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Assessing the costs of electric flexibility from distributed energy resources: A case from the Netherlands

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ABSTRACT

Managing electric flexibility is of importance for reliable electricity supply, especially in a situation with increasing penetration of renewable electricity production. One of the capabilities of electricity smart grids is the possibility to incorporate distributed energy resources for provision of electric flexibility to the system. This paper presents an approach to determine the investment and short-term average costs of distributed energy resources to supply flexibility services in a local system, and compares those costs to the average costs in the Dutch markets for balancing and day-ahead flexibility. The approach in this paper is useful for techno-economic analysis of flexibility from distributed energy resources and the economic valuation of flexibility for trading in traditional markets. The analysis shows that local flexibility in many cases is much more expensive than centrally provided flexibility.

Introduction

Traditionally low voltage grids have been designed to transport electricity towards users for consumption, and not the other way around. However, due to the increased penetration of distributed energy resources (DER), low voltage grids are increasingly carriers of bidirectional electricity flows and in some cases require extra flexibility in order to cope with variable production and demand patterns of DER [1–3]. With the increasing penetration of variable electricity resources like solar PV, combined heat and power (CHP) and Electric Vehicles, a need arises for electric flexibility, for example through storage solutions or demand response programs [4,5]. As a power adjustment sustained at a given moment, for a given duration, from a specific location within the network [6]. Instead of flexibility, literature speaks often about "demand response". Demand response might provide the impression that only electricity demand is eligible to 'respond' to triggers like prices or direct control, however, in this paper, the term flexibility refers to the overall responsiveness of demand, storage and production units. Therefore, in this paper rather the term electric flexibility is used. This flexibility could be activated for example with the use of price signals or direct control and could serve diverse objectives. Flexibility management or demand side management methods can make the penetration of DER provide flexibility value to the system [7–9]. Research has been done to calculate the benefits from demand response [5,10–14]. There are many different possibilities to set up (economic) incentives for the activation of electric flexibility. Authors discussed the pool approach and the bilateral arrangements for aligning flexibility supply and demand [15–18].

However, in traditional electricity systems, markets are only located at the high voltage level. In those markets, the meritorder of production units is the deciding factor to define which unit should provide the flexibility and set the marginal price in the market. Such system do not exist for local distribution networks, but different pilot projects do provide insight in the possibilities for those developments [7,16,19]. In order to assess the actual costs of local flexibility provision, it is important to calculate the investment and short-term average costs for enabling flexibility from DER technologies. Previous research showed indicators to define the capital and operation and maintenance (O&M) costs for storage units [20]. Furthermore, cost and performance assumptions for modeling large electricity generation technologies exist [21]. Regarding electric flexibility, the IEA developed the FAST method [22], a method to quantify how much variable renewable generation can be integrated within a system.

However, research does not provide a unified, comparable metric for determining the short term average cost for flexibility from a set of specific small, distributed energy resources in €/kWh. The aim of this paper is to show the costs for the provision of flexibility for different pre-defined time durations. The cost perspective is chosen to be an aggregator, which could potentially manage the flexibility from those resources and provide this aggregated flexibility in central markets.

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This perspective is chosen in order to include costs that an aggregator would have to bare (for example the installation of enabling devices for the provision of electric flexibility and short term cost for activation of flexibility), and exclude costs that the end-user would pay (for example investment for electric vehicles and solar photovoltaic panels). Eventually, the costs for each DER technology can be compared with the prices in the Dutch imbalance and day-ahead market. In this work, we follow a price taker approach, meaning that any provision of flexibility services does not affect market prices. Furthermore, the flexibility itself is seen as a service, which can be traded in different markets beyond balancing and day-ahead markets, but also for (local) congestions for example. The paper presents this methodology in order to assist decision-making regarding cost efficient solutions for both installation and operations of distributed energy resources.

This paper is organized as follows: Section “Traditional Cost calculations” presents a short definition of traditional cost analysis with the levelized cost of electricity (LCOE) approach. Section “Distributed energy resources” presents the different DER technologies considered in this paper. Section “Assumptions for calculating the flexibility costs from Distributed Energy Resources” describes the short-term average cost calculation and investment cost calculation method for flexibility. Section “Calculating the present value of DER investments and maintenance costs” illustrates an application of the method on a set of distributed energy resources and provides insight those costs for different time-scales. Section “Calculating the short-term operational cost for DER flexibility” presents the discussions and finally, Section “Results” presents the conclusions of this paper.

