Levelized Cost of Storage - Introducing Novel Metrics

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Abstract – The increasing share of variable renewable generation capacity leads to a growing interest in electricity storage technologies and a summarizing cost metric to analyze the economic viability of such electricity storage units. For conventional generation technologies, the levelized cost of electricity (LCOE) is a well-known metric. In the context of electricity storage however, such LCOE-like metrics are only limitedly applicable as the finite energy storage capacity can limit the charge and discharge scheduling decisions of the storage operator. In addition, the "fuel", i.e., charged electricity, and "generated electricity", i.e., discharged electricity, is one and the same commodity which provides the opportunity to use an adapted levelized cost metric. This work analyzes three different levelized cost metrics and their application to electricity storage units used for electric energy arbitrage. The strengths and shortcomings of these storage cost metrics are analyzed in order to determine how they can be applied correctly. This analysis results in the following recommendations. First, it is recommended to use a levelized cost metric in combination with an analysis of a representative price profile upon which the storage operator will act. This allows a more accurate estimation of the number of charging and discharging hours and the associated charging cost and discharging revenue, given the energy storage capacity constraints of the storage unit. Second, when a number of different representative price profiles, hence with different charging costs, is available, it is recommended to use a cost metric which is independent of the charging cost as this single metric can be compared to each price profile, thereby facilitating the interpretation of the results. The results and conclusions from this work provide a framework on how to use levelized cost metrics in the context of electricity storage. Such metrics may help policy makers and investors in prioritizing energy storage investment decisions.

Key-words: Levelized cost metric, operational profit, discharge price, price spread, storage investor

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Nomenclature

OCC	Overnight Investment Cost
FOM	Fixed Operation & Maintenance Cost
ACC	Average Charging Cost
TCC	Total Charging Cost
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
RADP	Required Average Discharge Price
RAPS	Required Average Price Spread
RAOP	Required Average Operational Profit
AADP	Available Average Discharge Price
AAPS	Available Average Price Spread
AAOP	Available Average Operational Profit

1 Introduction

The growing share of intermittent renewable energy sources (iRES) in the electricity system leads to an increasing interest in different flexibility options for the electricity system. Electricity storage is a valuable option as it can shift generation and demand in time, thereby both generating electric power when too little renewable generation is available and consuming electric power when too much renewable generation takes place (Steinke et al., 2013; Ess et al., 2012). To analyze the economic potential of different storage technologies and determine which technology could store the necessary electric energy in the most economically efficient way, investors[1] and policy makers can use a set of tools ranging from the calculation of a summary cost metric to a simulation of the entire electricity system or market. One of the most well-known summary cost metrics to analyze the economic potential of a conventional generation technology is the Levelized Cost of Electricity (LCOE) (IEA/NEA, 2015). This cost metric is well established for conventional generation technologies but Joskow has shown that applying the metric to generation technologies which are not fully dispatchable (e.g. iRES) should be done with caution as it could easily lead to flawed conclusions (Joskow, 2011a; Joskow, 2011b). An adapted formulation of the LCOE metric was presented by Reichelstein and Sahoo (2015) to make it applicable to iRES. Inspired by the reflections by Joskow on applying the levelized cost methodology to iRES, the aim of the present paper is to analyze the levelized cost metric applied to storage technologies and to outline how it can be used correctly.

Specifically for storage there are several studies which use a range of cost metrics to compare different storage technologies. The DOE and EPRI (2013) list 5 costs metrics which can be used to analyze the economic potential of different storage technologies: the installed cost, the levelized cost of capacity, the levelized cost of energy and the present value of life-cycle costs both expressed in cost per installed power capacity and cost per installed energy storage capacity. They apply the different metrics to different technologies, but do not elaborate on the metrics itself. In a similar way, Jülch (2016) applies

[1] Although the investor, owner and operator of a storage unit can be three different entities, in this work we assume they are all one and the same and will use the terms investor, owner and operator as synonyms.

the LCOE metric, termed the levelized cost of storage (LCOS), to different storage technologies in order to compare them. Zakeri and Syri (2015) distinguish between a levelized cost of electricity and a levelized cost of storage, where the latter excludes the cost of charging electricity. This metrics is then used to compare the life cycle cost of different storage technologies. In comparison to the aforementioned studies, the present paper aims to analyze the levelized cost metrics for storage technologies themselves and how to use such metrics in general rather than applying them to specific storage technologies.

Few studies exist which analyze the levelized cost metrics applied to storage in a general way, rather than applied to specific situations. The existing studies are discussed below and although the cost metrics proposed in each study have their specifics, they all couple storage to a specific generation technology, thereby assuming a fixed cost for input energy. Pawel (2013) has presented a method to calculate the levelized cost of stored electricity in a similar way as the traditional LCOE and has extended the formulation to analyze hybrid iRES-storage plants. The World Energy Council (WEC, 2016) proposed a formulation for the LCOS in their report on electricity storage. In this formulation, the cost for input energy, or the charging cost, is left out of the calculation to avoid obscuring the results with too many assumptions. However, during further analysis in the report, storage is coupled with iRES and thus implicitly taking the levelized cost of this iRES as cost of input energy, as Pawel (2013) did. Lai and McCulloch (2016) use the LCOS formulation as provided by the WEC to analyze the cost component of storage in a hybrid iRES-storage plant. Together with the levelized cost component of the iRES capacity, they come to a metric termed the Levelized Cost of Delivery (LCOD), which, although analyzed in a different manner, sums up to a similar metric as Pawel (2013) introduced. Poonpun and Jewell (2008) calculate a storage cost as a cost added to each kWh of stored energy. In this paper we show that this methodology neglects the cost due to efficiency losses, which in turn depends on the cost of input energy.

The research presented in this paper adds to the existing literature as we extend the analyses made by Pawel, the WEC and Lai and McCulloch. The presented work aims at giving a more comprehensive analysis as it studies the impact of each parameter of the levelized cost metric. Rather than looking at hybrid iRES- storage plants, we focus our analysis solely on storage which acts upon a given price profile. This facilitates interpretation of the results and makes the outcome more broadly applicable. The objective of this work is two-fold: first, different cost metrics are presented and analyzed in depth to gain insights on the cost of storage in general. Second, the strengths and shortcomings of these cost metrics are analyzed to outline when and how a levelized cost metric can be applied correctly to storage.

The perspective taken in this paper is that of an actor who sees a varying electricity price profile on which he can act to arbitrage between moments with high prices and moments with low prices. In contrast to the traditional terminology of naming the cost metrics from a cost perspective, the cost metrics in this paper are named from a price perspective to make a clearer distinction between the different metrics. For typical generation units (both of the conventional and intermittent/variable type), the LCOE is traditionally referred to as the levelized cost of electricity although it is defined in terms of the electricity price that breaks even the costs. In this paper, we will focus more on the required average electricity price for reaching that break-even point for the investor/owner/operator[2].

[2] The origin of this price related name will be explained in the next section.

Three storage cost metrics are presented and analyzed which differ in the part of the variable costs that is accounted for:

1. the "*required average discharge price"*, should cover the full cost of the stored electricity: it allows the investor/owner/operator to break-even the investment cost, including payments on capital (interest for debt financing and a certain rate of return for equity), and other fixed and variable costs, incorporating the cost for the input electricity (that is effectively "bought" and is the equivalent of the fuel cost in typical generation units, if any);
2. the "*required average price spread",* is equal to the difference between the *required average discharge price* and the average price (being a cost) at which input electricity is charged;
3. the third metric is the "*required average operational profit"* which is the average profit an investor should make from arbitrage for recovering the investment cost, including payments on capital.

The three cost metrics are analyzed analytically and illustrated by simple methodological examples. These examples allow to identify specific points of attention when applying a levelized cost metric to storage and to outline how a levelized cost metric can be used correctly in such cases.

Results of this research show that when a levelized cost metric is used, care should be taken when the average charging cost is neglected, or is assumed to be zero, as this implicitly means that the round-trip efficiency of a storage technology is not accounted for. Also, it will be shown that a limited energy storage capacity can limit the storage operator to capture the full possible arbitrage profit of a certain price profile. In fact, the influence of this limited energy capacity is hard to evaluate without extensive calculation as it impedes estimating the total number of operating hours, the average electricity price during charging and the average electricity price during discharging. Therefore it is recommended to use the levelized cost metric in combination with an analysis of an entire representative price profile. In such case, using a levelized cost metric which is independent of the charging cost is most convenient to use as it can be compared to multiple price profiles without having to change the assumption for the average charging cost. This is a similar finding as was mentioned by the World Energy Council (WEC, 2016).

As IRENA points out in their report on battery storage for renewables (International Renewable Energy Agency (IRENA) 2015), the levelized cost metric is not necessarily representative for the value of storage as a storage facility can provide additional ("ancillary") services to the energy system not accounted for in the levelized cost metric. In the presented research, the value of such services is not included. This could be taken into account by subtracting a value term from the cost calculation but it is opted to leave this for future work as extra complexity might obscure the presented results. A second assumption made in this work is that of full foresight of the price profile for the storage operator. The absence of full foresight in real applications could be taken into account by adapting the method used to calculate a storage operator's possible arbitrage profit. This does not change, however, the way in which the different cost metrics can be used.

