EU countries. We assume that only the existing conventional power plants in the Netherlands commissioned in or after 2010 are refurbished and operate in 2030, whereas older power plants are decommissioned. With this approach, we take an intermediate perspective between a short-term system, in which all capacity is given, and a long-term approach, in which all investments are optimal regardless of the legacy mix. The generation capacity expansion solution is used to calculate the backup costs of the residual system and taken as an input for the simulation of the day-ahead market in step 2.

3.2. Profile costs of variable renewables on the day-ahead market

In the second step, we simulate the day-ahead market by using the unit commitment (UC) model of COMPETES. The UC problem is the problem of deciding which power generating units must be committed or decommitted over a planning horizon. The COMPETES UC model minimizes the total variable, minimum-load, and start-up costs of generation, and the costs of load-shedding within a year in all the countries. The committed units must satisfy the electricity demand at each hour, as well as a large set of technological constraints.

- Power balance constraints ensure demand and supply is balanced at each node at every hour.
- Generation capacity constraints limit the maximum available capacity of each generating unit. These include the availability factors to capture the effect of planned and forced outages for the dispatchable plants, as well as the hourly variability for the non-dispatchable generation such as wind and solar.
- Cross-border transmission constraints limit the power flows between the countries at each hour for given Net Transfer Capacity (NTC) values.
- Ramping up and down constraints limit the maximum increase or decrease in generation of each unit between two consecutive hours.
- Minimum load constraints set the minimum generation level of each unit when it is committed.
- Minimum up and down time constraints (only for the Netherlands) set the minimum number of hours that each unit is on or off after start-up or shut-down.

With start-up and min-load costs in the objective and the minimum load and ramping constraints, the costs incurred as result of the flexibility limitations in the power system can be captured by the UC model. The full UC problem is formulated for the units in the Netherlands whereas we use a Tighter Relaxed UC (TRUC) formulation of Kasina et al., 2015 for the other countries.

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[3] This model is based on a two-stage set up similar to the ones described by Ehrenman and Smeers, 2010 and Ozdemir et al., 2013.

[4] For the load-shedding costs, the value of lost load (VOLL) is assumed to be 10,000 €/MWh (Stoft, 2002).

Given the optimal generation investment decisions taken as input from step 1, we simulate the day-ahead market in Europe by using predictions of wind and solar generation at an hourly resolution for each day of the year (see Fig. 3). The main output of step 2 are the day-ahead schedules of generation, imports/exports between countries, operational costs (generation costs, start-up costs, ramping costs, load shedding costs, and costs of renewable curtailment), and market prices. By using these outputs, we can calculate operational costs of the residual system resulting from the load factor reduction of the conventional generation, flexibility constraints and the increased frequency of start-ups of the generation units, and the curtailment of renewable generation. The outputs of step 1and step 2 together are used to calculate the profile costs.

3.3. Balancing costs in the intraday market

In the final step, we simulate the intraday market for the Netherlands with actual wind power generation. We assume a national intraday market and redispatch the domestic generation in the Netherlands against realised net load, subject to the net imports/exports from the day-ahead market. Therefore, we rerun COMPETES UC model with fixed import/exports schedules to/from the Netherlands on the day-ahead market. The commitment of slow generators is also fixed based on their day-ahead schedules whereas fast generators which are able to start up quickly are able to commit on the intraday market. The intraday market simulation results in upward or downward adjustment of domestic generation units as well as the corresponding balancing costs and prices. In addition, investments in stand-alone reserve capacity for balancing wind forecast error are calculated, ensuring that the demand curtailment is maximum 5 hours per year. The investments in stand-alone reserves are assumed to be gas turbines, which have low investment costs but high variable costs. Overall, the output of step 3 gives the balancing costs, consisting of the capital cost of stand-alone reserves and the redispatch costs of balancing deviations of wind power generation on the intraday market.

4. Case study: Integration cost of variable renewables in the Netherlands

4.1. Scenario assumptions

The costs and prices in a future electricity market are driven by a number of different factors such as electricity demand and generation-mix, fuel and CO2 prices, renewable penetration, and interconnection capacity. The future values of these factors are determined by a scenario framework presented below. For the analysis, the year 2030 is considered.

The developments of electricity demand and generation capacity in EU countries are based on “Slow progress” scenario (Vision 1) of ENTSO-E (ENTSO-E, 2013). In this scenario, the average annual growth rate in EU demand is 0.37%. The total generation capacity mix in EU shows an increasing share of renewable capacity rising up to 47% in 2030. The electricity demand in the Netherlands represents the existing policies measures of the national energy outlook (Hekkenberg & Verdonk, 2014). We assume that only the existing conventional power plants in the Netherlands commissioned in or after 2010 are refurbished and operate in 2030 whereas older power plants are decommissioned. The new conventional generation capacity for 2030 in the Netherlands is endogenously determined by the model. Regarding the future interconnection capacities between EU countries, we assume the transmission capacity investment plans given by the Ten Year Network Development Plan of ENTSO-E (ENTSO-E, 2012). The assumed fuel and CO2 prices in Table 1 represent the “Current Policies” scenario of IEA, 2013.