Traditional cost calculations

The costs to install and operate electricity units include both fixed and variable costs. The fixed cost includes costs that do not change based on the amount of electricity produced, or the number of times flexibility is provided to the system. These are for example the investment cost. Differently, variable cost are costs that change when the production output increases. An example of variable cost is the fuel cost. The next sections describe the definition of the Levelized Cost of Electricity and Marginal Cost.

Levelized cost of electricity

The levelized cost of electricity (LCOE) is a commonly used calculation to compare the production costs of different electricity producing units. The LCOE is an assessment of the total cost to **build** and **operate** a generation unit over its lifetime divided by the total energy produced by the unit over that lifetime. This calculation includes all the costs over its lifetime; the investment costs, operations and maintenance (O&M), cost of fuel and capital costs. To evaluate the total cost of production of electricity, the streams of costs are converted to a net present value (NPV). LCOEs can be typically calculated over 20–40 year lifetimes, in a unit of €/MWh for example. It must be noticed that the LCOEs values are very dependent on assumptions such as the capacity factors, economic lifetimes and discount rates. Next to the described metric, the LCOE can also be seen as the minimum cost at which electricity must be sold in order to break-even over the lifetime of the project [23].

Marginal cost

In electricity systems, the term “efficiency” refers to ensuring that the generators with the lowest variable costs are dispatched as much as possible. This unit, in time can be called the marginal unit. Marginal costs are a function of both fixed and variable costs and can be defined as the overall change in price when a buyer increases the amount purchased by one unit. It can therefore be expressed as the derivative of the total cost with respect to output [24]. Generally a distinction can be made between short-term marginal cost and long-term marginal cost. Typically the short-run marginal cost of electricity production at power system level is determined by the variable cost of the marginal generator, i.e. the one responding to changes in demand at a given time. Given that in electricity, fuel costs are the main variable cost, marginal costs are found as the derivative of fuel costs with respect to output, i.e. the amount of electricity produced.

Distributed energy resources

The following section introduces the important distributed energy resources considered in this paper.

Battery storage

There are different storage technologies available for battery storage. In this paper we describe the Sodium Sulfur (Na-s) and Lithion-ion (Li-ion) battery technologies firstly. Storage technologies have specific characteristics that differentiate them from other technologies. The capital costs include the cost for power conversion system (PCS). This power conversion system is required to convert from alternating current (AC) to direct current (DC) while the energy device is charged, and vice versa, when the device is discharged. Secondly, the cost for the balance of plant (BOP) include building construction, battery installation, interconnections, heating, ventilating, and air conditioning equipment. Next to those capital cost, there are characteristics of batteries related to the operations, for example the Dept of Discharge (DOD), which is a variable that influences the number of charge/discharge cycles the battery undergoes during its lifetime. Next to the named variables, the round-trip efficiency provides insight in the efficiency of the unit for storing and delivering electricity store. The round-trip efficiency includes losses due to power conversion from AC to DC and back to AC, the energy storage cells, busbars, battery management systems and thermal management systems. In real life, the round-trip efficiency is expected to change as a function of charge and discharge rate [20], however in this analysis the round trip efficiency is kept constant during the lifetime of the battery.

For many battery systems, the capital costs are provided in either $/kW or $/kWh, which relate to battery size and charging/discharging abilities. Furthermore, many battery systems have variable O&M cost included. In this work, we include both the variable O&M cost and additional degradation costs for the short term operational cost calculation due to the specificity of battery technologies with their cycles available in the lifetime of a unit [25]. Furthermore, in this study, the flywheel and compressed air energy storage are included (CAES) which have also energy storage capabilities.

Management of demand-side resources

EVs potentially can provide storage capacity to the system and therefore provide both upward and downward flexibility. In the calculation within this paper, the EV is seen as an upfront cost, which is made by a customer. Therefore, in this analysis, we do not take into account a specific EV type, due to the fact that these investments are not made by the aggregator/flexibility manager, but by the consumer themselves. Therefore the costs here are related to the costs to be able to manage the charging and discharging activities of the EV battery. These investment costs are similar as those for demand management. Also demand management could be both downward and upward directed. However in this study we focused mainly on the reduction of electricity demand in time for the associated cost with the control devices to activate such flexibility, due to the fact that increased consumption also requires the retail price to be paid.

Management of supply-side resources

Important possibilities for supply units are CHP units and solar PV.

PV units are different from the others, in the sense that their production output cannot be controlled – however, with the introduction of smart inverters, PV production can be curtailed and, considering aggregation across multiple sites, PV aggregations could even provide downward and upward reserves.