A few other remarks and caveats of this work must be mentioned upfront. The analysis presented should be as widely applicable as possible, meaning that it pertains to storage units/facilities of any size, capacity and application circumstance; the range of applicability stretches from short-time storage (like batteries) with perhaps several cycles per day, to intermediate-term storage (such as pumped hydro and compressed air storage), where cycling may range from days to weeks, up to long-term or seasonal storage (such as Power to Gas), where cycle periods may extend to months. This implies that the expressions must be able to account for various construction duration lengths (and hence the cost for "interest during construction")[3]—which may be negligible for e.g., batteries, but not for larger storage units. Furthermore, in the interest of generality,[4] we prefer not to use the concept of number of cycles. If desired, the conversion is easily made, e.g., for units with several cycles per day or per month, the amount of discharged electricity in year *t* (that we will refer to as MWh^d_t) can be written as $MWh^d_t = P{\cdot}365{\cdot}\chi_d{\cdot}\tau = E{\cdot}365{\cdot}\chi_d$ *or* $MWh^d_t = P{\cdot}12{\cdot}\chi_m{\cdot}\tau = E{\cdot}12{\cdot}\chi_m$ with P the installed power capacity, E the installed energy capacity, τ the discharge duration per cycle (with $E=P{\cdot}\tau$), and χ_d or χ_m the number of discharge cycles per day or per month, respectively. Note also that one can write the "produced" (i.e., discharged) electrical energy, using the "load factor", LF, being the ratio of the "number of discharging hours" NDH divided by 8760 h/a, as follows, $MWh^d_t= P{\cdot}NDH= P{\cdot}LF{\cdot}8760$.

To keep a sharp focus on the newly introduced metrics for storage, we will keep the formulae as transparent as possible, thereby ignoring taxes (e.g., tax deduction for depreciation) and subsidies. Although these transfer payments could be reasoned away as not being real economic costs, they do indeed impact the profitability for investors/owners and should therefore be accounted for in the LCOE as seen by investors in whatever tax regime or subsidy environment they operate. However, because this is very dependent of the tax/subsidy regimes (of which there is a large variety worldwide) we do not wish to overload our formulae to remain generic and complete on those aspects. Since it is important, though, we discuss important tax and subsidy elements in the LCOE concept, thereby relying strongly on Reichelstein and Yorston (2013), in Appendix A.

The remainder of this paper starts with a short review of the traditional LCOE metric, which is followed in section 3 and 4 by an introduction and analysis of three levelized cost metrics applicable to storage. The use of these cost metrics together with historical price profiles is shown in section 5 and discussed in section 6. Section 7 concludes this paper.

2 Levelized cost of electricity formulation and explanation of its meaning

The levelized cost of electricity (LCOE) for an electric power generating unit is defined as *the fictitious average electricity price during its operation hours and needed over the lifetime of the plant to break even the full costs for the investor/operator/owner (including the desired rate of return and interest payment on debt, which are included in the discount rate r, being equal to the "weighted average cost of capital", WACC [5]).* Thus, the LCOE is the fictitious stable electricity price needed to make the present value of the sum of all costs and all revenues over the entire operational life of the unit equal to zero.

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[3] For larger facilities, the word "construction" is commonly used; for smaller units, perhaps words like for "installation" or "erection" are more appropriate, whereby it is effectively understood that it does not take much time.

[4] Although we simplify our analysis by always charging and discharging at the rated/nominal power capacity of the storage device.

[5] Conventionally, WACC = $r_{debt}(Db/Tot)(1-tc)+r_{equity}(Eq/Tot)$, with Db+Eq = Tot and whereby Tot is the total volume of capital to be covered, Db the amount of debt financing and Eq the amount of equity; r_{debt} is the interest rate on debt and r_{equity} the expected rate of return for investors on own capital. tc is the corporate tax rate to be used to recover part of the interest paid on the loan. In the simplified philosophy of no taxes, the factor (1-tc) should

It is computed as follows (IEA/NEA, 2015):

$$\mathrm{LCOE} = \frac{\sum_t \left(OCC_t + OM_t + \mathrm{FC}_t + \mathrm{CO}_{2,t} + \mathrm{D}_t\right) \cdot (1+r)^{-t}}{\sum_t MWh_t (1+r)^{-t}} \tag{1}$$

Where:

OCC_t	= The Overnight Capital Cost expended in year t[6]
OM_t	= Operation & maintenance costs in year t, excluding fuel and possible CO_2 tax
FC_t	= Fuel costs in year t
$CO_{2,t}$	= CO_2 tax costs in year t
D_t	= Decommissioning and waste management costs in year t
MWh_t	= The amount of electricity generated in MWh in year t, being equal to P·NOH= P·LF·8760, with P the installed power capacity, NOH the number of operating hours and LF the average load factor.
$(1+r)^{-t}$	= The discount factor for year t, with r being the discount rate

Many of the costs usually take place in a different time period: investments (represented by OCC_t) take place during the construction or installation period, whereas OM_t, FC_t and $CO_{2,t}$ (if any) occur during the plant operation and decommissioning D_t takes place after the plant has stopped, and often even a few years after that. Often the index t is taken to be zero at the onset of operation, so that the construction period runs over a negative index. Through the discount factor $(1+r)^{-t}$, the expression then automatically computes the "interest during construction" expenditures.

To introduce a *levelized cost of storage* (LCOS), a 1-on-1 translation of the LCOE might be considered, thereby adopting its meaning in the sense that "fuel cost" becomes "charging cost" (i.e., the price at which input electrical power is "bought" by the storage facility) and "MWh generated" becomes the amount of MWh discharged and thus sold in the market. The meaning of LCOS would therefore read:

The LCOS could be defined as *the fictitious average electricity price during discharging needed over the lifetime of the storage plant to break even the full costs for the investor (including payments for capital).*

By means of the following analysis and the introduction of three cost metrics, it will become clear that the LCOS as defined above is incomplete in the sense that it is insufficiently precise and might therefore lead to poor investment decisions.

3 Storage cost terminology

It turns out that a distinction can be made between three cost metrics which, although being related to the LCOS, are more precisely formulated as: the *required average discharge price* (RADP), the *required average price spread* (RAPS) and the *required average operational profit* (RAOP). The word

be dropped. The user must decide whether to use the real or the nominal discount rate, and thus account for inflation or not.

[6] Note that t usually refers to one year, however, in every expression given in this paper, t could denote any time interval as long as the discount rate r is adapted accordingly.

"average" is a life-time average and each of these cost metrics is expressed on a per unit energy basis (i.e., per MWh). To improve the readability, often we will distinguish between "per unit of discharged energy" (MWh^d) and "per unit of charged energy" (MWh^c). Note that all three storage cost metrics must be expressed as 'required', to reflect the need for a break even overall cost.

As already mentioned, a levelized cost approach for an investor/owner/operator should include capital-related tax and/or subsidy effects to align these cost metric formulations with the Net Present Value result for such actors, as recommended by Reichelstein and Yorston (2013). However, to keep the focus on storage specific aspects of the cost metrics, the tax effect is neglected in the main text of the paper. For completeness, an extended formulation of each cost metric, including these tax effects, is given in Appendix A.

In the following part of this section, a mathematical formulation of all three cost metrics is given.

3.1 Required Average Discharge Price (RADP)

The *required average discharge price* (RADP) is basically a literal translation of the traditional LCOE formulation as given in Eq. (1). For full-cycle power to gas storage, CO_2 might be emitted by the electricity producing unit and should thus be taken into account, however, for most storage facilities, there would be no (operational) CO_2 tax and thus that term could be omitted. To simplify the formulation, the CO_2-tax cost and decommissioning costs are omitted and variable operation & maintenance costs are neglected. An extended formulation of the cost metrics, including these costs, is given in appendix A. The formulation for the required average discharge price is thus given in Eq. (2).

$$\mathrm{RADP} = \frac{\sum_t (OCC_t + FOM_t + \mathrm{TCC}_t) \cdot (1+r)^{-t}}{\sum_t MWh_t (1+r)^{-t}} \tag{2}$$

Where:

OCC_t	= Overnight construction costs in year t
FOM_t	= Fixed operation & maintenance costs in year t
TCC_t	= Total cost of charged electricity in year t
MWh_t^d	= The amount of electricity discharged in MWh in year t
$(1+r)^{-t}$	= The discount factor for year t, with r being the discount rate

Note that as already mentioned, $MWh^d_t = P\cdot 365\cdot \chi_d\cdot \tau = E\cdot 365\cdot \chi_d$ *or* $MWh^d_t = P\cdot 12\cdot \chi_m\cdot \tau = E\cdot 12\cdot \chi_m$ with P the installed power capacity, E the installed energy capacity, τ the discharge duration per cycle (with $E=P\cdot\tau$), and χ_d or χ_m the number of discharge cycles per day or per month, respectively. As seen, the energy storage capacity does not explicitly appear in the formula for *RADP* although it has an effect via the amount of discharged electricity; it is thus implicitly present in the factor MWh^d_t. This is obvious in the expressions of the previous sentence and it will be discussed more extensively in Section 5.

TCC refers to the total charging cost. The reader must observe that only one cost for the charged electricity is defined and used throughout the paper. This is similar to the LCOE philosophy for conventional generation plants, where there is one fuel cost, conventionally expressed in, €/MWh_e or \$/MWh_e, hence taking into account the conversion efficiency (and thus the efficiency losses) of the plant. In our case for storage devices, the equivalent "fuel cost" is the cost of the charged electricity, whereby this cost also includes the effects of the efficiency losses during both charging and discharging, which are in our definition combined in the round-trip efficiency η_{RT}[7]. There is no need to distinguish between efficiency losses during charging and discharging (similar to the fact that for conventional generation it is not necessary to split up the efficiency in a thermodynamic part of the cycle and an electric part of the electricity generator, etc.). The only difference from a system's perspective between a generation plant and a storage device is the time delay between the "fuel" input (i.e., charging) and electric power output (i.e., discharging) in a storage device.

In general, the "required" average discharge price differs from the average electricity price over the whole year as only prices during the time intervals of discharging are taken into account. Likewise, the charging cost is not equal to the annual average electricity price multiplied with the number of charging hours. Rather, the charging cost is the sum of the actual electricity prices at charging times, or said differently, the relevant "*average charging cost*" (ACC) is the weighted average cost obtained by averaging only during the charging hours and accounting for the amount of charged energy.