Table 1. Fuel and energy prices in euro of 2010

		2030
Coal Price	[€/GJ]	3.5
Natural gas price	[€/GJ]	9.4
CO_2 price	[€/tonne]	14.4

We take into account the variability of demand and renewables such as wind and solar. The data of hourly power generation profiles for solar and wind are taken from various sources (see appendix). The hourly demand represents the historical load profiles of the year 2012.

In order to calculate the integration costs of variable renewables in the Netherlands, we consider variations of the wind and solar capacity penetration in the Netherlands, ceteris paribus. The generation capacity, demand, and RES share in the other countries in all the scenarios are in line with Vision 1, which assumes an increasing share of variable renewables in EU. For instance, the total variable renewable share in the generation mix of the neighboring countries (i.e., Germany, Belgium, UK, and Norway) is 25%.

Table 2 gives the overview of the scenarios.

Scenario 0 and Scenario 1 are baseline scenarios to distinguish the integration costs of solar and wind capacity respectively. In Scenario 0, renewable capacity is assumed to remain at its current level with a share of 5% in total consumption. Scenario 1 includes 14.2 GW of additional solar PV capacity but wind capacity remains at its current level, resulting in 16% renewable share in total consumption. By comparing Scenario 1 with Scenario 0, the integration cost of solar penetration at medium level in the Netherlands can be calculated. Furthermore, Scenario 2 and Scenario 3 are variations of Scenario 1 at medium (25% which is in line with Vision 1 scenario) and high shares (60%) of wind generation in total consumption. The comparison of these wind scenarios with Scenario 1 indicates the integration costs of wind at these levels of wind penetration. We do not consider a benchmark technology supplying flat block of electricity in baseline scenarios. Instead, we endogenize the investments of the conventional generation capacity in the Netherlands in all scenarios. Thus, the additional investments or imports observed in the baseline scenarios reflect the additional generation needed to meet load, whereas that generation is provided by wind or solar in other scenarios.

Table 2. Main scenario drivers in the Netherlands.

Scenario	Renewable capacity (GW)		Renewable penetration		Cross-border transmission Capacity of NL	Description
	Wind	Solar	Wind	Solar	(MW)	
Scenario 0	2.01	0.97	4%	1%	6450	Low Solar and Wind
Scenario 1	2.01	14.16	4%	12%	6450	Low Wind Medium Solar
Scenario 2	12.14	14.16	25%	12%	6450	Medium Wind Medium Solar
Scenario 3	36.41	14.16	60%	12%	6450	High Wind Medium Solar
Scenario 1A	2.01	14.16	4%	12%	8750	Higher Transmission capacity
Scenario 2A	12.14	14.16	25%	12%	8750	Higher Transmission capacity

In Scenarios 1-3, cross-border transmission capacities between the Netherlands and its neighbors are fixed at 2012 levels. In order to investigate the benefits of additional cross-border transmission in Scenarios 1 and 2, we assume an increase of 36% in the cross-border transmission capacity of the Netherlands in line with the plans of ENTSO-E, 2012. This implies an extension of the transmission capacity on the German border with 1500 MW (Doetinchem-Wesel interconnection), 700 MW on the border with Denmark (COBRA cable), and

100 MW on the border with Belgium (enhancement of the internal Belgian network that increases cross-border transfer capacity).

4.2. Impact of variable renewables on residual load

Since variable renewables have very low marginal cost, they are dispatched first and thereby reduce the demand for the residual system (demand minus renewable generation). Furthermore, renewable generation is variable and has low capacity credit. While the reduction of residual demand during off-peak hours (e.g., high wind hours) is significantly high, the residual demand during peak hours when the renewable generation is low is hardly affected. Thereby, higher penetration of renewable generation increases the steepness of the residual duration curve as shown in Fig. 4.