Micro-CHP units are small heat and electricity generating units. CHP units exist in different types. CHP systems consist of a number of individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. This work only includes the fuel cell, gas turbine and micro turbine.

Assumptions for calculating the flexibility costs from distributed energy resources

The LCOE calculation is very interesting to compare different large units, but requires realistic assumptions regarding capacity factors. The LCOE price combines investment, operation and maintenance cost in a price per kWh. These can however change, and depending on whether a unit is being used can reduce or increase. Different from the LCOE, the short term average cost (STAC) calculation does not contain assumptions regarding yearly load factors but only regarding the maximum provided flexibility in kWh for a unit in time-frames. The calculation here therefore detaches the (kWh based) short-term average costs from the long-term investment (kW) costs for different flexibility time-frames and technologies. Due to the fact that flexibility costs in central flexibility markets are also based on variable, kWh based cost, also this division is made in this paper, leaving the installation costs out of the short term average cost calculation. Therefore the present value of the DER investment and maintenance cost can be seen as a LCOE specified for different event durations y, at which the entire capacity of the unit is used. Consequently, the short term average costs (STAC) are not based on how frequent the requests for flexibility (flexibility events) take place, but rather how much energy is delivered within event durations. In this method we took the event durations of 0.25 h, 1 h, 6 h and 12 h. This is based on the IEA report, which used four timescales — 15 min, 1 h, 6 h and 36 h — to categorize the flexibility potential in systems [22]. Only the largest timeframe (36 h) has been reduced to 12 h for the purpose of this work, because this longer timeframe was mostly needed for flexibility potential of large nuclear and older steam plants that are only able to respond only within 36 h. For smaller distributed energy resources such long timeframe is not necessary and therefore this has been adjusted to 12 h.

Comparison between technologies

To make comparison possible for different technologies, an investment capacity of 10 kW is chosen for all the technologies, this refers to a potential flexibility provision per timeframe of 2.5 kWh, 10 kWh, 60 kWh and 120 kWh. The 10 kW serves as a benchmark, and such capacity could provide power for around 10 households in the Netherlands. The cost of technologies is based on one or both of the metrics used (kW and/or kWh). This is due to the different technological characteristics of the technologies. E.g. a CAES with a high capacity (kWh) needs a large pressurized cylinder, and increasing the power (kW) requires a larger compressor. Differently, battery technologies required both a value for capacity (kW) and energy (kWh) in order to provide accurate values on the costs involved for battery size and the charging/discharging abilities.

Upward and downward flexibility

From a technical perspective, it is possible to provide upward and downward flexibility to the system. Upward flexibility means that the unit is able to feed-in electricity to the system or decrease consumption. Downward flexibility refers to the activity that electricity can be consumed, stored from the system or reduced generation. Generally, storage units and demand management are able to provide both upward and downward flexibility while PV curtailment could be an example of downward flexibility.

Investment perspective

The investment perspective in this paper is taken from the role of an aggregator. For an aggregator, the use of flexibility can be valuable if specific units are aggregated for market participation. Due to the fact that some technologies are typically invested in by the end-user, the analysis excludes the costs of investment for some technologies like the Electric Vehicle, Solar PV, and demand management. We assume that the EV, Solar PV and demand appliances are all owned by and ex-ante paid for by the end-user. The aggregator only invests in the enabling devices for flexibility management with those technologies. Differently, with all the other technologies (batteries, CHPs, Power to heat etc.), we assume that an aggregator both owns and operates those devices due to their typical size and the ability to supply multiple households.

Costs for charging and discharging

Another important assumption in this analysis is that for the appliances, which have bidirectional possibilities (all battery technologies), the flexibility taken from the device is always given back to the device if possible. This means that if a battery is discharged, it is charged again at another moment in time and if a unit is charged, it is discharged again at another moment. This means, that all the flexibility that is taken from the device, is also again placed back when possible at another moment in time in order to place the unit back in its original state. Therefore, the cost of electricity for many devices is left out of the calculation when storage takes place (e.g. for batteries, demand management and EVs) which makes it possible to compare DER from diverse nature with each other. However, of course, with variable pricing of electricity with the inclusion of the time-dependent price becomes crucial, see section A in the discussion Section VII of this paper.

Other cost assumptions

For the costs calculation for the different technologies, the electricity and gas prices from the Netherlands are used. In the Netherlands, in the year 2016, the average retail electricity price is € 0.20/kWh and the gas price is € 0.66/m^3[1].