3.2 Required Average Price spread (RAPS)

The price spread is defined as the difference between the discharging price and the charging price. The *required average price spread* (RAPS) is calculated as given in Eq. (3), where MWh_t^c expresses the amount of electricity charged in MWh in year t.

$$\begin{aligned} RAPS &= \frac{\sum_t (OCC_t + FOM_t + TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} - \frac{\sum_t (TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^c (1+r)^{-t}} \\ &= RADP - ACC \end{aligned} \quad (3)$$

We have identified the *average charging cost* (ACC) as the total charging cost divided by the total amount of charged electricity (MWh^c) as indicated in Eq. (4):

$$\mathrm{ACC} = \frac{\sum_t TCC_t (1+r)^{-t}}{\sum_t MWh_t^c (1+r)^{-t}} \quad (4)$$

When exogenous charging, e.g., due to rain in a pumped hydro storage reservoir, and self-discharging are neglected, the amount of energy charged and discharged are linked through the round-trip efficiency η_{RT}, where we have assumed that η_{RT} is constant:

$$\sum_t MWh_t^d (1+r)^{-t} = \eta_{RT} \sum_t MWh_t^c (1+r)^{-t} \quad (5)$$

Using Eq. (5), the *required average price spread* (RAPS) expression of Eq. (3) can be simplified to:

$$RAPS = \frac{\sum_t (OCC_t + FOM_t + (1-\eta_{RT}) \cdot TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \quad (6)$$

[7] The round-trip efficiency is introduced more precisely below.

Eq. (6) shows that the *required average price spread* (RAPS) should cover the investment costs, the operation & maintenance costs and the cost due to efficiency losses.

3.3 Required Average Operational Profit (RAOP)

The *total* operational profit (OP) is the total revenue from discharging electricity minus the total cost from charging electricity. The required *total* OP for breaking even must equal the total costs expended for capital investment and fixed operation & maintenance costs and equals the difference between the required total revenue from discharging and the total charging cost as expressed in Eq. (7)[8]:

$$\begin{aligned} \text{Required total OP} &= \sum_t (OCC_t + FOM_t + TCC_t) \cdot (1+r)^{-t} - \sum_t (TCC_t) \cdot (1+r)^{-t} \\ &= \sum_t (OCC_t + FOM_t) \cdot (1+r)^{-t} \end{aligned} \tag{7}$$

For the reasons explained underneath Eq. (2), there is only one TCC which is canceled out from the first line of Eq. (7).

The *required average operational profit* (RAOP) can be defined by expressing the required total OP on a per unit of discharged energy basis, leading to Eq. (8):

$$\text{RAOP} = \frac{\sum_t (OCC_t + FOM_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{8}$$

3.4 Numerical illustration of the different cost metrics

An example is presented to illustrate the *required average discharge price* (RADP), the *required average price spread* (RAPS) and the *required average operational profit* (RAOP) introduced in the previous subsection. The example looks only at one year of operation for simplicity; the capital costs and fixed operation and maintenance cost are therefore converted in an equivalent annual fixed cost. Table 1 shows the assumed fixed cost, the round-trip efficiency, the total number of discharging hours and the average charging cost for the reference case. Parameter values will be varied within the different illustrative cases to follow. The parameter values used are not based on a specific technology but are merely chosen for illustrative purposes. For all examples, the storage unit is assumed to charge and discharge at nominal power. This is not necessarily the case in real situations but results can easily be generalized by expressing them in equivalent full load hours.

[8] Remark that, when certain costs, like labor costs, would be accounted for as fixed rather than variable operation & maintenance cost, our definition of operational profit would differ from the traditional definition as the latter excludes labor costs from the FOM when calculating the operational profit; Where in our definition all indirect costs are regarded fixed and remain in the calculation. However, if such labor cost is a direct cost (hourly wage) and as such accounted as variable operation & maintenance cost, both definitions become equal as shown in Appendix A.

Table 1: Storage parameters used for the reference case

Installed power capacity (P)	1 MW
Equivalent Annual Fixed cost (OCC + FOM)	30,000 €
Round-trip efficiency (η_{RT})	80 %
Number of discharging hours (NDH)	1000 h
Averaged charging cost (ACC)	20 €/MWh^c

Recall that no parameter is provided for the energy storage capacity E as there is no need to explicitly take it into account in the different cost metrics.[9] Also the duration during which no charging or discharging takes place is not needed, although it limits the max time during which electric power can be discharged.

The RADP, RAPS and RAOP are calculated for the reference case. For 1,000 h of discharging at nominal capacity of 1 MW (and thus discharging 1,000 MWh), a total amount of 1,250 MWh (= 1,000 h x 1 MW/η_{RT}) needs to be charged, costing 25,000€. Using Eqs. (2), (6) and (8), this leads to the results shown in Table 2.

Table 2: Different cost metrics for a storage with parameters as provided in Table 1.

RADP	55 €/MWh^d
RAPS	35 €/MWh^d
RAOP	30 €/MWh^d

As indicated in the previous subsection, the *required average discharge price* (RADP) covers all fixed and variable costs. The sum of all costs per installed MW is in this example equal to 30,000€ fixed cost and 25,000€ charging cost, resulting in a total cost of 55,000 €. Divided by 1000 h of discharging electricity at nominal power results in a required discharge price of 55 €/MWh^d. The *required average price spread* (RAPS) is equal to the *required average discharge price*, RADP = 55 €/MWh^d , minus the *average charging cost* (ACC), 20 €/MWh^c , which is equal to 35 €/MWh^d.[10] Putting it in a different perspective, the *required average price spread* (RAPS) is also equal to the fixed cost and cost due to efficiency losses. Indeed, applied to this example, the efficiency losses per MW capacity amount to (1,250 MWh^c – 1,000 MWh^d) x 20 €/ MWh^c = 5,000 €. Added to the fixed cost and divided by all discharged electric energy leads to a *required average price spread* (RAPS) of 35€/MWh^d. The *required average operational profit* (RAOP) only covers the fixed costs as shown and explained by Eq. (8): dividing the capital cost of 30,000 € by all discharged electricity (being 1,000 MWh) leads to an RAOP of 30 €/MWh^d. Note that the RAOP does not explicitly account for any operational costs as this is implicitly captured in the definition of the *required average operational profit* (RAOP).

[9] Indeed, it is implicitly present via $MWh^d_t = P{\cdot}365{\cdot}\chi_d{\cdot}\tau = E{\cdot}365{\cdot}\chi_d$ or $MWh^d_t = P{\cdot}12{\cdot}\chi_m{\cdot}\tau = E{\cdot}12{\cdot}\chi_m$ with $E=P{\cdot}\tau$ and $NDH=12{\cdot}\chi_m{\cdot}\tau$ or $NDH=365{\cdot}\chi_d{\cdot}\tau$, so that $MWh^d_t= P{\cdot}NDH= P{\cdot}LF{\cdot}8760$. (The symbols were defined near the end of Section 1.)

[10] Note that the subtraction of €/MWh^c from €/MWh^d is valid as both terms have the same unit (i.e. €/MWh). The superscripts c and d are only added for clarity, but do not change the unit of the cost.

4 Parameter variations

To gain deeper insight in the presented cost metrics, different parameters (charging cost, efficiency and amount of discharged electricity) will now be varied to analyze their effect on each metric and on the difference between the metrics.

4.1 Varying the average charging cost

To analyze the sensitivity of each cost metric to different average charging costs, a numerical illustration is presented first. For this example, the same fixed cost, number of discharging hours and efficiency are used as given for the reference case in Table 1. The *average charging cost* (ACC) is changed from 0 €/MWh^c to 100 €/MWh^c. The resulting cost metrics RADP, RAPS and RAOP are shown in Figure 1.

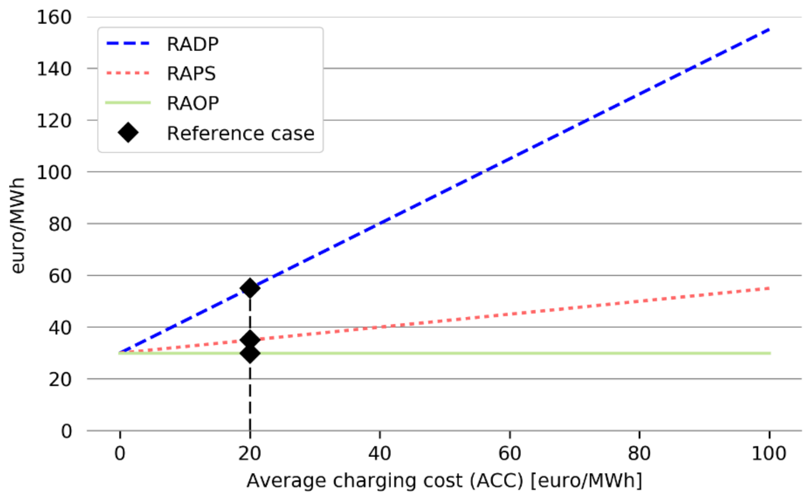

Figure 1: Required average discharge price (RADP), required average price spread (RAPS) and required average operational profit (RAOP) as a function of the average charging cost (ACC) for a storage device with characteristics as given in Table 1, with constant round-trip efficiency and constant amount of discharged electricity.

It is clear from Figure 1 that the *required average operational profit* (RAOP) is constant for all average charging costs (ACC). This follows from Eq. (8) which indicates that the RAOP should only cover the fixed costs. The *required average discharge* price (RADP) and the required *average price spread* (RAPS) increase with an increase in ACC, with a slope as given by Eqs. (9) and (10):

$$\frac{\partial \text{RADP}}{\partial ACC} = \frac{\sum_t (1+r)^{-t}}{\eta_{RT}} \tag{9}$$

$$\frac{\partial \text{RAPS}}{\partial ACC} = \frac{(1-\eta_{RT}) \sum_t (1+r)^{-t}}{\eta_{RT}} \tag{10}$$

Figure 1 and Eqs. (9) and (10) show that the RADP increases more steeply than the RAPS for an increasing ACC. This is reasonable as the RADP accounts for the full cost of all charged electricity, while the RAPS only account for the cost of energy lost due to efficiency losses. It is clear that the slopes of both sensitivities are not a function of the amount of discharged electricity but they do depend on the round-trip efficiency and the discount rate. This means that a change in ACC will have a bigger effect on the RADP and RAPS of storage units with a lower efficiency and will have no effect on the RAPS when the round-trip efficiency η_{RT} would become 100%.