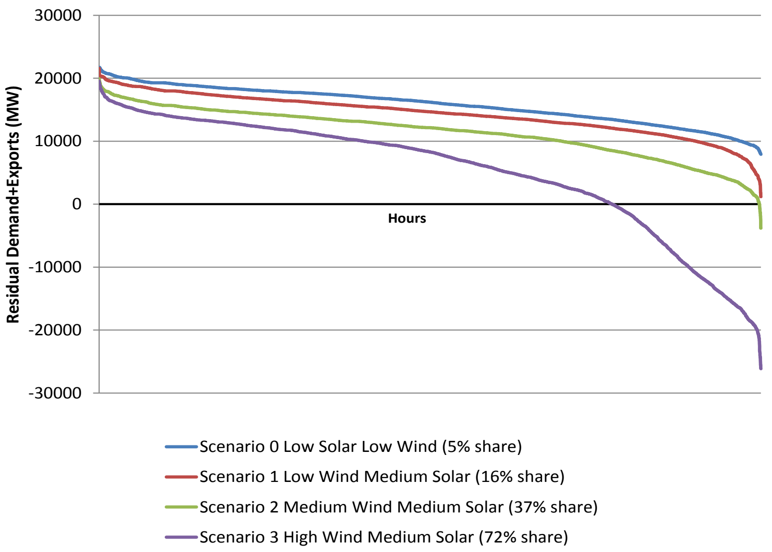

Fig. 4. The impact of increasing share of variable renewables on residual load

4.3. Generation capacity investments for the residual system

Fig. 5 illustrates the total dispatchable (non-renewable) capacity for the residual system with increasing shares of variable renewables in electricity generation. The total dispatchable capacity consists of existing capacities commissioned after 2010 (existing), the investments in conventional capacity for the day-ahead market (investments DA), and the stand-alone reserves required for balancing wind (reserves BA) to compensate wind forecast errors. Note that total demand in all scenarios is the same.

The simulation results show that the investments are mainly coal-fired power capacity for the day-ahead market under 5%-37% renewable shares in total electricity consumption (Scenarios 0-2). This can be explained by the relatively lower coal/gas price ratio and low CO_2 price assumptions (Section 4.1) as well as the availability of sufficient flexibility in the system due to existing gas units and imports from other countries. As the share of renewables in total consumption rises up to 72%, the full load hours of dispatchable power plants are reduced significantly and consequently investments in coal power plants with high investment costs decrease whereas investments in gas power plants with low investment costs (i.e., gas turbines) increase. The stand-alone reserve capacity of gas turbines to balance wind forecast errors also increases with increasing shares of wind (Scenario 1 to 3). As a result, the share of coal capacity in total dispatchable capacity decreases from 66% (Scenario 0) to 40% (Scenario 3) whereas the share of gas capacity in total dispatchable capacity almost doubles from 27% (Scenario 0) to 52% (Scenario 3).

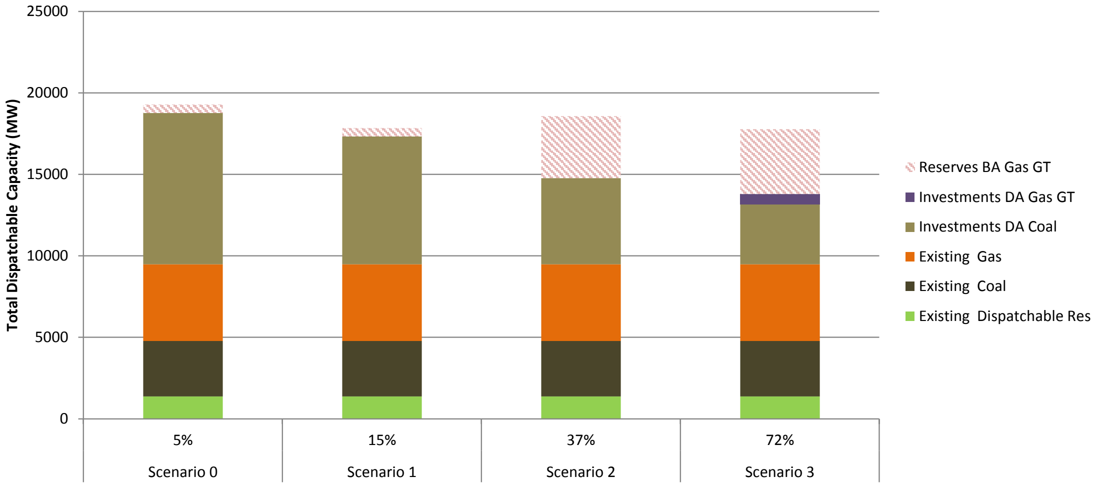

Fig. 5. The total dispatchable capacity in the Netherlands for the residual system with increasing % renewable shares.

Although the total dispatchable capacity required for the day-ahead market (excluding the reserve capacity) decreases, the reduction is low compared to the increase in renewable capacity as illustrated in Fig. 6. The low contribution of renewable generation to accommodate peak net load results in only a slight reduction in total backup capacity required for the residual system whereas the capacity factors of generators decrease significantly ("utilization effect").

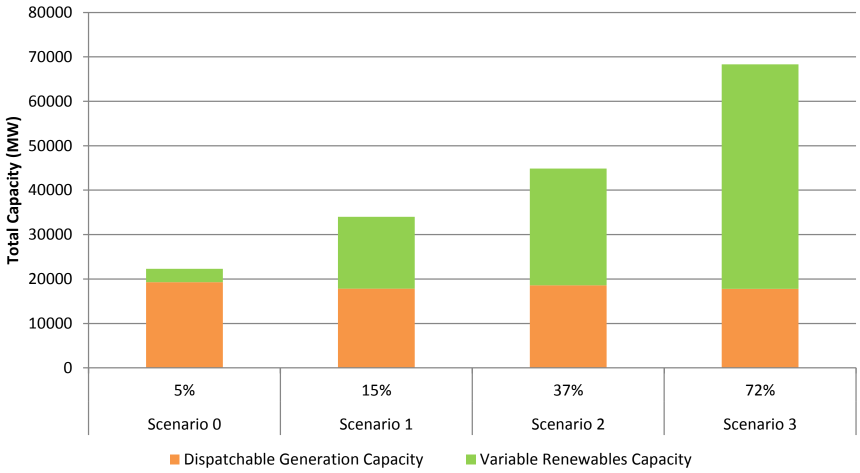

Fig. 6. The total capacity in the Netherlands with increasing % renewable penetration.