The cost for the different technologies are taken from the Department of Energy [20], The Environmental Protection Agency [26] and NREL [21]. The used planning horizon is 20 years (t = 20), with assumed electricity cost (including tax) of 0.20 euro/kWh (based on Dutch average) and discount rate d of 3%[2]. To make comparison possible along different technologies, investment is calculated for a capacity of 10 kW, meaning that the electricity flexibility provided per timeframe is 2.5 kWh, 10 kWh, 60 kWh and 120 kWh. Furthermore, we assumed no difference between the buying and selling price of electricity due to the existence of flat retail prices in the Netherlands. We do confirm that prices for night and day tariffs are different. Furthermore, in the intraday market, prices change hourly, and the feed-in of electricity could be valued on the hourly changing price basis. However, due to the fact that the focus of this study is to provide a unified method

[1] Average Energy prices for 2016 found on website: https://www.milieucentraal.nl/energie-besparen/snel-besparen/grip-op-je-energierekening/energieprijzen/.

[2] The discount rate has been set to 3% as an average, due to the fact that current exceptional low rates in the Dutch market do not reflect a general situation. See http://www.tradingeconomics.com/netherlands/interest-rate.

which resembles reality in the Dutch system, the feed-in and consumption are chosen to be valued by a flat retail price. This furthermore ensures that the cost differences between different DER are only reflecting technology related costs (and not time dependent price differences).

Important to note is that for storage investment cost, many times the cost are given either on kW bases and/or kWh bases, or both. In the reference we used for this paper, namely that of the Department of Energy, both terms have been incorporated.

Therefore, for the storage units the investment costs are a summation of the power capacity cost and energy costs relating to charging and discharging abilities of the installed unit. With regard to the degradation cost, we assumed that the amount of energy used during a timeframe is directly related to the length of the timeframe in this analysis, due to the fact that the entire unit capacity is used within a time frame.

Calculating the present value of DER investments and maintenance costs

First we define the average cost of a flexibility providing distributed energy resource. The calculation starts by defining the equivalent annual costs (*EAC*), which are the cost per year of owning and operating the asset over its entire lifespan. Let EAC_n be the equivalent annual cost n and I_n be the total investment costs per technology. Lastly, let L_n be the technical lifetime of the technology and Cm_n the maintenance cost in euro for each installed kW per year. The maintenance costs here are considered to be constant, not dependent on the use of the component. This provides the formula for the equivalent annual cost as (1):

$$EAC_n = \frac{I_n}{L_n} + Cm_n \tag{1}$$

These costs are then used to determine the present value of investments to be made during the lifetime of the technology. The calculation is a discounted cash flow calculation in order to assess the present value of the investments to be made. And can be called the present value of technology investment. Say that $NPV_{y,n}$ is the net present value of technology n within each event for flexibility y in hours (in the example calculation we use event durations of 15 min, 1 h, 6 h and 12 h).

And, say that d is the discount rate (%) and P_n the power capacity installed and t the number of years, for which the net present value is calculated. The *NPV* per technology are then calculated by (2):

$$NPV_{y,n} = \left(\frac{\sum_t^T \frac{EAC_n}{(1+d)^t}}{P_n} \right) \tag{2}$$

Calculating the short-term operational cost for DER flexibility

For storage technologies there are two specifics that need to be accounted within the short-term average costs per provided kWh of flexibility. These costs are the losses due to battery degradation cost (*Cd*) and the round-trip efficiency (*Re*), which will be described later. The cost due to battery degradation is the ratio of the investment costs and the power capacity used per timeframe. Different from traditional generation units, storage units have changing short-term average cost depending on the use of the capacity (in our calculation, depending on the size of the time frame) of the unit due to those degradation cost. The *Cd* are then calculated by dividing the investment costs I_n by the maximum amount of cycles per lifetime X_n times the power capacity used per timeframe E_n (where E_n is $P^* y$), see below:

$$Cd_{y,n} = \frac{I_n}{X_y E_n} \tag{3}$$

The degradation costs are based on the average investment costs and on the maximum amount of cycles that the technology can perform during its lifetime. These cost relate to the charge and discharging cycles of storage units. These cycles are not seen as maintenance cost due to the fact that cycling costs cannot be prevented with maintenance. Therefore, the degradation costs are costs related to the fact that storage devices have a limited amount of possible charge and discharge cycles during its a lifetime.

The specified degradation costs here are applied only to storage technologies. The short-term operational costs are expressed as a €/kWh and are based on the losses in round trip efficiency (€/kWh), fuel costs (€/kWh), degradation costs and losses due to differences in the buying and selling price of electricity in the market. For storage units the inclusion of the degradation costs, makes the short-term average costs related on the investment costs. This will be reflected upon in the discussion.