In the given example, all cost metrics (RADP, RAPS and RAOP) become equal when the ACC is equal to zero. This is reasonable since all three measures only differ in how they account for the cost of energy losses or the full cost of charged electricity, as can be seen from Eqs. (2), (3) and (8). Note that when a variable cost different from the charging cost would be taken into account, the RADP and RAPS would increase with equal magnitude and would thus be different than the RAOP for an ACC equal to zero.

4.2 Varying the round-trip efficiency

The round-trip efficiency is varied next. A graphical illustration shown in Figure 2 is used to gain some basic insights.

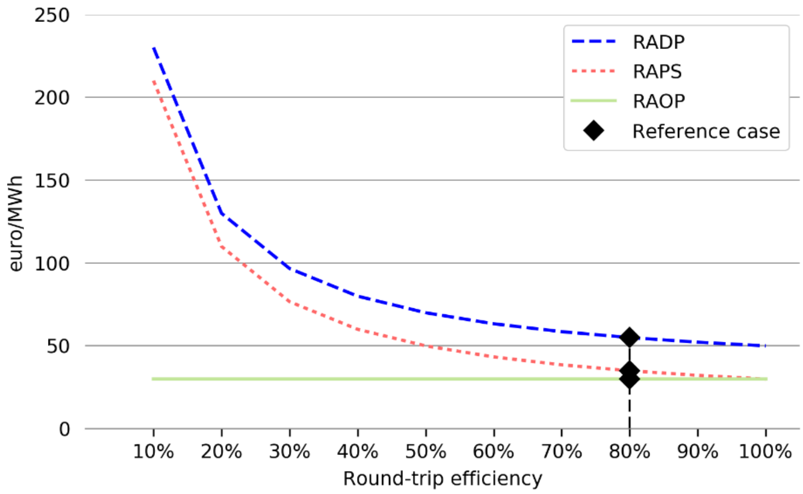

Figure 2: Required average discharge price (RADP), required average price spread (RAPS) and required average operational profit (RAOP) as a function of round-trip efficiency. For a storage unit with characteristics as given in Table 1, with constant average charging cost (ACC) and constant amount of discharged electricity.

It is clear that the *required average operational profit* (RAOP) is independent of the round-trip efficiency. This can be understood as the operational profit should, by definition, cover only the capital expenditures and fixed operational and maintenance costs. Since the round-trip efficiency impacts only the variable operational costs, it has no effect on the RAOP. This is also shown by Eq. (8). The *required average price spread* (RAPS) and the *required average discharge price* (RADP) both decrease with an increasing round-trip efficiency and do so both with the same absolute magnitude. This can be understood by looking at the sensitivity of the RADP and RAPS to a change in round-trip efficiency η_{RT} as given in Eq. (11):

$$\frac{\partial \text{RADP}}{\partial \eta_{RT}} = \frac{\partial \text{RAPS}}{\partial \eta_{RT}} = \frac{-\sum_t ACC \cdot (1+r)^{-t}}{\eta_{RT}^2} \tag{11}$$

The sensitivity formulated in Eq. (11) is negative since both the RADP and RAPS decrease with an increasing efficiency. This is normal as the RADP and the RAPS need to cover, besides the fixed costs, the full cost of charged electricity and the cost of efficiency losses, respectively. When the efficiency increases, less electricity needs to be charged per MWh of discharged electricity and hence, ceteris paribus, the total charging cost and the cost due to efficiency losses decrease. Eq. (11) shows that the slope of this sensitivity is not a function of the amount of discharged electricity but it does depend on the *average charging cost* (ACC). The magnitude of the slope of this sensitivity decreases with a decreasing *average charging cost* (ACC) (in absolute value), and becomes zero when the ACC is equal to zero.

The difference between the RADP and the RAPS is equal to the *average charging cost* (ACC) as presented in Eq. (12). This is obvious from Eq. (3), or following Eq. (4):

$$\text{RADP} - \text{RAPS} = \text{ACC} = \frac{\sum_t TCC_t \cdot (1+r)^{-t}}{\sum_t MWh_t^c (1+r)^{-t}} \tag{12}$$

As a final note, it is pointed out that the RAPS and RAOP merge when the round-trip efficiency is 100% and no variable costs different than the charging cost are accounted for. This can be understood by looking at the difference between the *required average price spread* (RAPS) and the *required average operational profit* (RAOP) which is obtained by subtracting Eq. (8) from Eq. (6), with the result shown in Eq. (13). This difference is exactly equal to the cost of efficiency losses per MWh of discharged electricity. Clearly, if no cost is incurred due to losses when the round-trip efficiency is 100%, the right hand side of Eq. (13) become zero and the RAPS is equal to the RAOP.

$$\text{RAPS} - \text{RAOP} = \frac{(1-\eta_{RT}) \sum_t TCC_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{13}$$

Rewriting Eq. (13) by using the relationship between the amount of charged and discharged electricity as given in Eq. (5) and the expression for the ACC in Eq. (4), shows that, although suggested differently by the denominator in Eq. (13), the difference between RAPS and RAOP is independent of the amount of discharged electricity:

$$\text{RAPS} - \text{RAOP} = \frac{(1-\eta_{RT}) \sum_t ACC \cdot (1+r)^{-t}}{\eta_{RT}} = \left(\frac{1}{\eta_{RT}} - 1\right) ACC \sum_t (1+r)^{-t} \tag{14}$$

4.3 Varying the amount of discharged electricity

The *required average discharge price* (RADP), the *required average price spread* (RAPS) and the *required average operational profit* (RAOP) of a storage unit with characteristics as given in the reference case (Table 1) are shown in Figure 3 for different numbers of discharge hours. It is clear that the RADP, RAPS and RAOP change with the same difference in absolute magnitude (i.e., they stay kind of "parallel"). To clarify this, we refer back to Eqs. (12) and (14) and present Eq. (15) which all show that the difference between the RADP, RAPS and RAOP only depends on the *average charging cost* (ACC) and, except for the difference between RADP and RAPS, on the round-trip efficiency but not on the number of discharging hours:

$$\text{RADP} - \text{RAOP} = \frac{\sum_t TCC_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} = \frac{\sum_t ACC \cdot (1+r)^{-t}}{\eta_{RT} \sum_t (1+r)^{-t}} = \frac{ACC \sum_t (1+r)^{-t}}{\eta_{RT} \sum_t (1+r)^{-t}} = \frac{ACC}{\eta_{RT}} \tag{15}$$

The decreasing trend of the RADP, RAPS and RAOP in Figure 3 originates from the fixed costs (capital and fixed operation & maintenance), which are divided by an increasing number of discharging hours. Hence the fixed costs decrease per unit of discharged energy.

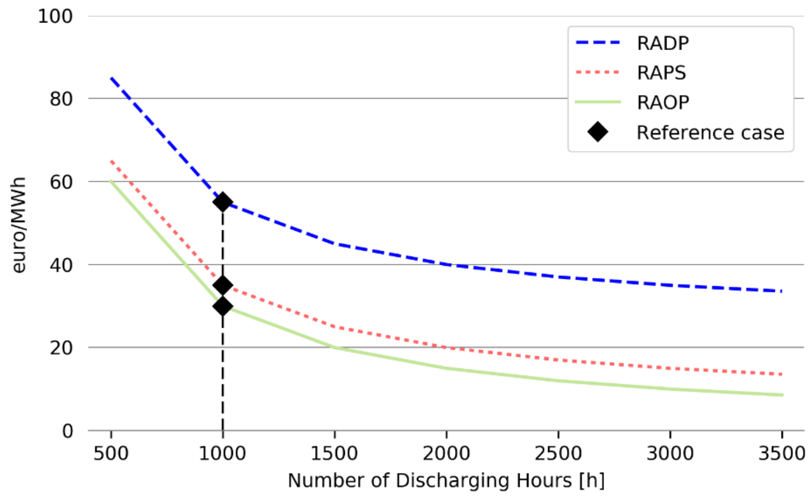

Figure 3: Required average discharge price (RADP), required average price spread (RAPS) and required average operational profit (RAOP) as a function of number of discharging hours. For a storage unit with characteristics as given in Table 1, with constant average charging cost (ACC) and constant round-trip efficiency.

From Figure 3 and Eqs. (12), (14) and (15) above, we can also conclude that the slope of change as a function of the change in number of discharging hours is equal for each cost metric. In Eq. (16), this is expressed by differentiating the RADP, RAPS and RAOP with respect to the amount of discharged electricity MWh^d:

$$\frac{\partial \mathrm{RADP}}{\partial MWh_t^d} = \frac{\partial \mathrm{RAPS}}{\partial MWh_t^d} = \frac{\partial \mathrm{RAOP}}{\partial MWh_t^d} = \frac{-\sum_t (OCC_t + FOM_t) \cdot (1+r)^{-t}}{\sum_t {MWh_t^d}^2 (1+r)^{-t}} \tag{16}$$

The formulation in Eq. (16) shows that the sensitivity of each cost metric to a varying amount of discharged electricity is independent of the *average charging cost* (ACC) and the round-trip efficiency.

5 'Available' prices compared to required prices

In the previous sections, three different *required* average price metrics were introduced, which express the conditions for the storage investor to break even the full investment cost, including the rate of return on investment, and possible operational costs, depending on the metric. To assess whether this storage investor will indeed break even on an investment, these required average price metrics could be compared to representative historical *available* average prices, as seen by the storage unit. Using available prices, again three metrics are formulated: the *available average discharge price* (AADP), the *available average price spread* (AAPS) and the *available average operational profit* (AAOP). It will be shown that when an available average price metric is higher than the required average price metric, it is worthwhile to invest in storage.