Fig. 7 illustrates the impact of cross-border transmission investments on total dispatchable capacity for the residual system. Additional transmission capacity in Scenarios 1A and 2A increases the availability of dispatchable capacity from the neighboring countries when wind in the Netherlands is low; therefore, the imports of the Netherlands from neighboring countries increase with increasing transmission capacity. As a consequence, the investments and total dispatchable capacity required for the residual system on the day-ahead market decrease. This has a positive impact on the integration costs as discussed in the next section. Since we assume national intraday market, the reserve capacity for balancing wind forecast errors is not affected significantly by the transmission capacity increase.

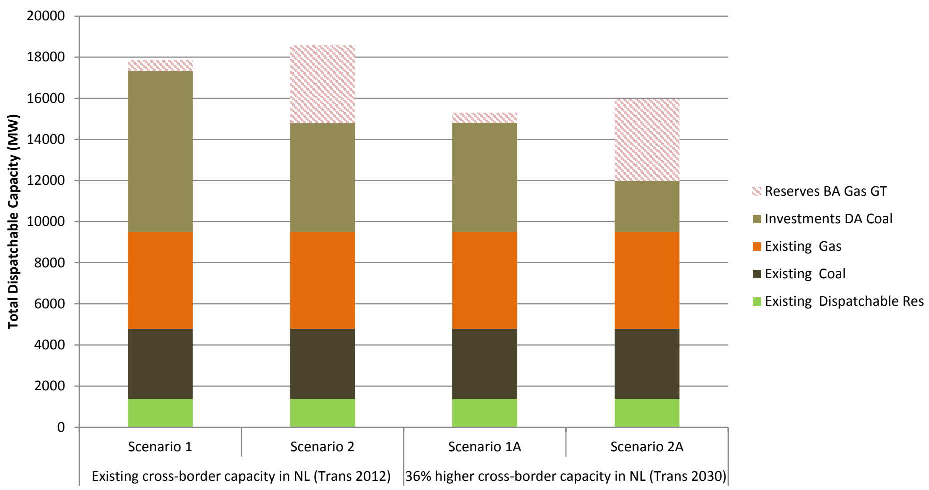

Fig. 7. The total dispatchable capacity in the Netherlands for the residual demand with increasing transmission capacity.

4.4. Integration costs of renewables and the impact of cross-border capacity expansion

Fig. 8 illustrates the investment, profile and balancing costs of wind with increasing wind shares and cross-border transmission capacity. The investment cost of wind is assumed to be 60 €/MWh in line with currently realized costs (Ueckerdt et al. 2013, Kost et al. 2012). The profile and balancing costs of wind in the Netherlands are quantified by incorporating the COMPETES output, which we obtain utilizing the methodology in Section 3, in the equations (1) and (2) given in Section 2.

In case of lower cross-border transmission capacity, the total profile and balancing costs are in the range of 28-36 €/MWh for 25%-60% wind shares. This constitutes about the half of the investment cost of wind. The largest part of these costs comes from profile costs which increase with increasing wind penetration. The profile costs include the additional operational and backup costs incurred by the residual system and implicitly take into account the costs of wind curtailment. Furthermore, the balancing costs (i.e., redispatch costs for balancing wind forecast errors and the capital cost of reserves) decrease with increasing shares of wind. Although the total balancing costs increase, the average balancing costs (per MWh of wind) decrease since the increase in wind generation is higher compared to the increase in total balancing cost.

An interesting finding is that the integration cost of wind decreases by 27% with 36% increase in cross-border transmission capacity. As discussed in Section **Error! Reference source not found.**, additional cross-border transmission capacity allows importing dispatchable resources from the neighboring countries when variable generation is low. Thereby, the total dispatchable capacity required in the Netherlands decreases for the residual system on the day-ahead market. This reduces the profile costs of wind significantly by 50%. However, balancing costs are not reduced since we assume a national intraday market for the Netherlands (i.e., intraday/balancing markets in Europe are not integrated). In addition, the capital cost of the transmission investments assumed is lower than the total reduction of profile costs. Hence, there is a net benefit of cross-border transmission investments reducing the total integration cost of wind. It should be noted that the magnitude of decrease in integration costs depends on the relative availability of generation capacity in the neighboring countries in the background scenario; i.e., the "Slow progress" scenario of ENTSO-E, 2013. The reduction in integration costs may be lower or higher depending on the generation capacity, demand developments, and renewable deployment in neighboring countries.