Next to the degradation costs, the round-trip efficiency losses indicate the efficiency of a storage technology to recover stored electricity power. It is the ratio between energy recovered and the energy input.

Given that Re is the round-trip efficiency, *Ce* is the energy cost, *Cf* the fuel cost, *Cvm* the variable operation and maintenance cost, Cd the degredation cost and *Cs* the selling price and *Cb* the buying price of electricity. Then, the short-term average cost $STC_{y,n}$ for each event duration y and each technology n is then calculated as:

$$STC_{y,n} = (1 - Re_n)Ce_n + Cf_n + Cvm_n + Cd_{y,n} + Cs - Cb \tag{4}$$

Results

This section presents the calculation of the NPV and $STC_{y,n}$ for diverse distributed energy resources. The analysis includes Battery Li-ion, Battery NaS, Flywheel, compressed air energy storage (CAES), EV Storage, Gas turbine, Microturbine, Fuel Cell CHP, Power to heat, Supply management and Demand management.

Table 1 and Fig. 1 present the net present value (NPV) of both investment and maintenance costs for the different technologies.

It is visible that the battery technologies (Battery Li-on and Battery NaS) have increasing NPV cost with increasing length of the flexibility event timeframes. This is due to the fact that the cost in order to supply the energy significantly increases the need for battery storage and the related cost. Differently, CAES, supply management and demand management have no or only slightly increasing cost with increasing timeframes of flexibility.

Table 2 and Fig. 2 present the short-term average costs for each technology. Differently as seen from the NPV cost calculation, it is visible, that the battery technologies (Li-ion, NaS and EV) have decreasing short-term average costs when used in longer time frames. This is due to the fact that the degradation cost decrease when the technology is used for provision of higher volumes of flexibility. Still,

Table 1
Net Present Value of both investment and maintenance cost for each technology in €/kW.

Direction	Technology NPV (€/kW)	EVENT DURATION			
		0.25 h	1 h	6 h	12 h
↑↓	*Battery Li-ion*	824	1845	8653	16,822
↑↓	*Battery NaS*	532	885	3239	6065
↑↓	*Flywheel*	1427	1495	1949	2494
↑↓	*CAES*	550	551	557	566
↑↓	*EV Storage*	281	281	281	281
↑	*Gas turbine*	1180	1180	1180	1180
↑	*Microturbine*	1702	1702	1702	1702
↑	*Fuel Cell CHP*	0	0	2685	2685
↓	*Power to heat*	2040	2142	2823	3640
↓	*Supply management*	281	281	281	281
↑↓	*Demand management*	281	281	281	281

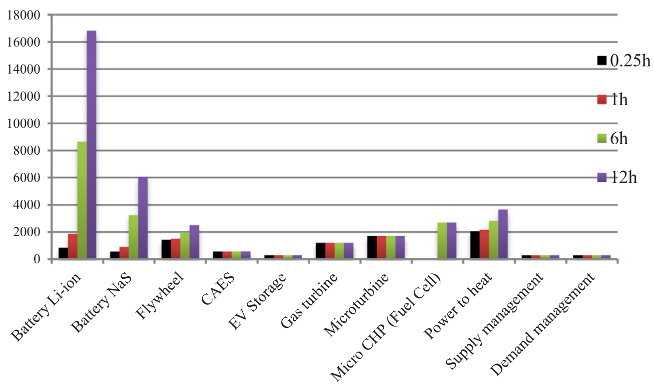

Fig. 1. Net Present Value of both investment and maintenance cost for each technology in €/kW.

Table 2
Short-term average cost for each technology in €/kWh.

Direction	Technology STC (€/kWh)	EVENT DURATION 0.25 h	1 h	6 h	12 h
↑↓	*Battery Li-ion*	0.441	0.278	0.232	0.228
↑↓	*Battery NaS*	0.465	0.232	0.168	0.161
↑↓	*Flywheel*	0.035	0.035	0.035	0.035
↑↓	*CAES*	0.091	0.091	0.091	0.091
↑↓	*EV Storage*	0.868	0.227	0.049	0.032
↑	*Gas turbine*	0.235	0.235	0.235	0.235
↑	*Microturbine*	0.279	0.279	0.279	0.279
↑	*Fuel Cell CHP*	0.176	0.176	0.176	0.176
↓	*Power to heat*	0.087	0.087	0.087	0.087
↓	*Supply management*	0.20	0.20	0.20	0.20
↑↓	*Demand management*	0.000	0.000	0.000	0.000