Note that the available, or observed, instantaneous electricity price chronology that prevails in the market and that a certain storage unit 'sees' might differ from the occurring electricity price chronology that the unit can take advantage of when the energy storage capacity is limited. Two examples are presented to illustrate this. In a first example, we learn that the number of hours actually available for arbitrage can differ between storage units even if they act upon the same occurring price profile. Figure 4 below shows a day-night price pattern with an alternating 12 hour low-price period and 12 hour high price period. If this pattern would occur for an entire year, there would be 4380 potential discharge hours with high prices and 4380 potential charging hours with low prices. A storage unit with a round-trip efficiency of 100% and an energy storage to power capacity ratio (E/P-ratio) of 12 hours or more, would be able to charge during all hours with low prices and discharge during all hours with high prices. However, a storage unit with an E/P-ratio of e.g. 5 hours would see the same price profile but would only be able to charge for 5 hours and discharge for 5 hours a day due to energy storage limitations. For a storage unit with a limited E/P-ratio of 5 hours, the occurring price pattern is clearly different from the actually "available" price pattern which the unit is able to capture.

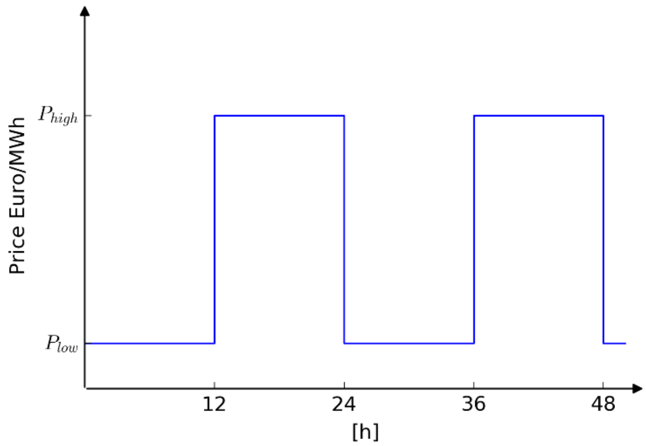

Figure 4: Reoccurring price signal with 24h period and alternating prices.

In a second example it is shown that one occurring price profile can lead to different available average charging and discharging prices for different storage units. An illustrative occurring price profile is presented in Figure 5. Consider again two storage units with different E/P-ratios, one with an E/P-ratio of 12h and one with an E/P-ratio of 5 hours. It is clear that the first storage unit can charge for 12 hours and then discharge for 12 hours, leading to an actually available average charging price of 15 €/MWh and an actually available average discharging price of 35 €/MWh. The second storage unit with a smaller E/P-ratio can only charge for 5 hours and would in an optimal scenario only charge during the hours with lowest price and discharge during the hours with highest price. Although this would lead to an actually available average charging price of 10 €/MWh and an actually available average discharge price of 40 €/MWh, the total profit of the storage operator would be lower.

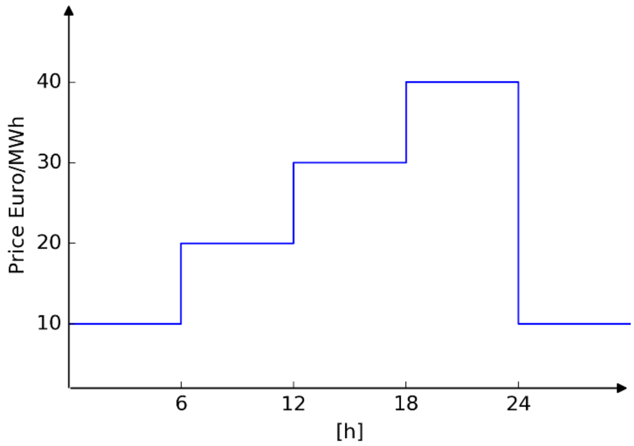

Figure 5: Reoccurring price signal with 20h period and increasing prices.

Both examples show the need to carefully analyze the entire occurring price profile when determining the average available cost metrics. The previous examples show furthermore that it is necessary to account for specific storage unit characteristics in this price profile analysis. Specifically when the storage unit is not always freely dispatchable by the storage operator, e.g., due to a limited energy storage capacity, considering only levelized cost metrics without analyzing representative price profiles might lead to erroneous conclusions considering the profitability of storage investments.

In the following sub-sections, the three *available* price metrics are introduced and graphically presented as a function of the number of discharge hours. A sensitivity analysis on the energy-to-power ratio and the round-trip efficiency is performed for each of the available price metrics. Furthermore, a comparison between the *required* price metric and the *available* price metric is presented and discussed.

5.1 Available Average Discharge Price (AADP)

The *available average discharged price* (AADP) is equal to the average electricity price during actual discharge hours and is entirely defined by a given price profile and storage operation, as expressed in Eq. (17),

$$\mathrm{AADP} = \frac{\sum_t Discharge\ revenue_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{17}$$

where:

Discharge revenue_t	= Total revenue of discharged electricity in year t
MWh_t^d	= The amount of electricity discharged in MWh in year t
$(1+r)^{-t}$	= The discount factor for year t

The *available average discharge price* (AADP) is calculated based on historical price profiles. In the following examples the Belgian day-ahead electricity prices in 2015 will be used (Belpex, 2016). To calculate the AADP, a small optimization program, presented in Appendix B, has been developed and is used to optimize the charging and discharging decisions of the storage operator, assuming perfect foresight of the prices and taking into account the installed capacity in terms of charging power, discharging power and energy storage. The optimization result is a charging and discharging sequence for the entire year and allows calculating the total charging cost, total discharging revenue, an available average charging price and *available average discharging price* (AADP). In the following examples, the AADP is calculated as a function of the number of discharging hours (NDH) which is imposed in a range from 250h to 3000h. This NDH is imposed on the storage operator as the maximum number of hours he is allowed to discharge in a year.

Two examples are presented in Figure 6 to gain insight in the AADP concept. On the left hand side of Figure 6, the AADP as a function of NDH is calculated for different values of the energy-to-power (E/P) ratio and a round-trip efficiency of 80%. On the right hand side of Figure 6, the AADP is calculated for different round-trip efficiencies and an unlimited energy-to-power ratio. Both figures show that the AADP decreases for an increasing number of discharging hours (NDH). This is reasonable as a very limited number of discharging hours (NDH) incentivizes the storage operator to discharge only during hours with very high electricity prices. When more discharging hours are allowed, the storage operator will also discharge during hours with lower electricity price which thus decreases the AADP. The left hand side of Figure 6 further shows that a limited E/P ratio both decreases the AADP and the number of hours for which arbitrage is profitable. Indeed, for small E/P ratios, a storage operator might be unable to discharge during a substantial period of consecutive hours with high prices as he can only store a limited amount of energy for small E/P ratios. This can limit the profitable arbitrage hours for the storage operator and force the operator to discharge during hours with lower prices, resulting in a lower AADP. The right hand side of Figure 6 shows the AADP for different round-trip efficiencies. If the storage unit were to have an unlimited E/P-ratio, the efficiency clearly has no influence on the magnitude of the AADP as the storage operator will always discharge during hours with highest prices. However, it has an effect on the number of hours for which arbitrage is profitable and hence the efficiency has an influence on the number of discharging hours that the storage unit is operated. Note that it is sometimes unprofitable to operate the storage unit for the maximum allowed NDH; for such cases, the different figures show only a curve for the NDH that the storage is effectively operated.

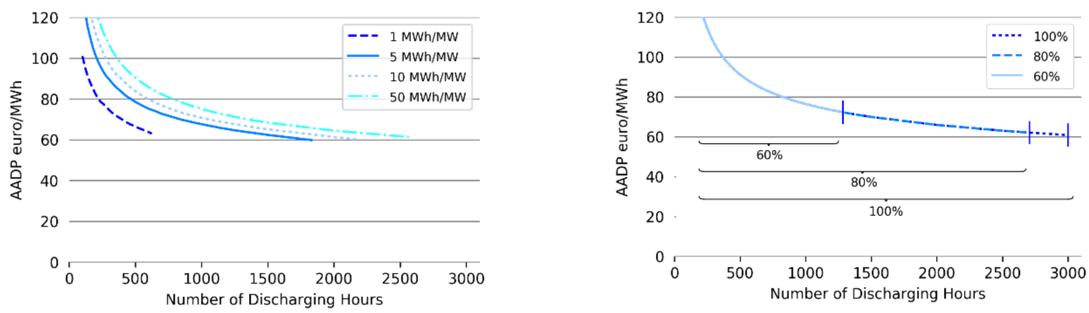

Figure 6: The *available average discharge price* (AADP) for a storage unit with parameters as presented in Table 1 for occurring prices at the Belgian day-ahead electricity market in 2015. In the left panel, the AADP is presented as a function of the number of discharging hours (NDH) for different energy-to-power (E/P) ratios. In the right panel, the AADP is presented for different round-trip efficiencies and an unlimited E/P ratio.

A comparison of the *available average discharge price* (AADP) and the *required average discharge price* (RADP) is illustrated in Figure 7 for different amounts of discharged electricity and for Belgian Day Ahead electricity prices of 2015. In Figure 7, the AADP is compared to the RADP whereby the latter is not calculated with a constant and thus average charging cost, but with the available *average charging* *cost* obtained from the optimization result which was used to calculate the AADP. The RADP shows a decreasing trend for an increasing number of discharging hours (NDH) which could be anticipated from Figure 3 as elaborated before, where a given constant charging price was applied. However, this trend in Figure 7 cannot be generalized since an increasing RADP for an increasing NDH could occur as the result of an increasing *average charging cost*. After all, recall that the *average charging cost* (ACC) used in the RADP calculation was based on the *average charging cost* (ACC) obtained from the AADP calculation and hence increases for increasing NDH. This increase in ACC counters the decrease in fixed costs per unit of discharged electricity. Depending on which of both effects is strongest, the RADP could show an increasing or decreasing trend for increasing NDH.