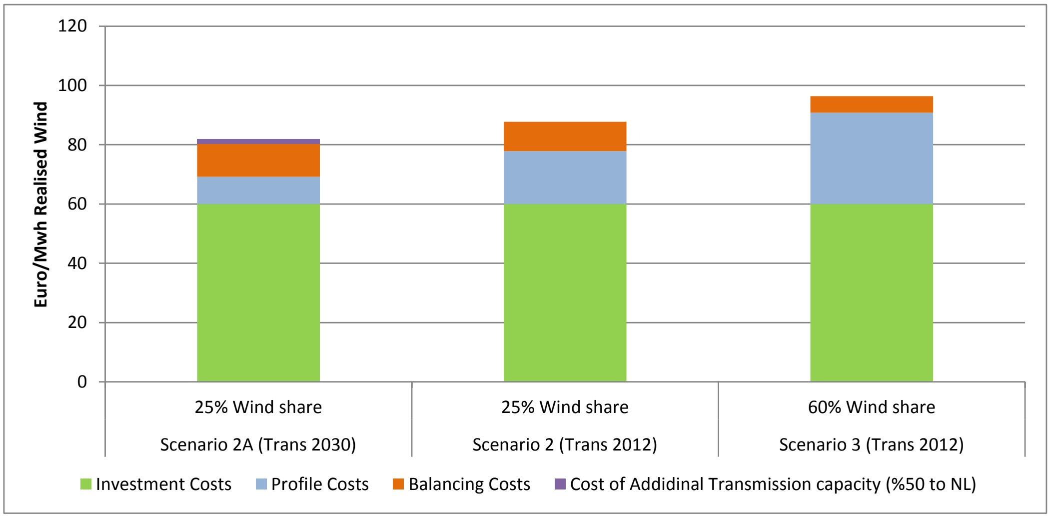

Fig. 8. Integration costs of wind and the impact of cross-border transmission capacity expansion

The profile cost of solar-PV is also calculated and it is 11 €/MWh with 11% increase in share of PV generation. The balancing cost of solar-PV is not calculated in this study since historical data on the forecast errors of solar were not available for the Netherlands.

4.5. Market value of renewables

Another impact of variable generation is the reduction in the market value of renewable generators, i.e., the hourly weighted average price they receive on the market. Since renewable generators have very low marginal cost, they reduce the prices during the hours they produce electricity, in particular during windy and sunny hours. As a result, their market value factors[5] decrease with increasing penetration. Fig. 9 illustrates the market value factors of wind and solar with increasing shares in total consumption. In Scenarios 1-3, wind value factor decreases with higher penetration and reach 0.8 at 25% share and 0.5 at 60% share. In Scenarios 0 and 1, solar value factor drops faster and reaches 0.8 at 12% share because solar PV generators produce during peak hours and have a higher impact on their market value. Furthermore, increase in wind penetration also reduces the market value of solar via a decrease in average market prices.

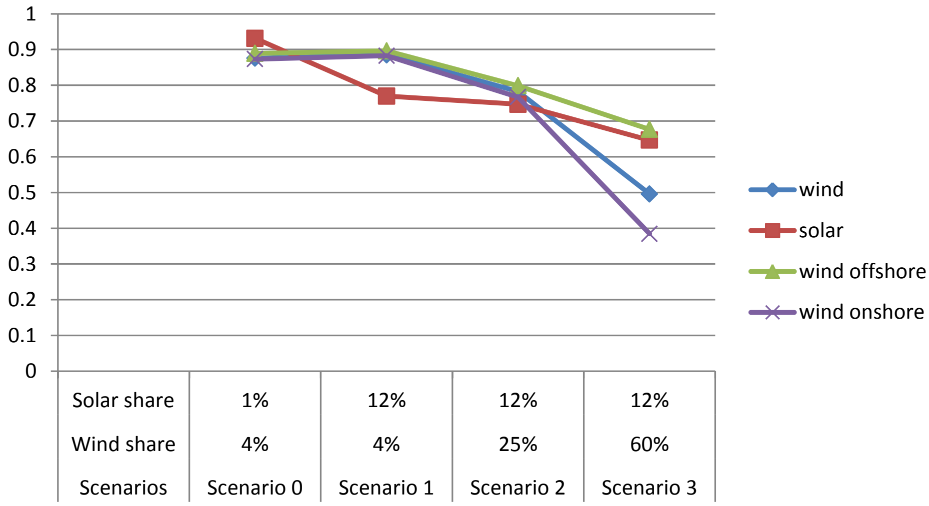

Fig. 9. Market value factors of wind and solar with increasing % penetration

Thus, the profile effect of variable renewables results in a gap between the average market price and the average price that variable renewables receive during the hours they are generating on the day-ahead market. This gap increases with increasing penetration of renewable generation as observed in Fig. 10. The market value of wind is 13 €/MWh lower than the average market price at 25% renewable share and the gap increases to 26 €/MWh with increasing wind penetration at 60% renewable share. The market value of solar is 15 €/MWh lower than the average market price and higher wind penetration increases the gap further to 18 €/MWh. The reduction in market values of renewable generators affects their profitability in a negative way

[5] The market value factor (Hirth, 2012) is calculated as the ratio of the average electricity price received by renewables during the hours they are generating and the average wholesale electricity price.

and it can mean more subsidies for variable renewables to cover their investment costs. One way to improve the profitability of renewable generators is establishing a more integrated electricity system via investments in cross-border transmission capacity. As observed for Scenario 1A, the higher transmission capacity reduces the impact of wind variability on the electricity prices which converge between the Netherlands and the neighboring countries. That is, the prices during windy hours increase and prices during low wind hours decrease. Consequently, the market value of renewables increase in the Netherlands.