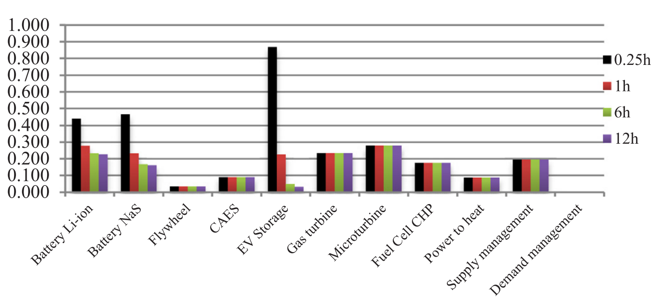

Fig. 2. Short-term average cost for each technology in €/kWh.

storage remains an expensive option, and becomes only interesting for medium-term usage. However, then the investments cost rise quickly when energy needs increase.

The gas turbine and micro turbine do not have changing costs per kWh due to the fact that longer flexibility needs only require more fuel input. It is visible that for short-term purposes (15 min flexibility) the costs of electric vehicles are very high. This is due to the fact that in our calculation the replacement of a Tesla battery is taken into account, with a maximum amount of cycles of 5000 and a price of €12,000 for replacement. If the aggregator is managing flexibility for only short-term purposes, these costs should be remunerated with the supply of short-term flexibility. However, the costs for EV storage reduce significantly with increasing flexibility timeframes due to the fact that the same level of degradation costs are shared over more kWh.

For supply management (mainly related to PV curtailment or other RES curtailment) the costs are very high due to the fact that it is assumed that owners of PV units are remunerated by a net-metering method, meaning that their electricity production is reduced from their consumption values. Therefore, in this calculation, the curtailed

Table 3
Imbalance Market prices from 2015 for 15 min timeframes, authors compilation from 2015 data of Dutch TSO Tennet in €/kWh.[3]

	Upward Flex		Downward Flex	
	Price > 0.30 €/kWh	Average price € cent/kWh	Payment frequency	Average price € cent/kWh
Winter week	10	7.20	82	7.30
Spring week	8	7.60	64	10.90
Summer week	2	6.40	14	12.10
Autumn week	0	6.50	81	4.30
Yearly estimate	260	6.93	3133	8.70

[3] See the website of Tennet for historical data: http://www.tennet.org/english/operational_management/export_data.aspx.

production makes the short-term cost equal to the electricity price of 0.20 €/kWh.

The potentials for flexibility trading in balancing and day-ahead markets

To analyze the possibility of trading of flexibility, the costs of flexibility of DER could be compared to the prices in the imbalance and day-ahead market. The data to analyze the profitability of flexibility trading has been taken from the Dutch TSO Tennet (see Table 3) and the market operator APX Endex. Imbalance markets are markets that are organized 15 min before real-time and require flexibility for 15 min time-frames, either upward or downward. Upward flexibility is generally being paid more than downward flexibility.

At peak pricing moments (where prices are 0.30 €/kWh or more), the prices are still too low to obtain profits from trading activities in the imbalance markets for many of the battery technologies. However, only for the flywheel technology, CAES, Fuel Cell CHP, demand management and supply management it is profitable to trade at such short-term peak moments (see Table 4). The peak prices higher than 0.30 €/kWh, happening at a frequency of an estimated time of 260 times per year based on 2015 data.

Furthermore, potentials exist to gain incomes with downward flexibility (for example by increasing demand) in order to receive a payment in the balancing market. This happens an estimated time of 3133 times a year with an average price of 8.9 ct/kWh. However it is

Table 4
Yearly revenues for upward and downward flexibility based on 2015 values for 15 min timeframes, authors compilation from 2015 data of Dutch TSO Tennet imbalance market in €/kWh.[4]

Direction	Technology STC (€/kWh)	Yearly revenue for upward flex (at 0.30 €/kWh price moments)	Yearly revenue downward flex taken average price of 0.087 €/kWh
↑↓	Battery Li-ion	−36.543	−1107.672
↑↓	Battery NaS	−42.916	−1184.472
↑↓	Flywheel	68.860	162.430
↑↓	CAES	54.397	−11.843
↑↓	EV Storage	−147.708	−2447.205
↑	Gas turbine	17.029	–
↑	Microturbine	5.344	–
↑	Fuel Cell CHP	32.207	–
↓	Power to heat	55.356	−0.291
↓	Supply management	27.092	−340.870
↑↓	Demand management	78.000	272.571

[4] See the website of Tennet for historical data: http://www.tennet.org/english/operational_management/export_data.aspx. The used data for this paper is based on a spring, winter, autumn and summer week in 2015.

visible from Table 4, that this is only interesting for the flywheel and demand management options. For the other DER this is not a profitable business.