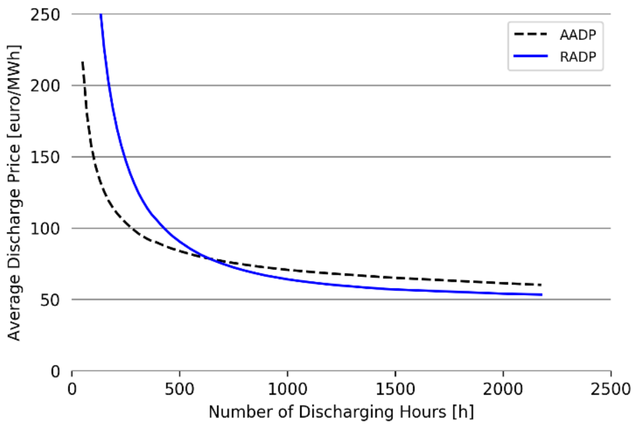

Figure 7: Comparison of the *available average discharge price* (AADP) and *required average discharge price* (RADP). The RADP is calculated with an average charging costs (ACC) obtained from the historical profile used to calculate the AADP. The AADP is calculated for a storage unit with an E/P ratio of 10h.

Note that the intersection between the RADP and the AADP on Figure 7 indicates the exact amount of electricity that needs to be discharged, expressed as a number of discharging hours at full power capacity, for the storage owner to break even the full investment cost. However, the same conclusion cannot be drawn if the RADP curve were to be calculated using an apriori given, or actually 'estimated', ACC. In such case, the intersection point would only give an indication of the break-even point. Therefore an accurate estimation of the ACC, compatible with the optimization procedure for charging and discharging, has to be made in order to compare the RADP to the AADP.

5.2 Available Average Price Spread (AAPS)

The *available average price spread* (AAPS) is defined as the difference between the *available average discharge price* (AADP) and the *average charging cost* (ACC) as expressed in Eq. (18):

$$\begin{aligned} \text{AAPS} \quad &= AADP - ACC \\ &= \frac{\sum_t Discharge\ revenue_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} - \frac{\sum_t (TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^c (1+r)^{-t}} \end{aligned} \tag{18}$$

Figure 8 shows the AAPS for different E/P ratios in the left panel and for different round-trip efficiencies in the right panel. Similar to the AADP, a small E/P-ratio leads to a decrease in the number of hours where arbitrage is profitable and thus a decrease in the AAPS . The decrease of the AAPS with NDH is stronger than the decrease of AADP as not only the average available discharge price decreases, but also the average charging cost increases with increasing NDH. The right panel shows the AAPS for different efficiencies between 60% and 100% while assuming the E/P-ratio to be unlimited. It is clear that the AAPS depends, albeit slightly, on the round-trip efficiency, as opposed to the AADP. This dependency of AAPS on the efficiency is due to an increase in the *average charging cost* (ACC). When the round-trip efficiency decreases, more electricity will have to be charged to maintain a certain amount of discharged electricity. To charge more electricity, the storage operator will be forced to charge also during hours with higher electricity prices, leading to an increase in both the total charging cost and the average charging cost and hence decreasing the AAPS for a decreasing efficiency. Although the hours during which the storage operator will discharge remain the same, and thus the AADP remains equal, the AAPS will decrease as the ACC increases.

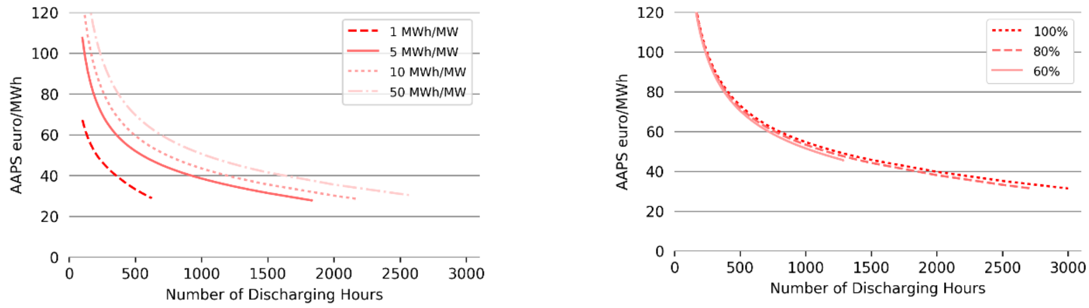

Figure 8: The *available average price spread* (AAPS) for a storage unit with parameters as presented in Table 1 for occurring prices at the Belgian day-ahead electricity market in 2015. In the left panel, the AAPS is presented as a function of the number of discharging hours (NDH) for different energy-to-power (E/P) ratios. In the right panel, the AAPS is presented as a function of the NDH for different round-trip efficiencies and an unlimited E/P ratio.

A comparison of the *available average price spread* (AAPS) and the *required average price spread* (RAPS) is illustrated in Figure 9. The RAPS curve is monotonically decreasing for an increasing NDH. It was shown before in Figure 1 that the RAPS is less sensitive to a change in ACC than the RADP as the RAPS does not account for the full cost of charged electricity but only for the cost of electricity charged to compensate for efficiency losses. Therefore, in this example, the impact of an increasing ACC is lower in magnitude than the decrease in fixed costs per unit of discharged electricity and hence the trend is monotonically decreasing.

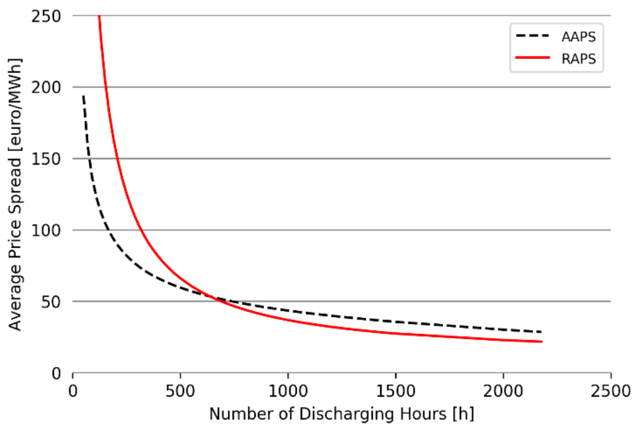

Figure 9: Comparison of the *available average price spread* (AAPS) and *required average price spread* (RAPS). The RAPS is calculated with an average charging costs (ACC) obtained from the historical profile used to calculate the AAPS. The AAPS is calculated for a storage unit with an E/P ratio of 10h.

Note again that the intersection between AAPS and RAPS on Figure 9 indicates the exact break-even point. When an apriori prescribed ACC would be used, the intersection point only indicates the estimated break-even point.

5.3 Available Average Operational Profit (AAOP)

The *available average operational profit* (AAOP) is expressed in Eq. (19). It is equal to the total revenue from discharged electricity minus the total cost of charged electricity, averaged over the total amount of discharged electricity:

$$\text{AAOP} = \frac{\sum_t (Discharge\ revenue_t - TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{19}$$

Figure 10 shows the AAOP as a function of the number of discharging hours (NDH) for different E/P-ratios and for different round-trip efficiencies in the left hand side and right hand side panels, respectively. Similar to the analysis in the previous sections, the left panel shows that a decrease in E/P-ratio decreases the AAOP. As before, a small E/P-ratio may cause the storage unit to be empty/full during many consecutive hours with high/low prices and thus prevent the storage operator to capture certain arbitrage opportunities. This in turn leads to a lower *available average operational profit* (AAOP). The right panel shows that the AAOP decreases for a decreasing round-trip efficiency. A similar trend was observed for the AAPS, where it was already mentioned that a decreasing efficiency leads to increased amount of electricity that needs to be charged in order to discharge a fixed amount of electricity. The electricity needed to compensate for the extra efficiency losses will be charged during hours with higher electricity prices. It thus increases the average charging cost and in turn decreases the *available average operational profit* (AAOP). Note that a change in round-trip efficiency leads to a change in AAOP which is greater in magnitude than the change in AAPS, which can be understood by comparing Eqs. (18) and (19).

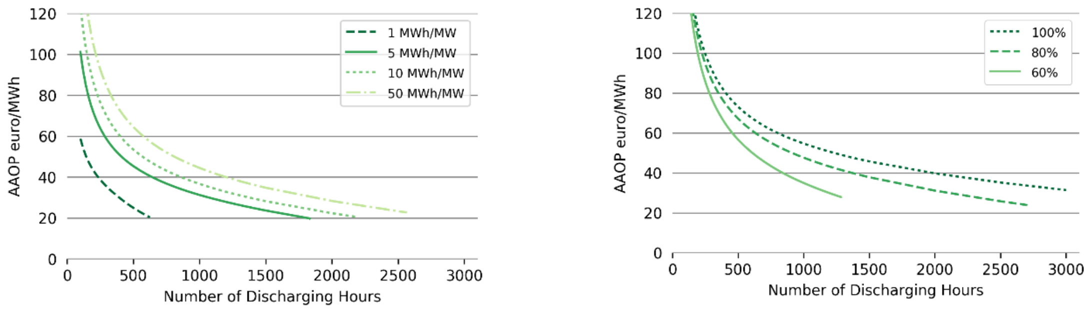

Figure 10: The *available average operational profit* (AAOP) for a storage unit with parameters as presented in Table 1 for occurring prices at the Belgian day-ahead electricity market in 2015. In the left panel, the AAOP is presented as a function of the number of discharging hours (NDH) for different energy-to-power (E/P) ratios. In the right panel, the AAOP is presented for different round-trip efficiencies with an unlimited E/P ratio.

A comparison of the AAOP and RAOP is shown in Figure 11. The intersection between the RAOP and the AAOP indicates the number of discharging hours at full power capacity needed for the storage owner to break even the full investment cost. Note that the RAOP is independent of the *average charging cost* (ACC) and hence the intersection between RAOP and AAOP indicates the exact break-even point.