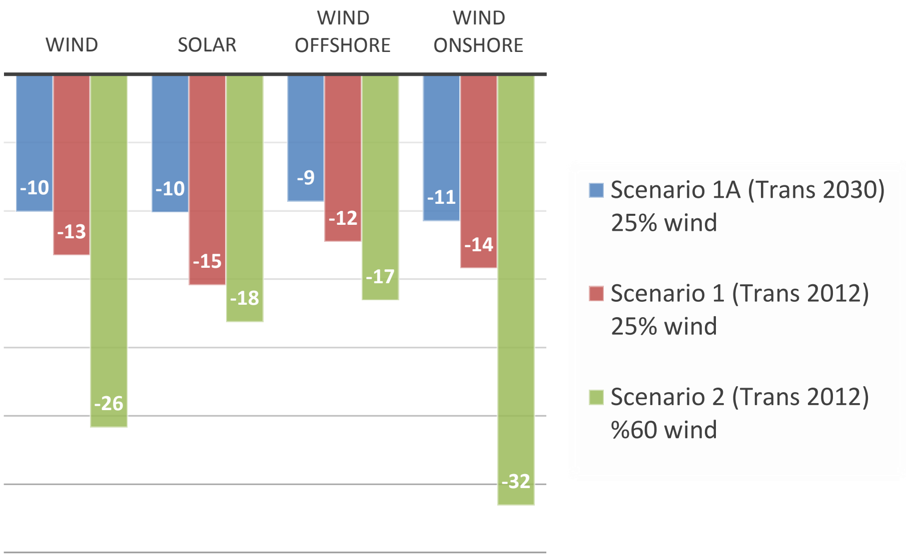

Fig. 10. The reduction of market value of renewable generators with increasing % wind share and transmission capacities

5. Conclusions and Policy Implications

Quantification of integration costs and the market value is crucial for policy makers and renewable generators to make an economic evaluation of renewables in the electricity system. The commonly used metric, LCOE, does not reflect integration costs. While the cost and price effects of variable renewables are common to all electricity markets, the magnitude of these effects to a large extent depends on the local characteristics, such as the incumbent generation mix, penetration levels of variable renewables, profiles of load and variable generation and their correlation as well as the interconnections with other electricity markets. Therefore, it is important to quantify the integration costs by using electricity market models that represent real world systems, which take into account both local characteristics and interdependencies between interconnected markets. In this study, we have assessed the cost and price impacts of integrating renewables in the future Dutch electricity market by utilizing COMPETES, which is an economic model of the transmission-constrained European power market including a detailed generation capacity mix and demand, and hourly wind and solar profiles of each country in Europe. COMPETES also includes the costs resulting from frequent start-ups, ramping capabilities of different generation technologies, and the lumpiness in generators' start-up decisions.

Simulations in COMPETES allowed us to calculate profile and balancing cost components of integration costs for variable renewables in the Netherlands under various scenarios of renewables penetration levels. For each scenario, we endogenously determine new generation capacity investments in the Netherlands, given the increasing renewable shares and the future generation and transmission capacity developments in Europe-based on Vision 1 scenario of ENTSO-E, 2013 and TYNDP of ENTSO-E, 2012. Our results confirm that integration costs increase with increasing wind penetration. With a 25%-60% wind share in electricity consumption in the Netherlands, the total integration costs of wind (excluding grid costs) are in the range of 28-36 €/MWh respectively. A significant portion (i.e., 64%-85%) of these costs is the profile cost. For solar PV, the profile cost is 11 €/MWh for a 12% share in total consumption.

Interconnections and electricity trade between countries is an important factor in determining the integration costs of intermittent renewables. Additional interconnection capacity allows domestic generation capacities to be shared between countries. As a result, the total backup capacity required for the European system and the Netherlands is reduced resulting in lower total profile cost for the whole system. Our results show that profile cost of wind penetration at medium levels decreases by 50% with a 36% increase in cross-border transmission capacity of the Netherlands. This reduction may be lower or higher depending on the developments of fuel and CO2 prices as well as the generation capacity and demand in the neighboring countries. Furthermore, the benefit of interconnection capacity investments in reducing the integration costs of renewables is high compared to the cost of these capacity extensions. Thus, the interconnection capacity investments in this study result in net benefits for the integration of renewables. Since we assume that the intraday markets in Europe are not coordinated, balancing costs are not affected by the increase in transmission capacity. However, we conjecture that the net benefits of cross-border capacity expansion in integration cost of variable renewables would further increase with coordination of intraday markets in future.