When taking a look at the day ahead market prices in the Netherlands, the spread in the Dutch market ranges from 30 €/MWh to 37 €/MWh (Based on APX price result for a day in August and September 2015). This refers to a range of 3–4 ct €/kWh. This shows a much lower revenues for trading flexibility in such markets; and uninteresting from an economic point of view.

On a general note, the balancing market could potentially be interesting, providing most revenues for demand management and the fly-wheel technology for the short term. Incomes could range between 5 and 78 Euro per year for upward flexibility and between 162 and 272 euro per year for downward flexibility. However, it is important to take into account the investment costs for the technologies, which are significant for the flywheel technology, however very low for demand management, supply management and EV storage. From this work, it is visible that the EV is not interesting for very short flexibility needs in the system, due to the battery degradation effects of short-term flexibility provision.

Discussion

This section presents a discussion regarding the method presented in this paper for the short-term average cost of distributed energy resources.

With the activation of flexibility, the costs for information technology (IT) equipment and data storage are left outside of the scope of this work. In order for smart grids to development, it is important that the role of data management is well defined and integrated with the techno-institutional design for flexibility management. Recommended is that future work includes the cost for data management to provide a complete picture of costs for flexibility management.

Value of flexibility for other purposes

This work presents the value of electric flexibility in existing markets. However, the value of flexibility for the network is discussed qualitatively and not quantitatively. Network related cost are very situation dependent and therefore a general valuation was not possible without making many assumptions regarding the network scale, location and the timing of flexibility. However, future work could touch upon the cost reduction effects of flexibility management, or cost increase if not managed correctly. As discussed in the recommendations, it is most probable that mechanisms for flexibility management would be most beneficial if managed in an automated manner instead of a price based approach.

The effects of real-time pricing

In many markets, including the Dutch electricity market, retail pricing is always fixed pricing. Therefore, the cost calculations did not include time dependency of the flexibility required. However, in a reality with real-time prices, the timing of flexibility could create higher profits or losses from the flexibility trading taking place. However, due to the fact that the focus of this study was to provide a unified method which resembles reality in the Dutch system, the feed-in and consumption are chosen to be valued by a flat retail price. This furthermore ensured that the cost differences between different DER are only reflecting technology related costs (and not time dependent price differences).

Cost for upward and downward flexibility

In the calculation of the price of flexibility, in this paper we assumed that every flexibility taken from a device, is also being set back at another moment in time, in order to focus on the costs of the device specifically. Due to the fact that electricity prices were assumed to be fixed, this electricity price therefore has not been included in the cost calculation for short-term average costs. However, with variable pricing of electricity with for example a time-of-use price, the inclusion of the price becomes crucial.

In the analysis done within this paper, the cost for upward and downward flexibility have been settled as the same price, due to the fact that round-trip efficiency is for both ways (upward and downward flexibility) the same. Furthermore, due to the fact that the flexibility provided is also “set back” by the system operator, the cost remained the same.

However, when different units are combined in an aggregated manner, this yields a deferent result due to the fact that the different components have heterogeneous costs for upward and downward flexibility. Some units are able to provide only downward or only upward flexibility and some are not, leading to differences in the aggregated costs for up and downward flexibility.

Opportunity costs

This study took into account technical cost for activating the flexibility from distributed energy resources. However, beside the technical cost (like fuel, investments and operation and maintenance), there might be also socio-economic cost involved with the activation of flexibility, namely opportunity cost. Opportunity cost are the cost that would be made if the flexibility would not be provided and the unit would be operated to serve another purpose, for example when the EV is used to drive and transport a passenger instead of providing flexibility to the system. However when opportunity cost is taken into account the value of upward and downward flexibility could be very different and even more time dependent. Similar issue can be seen with opportunity cost for solar PV, when this unit is curtailed there might be incomes avoided and therefore this creates an opportunity costs. It is suggested that a next study takes also the aspect of opportunity cost into account in order to analysis the provision of flexibility not only from a techno-economic but also a socio-economic aspect.