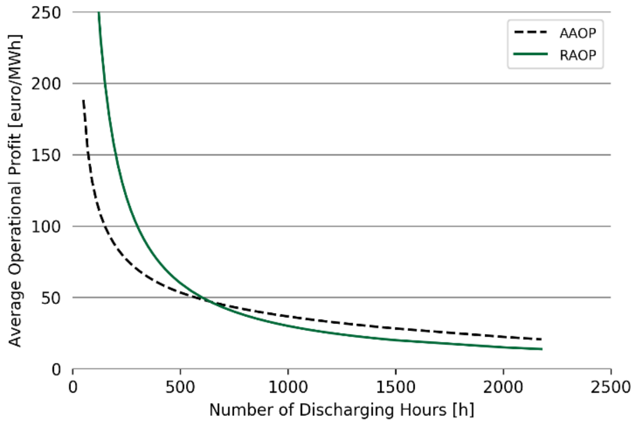

Figure 11: Comparison of the *available average operational profit* (AAOP) and *required average operational profit* (RAOP). The AAOP is calculated for a storage unit with an E/P ratio of 10h.

6 Discussion of the results

By comparing a required cost metric to the corresponding available cost metric, an investor can assess the profitability of a certain storage unit. When the required cost metric is lower than the available cost metric, it is profitable for the storage owner to invest in the storage unit. The amount of discharged electricity necessary to break-even the investment, is provided by the intersection of the required and available cost metrics. As noted before, this intersection provides the exact break-even point, when the *average charging cost* (ACC) used to calculate the required cost metric is based on the actually available *average charging cost*. If a certain given ACC would be used which usually differs from the actually available ACC, the intersection between two metrics provides only an estimation of the break-even point.

Figure 12 presents a comparison between the three required cost metrics and their corresponding available cost metrics. The actually available ACC is used for this figure, so the break-even point is equal for all three cost metrics.

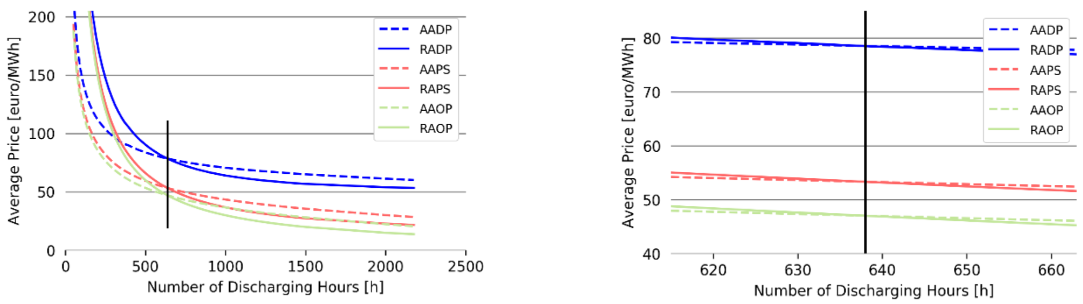

Figure 12: Comparison of the three available and the three required cost metrics, with a close-up on the intersection between required and available metrics in the right panel. The required cost metric is calculated using the average charging cost obtained from the calculation of the available cost metric. The available prices are calculated for a storage unit with an E/P ratio of 10h.

As indicated before, the *required average operational profit* (RAOP) is independent of the charging cost. It is therefore not necessary to assume a charging cost ex-ante to calculate the RAOP as a function of the expected number of discharging hours. This way, the profitability of a storage unit for the investor can be estimated without calculating an available average charging cost. It is therefore possible to compare only one RAOP to the AAOP based on different historical price profiles. This is an advantage of the RAOP compared to the RADP and RAPS; it is therefore recommended to use the RAOP. For this reason, the remaining of this section focusses on the operational profits only.

To obtain a better understanding of the effect of changing storage technology parameters on the comparison between the AAOP and the RAOP, some sensitivity analyses are presented next. From previous sections it became clear that the RAOP depends on the total fixed cost and on the number of discharging hours. The first analysis presented therefore consists of various RAOP curves as a function of the NDH for different fixed costs. This is shown in Figure 13, where the AAOP, calculated based on historical prices from 2015 as before, is compared to different RAOP curves. Depending on the height of the fixed costs, the storage unit becomes profitable above a certain number of discharging hours, in this example for fixed costs of 10,000 euro and for 30,000 euro. However, when the fixed costs are too high, a storage investor will not be able to break even his investment cost by temporal arbitrage on an electricity market with prices similar to those on the Belgian Day Ahead market in 2015, in this example for fixed costs of 50,000 euro and 100,000 euro. Note that current sodium sulfur batteries, for which the E/P-ratio of 10h as used in Figure 13 is representative, have a fixed cost between 3,000,000 and 4,000,000 euro for 1 MW of installed power capacity (WEC, 2016). A calculated RAOP for this storage technology would thus be so high that it would lay outside Figure 13. It is hence not profitable to install such battery for energy arbitrage only on the Belgian Day Ahead electricity market in 2015.

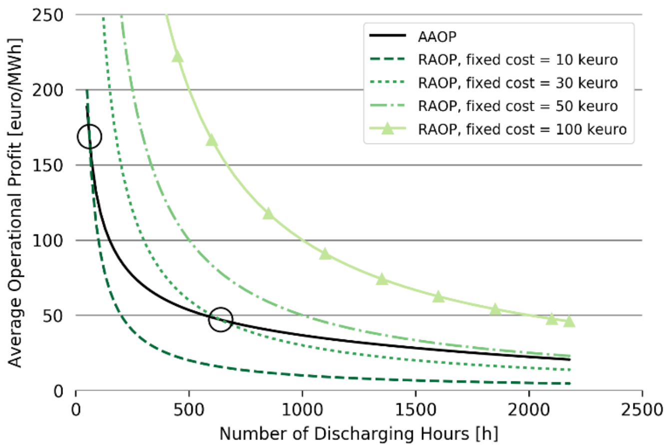

Figure 13: Comparison of the *available average operational profit* (AAOP) and *required average operational profit* (RAOP) for different capital cost values. The AAOP is based on Belgian day-ahead electricity prices in 2015 and is calculated for a storage unit with an E/P-ratio of 10h.

In the following sensitivity exercise, the number of discharging hours and energy-to-power ratio is varied, all parameters influencing the AAOP. Figure 14 presents a comparison of the RAOP to the AAOP calculated based on the historical prices occurring on the Belgian Day Ahead electricity market from different years. Although all AAOP curves differ slightly, they are of the same order of magnitude, especially for a higher number of discharging hours. In the left panel, the AAOP curves are calculated for a storage technology with an energy-to-power (E/P) ratio of 10 MWh/MW. The AAOP curves on the right figure are calculated for a storage technology with an unlimited E/P ratio. The difference between the left and right panel shows that the E/P ratio has a considerable impact on the AAOP and profitability of a storage unit.

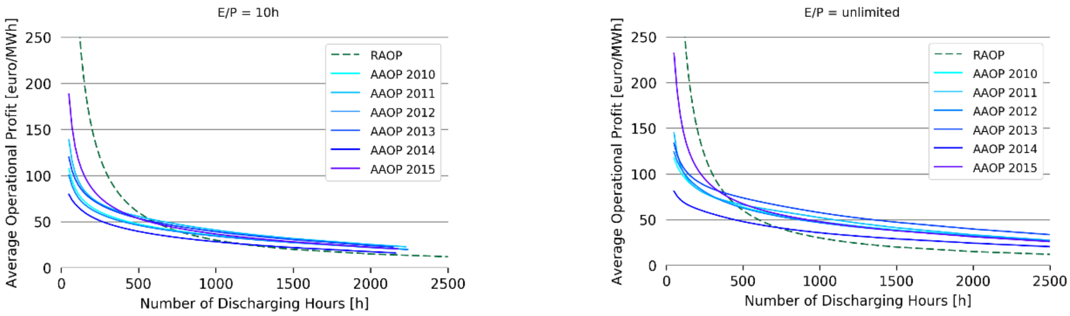

Figure 14: The *available average operational profit* (AAOP) for a storage unit with parameters as presented in Table 1 for occurring prices at the Belgian day-ahead market in the years 2010-2015. In the left panel, the AAOP is presented as a function of the number of discharging hours (NDH) for an energy-to-power ratio of 10 MWh/MW. In the right panel, the AAOP is presented for an unlimited energy-to-power ratio. The round-trip efficiency equals 80% in both panels.

As a last sensitivity exercise, the AAOP is calculated for different values of the round-trip efficiency. Figure 15 presents on the left hand side panel a comparison between the RAOP and the AAOP of different historical price profiles for a storage unit with a round-trip efficiency of 60%. The right hand side panel shows the same curves for a storage technology with a round-trip efficiency of 80%. Recall from section 4.2 that the RAOP is independent of the round-trip efficiency but the efficiency does have an influence on both the magnitude of the AAOP and on the amount of electricity for which it is profitable for the storage investor to arbitrage on the electricity market, as expressed by the attainable NDH and as shown in Figure 10 before.

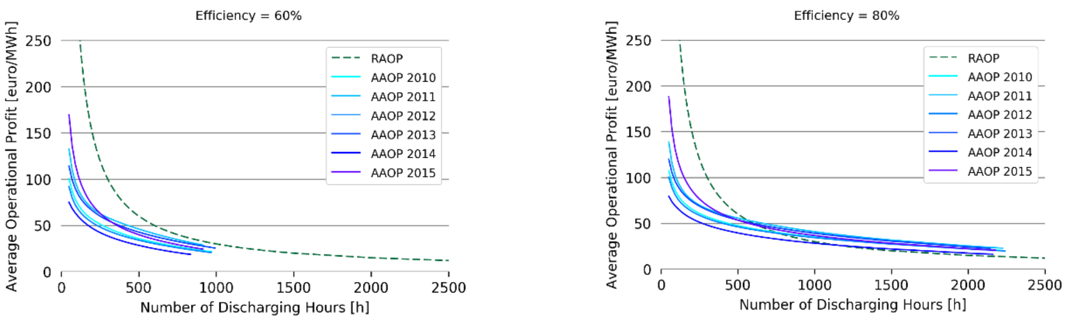

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Figure 15: The *available average operational profit* (AAOP) for a storage unit with parameters as presented in Table 1 for occurring prices at the Belgian day-ahead market in the years 2010-2015. In the left panel, the AAOP is presented as a function of the number of discharging hours (NDH) for an efficiency of 60%. In the right panel, the AAOP is presented for an efficiency of 80%. The E/P ratio used in both panels is 10h. The right panel is identical to the left panel of Figure 14.