The price impact of variable renewables is twofold. First, the average electricity market price is reduced due to the low marginal cost of renewables. However, as we observe in our simulations, this reduction is limited (e.g., for wind) when generation capacity is allowed to adapt to a situation with higher level of renewables. Second, renewable generators receive a lower price in the hours they produce electricity, thereby diminishing their revenues. As a result, their market value is lower than the average market price. The gap between the average market price and the market value of wind increases with an increasing penetration of renewables. For instance, the market value factor of wind is 0.8 at 25% wind share and decreases to 0.5 at 60% wind share. As observed for the integration costs, better use of existing interconnectors and/or investment in new interconnector capacity would increase the market value of renewables.

The reduction in market value is mainly caused by integration costs and can be an economic barrier for deployment of variable renewables at high shares. Without subsidies, renewable generators need to cover their investment costs from market revenues. An energy-only market, in principle, allows investors in dispatchable capacity to earn sufficient revenues during peak hours. However, variable renewables are non-dispatchable and the peak hours are the high residual demand hours when their generation is the lowest. As discussed earlier, variable renewables reduce the residual demand during the hours they produce and lower their market value. Decreasing market values with higher penetration of renewables reduce their profitability and impair their ability to cover investment costs. Therefore, policy targets of high shares of renewables may increase the need for subsidies if there are no additional policy measures that can help increase the revenue for renewables. Improvements to the electricity market such as further market integration, better use of existing interconnectors, and investing in interconnection capacities can help reduce the need for subsidies by raising revenues. Another option is to increase the carbon price. Although it has not been investigated in this study, flexibility options such as demand response or storage can also help increase the market value for renewables. These options have not been analyzed in this study; it would be an interesting subject for future research to compare the costs and benefits of these options with increased interconnections as a way to reduce integration costs.

Acknowledgements

This study was funded by the Dutch Ministry of Economic Affairs. The findings and conclusions expressed in this article are those of the authors and do not necessarily reflect the views of the Dutch Ministry of Economic Affairs. We would like to thank Anne Sjoerd Brouwer for his valuable review and comments and Robin Broder Hytowitz for the proofreading of the article.

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Appendix A. Description of COMPETES input data

A.1. Electricity Supply Characteristics

The input data of COMPETES UC involves a wide-range of generation technologies summarized in Table A.1. The generation type, capacity, and the location of existing generation technologies are regularly updated based on WEPPS database (UDI, 2012). The COMPETES database has detailed characteristics for each generators in the Netherlands. For the other countries, the generation units using the same technology and having similar characteristics (i.e., age, efficiency, technical constraints) are aggregated.

Table A.1. The categorization of electricity generation technologies in COMPETES

Fuel	**Types**	**Abbrev**
Gas	Gas Turbine	GT
	Combined cycle	NGCC
	Combined heat and power	Gas CHP
	Carbon capture and storage	Gas CCS

Derived Gas	Internal Combustion	DGas IC
	Combined heat and power	DGas CHP
Coal	Pulverized Coal	Coal PC
	Integrated gasification combined cycle	Coal IGCC
	Carbon capture and storage	Coal CCS
Lignite	Lignite	
Oil	Oil	
Nuclear	Nuclear	
Biomass	Cofiring	
	Standalone	
Waste	Standalone	
Geo	Geo	
Solar	Photovoltaic Solar Power	
	Concentrated Solar power	
Wind	Onshore	
	Offshore	
Hydro	Conventional	
	Pump Storage	

The flexibility assumptions for conventional units are assumed to differ with the type and the age of the technology as summarized in Table A.2. The part-load efficiency of min-load levels in Fig. A.2 is used for calculation of the min-load costs incurred when units with these technologies are committed.

Table A.2 Flexibility Assumptions for conventional technologies in COMPETES

Technology	Time of being commissioned	Minimum load (% of max capacity)	Ramp rate (% of max capacity/hour)	Start-up cost[a] (€/MW installed per start)	Min up time	Min down time
Nuclear	<2010	50	20	46 ±14	8	4
	2010	50	20	46 ±14	8	4
	>2010	50	20	46 ±14	8	4
Lignite and Coal PC/CCS	<2010	40	40	46 ±14	8	4
	2010	35	50	46 ±14	8	4
	>2010	30	50	46 ±14	8	4
Coal IGCC	<2010	45	30	46 ±14	8	4
	2010	40	40	46 ±14	8	4
	>2010	35	40	46 ±14	8	4
NGCC/Gas CCS	<2010	40	50	39 ±20	1	3
	2010	30	60	39 ±20	1	3
	>2010	30	80	39 ±20	1	3