Conclusions

This paper presented an assessment method to determine the short-term average cost of distributed energy resources and the net present value of the investment and maintenance costs. For battery technologies, the aspect of degradation costs is included. A first conclusion is that the short-term average costs of electric flexibility is significantly higher for most of the analyzed technologies than the revenues that can be obtained in existing markets like the day-ahead and balancing markets. The results shows that for short-term average cost perspective in short time frames of 15 min, the battery technologies and electric vehicle storage are very costly (€0.87), due to the degradation that such short battery usage would involve. The electric vehicle is very expensive for very short flexibility needs in the system (below 30 min) if the battery degradation costs of short-term flexibility provision are included (cost ranging between €0.23 and €0.83 per Kwh). These costs range for most technologies between €0.30 and €0.86 per kWh, which is already higher than the retail electricity price of €0.20 per kWh for electricity in the Netherlands. The cheapest options from a short term cost perspective are the fly-wheel technology (€0.04 per Kwh), compressed air storage (€0.09 per kWh), power to heat (€0.08 per Kwh) and fuel cell CHP (€0.18 per Kwh).

Even though the short-term costs are low, the upfront investments are exceptional high, ranging between 1500 and 2500 per kW for most technologies except for compressed air storage (550 per kW) and demand management (200 per kW). It is very questionable whether an end-user itself would invest in such technologies, or any aggregator in absence of financial incentives for such installations. Therefore, from an economic perspective, flexibility management is not economically viable for most technologies in the smart grid domain. If taken that the short-term average cost for demand management are set to zero, this might be the exception, discussed further in the next section.

In theory, demand management could be economically viable for both the end-user and the system. However, due to the fact that in this analysis only the investment costs for the activation of demand management have been taken into account, and the short-term average cost were set to zero, demand management requires further discussion. In reality, there are short-term costs related to demand management, for example, the opportunity costs if a specific device would operate non-interrupted. Other costs related to short term average costs for demand management could be device related costs. In short, it can be stated that if the short term average costs for demand management (which could be the opportunity cost or another device specific cost) are lower than the retail price of € 0.20 per kWh, and the revenue of performing demand management is higher than € 0.20 per kWh it is economically viable to perform demand management. The balancing market could potentially provide interesting flexibility trading opportunities for an aggregator. For demand management, revenues could be around € 78 upward and € 272 per year for downward flexibility service provision if the device is available at all times when flexibility is required.

On a general note, the balancing market could potentially be interesting for trading opportunities, providing most revenues for demand management and the flywheel technology. Incomes could range between € 5–78 per year for upward flexibility and between € 162 and € 272 per year for downward flexibility. However, it is important to take into account the investment costs for the technologies, which are significant for the flywheel technology, however very low for demand, supply and EV management. Important to note however, is that despite the high capacity and short-term average costs of battery technologies, these technologies are still being developed and costs are expected to fall in the future. However, for the longer time frames for flexibility (for example between 1 and 6 h), the costs for battery technologies decrease significantly. Beside the day-ahead and balancing market, it would be interesting for future research to take into account those short-term average costs and compare those to values in the intraday market. Other markets, like local (congestion) markets could also be an interesting issue, as presented by [16]. However, of importance is that the time-dependent prices in such local markets reflect plausible and generalizable network conditions.

For policy makers it is recommended is for policy to focus on the use of flexibility which is already economically efficient. This would involve demand management and fly wheel technologies. The work in this paper highlights the gap between the short term cost for distributed energy resources and the revenues in central markets and can therefore also provide insight in the level of subsidies needed for making distributed energy flexibility tradable at a central level. Important to note is that the incorporation of emission costs might change the affordability significantly. However, this is something for future work.

Future work could furthermore extend this work by incorporating a larger dataset of the central market prices. For example, with the charging and discharging of batteries and EVs, the strategic charging could lead to increased incomes for an aggregator.

Furthermore, simulation based work could incorporate network characteristics of the system and the use of flexibility for network congestion purposes. This work did not include the aspect of network related cost and the benefits that could be obtained when trading flexibility to solve congestion management issues. However, future research could include next to the short-term average cost, also the network short-term marginal cost in order to arrive to a nodal price of DER flexibility in the system. Locational energy prices send the right economic signals to the market players, enabling the market to operate properly in the short-term (with respect to losses and possible grid congestion). It should be bared in mind, that generally nodal prices do not lead to cost recovery [27]. Therefore the price should incorporate a minimum part, which could be the short-term average cost presented in this paper. Lastly, future work could incorporate the effects of opportunity cost, for example for the use of flexibility from EVs. However, important to take in mind is that those opportunity costs are highly dependent on the model assumptions and therefore should be set for a specific set of actors of which the opportunity costs are clear (like EV fleets belonging to taxi operators for example).

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