7 Summary and Conclusions

Since the increasing share of intermittent renewable energy sources leads to a growing interest in storage capacity, there is a need for simple economic tools which facilitate comparing different storage technologies in order to assess whether an investment in a certain storage unit is worthwhile in a particular market. In the presented work, three cost metrics were analyzed which are inspired by the well-known levelized cost of electricity (LCOE). The presented metrics differ in the share of variable costs that is accounted for. A first metric, the *required average discharge price* (RADP), covers the full cost of the stored electricity in order for the investor to break-even the investment, including a certain rate of return. The *required average price spread* (RAPS), a second metric, is equal to the difference between the *required average discharge price* and the average price at which input electricity is charged. It thus takes into account the fixed costs and the cost due to efficiency losses. A last metric is the *required average operational profit* (RAOP) which is the average profit an investor should make from arbitrage in order to finance the investment cost and a certain rate of return. This last metric only accounts for recovery of the fixed costs.

Analysis of the three metrics shows that for an increasing *average charging cost* (ACC), the RADP and RAPS increase, while the RAOP stays constant. Furthermore, when the ACC is exactly zero, or is neglected, care should be taken as this implicitly means that the storage efficiency is not accounted for. All three measures become equal in such case. An increase in the round-trip efficiency leads to a decrease in both the RADP and the RAPS but has again no influence on the RAOP. An increasing number of discharging hours, which is representative for the amount of discharged electricity, leads to a decrease which is equal in magnitude for all three metrics.

Two simple examples show however that the energy capacity is not explicitly accounted for in the calculation of the cost metrics. Moreover, it is difficult to evaluate the impact of a small energy capacity on the number of discharging hours and the average price at which electricity can be charged. It is therefore necessary to use the levelized cost metrics in combination with the analysis of entire historical price profiles. Examples were used to show that the RAOP is the most transparent cost metric to use as it is independent of the charging cost and can therefore easily be compared to analyses of historical price profiles of different years without having to change the assumption for the average charging cost. Price profile analyses in this work are made under the assumption of perfect foresight for the storage operator. Incorporating uncertainty related to non-perfect price foresight and exploring different operational strategies, by e.g., setting price thresholds for an upper charging price and a lower discharging price, might be examined in future research.

The presented work only accounts for arbitrage revenues and does not incorporate possible revenue from providing additional services, e.g., ancillary services. This means that the obtained results give a pessimistic outlook of possible profits as it is expected that technically suitable storage units will participate in providing ancillary services and hence increase their profit. Accounting for this extra revenue is possible by adding the profit from such services to the AAOP. This could be the subject of future work.

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Appendix A – Levelized cost metrics including income tax

Following the example set by Reichelstein and Yorston (2013), the levelized cost metrics for storage are now extended to account for corporate income tax. The corporate income affect the levelized cost of storage through a direct tax on the cash flow, depreciation and debt tax shields and a possible investment tax credit. The debt related tax shield is assumed to be accounted for in the calculation of the Weighted Average Cost of Capital, which is represented in the levelized cost of storage through the discount rate r. To incorporate the other tax factors, following variables are used:

i	= Investment tax credit (in %)
α	= Effective corporate income tax rate (in %)
T^0	= Useful plant life for tax purposes (in years)
d_t	= Allowable tax depreciation charge in year t (in %)

Similar to Reichelstein and Yorston (2013), a tax factor Δ is defined as in Eq. (20) to incorporate corporate income tax following US tax arrangements. In contrast to Reichelstein and Yorston (2013), the asset value reduction factor for tax purposes is left out in our formulation as it is only applicable in specific situations.

$$\Delta = \frac{1 - i - \alpha \cdot (1 - i) \cdot \sum_t \ d_t \cdot (1 + r)^{-t}}{1 - \alpha} \tag{20}$$

In the following metric formulation, the overnight construction cost is assumed to be invested entirely during year t=0. If the construction period would span multiple years, different depreciation charges would be introduced corresponding to each year of construction and applying to the share of the construction cost invested during that year. Furthermore, for completeness, a term for the variable operational and maintenance cost (VOM_t) is incorporated. Any variable cost different from the charging cost is represented by this term, like e.g. a carbon tax.

Proposition 1. The *Required Average Discharge Price* (RADP) is defined as in Eq. (21).

$$\text{RADP} = \frac{OCC \cdot \Delta + \sum_t \ (FOM_t + VOM_t + TCC_t) \cdot (1 + r)^{-t}}{\sum_t \ MWh_t^d (1 + r)^{-t}} \tag{21}$$

To proof that the RADP as defined in Eq. (21) is indeed equal to the verbal definition of *Required Average Discharge Price* for the investor to break even on his investment, let us define the taxable income I_t in period t as in Eq. (22) with p the sales price during discharging.

$$I_t = MWh_t^d \cdot p - TCC_t - FOM_t - VOM_t - \ OCC \cdot (1 - i) \cdot d_t \tag{22}$$

Assuming the firm pays a share α of its taxable income as corporate income tax, the annual after-tax cash-flow CFL_t becomes:

$$CFL_t = MWh_t^d \cdot p - TCC_t - FOM_t - VOM_t - \ \alpha \cdot I_t \tag{23}$$

In accordance with conventional Net-Present Value calculations, the investor will break even on his investment when the price p during discharging is such that the present value of his investment is zero:

$$0 = -OCC \cdot (1-i) + \sum_t CFL_t \cdot (1+r)^{-t} \tag{24}$$

Solving Eq. (24) for *p* yields Eq. (25). The numerator in Eq. (25) equals the present value of all cash outflows per unit installed capacity. The last term represents the depreciation tax shield. The denominator equals the total value of electricity output, multiplied by the factor (1-α).

$$p = \frac{(1-i) \cdot OCC + (1-\alpha) \cdot \sum_t [TCC_t + FOM_t + VOM_t] \cdot (1+r)^{-t}}{(1-\alpha) \cdot \sum_t MWh_t^d (1+r)^{-t}} \\ \frac{-\alpha \cdot \sum_t [OCC \cdot (1-i) \cdot d_t] \cdot (1+r)^{-t}}{(1-\alpha) \cdot \sum_t MWh_t^d (1+r)^{-t}} \tag{25}$$

Using the tax factor Δ as defined in Eq. (20), Eq. (25) can be rewritten as Eq. (26) which is precisely the RADP as defined in Eq. (21).

$$p = \frac{OCC \cdot \Delta + \sum_t [TCC_t + FOM_t + VOM_t] \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{26}$$

Similar to the LCOE interpretation of Reichelstein and Yorston (2013), The RADP can be interpreted as the lifetime cost of the storage plant over the lifetime electricity discharged (Eq. (25)) or as the sum of the initial investment cost, adapted with a tax factor, and the lifetime operating costs, over the lifetime electricity discharged (Eq. (26)).

In analogy to the RADP, an adapted definition of the RAPS and the RAOP is given in Eqs. (27)-(28).

Proposition 2. The *Required Average Price Spread* (RAPS) is defined as in Eq. (27).

$$\text{RAPS} = \frac{OCC \cdot \Delta + \sum_t (FOM_t + VOM_t + (1-\eta_{RT}) \cdot TCC_t) \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{27}$$

To proof that the RAPS as defined in Eq. (27) is indeed equal to the verbal definition of *Required Average Price Spread* for the investor to break even on his investment, Eq. (24) is solved for *(p-ACC)*. Doing so yields precisely the definition as given in Eq. (27).

Proposition 3. The *Required Average Operational Profit* (RAOP) is defined as in Eq. (28)(27).

$$\text{RAOP} = \frac{OCC \cdot \Delta + \sum_t FOM_t \cdot (1+r)^{-t}}{\sum_t MWh_t^d (1+r)^{-t}} \tag{28}$$

To proof that the RAPS as defined in Eq. (28) is indeed equal to the verbal definition of *Required Average Operational Profit* for the investor to break even on his investment, Eq. (24) is solved for *(p-* $\sum_{t=1}^{T} TCC_t (1+r)^{-t}$ / $\sum_{t=1}^{T} MWh_t^d (1+r)^{-t}$ *= p-ACC/*η_{RT}*)*.

Appendix B – Arbitrage model formulation

t	Time step in set T
φ(t)	Electricity price during time step t
η_C	Charging efficiency of the storage unit
η_D	Discharging efficiency of the storage unit
Π	Total profit
D(t)	Amount of discharged electricity within time-step t
C(t)	Amount of charged electricity within time-step t
S(t)	Storage level at time t
$\overline{D}$	Maximum discharging capacity
$\bar{C}$	Maximum charging capacity
$\bar{S}$	Maximum energy storage capacity

The objective of the storage operator is to maximize the profit Π by optimizing the charging and discharging actions.

$$\Pi = \sum_{t} \varphi(t) \cdot [D(t) - C(t)]$$

The storage level at time step t is determined by the storage level from the previous time step and the charging and discharging actions during time step t.

$$\forall t \qquad S(t) = S(t-1) + \eta_C \cdot C(t) - \frac{D(t)}{\eta_D}$$

The charging and discharging actions are limited by a maximum charging capacity, discharging capacity and energy storage capacity.

$$\forall t \qquad C(t) \leq \bar{C}$$

$$\forall t \qquad D(t) \leq \overline{D}$$

$$\forall t \qquad S(t) \leq \bar{S}$$