GT	<2010	10	100	16 ±8	1	1
	2010	10	100	16 ±8	1	1
	>2010	10	100	16 ±8	1	1
Gas CHP	<2010	10	90	16 ±8	1	1
	2010	10	90	16 ±8	1	1
	>2010	10	90	16 ±8	1	1

a) Warm start-up costs are assumed for all technologies but OCGT. For OCGT, a cold start is assumed.
b) Source: Brouwer et al., 2015

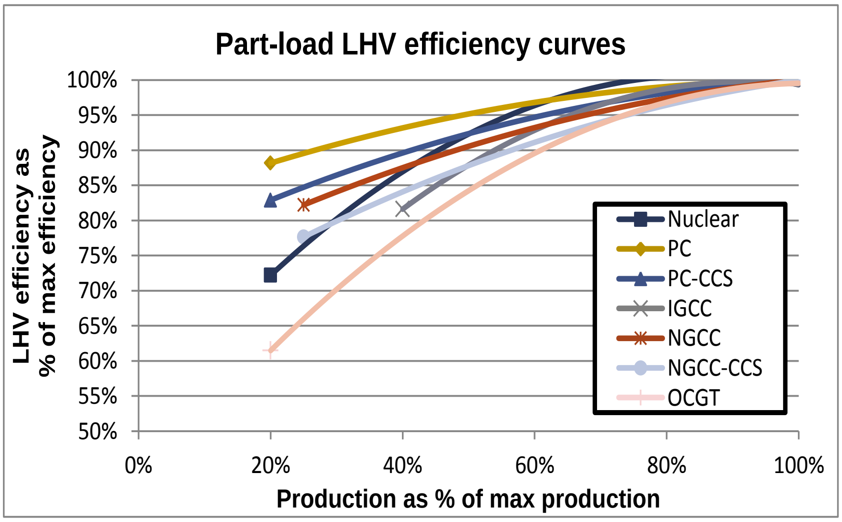

Fig. A.2. Part-load efficiency curves for different technologies. Source: ECN (Brouwer et al., 2015)

Overnight costs for conventional generation for capacity expansion model represent **e**ngineering, procurement and construction plus owners' costs to develop the project (see Table A.).

Table A.3. Overnight investment costs of generation technologies

Generation	**Technology**	**Overnight Costs €/kW**	**Economic Lifetime**	**Efficiency**
COAL	**PC**	1350	40	46%
COAL	**IGCC**	1925	40	40%
GAS	**CCGT**	700	30	60%
GAS	**GT**	400	30	40%

The hourly power generation profiles from solar and wind and their installed capacities are inputs to the model. The hourly wind generation profiles of 2012 in some EU countries are provided by their TSOs. These are Amprion (2015), Bach (2015), Energinet (2015), Eirgrid (2015), 50Hertz (2015), Nordpoolspot (2015), TenneT (2015), Terna (2015), and TransnetBW (2015). For the other countries for which the 2012 wind time series are not available, correlations from the Tradewind, 2009 data set of the year 2004 are taken into account to drive the wind load factors.[6] The solar generation profiles are based on 2005 hourly solar production data of SODA, 2011.[7] Since there is a seasonal correlation between wind and solar (e.g. summer is relatively more sunny and less windy), but not necessarily an hourly correlation, it is acceptable to use wind and solar profiles of two different years to represent a future year.

Hydro production is categorized as conventional hydro (run-of-river (ROR) and reservoir storage) and hydro pump storage. Hourly hydro generation is calculated a prior as an input to the model. Hourly ROR generation is determined by using data on annual hydro generation, the share of ROR per country, and monthly data on the ROR production. In order to calculate hourly hydro storage production, ROR is assumed to be a must run technology, and the dispatch of hydro storage is assumed to depend on the residual demand hours (demand minus variable generation). Since the highest prices are expected in the high residual demand hours, hydro storage is assumed to produce in the highest residual demand hours in a certain year. Hydro storage is dispatched in a way that the sum of the generation of the 8760 hours in a year is equal to the annual hydro production given by the Vision 1scenario of ENTSO-E.

The operation of electricity storage technologies (e.g., hydro pumped storage and compressed air energy storage (CAES)) is optimized such that they maximize their revenues by charging and discharging electrical energy within a day. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for generation-demand balancing. The amount of the power consumed and produced in the charge and discharge processes and the duration of these processes depend on the characteristics of the storage technology such as efficiency losses and power/energy ratings which are input to the model.

A.2. Electricity Demand

The demand represents the final electricity demand in each country. The hourly load profiles of demand are based on hourly data given by ENTSO-E of the year 2014.

[6] In case Tradewind data suggests that there is a strong positive correlation between two countries, it indicates that the countries generally show the same wind patterns. For example, there is a strong correlation between Portugal and Spain (±80%); thereby, the wind profile of Portugal in 2012 and 2013 is represented by the profile of Spain. In case there is a weak correlation, the wind patterns of the two countries are generally not alike. Then, TradeWind data of the year 2004 is used.

[7] Solar hourly load factors are calculated on the basis of the sunset time, sunrise time, their evolution throughout the year and solar irradiation values in 118 nodes distributed in Europe (SODA, 2011).